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

Exhibit J-2

OUTER CONTINENTAL SHELF
PERMIT TO CONSTRUCT AND TITLE V AIR QUALITY OPERATING PERMIT

Permit Number:	R10OCS030000	Issuance Date:	October 21, 2011
AFS Plant I.D. Number:	02-010-OCS02	Effective Date:	November 28, 2011
		Expiration Date:	November 28, 2016

In accordance with the provisions of Section 328 and Title V of the Clean Air Act and 40 CFR Parts 55 and 71, and the applicable rules and regulations,

Shell Offshore Inc.
3601 C Street, Suite 1000
Anchorage, AK 99503

is authorized to construct and operate the Conical Drilling Unit Kulluk (Kulluk) and associated air emission units and to conduct other air pollutant emitting activities in accordance with the conditions listed in this permit, and only at the following lease blocks from the Beaufort Sea lease sales 186, 195 and 202:

OPD NR05-04 (Harrison Bay)
- Lease Sale 186: 6369, 6370, 6419, 6420, 6421BC
- Lease Sale 195: 6173, 6222, 6223, 6272, 6273, 6320,6321, 6322, 6323, 6371, 6372, 6373, 6374BC, 6424C, 6418, 6422B, 6423B, 6468, 6469B, 6518B, 6519A
- Lease Sale 202: 6221, 6274, 6319, 6324, 6367, 6368, 6470, 6471

OPD NR06-03 (Beechey Point)
- Lease Sale 186: 6352, 6402A, 6403B
- Lease Sale 195: 6152, 6202, 6203, 6204, 6251A, 6301B, 6252, 6253, 6254, 6255, 6256, 6302, 6303, 6304, 6305, 6306, 6307, 6308, 6309, 6351AB, 6401C, 6353, 6354, 6355, 6356, 6358, 6359, 6360, 6404A, 6405B, 6406B, 6409B, 6410, 6411, 6412
- Lease Sale 202: 6009, 6010, 6011, 6012, 6058, 6059, 6060, 6061, 6062, 6063, 6064, 6065, 6066, 6067, 6068, 6114, 6115, 6116, 6117, 6118, 6324

OPD NR06-04 (Flaxman Island)
- Lease Sale 195: 6657, 6658, 6659, 6707, 6708, 6709, 6712, 6713, 6757, 6758, 6764, 6773, 6774, 6814, 6815, 6822, 6823, 6824, 6873, 6874
- Lease Sale 202: 6251, 6252, 6259, 6301, 6302, 6303, 6304, 6305, 6308, 6309, 6310, 6351, 6352, 6353, 6354, 6355, 6356, 6357, 6358, 6359, 6401, 6402, 6403, 6404, 6405, 6406, 6407, 6408, 6409, 6410, 6453, 6454, 6455, 6456, 6457, 6458, 6459, 6460, 6461, 6504, 6505, 6506, 6508, 6510, 6511, 6512, 6554, 6555, 6558, 6559, 6560, 6561, 6562, 6609, 6610, 6611, 6612, 6660, 6662

OPD NR07-03 (Barter Island)
- Lease Sale 195: 6751, 6752, 6801, 6802, 6851

Terms not otherwise defined in this permit have the meaning assigned to them in the referenced statutes and regulations. All terms and conditions of the permit are enforceable by the United States Environmental Protection Agency (EPA) and citizens under the Clean Air Act (CAA).

__________________________ __________________________

Richard Albright — Date
Director, Office of Air, Waste and Toxics

TABLE OF CONTENTS

ABBREVIATIONS AND ACRONYMS

AAC ....Alaska Administrative Code
ASTM ....American Society of Testing and Materials
Btu................................British thermal units
^oC..................................degree Celsius
CAA ....Clean Air Act
CFR. ....Code of Federal Regulations
CH_4...............................Methane
CO ....Carbon Monoxide
CO_2...............................Carbon Dioxide
CMS ....Continuous monitoring system
dscf...............................dry standard cubic foot
EPA ....United States Environmental Protection Agency
^oF..................................degree Fahrenheit
GHG or GHGs ....Greenhouse Gas or Greenhouse Gases
hp..................................Horsepower
HPU..............................Hydraulic Power Units
hr ....hour
kWe ....KiloWatts electric
kWe-hr ....KiloWatts electric generated in an hour
lbs.................................Pounds
MLC..............................Mud line cellars
MMBtu/hr ....Million British thermal units per hour
N_2O ....Nitrous Oxide
NA.................................Not applicable
NAAQS ....National Ambient Air Quality Standards
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
OPD NR........................Official protraction diagram number
OSRV............................Oil spill response vessel
OTM.............................Other Test Method
Part 55 ....40 CFR Part 55
$PM_{2.5}$ ....Particulate matter with an aerodynamic diameter less than 2.5 microns
PM_{10} ....Particulate matter with an aerodynamic diameter less than 10 microns
pph................................pounds per hour
ppm ....Parts per million
ppmvd ....Parts per million by volume dry
PTE ....Potential to Emit
SCR ....Selective Catalytic Reduction
SO_2 ....Sulfur dioxide
Shell ....Shell Gulf of Mexico Inc. (the permittee)
tpy ....Tons per year
wt% ....Weight percent

AUTHORITY

The EPA is issuing this outer continental shelf (OCS) permit to construct (PTC) and Title V air quality operating permit pursuant to Section 328 of the CAA, 42 U.S.C. § 7627, and the implementing OCS regulations at 40 CFR Part 55, and pursuant to Title V of the CAA, 42 U.S.C § 7661, and the implementing air quality regulations at 40 C.F.R. Part 71 and Article 5 of the State of Alaska Air Quality Control Regulations 18 Alaska Administrative Code (AAC) 50.326 (Title V permit), and consistent with 18 AAC 50.502 (Minor Permits for Air Quality Protection) and 18 AAC 50.508 (Minor Permits Requested by the Owner or Operator), the applicable provisions of which have been incorporated into 40 C.F.R. Part 55 Appendix A. This action is based upon the application initially submitted by Shell Offshore Inc. (Shell or permittee) on February 28, 2011, supplemental submittals identified in the administrative record for this permit action, and upon the technical analysis performed by EPA.

FINDINGS

On the basis of the information in the administrative record, EPA has determined that:

1. The permittee will meet all of the applicable requirements of the 40 CFR Part 55;
2. The permittee will meet all of the applicable requirements of the 40 CFR Part 71; and
3. The permittee will meet all of the applicable requirements of 18 AAC 50.

SOURCE DESCRIPTION

The information contained within Tables 1 and 2 reflects vessels and emission units used by the permittee in preparing their application materials.

Table 1 – Kulluk Emission Units

Emission Unit ID[a]	Description	Approximate Aggregate Rating[b]
K-1A – 1D	Electricity Generation Engines	10,352 hp
K-2A – 2Z	MLC HPU Engines	1,500 hp
K-3A – 3Z	MLC Air Compressor Engines	1,500 hp
K-4A – 4C	Deck Crane Engines	1,200 hp
K-5A – 5Z	Heaters and Boilers	6 MMBtu/hr

[a] The “K” in the ID stands for the Kulluk. The number following the “K” in the ID distinguishes the different groups of units. For example, “1” is for electricity generation engines and “2” is for MLC HPU engines. The letters refer to the individual units within a group. The four electricity generation engines are identified K-1A, K-1B, K-1C and K-1D or together as K-1A – 1D. When a letter has not been assigned as is the case for the emergency engine and incinerator, the group consists of only one unit. The table references engines “A” to “Z” when the number of units within a group has not yet been determined. For seldom-used sources, there are four categories of engines, “A” to “D”, and for the “D” category, there are up to five engines.
[b] This permit does not limit the permittee to the specific rating listed. Permit conditions may limit operations to less than rated capacity.

Emission Unit ID[a]	Description	Approximate Aggregate Rating[b]
K-6	Emergency Generator Engine	1,047 hp
K-7A – 7D: Seldom-Used Sources		1,650 hp
K-7A	Remote-Operated-Vehicle Engine	300 hp
K-7B	Emergency Anchor Lifting Crane Engine	300 hp
K-7C	Emergency Diver Compressor Engine	300 hp
K-7D1 – 7D5	Emergency Lifeboat Propulsion Engines	750 hp
K-8	Incinerator	276 lb/hr
K-9	Fuel Tanks	423,469 gallons
K-10	Drilling Mud System	NA
K-11	Shallow Gas Diverter System[c]	NA

Table 2 – Associated Fleet Emission Units

Emission Unit ID[d]	Description	Approximate Aggregate Rating[e]
Icebreaker No. 1 (IB1)		
IB1-1A – 1Z	Propulsion Engines and Generator Engines	32,200 hp
IB1-2A – 2Z	Heaters and Boilers	10 MMBtu/hr
IB1-3A – 3Z	Seldom-Used Sources	Various
IB1-4	Incinerator	154 lb/hr
Icebreaker No. 2 - Anchor Handler (IB2)		
IB2-1A – 1Z	Propulsion Engines and Generator Engines	32,200 hp
IB2-2A – 2Z	Heaters and Boilers	10 MMBtu/hr
IB2-3A – 3Z	Seldom-Used Sources	Various
IB2-4	Incinerator	154 lb/hr
Resupply Vessel/Barge and Tug (RV/BT)[f,g]		
RV/BT-1A – 1Z	Propulsion Engines and Generator Engines	12,000 hp[h]
RV/BT-2A – 2Z	Seldom-Used Sources	Various
Oil Spill Response Vessel (OSRV)		
OSRV-1A – 1Z	Propulsion Engines and Generator Engines	3,500 hp

[c] Permit conditions prohibit the shallow gas diverter system from emitting any air pollutants.
[d] The acronym to begin the ID stands for the vessel. For instance, "IB1" stands for Icebreaker No. 1. The number following the acronym in the ID distinguishes the different groups of units. For example, "2" is for heaters and boilers on both Icebreaker No. 1 and Icebreaker No. 2. The letters refer to the individual units within a group. When a letter has not been assigned as is the case for incinerators, the group consists of only one unit. In many instances, the table references engines "A" to "Z" given that the number of units within a group has not yet been determined.
[e] This permit does not limit the permittee to the specific rating listed. Permit conditions may limit operations to less than rated capacity.
[f] Resupply vessels include, but are not limited to, resupply ships and barge and tugboat combinations.
[g] Multiple different RV/BT and OSRV WB may be employed over the course of a single drilling season.
[h] The rating for RV/BT and OSRV WB propulsion engines and generator engines listed in the table reflects approximate aggregate rating for an individual vessel, not for all RV/BT and OSRV WB combined.

Emission Unit ID[d]	Description	Approximate Aggregate Rating[e]
OSRV-2A – 2Z	Seldom-Used Sources	Various
OSRV-3	Incinerator	125 lb/hr
OSRV Work Boats (OSRV WB)[g]		
OSRV WB-1A – 1Z	Propulsion Engines and Generator Engines	600 hp[h]

COA PERMIT DETAILS

Date	Document Details
July 5, 2011	OCS Permit Application to Construct and Operate Conical Drilling Unit Kulluk in Beaufort Sea
July 7, 2011	Fuel Monitoring Information
July 13, 2011	Icebreaker No. 1 Additional Modeling Results and Modeling Files on Hard Drive

APPROVAL CONDITIONS

The permittee is authorized to construct and operate the Kulluk and Associated Fleet at any of the lease blocks identified on Page 1 of this permit, and consistent with the representations in the permit application and subject to the conditions in this permit.

OCS Source and Associated Fleet. Permit conditions contained in Sections B through G that apply to the Kulluk, except for those conditions addressing notification, reporting and testing, apply only during the time that the Kulluk is an OCS Source. Permit conditions contained in Sections B through G that apply to any vessel in the Associated Fleet, except for those conditions addressing notification, reporting and testing, apply only during the time that the Kulluk is an OCS Source and subject vessel in the Associated Fleet is within 25 miles of the Kulluk. Permit conditions in Section A as well as permit conditions contained in Sections B through G addressing notification, reporting and testing, apply at all times as specified.

For the purpose of this permit:

a. The Kulluk is an "OCS Source" at any time the Kulluk is attached to the seabed at a drill site by at least one anchor;

b. A drill site is any location at which Shell is authorized to operate under this permit and for which Shell or a leaseholder has received from the Bureau of Ocean, Energy, Management and Regulatory Enforcement (BOEMRE) an authorization to drill; and

c. The "Associated Fleet" refers to the following vessels: Icebreaker No. 1, Icebreaker No. 2 – Anchor Handler, resupply vessel(s)/barge(s) and tug(s), oil spill response vessel, and oil spill response vessel work boats.

Corresponding Onshore Area (COA) and Outer OCS Conditions. Conditions identified with "COA" in this permit only apply to lease blocks wholly or partially (the part that is within) on the "inner OCS" (within 25 miles of the state's seaward boundary) as listed below. Conditions identified as "outer OCS" in this permit only apply to lease blocks wholly or partially (the part that is outside) on the outer OCS (outside 25 miles of the state's seaward boundary) as listed below. All other conditions in this permit apply to lease blocks on both the inner and outer OCS.

OPD/Area	Lease Sale	Lease Block Numbers
Lease Blocks Entirely Inside 25 Miles of the State's Seaward Boundary		
NR05-04 Harrison Bay	186	6369, 6370, 6419, 6420, 6421BC
	195	6173, 6222, 6223, 6272, 6273, 6320,6321, 6322, 6323, 6371, 6372, 6373, 6374BC, 6424C, 6418, 6422B, 6423B, 6468, 6469B, 6518B, 6519A
	202	6221, 6274, 6319, 6324, 6367, 6368, 6470, 6471
NR06-03 Beechey Point	186	6352, 6402A, 6403B
	195	6152, 6202, 6203, 6204, 6251A, 6301B, 6252, 6253, 6254, 6255, 6256, 6302, 6303, 6304, 6305, 6306, 6307, 6308, 6309, 6351AB, 6401C, 6353, 6354, 6355, 6356, 6358, 6359, 6360, 6404A, 6405B, 6406B, 6409B, 6410, 6411, 6412
	202	6009, 6058, 6059, 6060, 6061, 6063, 6064, 6065, 6066, 6067, 6068, 6114, 6115, 6116, 6117, 6118, 6324
NR06-04 Flaxman Island	195	6657, 6658, 6659, 6707, 6708, 6709, 6712, 6713, 6757, 6758, 6764, 6773, 6774, 6814, 6815, 6822, 6823, 6824, 6873, 6874
	202	6251, 6252, 6301, 6302, 6303, 6351, 6352, 6353, 6354, 6355, 6356, 6401, 6402, 6403, 6404, 6405, 6406, 6407, 6408, 6409, 6410, 6453, 6454, 6455, 6456, 6457, 6458, 6459, 6460, 6461, 6504, 6505, 6506, 6508, 6510, 6511, 6512, 6554, 6555, 6558, 6559, 6560, 6561, 6562, 6609, 6610, 6611, 6612, 6660, 6662
NR07-03 Barter Island	195	6751, 6752, 6801, 6802, 6851
Lease Blocks Both Inside and Outside 25 Miles of the State's Seaward Boundary		
NR06-03 Beechey Point	202	6010, 6011, 6012, 6062
NR06-04 Flaxman Island	202	6304, 6305, 6357, 6358, 6359
Lease Blocks Entirely Outside 25 Miles of the State's Seaward Boundary		
NR06-04 Flaxman Island	202	6259, 6308, 6309, 6310

A. GENERALLY APPLICABLE REQUIREMENTS

1. Construction and Operation.

1.1. The permittee shall construct and operate the OCS Source and the Associated Fleet in accordance with the application and supporting materials submitted by the permittee as identified in the Statement of Basis for this permit action and in accordance with this permit. [40 CFR §55.6(a)(4)(i)]

1.2. Upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, the permittee shall promptly submit such supplementary facts or corrected information. [40 CFR §71.5(b), 18 AAC 50.326(a)]

2. **Overlapping Requirements.** When two or more provisions apply to the same emission unit or activity the permittee must comply with both. [40 CFR § 71.6(a)(1); 18 AAC 50.326(a)]

3. **Compliance Required.**

3.1. The permittee shall comply with all applicable requirements of 40 CFR Part 55 and this permit. In the inner OCS, the permittee shall also comply with all applicable requirements of 18 AAC 50. [40 CFR §§ 55.9(a) and 71.6(a)(6)(i);18 AAC 50.345(c)]

3.2. For applicable requirements with which the source is in compliance, the permittee will continue to comply with such requirements. For applicable requirements that will become effective during the permit term, the permittee shall meet such requirements on a timely basis. [40 CFR §§ 71.5(c)(8)(iii)(A)-(B) and 71.6(c); 18 AAC 50.326(a)]

3.3. Failure to comply with all requirements of 40 CFR Part 55 and this permit shall be considered a violation of Section 111(e) and Title V of the CAA and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application. All enforcement provisions of the CAA, including but not limited to, Section 113, 114, 120, 167, 303, and 304 apply to the permittee. [40 CFR §§ 55.9(a)-(b) and 71.6(a)(6)(i); 18 AAC 50.345(c)]

3.4. All terms and conditions of this permit, including any provision designed to limit the permittee's potential to emit, are enforceable by EPA and citizens under the CAA. [40 CFR § 71.6(b); 18 AAC 50.345(c)]

3.5. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. [40 CFR §71.6(a)(6)(ii); 18 AAC 50.345(d)]

4. **Compliance with Other Requirements; Permit Shield.**

4.1. This permit does not relieve the permittee of the responsibility to comply fully with applicable provisions of any other requirements under federal law, provided, however, that compliance with the terms and conditions of this permit shall be deemed compliance with the CAA applicable requirements as of the date of permit issuance that are included in and specifically identified in this permit. [40 CFR §§ 55.6(a)(4)(iii) and 71.6(f)(1); 18 AAC 50.345(b)]

4.2. Nothing in this permit shall alter or affect the following:

4.2.1. The provisions of section 303 of the CAA (emergency orders), including the authority of the Administrator under that section;

4.2.2. The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

4.2.3. The applicable requirements of the acid rain program, consistent with section 408(a) of the CAA; or

4.2.4. The ability of EPA to obtain information from a source pursuant to section 114 of the CAA.

[40 CFR §71.6(f)(3)(i-iv); 18 AAC 50.326(a)]

5. **Notification to Owners, Operators, and Contractors.** The permittee must notify all other owners or operators, contractors, and the subsequent owners or operators associated with emissions from the source of the conditions of this permit. [40 CFR § 55.6(a)(4)(iv)]

6. **Permit Expiration and Renewal.**

6.1. This permit shall expire on the expiration date on page one of this permit. Expiration of this permit terminates the permittee's right to operate unless a timely and complete permit renewal application has been submitted at least six months, but not more than 18 months, prior to the date of expiration of this permit. [40 CFR §§71.6(a)(11), 71.7(b), and 71.7(c)(1)(ii); 18 AAC 50.326(a) and 50.326(j)(2)]

6.2. The permittee shall submit a timely and complete application for a permit renewal at least six months, but not more than 18 months, prior to the date of expiration of this permit. The application for renewal shall include the current permit number, a description of permit revisions and off-permit changes that occurred during the permit term and were not incorporated into the permit during the permit term, any applicable requirements that were promulgated and not incorporated into the permit during the permit term, and other information required by the application form. [40 CFR §§71.5(a)(1)(iii), 71.5(a)(2), 71.5(c)(5), and 71.7(c)(1)(ii); 18 AAC 50.326(a)]

6.3. If the permittee submits a timely and complete renewal application, consistent with 40 CFR § 71.5 (a)(2), but EPA has failed to issue or deny the renewal permit, then all the terms and conditions of the permit, including any permit shield granted pursuant to 40 CFR § 71.6(f) shall remain in effect until the renewal permit has been issued or denied. This permit shield shall cease to apply if, subsequent to the completeness determination, the permittee fails to submit by the deadline specified in writing by EPA any additional information identified as being needed to process the application. [40 CFR §§ 71.5(a)(1)(iii), 71.7(b), and 71.7(c)(3); 18 AAC 50.326(a)]

6.4. Renewal of this permit is subject to the same procedural requirements that apply to initial permit issuance, including those for public participation, affected State, and tribal review. [40 CFR § 71.7(c)(1); 18 AAC 50.326(a)]

6.5. This approval to construct shall become invalid in the inner OCS if construction is not commenced within 18 months after the effective date of this permit, construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. EPA may extend the 18-month period upon a satisfactory showing that an extension is justified. Sources obtaining an extension are subject to all new or interim requirements and an assessment of applicable control technology when the extension is granted [40 CFR § 55.6(b)(4)]

7. Permit Revision, Termination and Reissuance.

7.1. This permit may be modified, revoked, reopened and reissued, or terminated by EPA for cause. Cause exists under any of the circumstances described in 40 CFR §71.7(f). The filing of a request by the permittee for modification, revocation and reissuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 CFR §§ 71.6(a)(6)(iii) and 71.7(f); 18 AAC 50.345(f)]

7.2. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in this permit. [40 CFR § 71.6(a)(8); 18 AAC 50.326(a)]

8. Credible Evidence. For the purpose of submitting compliance certifications in accordance with Condition A.12 for establishing whether or not the permittee has violated or is in violation of any requirement of this permit, nothing in this permit shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether the permittee would have been in compliance with applicable requirements if the appropriate performance or reference test or procedure had been performed. [section 113(a) and 113(e)(1) of the CAA, 40 CFR §§ 51.212, 52.12, 52.33, 60.11(g), and 61.12]

9. Inspection and Entry. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow EPA or an authorized representative to perform the following:

9.1. Enter upon the Kulluk, any support vessel, any location where emissions-related activity is conducted, or any location where records must be kept under the conditions of the permit;

9.2. Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;

9.3. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

9.4. As authorized by the CAA, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

[40 CFR § 71.6(c)(2); 18 AAC 50.345(h)]

10. Recordkeeping Requirements. In addition to the specific recordkeeping requirements contained in the source-wide and emission unit sections of this permit, the permittee shall keep records of required monitoring information that include the following:

10.1. The date, place, and time of sampling or measurements;

10.2. The date(s) analyses were performed;

10.3. The company or entity that performed the analyses;

10.4. The analytical techniques or methods used;

10.5. The results of such analyses;

10.6. The operating conditions as existing at the time of sampling or measurement;

10.7. Copies of all reports and certifications submitted pursuant to this permit; and

10.8. The locations where samples were taken.

The permittee shall retain records of all required monitoring data and support information for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

[40 CFR §§ 71.6(a)(3)(ii)(A-B) and 71.6(a)(3)(i); 18 AAC 50.326(a)]

11. Agency Notifications. Unless otherwise specified in this permit, any documents required to be submitted under this permit, including reports, test data, monitoring data, notifications, compliance certifications, fee calculation worksheets, and applications for renewals and permit modifications shall be submitted to:

OCS Air Quality Permits
U.S. EPA - Region 10, AWT-107
1200 Sixth Avenue, Suite 900
Seattle, WA 98101
Facsimile: 206-553-0110
Email: R10OCSAirPermits_Reports@epa.gov

[40 CFR §§ 71.5(d), 71.6(c)(1) and 71.9(h)(2); 18 AAC 50.326(a)]

12. Certification. Any document required to be submitted under this permit shall be certified by a responsible official, as that term is defined in 40 CFR § 71.2, of the permittee as to truth, accuracy, and completeness. Such certification shall state that based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. [40 CFR §§ 71.5(d), 71.6(c)(1) and 71.9(h)(2); 18 AAC 50.205, 50.326(c) and 50.345(j)]

13. Severability. The provisions of this permit are severable, and in the event of any challenge to any portion of this permit, or if any portion is held invalid, the remaining permit conditions shall remain valid and in force. [40 CFR § 71.6(a)(5);18 AAC 50.345(e)]

14. **Property Rights.** This permit does not convey any property Rights of any sort, or any exclusive privilege. [40 CFR § 71.6(a)(6)(iv);18 AAC 50.345(g)]

15. **Information Request.** The permittee shall furnish the EPA, within a reasonable time, any information the EPA requests in writing to determine whether cause exists to modify, revoke and reissue, or terminate the permit or to determine compliance with the permit. Upon request, the permittee shall furnish the EPA with copies of records required to be kept by the permit, including information claimed to be confidential. Information claimed to be confidential must be accompanied by a claim of confidentiality according to the provisions of 40 CFR Part 2, Subpart B. [40 CFR §§71.6(a)(6)(v) and 71.5(a)(3);18 AAC 50.345(i)]

16. **Emergency Provisions.** In addition to any emergency or upset provision contained in any applicable requirement, the permittee may seek to establish that noncompliance with a technology-based emission limitation under this permit was due to an emergency.

16.1. To do so, the permittee shall demonstrate the affirmative defense of emergency through properly signed, contemporaneous operating logs, or other relevant evidence that:

16.1.1. An emergency occurred and that the permittee can identify the cause(s) of the emergency;

16.1.2. The permitted facility was at the time being properly operated;

16.1.3. During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards, or other requirements in this permit; and

16.1.4. The permittee submitted notice of the emergency to EPA within 2 working days of the time when emission limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken. This notice fulfills the requirements of Condition A.17 of this permit, concerning prompt notification of deviations.

[40 CFR §§ 71.6(g)(2), (3) and (5)]

16.2. In any enforcement proceeding, the permittee attempting to establish the occurrence of an emergency has the burden of proof. [40 CFR § 71.6(g)(4)]

16.3. An “emergency” means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [40 CFR § 71.6(g)(1)]

17. **Outer OCS Deviation Reports.** The permittee shall promptly report to EPA, by telephone or facsimile or email, deviations from permit conditions, including those attributable to upset conditions as defined in this permit, the probable cause of such deviations, and any corrective actions or preventive measures taken. The report shall be made using the contact information provided in Condition A.11.

[40 CFR § 71.6(a)(3)(iii)(B)]

17.1. For the purposes of Conditions A.17 and A.18, deviation means any situation in which an emissions unit fails to meet a permit term or condition. A deviation is not always a violation. A deviation can be determined by observation or through review of data obtained from any testing, monitoring, or record keeping required by this permit. For a situation lasting more than 24 hours, each 24 hour period is considered a separate deviation. Included in the meaning of deviation are any of the following:

17.1.1. A situation where emissions exceed an emission limitation or standard;

17.1.2. A situation where process or emissions control device parameter values indicate that an emission limitation or standard has not been met;

17.1.3. A situation in which observations or data collected demonstrate noncompliance with an emission limitation or standard or any work practice or operating condition required by the permit (including indicators of compliance revealed through parameter monitoring);

17.1.4. A situation in which any testing, monitoring, recordkeeping or reporting required by this permit is not performed or not performed as required;

17.1.5. A situation in which an exceedance or an excursion, as defined in 40 CFR Part 64, occurs; and

17.1.6. Failure to comply with a permit term that requires submittal of a report.

[40 CFR § 71.6(a)(3)(iii)(C)]

17.2. For the purpose of Condition A.17 of the permit, prompt is defined as any definition of prompt or a specific time frame for reporting deviations provided in the underlying applicable requirement as identified in this permit. Where the underlying applicable requirement fails to address the time frame for reporting deviations, reports of deviations shall be submitted based on the following schedule:

17.2.1. For emissions of a hazardous air pollutant that continue for more than an hour in excess of permit requirements, the report must be made within 24 hours of the occurrence;

17.2.2. For emissions of any regulated pollutant excluding those listed in Condition A.17.2.1 above, that continue for more than two hours in excess of permit requirements, the report must be made within 48 hours of the occurrence; or

17.2.3. For all other deviations from permit requirements, the report shall be submitted within 30 days of the occurrence.

[40 CFR §§ 71.6(a)(3)(iii)(B) and 71.6(a)(3)(i)(B)]

17.3. Within 10 working days of the occurrence of a deviation as provided in Condition A.17.2.1 or A.17.2.2 above, the permittee shall also submit a written notice, which shall include a narrative description of the deviation and updated information as listed in Condition A.17, to EPA, certified consistent with Condition A.12 of this permit.

[40 CFR §§ 71.6(a)(3)(i)(B) and (iii)(B)]

18. COA Excess Emission and Permit Deviation Reports. Except as otherwise provided in this permit, the permittee shall report via fax or email, all emissions or operations that exceed or deviate from the requirements of this permit as follows:

18.1. As soon as possible after the event commences or is discovered, report:

18.1.1. Emissions that present a potential threat to human health or safety; and

18.1.2. Excess emissions that the permittee believes to be unavoidable.

18.2. Within two working days after the event commenced or was discovered, report an unavoidable emergency, malfunction, or non-routine repair that causes emissions in excess of a technology based emission standard; or any exceedance of an emission limit; or any exceedance of a throughput limit.

18.3. Report all other excess emissions and permit deviations:

18.3.1. Within 30 days after the end of the month during which the emissions or deviation occurred;

18.3.2. If a continuous or recurring excess emissions is not corrected within 48 hours of discovery, within 72 hours of discovery; and

18.3.3. For failure to monitor, as required in other applicable conditions of this permit.

18.4. When reporting excess emissions or permit deviations, the permittee must report using the form contained in Attachment A to this permit. The permittee must provide all information called for by the form.

18.5. If requested by the EPA, the permittee shall provide a more detailed written report as requested to follow up on an excess emissions report.

[18 AAC 50.346(b)(2)]

19. Semi-Annual and Annual Reporting. During the life of this permit[i], the permittee shall submit the following:

19.1. An original and two copies of an Operating Report by August 31 for the period January 1 to June 30 of the current year and by February 28 for the period July 1 to December 31 of the previous year. The Operating Report must include all information required to be in Operating Reports by other conditions of this permit. All instances of deviations from permit requirements must be clearly identified in such Operating Reports as required below. All required reports must be certified by a responsible official consistent with 40 CFR § 71.5(d).

19.1.1. If excess emissions or permit deviations that occurred during the reporting period are not reported under Condition A.18, either

19.1.1.1. The permittee shall identify:

19.1.1.1.1. The date of the deviation;

19.1.1.1.2. The equipment involved;

19.1.1.1.3. The permit condition affected;

19.1.1.1.4. A description of the excess emissions or permit deviation; and

19.1.1.1.5. Any corrective action or preventive measures taken and the date or dates of such actions; or

19.1.1.2. When excess emissions or permit deviations have already been reported under Condition A.18, the permittee shall cite the date or dates of those reports.

19.1.2. The Operating Report must include, for the period covered by the report, a listing of emissions monitored which trigger additional testing or monitoring, whether or not the emissions monitored exceed an emission standard. The permittee shall include in the report:

19.1.2.1. The date of the emissions;

19.1.2.2. The equipment involved;

19.1.2.3. The permit condition affected; and

19.1.2.4. The monitoring result which triggered the additional monitoring.

19.1.3. The Operating Report shall include reports of any required monitoring, including all emission calculations required by the permit.

[40 CFR §§ 71.9(h)(1),71.6(a)(3)(iii)(A), and 71.6(a)(3)(i)(B); 18 AAC 50.346(b)(6)]

[i] "Life of this permit" is defined as the permit effective dates, including any periods of reporting obligations that extend beyond the permit effective date. For example, if a permit expires prior to the end of a calendar year, there is still a reporting obligation to provide operating reports for the periods when the permit was in effect.

19.2. The permittee shall submit to EPA an annual certification of compliance with permit terms and conditions, including emission limitations, standards, or work practices, by February 28 of each year and covering the permit or permits in effect during the previous calendar year. The compliance certification shall be certified as to the truth, accuracy, and completeness by a responsible official consistent with Condition A.12 of this permit. The annual compliance certification shall include the following:

19.2.1. The identification of each permit term or condition that is the basis of the certification;

19.2.2. The identification of the method(s) or other means used by the permittee for determining the compliance status with each term and condition during the certification period. Such methods and other means shall include, at a minimum, the methods and means required in this permit. If necessary, the permittee also shall identify any other material information that must be included in the certification to comply with section 113(c)(2) of the CAA, which prohibits knowingly making a false certification or omitting material information;

19.2.3. The status of compliance with each term and condition of the permit for the period covered by the certification, including whether compliance was continuous or intermittent. The certification shall be based on the method or means designated above. The certification shall identify each deviation and take it into account in the compliance certification. The certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 occurred; and

19.2.4. Such other facts as the permitting authority may require to determine the compliance status of the source.

[40 CFR § 71.6(c)(5); 18 AAC 50.326(a)]

20. Off Permit Changes. The permittee is allowed to make certain changes without a permit revision, provided that the following requirements are met;

20.1. Each change is not addressed or prohibited by this permit;

20.2. Each change meets all applicable requirements and does not violate any existing permit term or condition;

20.3. The changes are not changes subject to any requirement of 40 CFR Parts 72 through 78 or modifications under any provision of Title I of the CAA;

20.4. The permittee provides contemporaneous written notice to EPA of each change, except for changes that qualify as insignificant activities under 40 CFR § 71.5(c)(11), that describes each change, the date of the change, any change in emissions, pollutants emitted, and any applicable requirements that would apply as a result of the change;

20.5. The changes are not covered by a permit shield provided under 40 CFR § 71.6(f) and Condition A.4 of this permit; and

20.6. The permittee keeps a record describing all changes that result in emissions of any regulated air pollutant subject to any applicable requirement not otherwise regulated under this permit, and the emissions resulting from those changes.

[40 CFR §71.6(a)(12); 18 AAC 50.326(a)]

21. Emissions Trading and Operational Flexibility. The permittee is allowed to make a limited class of changes under section 502(b)(10) of the CAA within this permitted facility that contravene the specific terms of this permit without applying for a permit revision, provided:

21.1. The changes do not exceed the emissions allowable under this permit (whether expressed therein as a rate of emission or in terms of total emissions);

21.2. The changes are not Title I modifications;

21.3. The changes do not violate applicable requirements;

21.4. The changes do not contravene federally enforceable permit terms and conditions that are monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements;

21.5. The permittee sends a notice to EPA, at least 7 days in advance of any change made under this provision, that describes the change, when it will occur and any change in emissions and identifies any permit terms of conditions made inapplicable as a result of the change and the permittee attaches each notice to its copy of this permit; and

21.6. The changes are not covered by a permit shield provided under 40 CFR § 71.6(f) and Condition A.4 of this permit.

[40 CFR § 71.6(a)(13)(i); 18 AAC 50.326(a)]

22. COA Administration Fees. The permittee shall pay to the EPA all assessed permit administration fees. Administration fee rates are set out in 18 AAC 50.400 – 50.403. [18 AAC 50.400 – 50.403]

23. COA Assessable Emissions. The permittee shall pay to the EPA annual emission fees based on the OCS source's (including the Associated Fleet) assessable emissions as determined by the EPA under 18 AAC 50.410. The assessable emission fee rate is set out in 18 AAC 50.410. The EPA will assess fees per ton of each air pollutant that the OCS source emits or has the potential to emit in quantities greater than 10 tons per year (tpy). The quantity for which fees will be assessed is the lesser of:

23.1. The OCS source's (including the Associated Fleet) assessable potential to emit of 459 tpy; or

23.2. The OCS source's (including the Associated Fleet) projected annual rate of emissions that will occur from July 1 to the following June 30, based upon actual annual emissions emitted during the most recent calendar year or another 12 month period approved in writing by the EPA, when demonstrated by:

23.2.1. An enforceable test method described in 18 AAC 50.220;

23.2.2. Material balance calculations;

23.2.3. Emission factors from EPA's publication AP-42, Vol. I, adopted by reference in 18 AAC 50.035; or

23.2.4. Other methods and calculations approved by the EPA.

[18 AAC 50.410 – 50.420]

24. COA Assessable Emissions Estimates. Emission fees will be assessed as follows:

24.1. No later than March 31 of each year, the permittee may submit an estimate of the OCS source's assessable emissions to the EPA at the address listed in Condition A.11, Agency Notification. The submittal must include all of the assumptions and calculations used to estimate the assessable emissions in sufficient detail so that EPA can verify the estimates; or

24.2. If no estimate is received on or before March 31 of each year, emission fees for the next fiscal year will be based on the potential to emit set out in Condition A.23.1.

[18 AAC 50.410 – 50.420]

25. Outer OCS Part 71 Emission and Fee Reporting.

25.1. Part 71 Annual Emission Report. No later than the date specified in Condition A.19.2 of each year, the permittee shall submit to EPA an annual report of actual emissions for the preceding calendar year. [40 CFR § 71.9(h)(1)]

25.1.1. "Actual emissions" means the actual rate of emissions in tons per year of any "regulated pollutant (for fee calculation)," as defined in 40 CFR § 72.2, emitted from a Part 71 source over the preceding calendar year. Actual emissions shall be calculated using each emissions unit's actual operating hours, production rates, in-place control equipment, and types of materials processed, stored, or combusted during the preceding calendar year. [40 CFR § 71.9(c)(6)]

25.1.2. Actual emissions shall be computed using methods required by the permit for determining compliance, such as monitoring or source testing data. [40 CFR § 71.9(h)(3)]

25.1.3. Actual emissions shall include fugitive emissions. [40 CFR § 71.9(c)(1)]

25.2. Part 71 Fee Calculation Worksheet. Based on the annual emission report required in Condition A.25.1 and no later than the date specified in Condition A.19.2 of each year, the permittee shall submit to EPA a fee calculation worksheet (blank forms provided by EPA) and a photocopy of each fee payment check (or other confirmation of actual fee paid). [40 CFR §§ 71.9(c)(1), 71.9(e)(1) and 71.9(h)(1)]

25.2.1. The annual emissions fee shall be calculated by multiplying the total tons of actual emissions of each "regulated pollutant (for fee calculation)," emitted from the source by the presumptive emission fee (in dollars/ton) in effect at the time of calculation. The presumptive emission fee is revised each calendar year and is available from EPA prior to the start of each calendar year. [40 CFR § 71.9(c)(1)]

25.2.2. The permittee shall exclude the following emissions from the calculation of fees:

25.2.2.1. The amount of actual emission of each regulated pollutant (for fee calculation) that the source emits in excess of 4,000 tons per year;

25.2.2.2. Actual emissions of any regulated pollutant (for fee calculation) already included in the fee calculation; and

25.2.2.3. The insignificant quantities of actual emissions not required to be listed or calculated in a permit application pursuant to 40 CFR § 71.5(c)(11).

[40 CFR § 71.9(c)(5)]

25.3. Part 71 Annual Fee Payment. No later than the date specified in Condition A.19.2 of each year, the permittee shall submit to EPA full payment of the annual permit fee based on the fee calculation worksheet required in Condition A.25.2. [40 CFR §§ 71.9(a), 71.9(c)(1) and 71.9(h)(1)]

25.3.1. The fee payment and a completed fee filing form shall be sent to:

U.S. EPA
FOIA and Miscellaneous Payments
Cincinnati Finance Center
P.O. Box 979078
St Louis, MO 63197-9000

[40 CFR § 71.9(k)(2)]

25.3.2. The fee payment shall be in United States currency and shall be paid by money order, bank draft, certified check, corporate check, or electronic funds transfer payable to the order of the U.S. Environmental Protection Agency. [40 CFR § 71.9(k)(1)]

25.3.3. The permittee, when notified by EPA of additional amounts due, shall remit full payment within 30 days of receipt of an invoice from EPA. [40 CFR § 71.9(j)(2)]

25.3.4. If the permittee thinks an EPA assessed fee is in error and wishes to challenge such fee, the permittee shall provide a written explanation of the alleged error to EPA along with full payment of the EPA assessed fee. [40 CFR § 71.9(j)(3)]

25.3.5. Failure of the permittee to pay fees in a timely manner shall subject the permittee to assessment of penalties and interest in accordance with 40 CFR § 71.9(l). [40 CFR § 71.9(l)]

25.4. The annual emission report and fee calculation worksheet (and photocopy of each fee payment check), required in Conditions A.25.1 and A.25.2, shall be submitted to EPA at the address listed in Condition A.11 of this permit.[j] [40 CFR § 71.9(k)(1)]

25.5. The annual emission report and fee calculation worksheet (and photocopy of each fee payment check), required in Conditions A.25.1 and A.25.2, shall be certified by a responsible official in accordance with Condition A.12 of this permit. [40 CFR § 71.9(h)(2)]

25.6. The permittee shall retain in accordance with the provisions of Condition A.10 of this permit, all work sheets and other materials used to determine fee payments. Payments shall be retained for five years following the year in which the emissions data is submitted. [40 CFR § 71.9(i)]

26. COA General Source Test Requirements.

26.1. Requested Source Tests. In addition to any source testing explicitly required by this permit, the permittee shall conduct source testing as requested by the EPA to determine compliance with applicable permit requirements. [18 AAC 50.220(a) and 50.345(k)]

26.2. Operating Conditions. Unless otherwise specified by an applicable requirement or test method, the permittee shall conduct source testing:

26.2.1. At a point or points that characterize the actual discharge into the ambient air; and

26.2.2. At the maximum rated burning or operating capacity of the source or another rate determined by the EPA to characterize the actual discharge into the ambient air.

[18 AAC 50.220(b)]

26.3. Reference Test Methods. The permittee shall use the following as reference test methods when conducting source testing for compliance with this permit

[j] The permittee should note that an annual emissions report, required at the same time as the fee calculation worksheet by 40 CFR § 71.9(h), has been incorporated into the fee calculation worksheet.

26.3.1. Source testing for compliance with requirements adopted by reference in 18 AAC 50.040(a) must be conducted in accordance with the methods and procedures specified in 40 CFR 60.

26.3.2. Source testing for compliance with requirements adopted by reference in 18 AAC 50.040(b) must be conducted in accordance with the methods and procedures specified in 40 CFR 61.

26.3.3. Source testing for compliance with requirements adopted by reference in 18 AAC 50.040(c) must be conducted in accordance with the source test methods and procedures specified in 40 CFR 63.

26.3.4. Source testing for the reduction in visibility through the exhaust effluent must be conducted in accordance with the procedures set out in Reference Method 9. The permittee may use the form in Appendix B to record data.

26.3.5. Source testing for emissions of total particulate matter (PM), sulfur compounds, nitrogen compounds, carbon monoxide, lead, volatile organic compounds, fluorides, sulfuric acid mist, municipal waste combustor organics, metals, and acid gases must be conducted in accordance with the methods and procedures specified in 40 CFR 60, Appendix A.

26.3.6. Source testing for emissions of PM_{10} must be conducted in accordance with the procedures specified in 40 CFR 51, Appendix M, Method 201, or 201A and 202.

26.3.7. Source testing for emissions of any contaminant may be determined using an alternative method approved by the EPA in accordance with 40 CFR 63 Appendix A, Method 301.

[18 AAC 50.220(b)]

26.4. Excess Air Requirements. To determine compliance with this permit, standard exhaust gas volumes must include only the volume of gases formed from the theoretical combustion of fuel, plus the excess air volume normal for the specific source type, corrected to standard conditions (dry gas at 68° F and an absolute pressure of 760 millimeters of mercury). [18 AAC 50.220(b)]

26.5. Test Exemption. The permittee is not required to comply with Conditions E.1.2 when the exhaust is observed for visible emissions. [18 AAC 50.345(a)]

26.6. Test Deadline Extension. The permittee may request an extension to a source test deadline established by the EPA. The permittee may delay a source test beyond the original deadline only if the extension is approved in writing by the EPA. [18 AAC 50.345(l)]

26.7. Particulate Matter Calculation. In source testing for compliance with the PM standards in Condition B.5, the three-hour average is determined using the average of three one-hour test runs. [18 AAC 50.220(f)]

B. COA SOURCE-WIDE REQUIREMENTS

1. COA Industrial Process and Fuel-Burning Equipment Visible Emissions Standard. The permittee shall comply with the following.

1.1. Do not cause or allow visible emissions, excluding condensed water vapor, emitted from Units K-1A through K-7D5 listed in Table 1 to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes. [18 AAC 50.040(j), 50.326(j) and 50.055(a)(1); 40 CFR §71.6(a)(1)]

1.2. For Units K-1A through K-7D5, monitor, record, and report in accordance with Condition B.2.1 – B.2.4.

1.3. For Units K-1A through K-7D5, as long as they do not exceed the limits in Condition B.1, monitoring shall consist of an annual compliance certification (as provided in Condition A.19.1) with the opacity standard.

[18 AAC 50.326(j), 50.040(j), and 50.346(c); 40 CFR §71.6(a)(3)]

2. COA Visible Emissions.

2.1. Visible Emissions Monitoring. When required by any of the requirements for Units K-1A through K-7D5 specified in Sections B through G below, the permittee shall observe the exhaust of Units K-1A through K-7D5 listed in Table 1 for visible emissions using either the Method 9 Plan under Condition B.2.2 or the Smoke/No-Smoke Plan under Condition B.2.3. The permittee may change visible-emissions plans for an emission unit at any time unless prohibited from doing so by Condition B.2.4. The permittee may, for each unit, elect to continue the visible emission monitoring schedule in effect from the previous permit at the time a renewal permit is issued, if applicable.

2.2. Method 9 Plan. For all 18-minute observations in this plan, observe exhaust, following 40 CFR 60, Appendix A-4, Method 9, adopted by reference in 18 AAC 50.040(a), for 18 minutes to obtain 72 consecutive 15-second opacity observations.

2.2.1. First Method 9 Observation. Within 30 days of the Kulluk becoming an OCS source or within 30 days of startup of the emission unit, whichever is later, observe exhaust for 18 minutes . For any emission unit, observe exhaust for 18 minutes within 14 calendar days after changing from the Smoke/No-Smoke Plan of Condition B.2.3. For any emission units replaced during the term of this permit, observe exhaust for 18 minutes within 30 days of startup.

2.2.2. Monthly Method 9 Observations. After the first Method 9 observation, perform 18-minute observations at least once in each calendar month that an emission unit operates.

2.2.3. Annual Method 9 Observations. After observing emissions for three consecutive operating months under Condition B.2.2.1, unless a six-minute average is greater than 15 percent and one or more observations are greater than 20 percent, perform 18-minute observations at least annually.

2.2.4. Increased Method 9 Frequency. If a six-minute average opacity is observed during the most recent set of observations to be greater than 15 percent and one or more observations are greater than 20 percent, then increase or maintain the 18-minute observation frequency for that emission unit to at least monthly intervals, until the criteria in Condition B.2.2.3 for annual monitoring are met.

2.3. Smoke/No Smoke Plan. Observe the exhaust for the presence or absence of visible emissions, excluding condensed water vapor.

2.3.1. Initial Monitoring Frequency. Observe the exhaust during each calendar day that an emission unit operates.

2.3.2. Reduced Monitoring Frequency. After the emission unit has been observed on 30 consecutive operating days, if the emission unit operated without visible smoke in the exhaust for those 30 days, then observe emissions at least once in every calendar month that an emission unit operates.

2.3.3. Smoke Observed. If smoke is observed, either begin the Method 9 Plan of Condition B.2.2 or perform the corrective action required under Condition B.2.4.

2.4. Corrective Actions Based on Smoke/No Smoke Observations. If visible emissions are present in the exhaust during an observation performed under the Smoke/No Smoke Plan of Condition B.2.3, then the permittee shall either follow the Method 9 plan of Condition B.2.2 or:

2.4.1. Initiate actions to eliminate smoke from the emission unit within 24 hours of the observation;

2.4.2. Keep a written record of the starting date, the completion date, and a description of the actions taken to reduce smoke; and

2.4.3. After completing the actions required under Condition B.2.4.1,

2.4.3.1. Take Smoke/No Smoke observations in accordance with Condition B.2.3.

2.4.3.1.1. At least once per day for the next seven operating days and until the initial 30 day observation period is completed; and

2.4.3.1.2. Continue as described in Condition B.2.3.2; or

2.4.3.2. If the actions taken under Condition B.2.4.1 do not eliminate the smoke, or if subsequent smoke is observed under the schedule of Condition B.2.4.3.1.1, then observe the exhaust using the Method 9 Plan unless the EPA gives written approval to resume observations under the Smoke/No Smoke Plan; after observing smoke and making observations under the Method 9 Plan, the permittee may at any time take corrective action that eliminates smoke and restart the Smoke/No Smoke Plan under Condition B.2.3.1.

[18 AAC 50.326(a), 50.326(j), 50.040(j), and 50.346(c); 40 CFR §71.6(a)(3)(i)]

3. COA Visible Emissions Recordkeeping. The permittee shall keep records as follows.

3.1. If using the Method 9 Plan of Condition B.2.2,

3.1.1. The observer shall record:

3.1.1.1. The name of the OCS Source, emission unit and location, emission unit type, observer's name and affiliation, and the date on the Visible Emissions Field Data Sheet in Appendix B;

3.1.1.2. The time, estimated distance to the emissions location, sun location, approximate wind direction, estimated wind speed, description of the sky condition (presence and color of clouds), plume background, and operating rate (load or fuel consumption rate) on the sheet at the time opacity observations are initiated and completed;

3.1.1.3. The presence or absence of an attached or detached plume and the approximate distance from the emissions outlet to the point in the plume at which the observations are made;

3.1.1.4. Opacity observations to the nearest five percent at 15-second intervals on the Visible Emissions Field Data Sheet in Appendix B;

3.1.1.5. The minimum number of observations required by the permit; each momentary observation recorded shall be deemed to represent the average opacity of emissions for a 15-second period.

3.1.2. To determine the six-minute average opacity, divide the observations recorded on the record sheet into sets of 24 consecutive observations; sets need not be consecutive in time and in no case shall two sets overlap; for each set of 24 observations, calculate the average by summing the opacity of the 24 observations and dividing this sum by 24; record the average opacity on the sheet;

3.1.3. Calculate and record the highest 18-consecutive-minute averages observed.

3.2. If using the Smoke/No Smoke Plan of Condition B.2.3, record the following information in a written log for each observation and submit copies of the recorded information upon request of the EPA:

3.2.1. The date and time of the observation;

3.2.2. From Table 1, the emission unit identification number of the emission unit observed;

3.2.3. Whether visible emissions are present or absent in the exhaust;

3.2.4. A description of the background to the exhaust during the observation;

3.2.5. If the emission unit starts operation on the day of the observation, the startup time of the emission unit;

3.2.6. Name and title of the person making the observation; and

3.2.7. Operating rate (load or fuel consumption rate).

[18 AAC 50.326(a), 50.326(a), 50.040(j), and 50.346(c); 40 CFR 71.6(a)(3)(ii)]

4. COA Visible Emissions Reporting. The permittee shall report visible emissions as follows.

4.1. Include in each Operating Report under Condition A.19:

4.1.1. Which visible-emissions plan of Condition B.2.1 was used for each emission unit; if more than one plan was used, give the time periods covered by each plan;

4.1.2. For each emission unit under the Method 9 Plan,

4.1.2.1. Copies of the observation results (i.e. opacity observations) for each emission unit that used the Method 9 Plan, except for the observations the permittee has already supplied to the EPA; and

4.1.2.2. A summary to include:

4.1.2.2.1. Number of days observations were made;

4.1.2.2.2. Highest six-minute average observed; and

4.1.2.2.3. Dates when one or more observed six-minute averages were greater than 20 percent.

4.1.3. For each emission unit under the Smoke/No Smoke Plan, the number of days that Smoke/No Smoke observations were made and which days, if any, that smoke was observed; and

4.1.4. A summary of any monitoring or record keeping required under Conditions B.2.1 and B.2.4.3.2 that was not done.

4.2. Report under Condition A.18:

4.2.1. The results of Method 9 observations that exceed an average 20 percent for any six-minute period; and

4.2.2. If any monitoring under Condition B.2.1 was not performed when required, report within three days of the date the monitoring was required.

[18 AAC 50.326(a), 50.326(j), 50.040(j), and 50.346(c); 40 CFR 71.6(a)(3)(iii)]

5. COA Industrial Process and Fuel-Burning Equipment Particulate Matter Standard. The permittee shall not cause or allow PM emitted from Units K-1A through K-7D5 listed in Table 1 to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours. [18 AAC 50.040(j), 50.326(a), 50.326(j), and 50.055(b)(1); 40 CFR 71.6(a)(1)]

5.1. For Units K-1A through K-7D5 listed in Table 1, monitor, record and report in accordance with Conditions B.6 – B.7.

5.2. For emission Units K-1A through K-7D5, as long as they do not exceed the limits in Condition B.5, monitoring shall consist of an annual compliance certification (as provided in Condition A.19.1) with the PM standard. [18 AAC 50.326(j), 18 AAC 50.040(j)(4) and 40 CFR 71.6(a)(3)(i)(B)]

5.3. In source testing for compliance with the PM standards in 18 AAC 50.050 or 18 AAC 50.055, the three-hour average is determined using the average of three one-hour test runs. The source test must account for those emissions caused by soot blowing, grate cleaning, or other routine maintenance activities by ensuring that at least one test run includes the emissions caused by the routine maintenance activity and is conducted under conditions that lead to representative emissions

$$E = E_M\left[(A+B)\,x\,\frac{S}{R\,x\,A}\right] + E_{NM}\left[\frac{(R-S)}{R} - \frac{BS}{R\,x\,A}\right]$$

from that activity. The emissions must be quantified using the following equation:

Where:

- E = the total particulate emissions of the source in grains per dry standard cubic foot (gr/dscf).
- E_M = the particulate emissions in gr/dscf measured during the test that included the routine maintenance activity.
- E_{NM} = the arithmetic average of particulate emissions in gr/dscf measured by the test runs that did not include routine maintenance activity.
- A = the period of routine maintenance activity occurring during the test run that included routine maintenance activity, expressed to the nearest hundredth of an hour.
- B = the total period of the test run, less A.
- R = the maximum period of source operation per 24 hours, expressed to the nearest hundredth of an hour.
- S = the maximum period of routine maintenance activity per 24 hours, expressed to the nearest hundredth of an hour.

[18 AAC 50.326(j), 18 AAC 50.040(j), 18 AAC 50.346(c) and 40 CFR 71.6(a)(3)]

6. **COA Particulate Matter Monitoring for Diesel Engines.** The permittee shall conduct source tests on Units K-1A through K-4C and K-6 through K-7D5 to determine the concentration of PM in the exhaust of a source in accordance with Condition B.6.

6.1. Within six months of exceeding the criteria of Conditions B.6.2 or B.6.2.1, either:

6.1.1. Conduct a PM source test according to requirements set out in Condition E.1, or

6.1.2. Make repairs so that emissions no longer exceed the criteria of Condition B.6.1.2 to show that emissions are below those criteria, observe emissions as described in Condition B.2.1 under load conditions comparable to those when the criteria were exceeded.

6.2. Conduct the test according to Condition 6 if:

6.2.1. 18 consecutive minutes of Method 9 observations result in an 18-minute average opacity greater than 20 percent; or

6.2.2. For a source with an exhaust stack diameter that is less than 18 inches, 18 consecutive minutes of Method 9 observations result in an 18-minute average opacity that is greater than 15 percent and not more than 20 percent, unless the EPA has waived this requirement in writing.

6.3. During each one-hour PM source test run, observe the exhaust for 60 minutes in accordance with Method 9 and calculate the average opacity measured during each one-hour test run. Submit a copy of these observations with the source test report.

6.4. The automatic PM source test requirements in Conditions B.6 and B.6.1.2 is waived for an emissions unit if a PM source test on that emission unit has shown compliance with the PM standard during this permit term.

[18 AAC 50.326(j), 18 AAC 50.040(j), 18 AAC 50.346(c) and 40 CFR §71.6(a)(3)(i)(B)]

7. **COA Particulate Matter Record Keeping and Reporting for Diesel Engines.** Within 180 calendar days after the effective date of this permit, the permittee shall record the exhaust stack diameter(s) of Units K-1A through K-4C and Units K-6 through K-7D5 from Table 1 in the permit. Report the stack diameter(s) in the next Operating Report under Condition A.19.

7.1. PM Reporting for Diesel Engines. The permittee shall report as follows:

7.1.1. Report under Condition A.18:

7.1.1.1. The results of any PM source test that exceeds the PM emissions limit; or

7.1.1.2. If one of the criteria of Condition B.6.1.2 was exceeded and the permittee did not comply with either Condition B.6.1 or

B.6.1.1, this must be reported by the day following the day compliance with Condition B.6 was required;

7.2. Report observations in excess of the threshold of ConditionB.6.2.1 within 30 days of the end of the month in which the observations occur.

7.3. In each OCS source Operating Report under Condition A.19, include:

7.3.1. The dates, emission unit EU ID(s), and results when an observed 18-minute average was greater than an applicable threshold in Condition B.6.1.2;

7.3.2. A summary of the results of any PM testing under ConditionB.6; and

7.3.3. Copies of any visible emissions observation results (opacity observations) greater than the thresholds of Condition B.6.1.2, if they were not already submitted.

[18 AAC 50.326(j), 18 AAC 50.040(j), 18 AAC 50.346(c) and 40 CFR §71.6(a)(3)(ii)]

8. COA Particulate Matter Monitoring for Liquid-Fired Boilers and Heaters. The permittee shall conduct source tests on Units K-5A through K-5Z to determine the concentration of PM in the exhaust of the units as follows.

8.1. Conduct a PM source test according to the requirements set out in Condition E.2.1 no later than 90 calendar days after any time corrective maintenance fails to eliminate visible emissions greater than the 20 percent opacity threshold for two or more 18-minute observations in a consecutive six-month period.

8.2. During each one-hour PM source test run, observe the exhaust for 60 minutes in accordance with Method 9 and calculate the average opacity measured during each one-hour test run.

8.3. The PM source test requirement in Condition B.8 is waived for an emission unit if:

8.3.1. A PM source test during the most recent annual reporting period on that emission unit shows compliance with the PM standard since permit issuance, or

8.3.2. If a follow-up visible emission observation conducted using Method 9 during the 90 days shows that the excess visible emissions described in Condition B.2.2.3 no longer occur.

[18 AAC 50.326(j)(4), 18 AAC 50.040(j), 40 CFR §§71.6(a)(3)(i) and 71.6(c)(6)]

9. COA Particulate Matter Recordkeeping for Liquid-Fired Boilers and Heaters. The permittee shall keep records of the results of any PM testing and visible emissions observations conducted under Condition B.8. The permittee shall report as follows.

9.1. In each OCS source Operating Report required by Condition A.19, include:

9.1.1. The dates, emission units, and results when an 18-minute opacity observation was greater than the applicable threshold criterion in Condition B.2.2.3; and

9.1.2. A summary of the results of any PM testing and visible emissions observations conducted under Condition B.8.

9.2. Report as excess emissions, in accordance with Condition A.18, any time the results of a source test for PM exceeds the PM emission limit stated in Condition B.5.

[18 AAC 50.326(j)(4), 18 AAC 50.040(j), 40 CFR §§71.6(a)(3)(ii), (iii) and 71.6(c)(6)]

10. COA Sulfur Compound Emissions Standard. Sulfur Compound Emissions. In accordance with 18 AAC 50.055(c), the permittee shall not cause or allow sulfur compound emissions, expressed as SO_2, from Units K-1A through K-7D5 listed in Table 1 to exceed 500 parts per million (ppm) averaged over three hours. [18 AAC 50.055(c)]

10.1. For Units K-1A through K-7D5, monitor, record and report in accordance with Conditions B.11 through B.12. [18 AAC 50.326(j), 18 AAC 50.040(j), 40 CFR §71.6(a)(3)(i)(B)]

11. COA Sulfur Compound Monitoring and Record Keeping Liquid Fuel-fired Sources. Sulfur Compound Emissions – Monitoring and Recordkeeping.

11.1. If a load of fuel contains greater than 0.01 percent sulfur by weight, the permittee shall calculate SO_2, emissions in ppm using the SO_2, Material Balance Calculation as described below or Method 19 of 40 CFR 60, Appendix A-7, adopted by reference in 18 AAC 50.040(a).

SO_2 Material Balance Calculation

If a fuel shipment contains more than 0.01 percent sulfur by weight, calculate the three-hour exhaust concentration of SO_2 using the following equations:

A = 31,200 x [wt%S_{fuel}] = 31,200 x ______ = ______

B = 0.148 x [wt%S_{fuel}] = 0.148 x ______ = ______

C = 0.396 x [wt%C_{fuel}] = 0.396 x ______ = ______

D = 0.933 x [wt%H_{fuel}] = 0.933 x ______ = ______

E = B + C + D = ______ + ______ + ______ = ______

F = 21 – [vol%dry$O_{2,\ exhaust}$] = 21 - ______ = ______

G = [vol%dry$O_{2,\ exhaust}$] ÷ F = ______ ÷ ______ = ______

H = 1 + G = 1 + ______ = ______

I = E x H = ______ x ______ = ______

SO_2 concentration = A ÷ I = ______ ÷ ______ = ______ PPM

The $wt\%S_{fuel}$, $wt\%C_{fuel}$, and $wt\%H_{fuel}$ are equal to the weight percents of sulfur, carbon, and hydrogen in the fuel. These percentages should total 100%.

The fuel weight percent (wt%) of sulfur is obtained pursuant to Condition F.2.3. The fuel weight percents of carbon and hydrogen are obtained from the fuel refiner.

The volume percent of oxygen in the exhaust ($vol\%dryO_{2,\ exhaust}$) is obtained from oxygen meters, manufacturer's data, or from the most recent analysis under 40 C.F.R. 60, Appendix A-2, Method 3, adopted by reference in 18 AAC 50.040(a), at the same engine load used in the calculation.

[18 AAC 50.326(j), 18 AAC 50.040(j), 40 CFR §71.6(a)(3)(i)(B)]

12. COA Sulfur Compound Emissions – Reporting. The permittee shall report as follows.

12.1. If SO_2 emissions are calculated under Condition B.11 to exceed 500 ppm, the permittee shall report under Condition A.18. When reporting under this Condition B.12 include the calculation under Condition B.11.

12.2. The permittee shall include in the report required by Condition A.19 a list of the fuel grades received at the OCS Source during the reporting period:

12.2.1. For any grade with a maximum fuel sulfur greater than 0.0015 percent sulfur, the fuel sulfur of each shipment; and

12.2.2. For fuel with a sulfur content greater than 0.0015 percent, the calculated SO_2 emissions in ppm.

[18 AAC 50.326(j), 18 AAC 50.040(j), 40 CFR §71.6(a)(3)(i)(B)]

13. COA Incinerator Visible Emissions. The permittee shall comply with the following.

13.1. Do not cause or allow visible emissions, excluding condensed water vapor, through the exhaust of Unit K-8, to reduce visibility by more than 20 percent averaged over any six consecutive minutes. [18 AAC 50.040(j), 18 AAC 50.326(j),18 AAC 50.050(a), and 40 CFR 71.6(a)(1)]

13.2. Observe, record, and report the exhaust of Unit K-8 using the visible emission monitoring, recordkeeping, and reporting Conditions B.2 through B.4.

[18 AAC 50.326(j), 18 AAC 50.040(j), 18 AAC 50.346(c) and 40 CFR §71.6(a)(3)(i)]

14. COA Good Air Pollution Control Practice. The permittee shall do the following for Units K-1A through K-8:

14.1. Perform regular maintenance considering the manufacturer's or the operator's maintenance procedures;

14.2. Keep records of any maintenance that would have a significant effect on emissions; the records may be kept in electronic format; and

14.3. Keep a copy of either the manufacturer's or the operator's maintenance procedures.

[18 AAC 50.346(b)(5)]

15. COA Air Pollution Prohibited. No person may permit any emission which is injurious to human health or welfare, animal or plant life, or property, or which would unreasonably interfere with the enjoyment of life or property.

15.1. If emissions present a potential threat to human health or safety, the permittee shall report any such emissions according to Condition A.18.

15.2. As soon as practicable after becoming aware of a complaint that is attributable to emissions from the emission units regulated under this permit, the permittee shall investigate the complaint to identify emissions that the permittee believes have caused or are causing a violation of Condition B.15.

15.3. The permittee shall initiate and complete corrective action necessary to eliminate any violation identified by a complaint or investigation as soon as practicable if:

15.3.1. After an investigation because of a complaint or other reason, the permittee believes that emissions from the OCS source have caused or are causing a violation of Condition B.15; or

15.3.2. The EPA notifies the permittee that it has found a violation of Condition B.15.

15.4. The permittee shall keep records of:

15.4.1. The date, time, and nature of all emissions complaints received;

15.4.2. The name of the person or persons that complained, if known;

15.4.3. A summary of any investigation, including reasons the permittee does or does not believe the emissions have caused a violation of Condition B.15; and

15.4.4. Any corrective actions taken or planned for complaints attributable to emissions from the OCS source.

15.5. With each OCS Operating Report under Condition A.19, the permittee shall include a brief summary report which must include:

15.5.1. The number of complaints received;

15.5.2. The number of times the permittee or the EPA found corrective action necessary;

15.5.3. The number of times action was taken on a complaint within 24 hours; and

15.5.4. The status of corrective actions the permittee or EPA found necessary that were not taken within 24 hours.

15.6. The permittee shall notify the EPA of a complaint that is attributable to emissions from the emission units regulated under this permit within 24 hours after receiving the complaint, unless the permittee has initiated corrective action within 24 hours of receiving the complaint.

[18 AAC 50.110, 18 AAC 50.326(j), 18 AAC 50.040(j) and 40 CFR §71.6(a)(3)(i)(B)]

16. COA Obligations for Modifications Subject to 18 AAC Article 5 Minor Permits. Nothing in this permit relieves the permittee from the requirements to obtain a minor permit for modifications that are subject to 18 AAC Article 5 Minor Permits. [18 AAC 50.502, 40 CFR 71.6(a)(1)]

17. COA Emission Inventory Reporting. The permittee shall submit to EPA reports of actual emissions, by emission unit, of CO, NH_3, NO_X, PM_{10}, $PM_{2.5}$, SO_2, VOCs and lead (Pb) (and lead compounds) using the form in Attachment C of this permit, as follows:

17.1. Each year by March 31, if the Kulluk and Associated Fleet's potential to emit (PTE) emissions for the previous calendar year:

17.1.1. Equal or exceed 250 tpy of NH_3, PM_{10}, $PM_{2.5}$ or VOCs; or

17.1.2. Equal or exceed 2500 tpy of CO, NO_X or SO_2.

17.2. Every third year by March 31 if the Kulluk and Associated Fleet's PTE emissions for the previous calendar year exceed:

17.2.1. 5 tpy of lead, 1000 tpy of CO; or

17.2.2. 100 tpy of SO_2, NH_3, PM_{10}, $PM_{2.5}$, NO_X or VOCs.

17.3. The permittee shall commence reporting in 2013 for the calendar year of 2012, 2015 for calendar year 2014, etc.

17.4. Include in the report required by this condition, the required data elements contained within the stack description section of the form or those contained in Table 2A of Appendix A to Subpart A of 40 CFR 51 (final rule published in 73 FR 76556 (December 17, 2008)) for each stack associated with an emission unit.

[40 CFR §§ 51.15, 51.30(a)(1) and (b)(1) and 40 CFR 51, Appendix A to Subpart A, 73 FR 76556 (12/17/08), and 18 AAC 50.346(b)(8), 18 AAC 50.200]

C. SOURCE-WIDE NOTIFICATIONS

1. Drill Site Notification. By April 1 each year, the permittee shall notify EPA via facsimile or email of the following information:

1.1. The location of the proposed drill site, using coordinates in the following formats:

1.1.1. Latitude and longitude, and

1.1.2. Universal Transverse Mercator grid system.

1.2. The lease block where the drill site is located; and

1.3. The proposed date that the Kulluk will become an OCS Source at that drill site.

[40 CFR §§ 55.8(a), 71.6(a)(3)(iii) and 71.6(e), 18 AAC 50.326(a)]

2. **Drilling Season Notification.** Each drilling season, the permittee shall report to EPA via facsimile or email the information below, within 3 days of occurrence:

2.1. The date and hour that the Kulluk became an OCS Source at the first drill site of that drilling season; and

2.2. The date and hour that the Kulluk ceased to be an OCS Source at the last drill site of that drilling season.

[40 CFR §§ 55.8(a), 71.6(a)(3)(iii) and 71.6(e), 18 AAC 50.326(a)]

3. **Seasonal Notification of Specific Vessels and Emission Units.** By April 1 of each year, the permittee shall submit to EPA information identifying the specific vessels in the Associated Fleet and all equipment that will be operated as emission units under this permit. The information submitted shall include at a minimum:

3.1. A complete listing of all air pollution emitting equipment onboard the Kulluk along with identification numbers and photos and/or schematic diagrams.

3.2. Information clearly identifying each vessel in the Associated Fleet, including name, identification numbers, photos and/or schematic diagrams, role in the Associated Fleet under this permit, and a complete listing of all air pollution emitting equipment onboard.

3.3. Information clearly identifying each piece of equipment whose operation will emit air pollution, both as listed under the categories and units covered by this permit and any unlisted emission units. For each emission unit, include the type of unit, make, model, manufacturer's rated capacity (kW-hr and gal/hr for engines, MMBtu/hr and gal/hr for boilers and heaters, ton/hr for incinerators) and fuel used.

[40 CFR §§ 55.8(a) and 71.6(a)(3)(iii), 18 AAC 50.326(a)]

4. **Demonstration of Compliance with NAAQS.** By April 1 of each drilling season, the permittee shall submit to EPA a modeling analysis for the specific vessels in the Associated Fleet, all equipment, and all emission units on the Kulluk and Associated Fleet proposed for operation under this permit for the upcoming drilling season. If the proposed combination of Associated Fleet, equipment, and emission units has previously been modeled, the permittee may submit a certification referencing the previous modeling analysis in lieu of a new modeling analysis.

4.1. Modeling analyses conducted under this permit condition shall be identical in all respects to the modeling analysis conducted in support of the initial permitting action, except that the subsequent modeling analyses shall reflect any actual changes to the Kulluk, Associated Fleet, equipment, and emission units from those assumed in the initial modeling analysis. Modeling analyses shall be conducted using the same model, meteorological data, and other assumptions used in the initial modeling analysis. For equipment that is not changing, the modeling analyses shall use the same stack characteristics and other source parameters as those used in the initial modeling analysis. In addition, the subsequent modeling analyses shall use the same non-project sources that were included in any cumulative impact analysis and the same background ambient air quality values as set forth in the Statement of Basis.

4.2. The information supporting the initial permit is contained in the application materials prepared and submitted by the permittee or their contractors as part of, or supporting, the permit application.

4.3. The modeling analyses shall demonstrate that, for the Kulluk, Associated Fleet, equipment, and emission units actually proposed for operation in the upcoming drilling season, the total modeled air quality impacts (including background) are predicted to be less than the NAAQS.

[40 CFR §§ 55.8(a), 71.6(a)(1), 71.6(a)(3)(iii) and 71.6(e)]

D. SOURCE-WIDE EMISSION LIMITS & OPERATIONAL RESTRICTIONS

1. Emission Calculations.

1.1. By Friday of each week, the permittee shall calculate and record the hourly emissions of NOx and the daily emissions of NO_X, CO, $PM_{2.5}$ and PM_{10} from each emission unit or group of emission units for the previous week.

1.2. By Friday of each week, the permittee shall calculate and record the daily rolling 365-day emissions of NO_X and CO for each day of the previous week by using the daily emissions calculated for the previous 365 days pursuant to Condition D.1.1.

1.3. By the tenth of each month, the permittee shall calculate and record the monthly emissions of GHGs from each emission unit or group of emission units for the preceding month.

1.4. By the tenth of each month, the permittee shall calculate and record the rolling 12-month emissions of GHG by using the monthly emissions calculated for the previous 12 months pursuant to Condition D.1.3.

1.5. For groups of emission units required to perform source testing to determine test-derived emission factors pursuant to Condition E.3.1 and that only measure fuel used by the group, rather than by individual emission units, use the worst case group emission factor as specified in Condition E.2.2.1.4 and the fuel combusted by the group of emission units in calculations required in Condition D.1.

[40 CFR §§ 71.6(a)(3)(i)(B) and 71.6(a)(3)(ii), 18 AAC 50.326(a)]

2. Emission Factors. The emission factors included in the Tables D.2.1 – D.2.2 shall be used for purposes of this permit until an alternative test-derived emission factor has been determined according to Condition E.2 of this permit.

[40 CFR §§ 71.2, 71.6(a)(1) and 71.6(c)(1), 18 AAC 50.326(a)]

Table D.2.1 – Kulluk Emission Factors[k]

EMISSION UNIT ID	Description	Emission Unit Rating	Emission Factor Units[l]	NO_X[m]	CO[n]	PM_{10}[o]	$PM_{2.5}$[p]	CO_2	N_2O	CH_4
K-1A – 1D	Electricity Generation Engines	Various	lb/gal	C:0.049 U:0.49	C:0.022 U:0.112	C:0.009 U:0.018	C:0.009 U:0.018	22.5	0.0002	0.0009
K-2A – 2Z K-3A – 3Z K-4A – 4C	MLC HPU MLC Air Compressor Deck Crane Engines	> 600 hp	lb/gal	0.370	C:0.022 U:0.112	C:0.009 U:0.018	C:0.009 U:0.018	22.5	0.0002	0.0009
		< 600 hp	lb/gal	0.462	C:0.025 U:0.125	C:0.018 U:0.037	C:0.018 U:0.037	22.5	0.0002	0.0009
K-5A – 5Z	Heaters and Boilers	Various	lb/gal	0.02	0.007	0.0033	0.0033	22.5	0.0002	0.0009
K-6	Emergency Generator	> 600 hp	lb/gal	0.399	0.112	0.038	0.038	22.5	0.0002	0.0009
K-7A – 7D	Seldom-Used Sources	< 600 hp	lb/gal	0.462	0.125	0.037	0.037	22.5	0.0002	0.0009
K-8	Incinerator	276 ton/hr	lb/ton	3	300	16.4	14	1990	0.092	0.702
K-10	Drilling Mud System	NA	lb/month	NA	NA	NA	NA	NA	NA	1596

[k] Footnotes in Table D.2.1 also apply to Table D.2.2.
[l] Emission factors are in terms of pounds of emissions per unit of operation except for the drilling mud system which are worst case emission per month; lb/gal means pounds of pollutant emitted per gallon of diesel burned; lb/ton means pounds of pollutant emitted per ton of waste incinerated; lb/month means pounds of pollutant emitted per month.

[m] C = controlled. U = uncontrolled. Controlled NO_X emission factors for emission units K-1A – 1D, IB1-1A – 1Z and IB2-1A – 1Z reflect an SCR control efficiency of 90%.
[n] C = controlled. U = uncontrolled. Controlled CO emission factors for emission units K-1A – 1D, K-2A – 2Z, K-3A – 3Z, K-4A – 4C, IB1-1A – 1Z and IB2-1A – 1Z reflect an oxidation catalyst control efficiency of 80%.
[o] C = controlled. U = uncontrolled. Controlled PM_{10} emission factors for emission units K-1A – 1D, K-2A – 2Z, K-3A – 3Z, K-4A – 4C, IB1-1A – 1Z and IB2-1A – 1Z reflect an oxidation catalyst control efficiency of 50%.
[p] C = controlled. U = uncontrolled. Controlled $PM_{2.5}$ emission factors for emission units K-1A – 1D, K-2A – 2Z, K-3A – 3Z, K-4A – 4C, IB1-1A – 1Z and IB2-1A – 1Z reflect an oxidation catalyst control efficiency of 50%.

Table D.2.2 – Associated Fleet Emission Factors

EMISSION UNIT ID	Description	Emission Unit Rating	Emission Factor Units	NO_X	CO	PM_{10}	$PM_{2.5}$	CO_2	N_2O	CH_4
IB1-1A – 1Z IB2-1A – 1Z	Propulsion Engines and Generator Engines on Icebreakers	Various	lb/gal	C:0.049 U:0.49	C:0.022 U:0.112	C:0.009 U:0.018	C:0.009 U:0.018	22.5	0.0002	0.0009
IB1-2A – 2Z IB2-2A – 2Z	Heaters and Boilers on Icebreakers	Various	lb/gal	0.02	0.007	0.0033	0.0033	22.5	0.0002	0.0009
RV/BT-1A – 1Z OSRV-1A – 1Z	Propulsion Engines and Generator Engines on Resupply Vessel/Barge and Tug	> 600 hp	lb/gal	0.370	0.112	0.018	0.018	22.5	0.0002	0.0009
		< 600 hp	lb/gal	0.462	0.125	0.037	0.037	22.5	0.0002	0.0009
OSRV WB-1A - 1Z	Oil Spill Response Vessel and Oil Spill Response Vessel Work Boats	> 600 hp	lb/gal	0.399	0.112	0.038	0.038	22.5	0.0002	0.0009
		< 600 hp	lb/gal	0.462	0.125	0.037	0.037	22.5	0.0002	0.0009
IB1-3A – 3Z IB2-3A – 3Z RV/BT-2A – 2Z OSRV-2A – 2Z	Seldom-Used Sources on Associated Fleet	< 600 hp	lb/gal	0.462	0.125	0.037	0.037	22.5	0.0002	0.0009
IB1-4 IB2-4 OSRV-3	Incinerators on Icebreakers and Oil Spill Response Vessel	Various	lb/ton	3	300	16.4	14	1990	0.092	0.702

3. Duration of Exploration Operations.

3.1. The permittee shall only conduct exploration drilling operations in the Beaufort Sea between July 1 and November 30 each year (referred to hereafter as the "drilling season").

3.2. During the drilling season, the permittee shall not operate the Kulluk as an OCS Source in excess of 120 calendar days. Each partial day shall be counted as a calendar day.

3.3. The permittee shall not conduct any Drilling Activity in excess of 1,632 hours within a drilling season. Drilling Activity includes MLC Drilling Activity and Well Drilling Activity.

3.4. The permittee shall not conduct any MLC Drilling Activity in excess of 480 hours within a drilling season.

3.5. For the purpose of this permit, the following definitions apply:

3.5.1. MLC Drilling Activity is defined as any time when any MLC HPU engine or MLC air compressor engine is operating.

3.5.2. Well Drilling Activity is defined as any time when the top drive is engaged and turning the conventional rotary bit.

3.6. For each drill site at which the Kulluk operates, the permittee shall record the following:

3.6.1. The lease block within the Beaufort Sea lease sales 186, 195 or 202 where the drill site is located;

3.6.2. The date and hour that the Kulluk became an OCS Source at that drill site;

3.6.3. The date and hour that the Kulluk ceased to be an OCS Source at that drill site.

3.7. For each period of Well Drilling Activity, the permittee shall record the following:

3.7.1. The date and hour at which the top drive is first engaged and turning the conventional rotary bit; and

3.7.2. The date and hour at which the top drive is disengaged and no longer turning the conventional rotary bit.

3.8. For each period of MLC Drilling Activity the permittee shall record the following:

3.8.1. The date and hour in which the first MLC HPU engine or MLC air compressor engine begins operation; and

3.8.2. The date and hour in which the last MLC HPU engine or MLC air compressor engine ceases operation.

3.9. Any time spent drilling a relief well shall be included in the time recorded in Conditions D.3.2 and D.3.3.

3.10. By the 10th of each month, the permittee shall calculate and record the following operating parameters for the previous month and a running total for the current drilling season based upon recordkeeping performed pursuant to Conditions D.3.6, 3.7and 3.8:

3.10.1. The number of days the Kulluk operated as an OCS source;

3.10.2. The number of hours of Drilling Activity; and

3.10.3. The number of hours of MLC Drilling Activity.

[40 CFR §§71.2, 71.6(a)(1), 71.6(a)(3)(i)(B), 71.6(a)(3)(ii), 71.6(e), 55.8(a), 18 AAC 50.326(a)]

4. Synthetic Minor PTE Limits.

4.1. Nitrogen oxides (NO_X) emissions from the Kulluk and Associated Fleet shall not exceed 240 tpy as determined on a rolling 365-day basis by calculating the emissions (tons) for each day and adding the emissions (tons) calculated for the previous 364 days.

4.1.1. Daily NO_X emissions (tons) from each emission unit or group of emission units shall be determined by multiplying the appropriate emission factor (lb/unit) specified in Tables D.2.1 – D.2.2 (until a test-derived emission factor has been determined according to Condition E.2) by the recorded daily operation rate (units/day) and dividing by 2000 lb/ton.

4.1.1.1. For the Kulluk electricity generation engines (Units K-1A – 1D), Icebreaker No. 1 propulsion engines and generator engines (IB1-1A – 1Z), and Icebreaker No. 2 propulsion and generator engines (IB2-1A – 1Z), the permittee shall use the appropriate uncontrolled emission factor from Tables D.2.1 and D.2.2 for all periods when any of the deviations described in Condition F.3.7 exist.

4.1.2. For the Kulluk incinerator (Unit K-8), the permittee shall use the maximum incineration capacity (ton/hr) documented pursuant to Condition C.3.3 multiplied by 12 in place of the recorded daily operation rate when calculating emissions pursuant to Condition D.4.1.1.

4.1.3. For the icebreaker and OSRV incinerators (Units IB1-4, IB2-4 and OSRV-3), the permittee shall use the maximum incineration capacity (ton/hr) documented pursuant to Condition C.3.3 multiplied by 24 in place of the recorded daily operation rate when calculating emission pursuant to Condition D.4.1.1.

4.2. Carbon monoxide (CO) emissions from the Kulluk and Associated Fleet shall not exceed 200 tpy as determined on a rolling 365-day basis by calculating the emissions (tons) for each day and adding the emissions (tons) calculated for the previous 364 days.

4.2.1. Daily CO emissions (tons) from each emission unit or group of emission units shall be determined by multiplying the appropriate emission factor (lb/unit) specified in Tables D.2.1 – D.2.2 (until a test-derived emission factor has been determined according to Condition E.2) by the recorded daily operation rate (units/day) and dividing by 2000 lb/ton.

4.2.1.1. For Kulluk electricity generation engines (Units K-1A – 1D), Kulluk MLC HPU engines (Units K-2A – 2Z), Kulluk MLC air compressor engines (Units K-3A – 3Z), Kulluk deck crane engines (Units K-4A – 4C), Icebreaker No. 1 propulsion engines and generator engines (IB1-1A – 1Z), and Icebreaker No. 2 propulsion and generator engines (IB2-1A – 1Z), the permittee shall use the appropriate uncontrolled emission factor from Tables D.2.1 and D.2.2 for all periods when any of the deviations described in Condition F.4.7 exist.

4.2.2. For the Kulluk incinerator (Unit K-8), the permittee shall use the maximum incineration capacity (ton/hr) documented pursuant to Condition C.3.3 multiplied by 12 in place of the recorded daily operation rate when calculating emissions pursuant to Condition D.4.2.1.

4.2.3. For the icebreaker and OSRV incinerators (Units IB1-4, IB2-4 and OSRV-3), the permittee shall use the maximum incineration capacity (ton/hr) documented pursuant to Condition C.3.3 multiplied by 24 in place of the recorded daily operation rate when calculating emission pursuant to Condition D.4.2.1.

4.3. Sulfur dioxide (SO_2) emissions from the Kulluk and Associated Fleet shall not exceed 10 tpy as determined on a rolling 12-month basis by confirming compliance with Conditions D.4.5 and D.4.6 as specified in this permit.

4.4. Greenhouse gas (GHG) emissions as defined in 40 CFR § 52.21(b)(49) from the Kulluk and Associated Fleet shall not exceed 80,000 tons carbon dioxide equivalent (CO_2e) as determined on a rolling 12-month basis by calculating the emissions (tons) for each month and adding the emissions (tons) calculated for the previous 11 months.

4.4.1. For each emission unit or group of emission units, monthly carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions (tons) shall be determined by multiplying the appropriate emission factors (lb/unit) specified in Tables D.2.1 – D.2.2 (until a test-derived emission factor has been determined according to Condition E. 2) by the recorded monthly operation rate (units/month) and dividing by 2000 lb/ton.

4.4.2. To account for mud off-gassing from the drilling mud system (Unit K-10), monthly CH_4 emissions from the drilling mud shall be assumed to be the emission rate specified in Table D.2.1.

4.4.3. For the Kulluk incinerator (Unit K-8), the permittee shall use the maximum incineration capacity (ton/hr) documented pursuant to Condition C.3.3 multiplied by 12 in place of the recorded daily operation rate when calculating emissions pursuant to Condition D.4.4.1.

4.4.4. For the icebreaker and OSRV incinerators (Units IB1-4, IB2-4 and OSRV-3), the permittee shall use the maximum incineration capacity (ton/hr) documented pursuant to Condition C.3.3 multiplied by 24 in place of the recorded daily operation rate when calculating emission pursuant to Condition D.4.4.1.

4.4.5. Monthly CO_2e emissions (tons) shall be determined by multiplying the calculated monthly emissions for CO_2, CH_4, and N_2O from all emission units or group of emission units and activities by the applicable global warming potential factors from 40 CFR Part 98, Subpart A, Table A-1, and summing the products.

4.5. The permittee shall not combust any liquid fuel with sulfur content greater than 0.01 percent by weight, as determined by Condition F.2.3, in any emission unit on the Kulluk or the Associated Fleet.

4.6. The total amount of fuel combusted in engines and boilers on the Kulluk and Associated Fleet shall not exceed 7,004,428 gallons during any rolling 12-month period.

4.7. The total capacity of incinerators on the Kulluk and Associated Fleet, considering enforceable conditions on hours of operation, to incinerate waste shall not exceed 13,704 pounds per day.

4.8. The permittee shall not operate the Kulluk in the Beaufort Sea within the same drilling season as the Noble Discoverer drillship.

4.9. All fuel purchased for use in the Kulluk and Associated Fleet shall have amaximum sulfur content of 0.0015 percent by weight for all emission units on the Kulluk and Associated Fleet.

4.9.1. Compliance with Condition D.4.9 shall be determined for each diesel fuel purchase based upon recordkeeping required by Condition D.4.9.2.

4.9.2. Keep diesel fuel purchase records for each batch of fuel that documents sulfur content.

[40 CFR §§ 52.21, 71.6(a)(1) and 71.6(b), 18 AAC 50.326(a), 18 AAC 50.225, 18 AAC 50.508]

5. Operational Restrictions to Protect the NAAQS. The permittee shall comply with the following:

5.1. The permit does not authorize operation unless:

5.1.1. The Kulluk is subject to a currently effective safety zone established by the United Sates Coast Guard (USCG) which encompasses an area within at least 500 meters from the hull of the Kulluk and which prohibits members of the public from entering this area except for attending vessels or vessels authorized by the USGC (such area shall be referred to as the "Safety Zone"); and

5.1.2. The permittee has developed in writing and is implementing a public access control program to:

5.1.2.1. Locate, identify, and intercept the general public by radio, physical contact, or other reasonable measures to inform the public that they are prohibited by Coast Guard regulations from entering the Safety Zone; and

5.1.2.2. Communicate to the North Slope communities on the Beaufort Sea on a periodic basis when exploration activities are expected to begin and end at a drill site, the location of the drill site, and any restrictions on activities in the vicinity of the Kulluk's exploration operations.

5.2. The permittee shall equip each emission unit on the Kulluk and on any RV/BT that operates in dynamic positioning mode with a vertical uncapped stack. A stack equipped with a "flapper valve" rain cover or similar design that does not hinder the vertical momentum of the exhaust plume is considered an uncapped stack.

5.3. The permittee shall not operate the Kulluk Emergency Generator Engine (Unit K-6) more than one day for every 30 calendar days. On that one day of operation, the permittee shall not operate emission unit K-6 more than a combined 2 hours.

5.4. The permittee shall not operate the Kulluk Incinerator (Unit K-8) more than 12 hours each day.

5.5. The total number of events during which RV/BT transit to and from the Kulluk and operate in dynamic positioning mode shall not exceed 24 in any drilling season. Each full or partial day of operation in dynamic positioning mode is considered a separate event.

[40 CFR §§ 71.2, 71.6(a)(1), 71.6(a)(3)(i)(B), 71.6(a)(3)(ii), 71.6(e) and 55.8(a), 18 AAC 50.326(a), 18 AAC 50.502]

6. **Emission Limits to Protect the NAAQS.** The permittee shall comply with the following emission limits to protect the 1-hour NO_2 NAAQS and the 24-Hour PM_{10} and $PM_{2.5}$ NAAQS:

6.1. Kulluk Generator Engines (Units K-1A – 1D)

6.1.1. During Drilling Activity, combined emissions from Units K-1A – 1D shall not exceed the limits specified below:

6.1.1.1. NO_X: 19.0 lb/hr

6.1.1.2. $PM_{2.5}$: 71.3 lb/day

6.1.1.3. PM_{10}: 71.3 lb/day

6.1.2. During all times other than Drilling Activity, combined emissions from Units K-1A – 1D shall not exceed the emission limits specified for each of the pollutants below.

6.1.2.1. NO_X: 13.4 lb/hr

6.1.2.2. $PM_{2.5}$: 50.4 lb/day

6.1.2.3. PM_{10}: 50.4 lb/day

6.2. Kulluk MLC HPU Engines (Units K-2A – 2Z)

6.2.1. Combined emissions from Units K-2A – 2Z shall not exceed the emission limits specified for each of the pollutants below.

6.2.1.1. NO_X: 37.0 lb/hr

6.2.1.2. $PM_{2.5}$: 35.5 lb/day

6.2.1.3. PM_{10}: 35.5 lb/day

6.3. Kulluk MLC Air Compressor Engines (Units K-3A – 3Z)

6.3.1. Combined emissions from Port MLC air compressor engines shall not exceed the emission limits specified for each of the pollutants below.

6.3.1.1. NO_X: 14.8 lb/hr

6.3.1.2. $PM_{2.5}$: 7.4 lb/day

6.3.1.3. PM_{10}: 7.4 lb/day

6.3.2. Combined emissions from Starboard MLC air compressor engines shall not exceed the emission limits specified for each of the pollutants below.

6.3.2.1. NO_X: 14.8 lb/hr

6.3.2.2. $PM_{2.5}$: 7.4 lb/day

6.3.2.3. PM_{10}: 7.4 lb/day

6.4. Deck Crane Engines (Units K-4A – 4C)

6.4.1. During Drilling Activity, combined emissions from Units K-4A – 4C shall not exceed the emission limits specified for each of the pollutants below.

6.4.1.1. NO_X: 12.0 lb/hr

6.4.1.2. $PM_{2.5}$: 3.4 lb/day

6.4.1.3. PM_{10}: 3.4 lb/day

6.4.2. During all times other than Drilling Activity, combined emissions from Units K-4A – 4C shall not exceed the emission limits specified for each of the pollutants below.

6.4.2.1. NO_X: 12.0 lb/hr

6.4.2.2. $PM_{2.5}$: 5.7 lb/day

6.4.2.3. PM_{10}: 5.7 lb/day

6.5. Heaters and Boilers (Units K-5A – 5Z)

6.5.1. Combined emissions from Units K-5A – 5Z shall not exceed the emission limits specified for each of the pollutants below.

6.5.1.1. NO_X: 0.9 lb/hr

6.5.1.2. $PM_{2.5}$: 3.6 lb/day

6.5.1.3. PM_{10}: 3.6 lb/day

6.6. Emergency Generator (Unit K-6)

6.6.1. Emissions from Unit K-6 shall not exceed the emission limits specified for each of the pollutants below.

6.6.1.1. NO_X: 17.8 lb/hr

6.6.1.2. $PM_{2.5}$: 2.8 lb/day

6.6.1.3. PM_{10}: 2.8 lb/day

6.7. Seldom Used Sources (Units K-7A – 7D5)

6.7.1. Combined emissions from Units K-7A – 7D5 shall not exceed the emission limits specified for each of the pollutants below.

6.7.1.1. NO_X: 0.4 lb/hr

6.7.1.2. $PM_{2.5}$: 0.7 lb/day

6.7.1.3. PM_{10}: 0.7 lb/day

6.8. Waste Incinerator (Unit K-8)

6.8.1. Emissions from Unit K-8 shall not exceed the emission limits specified for each of the pollutants below.

6.8.1.1. NO_X: 0.4 lb/hr

6.8.1.2. $PM_{2.5}$: 23.2 lb/day

6.8.1.3. PM_{10}: 27.1 lb/day

6.9. Icebreaker No. 1 (IB1) and No. 2 (IB2)

6.9.1. Combined emissions from emission units on IB1 and IB2 shall not exceed the emission limits specified for each of the pollutants below.

6.9.1.1. NO_X: 174 lb/hr

6.9.1.2. $PM_{2.5}$: 700.8 lb/day

6.9.1.3. PM_{10}: 710.4 lb/day

6.10. Resupply Vessel/Barge and Tug (RV/BT)

6.10.1. During dynamic positioning mode, combined emissions from emission units on RV/BT shall not exceed the emission limits specified for each of the pollutants below.

6.10.1.1. NO_X: 74.0 lb/hr

6.10.1.2. $PM_{2.5}$: 74.4 lb/day

6.10.1.3. PM_{10}: 74.4 lb/day

6.11. Oil Spill Response Vessel (OSRV)

6.11.1. Combined emissions from emission units on OSRV shall not exceed the emission limits specified for each of the pollutants below.

6.11.1.1. NO_X: 43.5 lb/hr

6.11.1.2. $PM_{2.5}$: 64.6 lb/day

6.11.1.3. PM_{10}: 68.2 lb/day

6.12. OSRV Work Boats (OSRV WB)

6.12.1. Combined emissions from emission units on OSRV WB shall not exceed the emission limits specified for each of the pollutants below.

6.12.1.1. NO_X: 10.4 lb/hr

6.12.1.2. $PM_{2.5}$: 19.9 lb/day

6.12.1.3. PM_{10}: 19.9 lb/day

6.13. For emission unit groups K-2A – 2Z and K-3A – 3Z, compliance with the hourly NO_X emission limit contained in Condition D.6.2 and D.6.3 shall be determined by summing the pounds per hour (pph) emission test results from each engine in the group using the test results at the highest engine load as required in Condition E.3.1.1.

6.14. For all emission units and emission unit groups, except K-2A – 2Z and K-3A – 3Z, compliance with the hourly NO_X emission limits contained in Conditions D.6.1 through D.6.12 shall be determined by multiplying the appropriate emission factors (lb/unit) specified in Tables D.2.1 – D.2.2 (until a test-derived emission factor has been determined according to Condition E.2) by the recorded hourly operation rate (units/hour).

6.14.1. For the Kulluk electricity generation engines (Units K-1A – 1D), Icebreaker No. 1 propulsion engines and generator engines (Units IB1-1A – 1Z) and Icebreaker No. 2 propulsion and generator engines (Units IB2-1A – 1Z) the permittee shall use the appropriate uncontrolled emission factor from Tables D.2.1 and D.2.2 for all periods when any of the deviations described in Condition F.3.7 exist.

6.14.2. For the Kulluk, icebreaker and OSRV incinerators (Units K-8, IB1-4, IB2-4 and OSRV-3), the permittee shall use the maximum incineration capacity (ton/hr) documented pursuant to Condition C.3.3 in place of the recorded daily operation rate when calculating emissions pursuant to Condition D.6.14.

6.15. For all emission units and emission unit groups, compliance with the daily $PM_{2.5}$ and PM_{10} emission limits contained in Conditions D.6.1 through D.6.12 shall be determined by multiplying the appropriate emission factors (lb/unit) specified in Tables D.2.1 – D.2.5 (until a test-derived emission factor has been determined according to Condition E.2) by the recorded daily operation rate (units/day).

6.15.1. For the Kulluk electricity generation engines (Units K-1A – 1D), Kulluk MLC HPU engines (Units K-2A – 2Z), Kulluk MLC air compressor engines (Units K-3A – 3Z), Kulluk deck crane engines (Units K-4A – 4C), Icebreaker No. 1 propulsion engines and generator engines (Units IB1-1A – 1Z) and Icebreaker No. 2 propulsion and generator engines (Units IB2-1A – 1Z), the permittee shall use the appropriate uncontrolled emission factor from Tables D.2.1 and D.2.2 for all periods when any of the deviations described in Condition F.4.7 exist.

6.15.2. For the Kulluk incinerator (Unit K-8), the permittee shall use 12 times the maximum incineration capacity (ton/hr) documented pursuant to Condition C.3.3 in place of the recorded daily operation rate when calculating emissions pursuant to Condition D.6.15.

6.15.3. For the icebreaker and OSRV incinerators (Units IB1-4, IB2-4 and OSRV-3), the permittee shall use 24 times the maximum incineration capacity (ton/hr) documented pursuant to Condition C.3.3 in place of the recorded daily operation rate when calculating emissions pursuant to Condition D.6.15.

[40 CFR §§ 71.2, 71.6(a)(1), 71.6(a)(3)(i)(B), 71.6(a)(3)(ii), 71.6(e) and 55.8(a), 18 AAC 50.502, 18 AAC 50.326(a)]

7. Prohibited Activities. The permittee shall not:

7.1. Flow test wells;

7.2. Flare gas;

7.3. Store liquid hydrocarbons recovered during well testing;

7.4. Allow any vessel associated with this project, and that is not listed in Tables 1 and 2 of this permit, to approach within 25 miles of the Kulluk, while the Kulluk is an OCS Source; and

7.5. Emit any regulated NSR pollutants or GHGs from the shallow gas diverter system.

7.5.1. The permittee shall record the date, time and duration of each shallow gas diversion.

[40 CFR §§ 52.21, 71.2, 71.6(a)(1), 71.6(e) and 71.6(b), 18 AAC 50.502, 18 AAC 50.326(a)]

8. Good Operating and Maintenance Requirements. At all times, including periods of startup, shutdown, maintenance, and malfunction, the permittee shall, to the extent practicable, maintain and operate each emission unit, including any associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions and considering the manufacturer's recommended operating procedures. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to EPA which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. The Permittee shall:

8.1. Ensure that a full-time equipment maintenance specialist is on board the Kulluk at all times during operation as an OCS Source;

8.2. Ensure that a crew member on each vessel in the Associated Fleet is responsible for fulfilling the requirements of this Condition;

8.3. Train operating personnel to identify signs of improper operation and maintenance, including visible plumes, and to report these events to the maintenance specialist as soon as possible, but no later than within three hours of identification;

8.4. Perform regular maintenance considering the manufacturer's or the operator's maintenance procedures;

8.5. Routinely inspect each emission unit for proper operation and maintenance consistent with the manufacturer's recommendations;

8.6. Ensure that the operation and maintenance manual provided by the manufacturer for each emission unit is kept on board the subject vessel at all times; and

8.7. Maintain on board each vessel a log documenting when reporting, inspections and maintenance are conducted. Logs for the OSRV WB may be maintained on the OSRV.

[40 CFR §§ 52.21, 55.8(a), 60.11(d), 63.6(e), 71.2, 71.6(a)(1), 71.6(a)(3)(i)(B), 71.6(b) and 71.6(c)(1), 18 AAC 50.326(a)]

9. Closed Crankcase Ventilation. Each internal combustion engine on the Kulluk and the Associated Fleet shall be equipped with a closed crankcase ventilation (CCV) system. [40 CFR §§ 52.21, 55.8(a), 71.2, 71.6(a)(1), 71.6(a)(3)(i)(C), 71.6(b) and 71.6(c)(1), 18 AAC 50.502, 18 AAC 50.326(a)]

10. Selective Catalytic Reduction (SCR) Control Device. Exhaust from each of the following emission units shall be directed to an operating SCR control device unit at all times:

10.1. Kulluk electricity generation engines (Units K-1A – 1D).

10.2. Icebreaker No. 1 propulsion and generator engines (Units IB1-1A – 1Z).

10.3. Icebreaker No. 2 propulsion and generator engines (Units IB2-1A – 1Z)

[40 CFR §§ 52.21, 55.8(a), 60.11(d), 63.6(e), 71.2, 71.6(a)(1), 71.6(a)(3)(i)(B), 71.6(b) and 71.6(c)(1), 18 AAC 50.502, 18 AAC 50.326(a)]

11. Oxidation Catalyst Control Device. Exhaust from each of the following emission units shall be directed to an operating oxidation catalyst control device at all times:

11.1. Kulluk electricity generation engines (Units K-1A – 1D).

11.2. Kulluk MLC HPU engines (Units K-2A – 2Z).

11.3. Kulluk MLC air compressor engines (Units K-3A – 3Z).

11.4. Kulluk deck crane engines (Units K-4A – 4C).

11.5. Icebreaker No. 1 propulsion engines and generator engines (Units IB1-1A – 1Z).

11.6. Icebreaker No. 2 propulsion and generator engines (Units IB2-1A – 1Z).

[40 CFR §§ 52.21, 55.8(a), 60.11(d), 63.6(e), 71.2, 71.6(a)(1), 71.6(a)(3)(i)(B), 71.6(b) and 71.6(c)(1), 18 AAC 50.502, 18 AAC 50.326(a)]

E. SOURCE-WIDE TESTING CONDITIONS

1. General Testing Requirements. Whenever conducting a stack test required by this permit, and unless specifically stated otherwise in this permit, the permittee shall comply with the following testing requirements in addition to the specific testing requirements contained in the emission unit sections of this permit:

1.1. The permittee shall provide EPA at least 30 days prior notice of any stack test. If after 30 days notice for an initially scheduled stack test, there is a delay in conducting the scheduled stack test, the permittee shall notify EPA as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the stack test, or by arranging a rescheduled date with EPA by mutual agreement.

1.2. The permittee shall submit to EPA a complete stack test plan within 60 days after receiving a request under Condition E.1.14 and at least 30 days prior to any required testing unless EPA agrees in writing to some other time period. Retesting may be done without resubmitting the plan provided it is conducted in accordance with the previously submitted plan. The permittee shall follow the submitted test plan except as otherwise agreed to in writing by EPA prior to the testing. The source test plan shall include and address the following elements:

1.2.1. Purpose and scope of testing;

1.2.2. Source description (including groups of emission units), nameplate and actual capacity of the equipment, including a description of the operating scenarios and mode of operation during testing and including fuel sampling and analysis procedures;

1.2.3. Schedule/dates of testing;

1.2.4. Process data to be collected during the test and reported with the results, including source-specific data identified in the emission unit sections of this permit;

1.2.5. Information from the manufacturer of the fuel flow meter so as to determine its accuracy;

1.2.6. Sampling and analysis procedures, specifically requesting approval for any proposed alternatives to the reference test methods, and addressing minimum test length (e.g., one hour, 8 hours, 24 hours, etc.) and minimum sample volume;

1.2.7. Sampling location description and compliance with the reference test methods;

1.2.8. Analysis procedures and laboratory identification;

1.2.9. Quality assurance plan;

1.2.10. Calibration procedures and frequency;

1.2.11. Sample recovery and field documentation;

1.2.12. Chain of custody procedures;

1.2.13. Quality Assurance (QA)/Quality Control (QC) project flow chart;

1.2.14. Data processing and reporting;

1.2.15. Description of data handling and QC procedures; and

1.2.16. Report content and timing.

1.3. Unless otherwise specified in this permit, or EPA determines in writing, that other operating conditions are representative of normal operations or unless specified in the emission unit sections of this permit, the source shall be operated at a capacity of at least 90% but no more than 100% of maximum capacity during all tests.

1.4. Unless otherwise specified by an applicable requirement or test method, the permittee shall conduct source testing at a point or points that characterize the actual discharge into the ambient air.

1.5. Only regular operating staff may adjust the processes or emission control devices during or within 2 hours prior to the start of a source test. Any operating adjustments made during a source test, that are a result of consultation during the tests with source testing personnel, equipment vendors, or consultants, may render the source test invalid.

1.6. For the duration of each test run (unless otherwise specified), the permittee shall record the following information:

1.6.1. All data which is required to be monitored during the test in the emission unit sections of this permit; and

1.6.2. All continuous monitoring system data which is required to be routinely monitored in the emission unit sections of this permit for the emission unit being tested.

1.7. Each source test shall follow the reference test methods specified by this permit and consist of at least three (3) valid test runs. For purposes of this permit:

1.7.1. EPA Test Methods 1, 2, 3A, 4, 5, 6C, 7E, 9, 10, 19, and 25A are set forth in 40 CFR Part 60, Appendix A;

1.7.2. EPA Test Methods 201, 201A and 202 are set forth in 40 CFR Part 51, Subpart M;

1.7.3. ASTM D 5453-09 is set forth at http://www.astm.org/Standards/D5453.htm

1.8. Facilities for performing and observing the emission testing shall be provided that meet the requirements of 40 CFR § 60.8(e) and EPA Method 1.

1.9. Emission test reports shall be submitted to EPA within 45 days of completing any emission test required by this permit along with items required to be recorded in Condition E.1.6 above.

1.10. EPA Methods 1, 2, 3A, 3B, 4 and 19 shall be used as necessary to convert the measured NO_X, PM, PM_{10}, $PM_{2.5}$ and CO emissions into units of the emission limits in the permit.

1.11. Source test emission data shall be reported as the arithmetic average of all valid test runs and in the unit terms of any applicable emission limit, unless otherwise specified in the emission unit sections of this permit.

1.12. An alternative test method or a deviation from a test method identified in this permit may be approved as follows:

1.12.1. The permittee must submit a written request to EPA at least 60 days before the stack test is scheduled to begin which includes the reasons why the alternative or deviation is needed and the rationale and data to demonstrate that the alternative test method or deviation from the reference test method:

1.12.1.1. Provides equal or improved accuracy and precision as compared to the specified reference test method; and

1.12.1.2. Does not decrease the stringency of the standard as compared to the specified reference test method.

1.12.2. If requested by EPA, the demonstration referred to in Condition E.1.12.1 must use Method 301 in 40 CFR Part 63, Appendix A, to validate the alternative test method or deviation.

1.12.3. EPA must approve the request in writing.

1.12.4. Until EPA has given written approval to use an alternative test method or to deviate from the test method specified in this permit, the permittee is required to use the test method specified in this permit when conducting a source test under this permit.

1.13. The permittee may request an extension to a source test deadline established by the EPA. The permittee may delay a source test beyond the original deadline only if the extension is approved in writing by EPA.

1.14. In addition to any source testing explicitly required by this permit, the permittee shall conduct source testing as requested by the EPA to determine compliance with applicable permit requirements.

1.15. For any source test requiring the use of Method 201A, the permittee may substitute the use of Method 5. In either case, Method 202 shall also be employed for condensable particulate matter.

[40 CFR § 71.6(a)(3)(i)(B) and 71.6(c)(1) 18 AAC 50.326(a)]

2. **Test-Derived Emission Factors.** The following conditions apply to the procedure for determining the equipment-specific emission factors as well as to the supporting testing for all emission units where this testing condition is cited in other conditions of this permit:

2.1. Testing Conditions for Engines.

2.1.1. Except as otherwise provided for specific emission units, testing shall be conducted by May 1 of the first two drilling seasons in which a specific emission unit is to be used. In addition, beginning with the second performance test, the following shall be used to determine the frequency of any future testing for each emission unit and pollutant: If the worst case emission factor results from the most recent two tests vary by less than 20% from their average, the testing frequency may be reduced thereafter to every 5 years; if the worst case emission factor results vary by 20% or more from their average, testing frequency shall be every 2 years. EPA may require that specific test results be excluded from use for purposes of this procedure if EPA determines in writing that the results are invalid.

2.1.2. During testing, the permittee shall equip each emission unit with a device to measure fuel injection timing.

2.1.3. During testing, the permittee shall equip each emission unit with a electrical output monitoring device with an accuracy equal to or better than 2 percent of the engine's maximum output (in kWe). The permittee shall maintain the accuracy of each electrical output monitoring device in accordance with manufacturer's recommendations. The permittee may propose in writing to EPA an alternative method for determining operating load during performance testing. Any alternative method of determining operating load must be approved by EPA in writing. If the permittee requests and obtains EPA approval of an alternative method of measuring load, the accuracy and maintenance requirements of this condition apply to any related equipment or monitoring device relied upon by the alternative method.

2.1.4. If the emission unit is not equipped with a fuel flow meter as required by Condition F.2.2, during testing equip the emission unit with a fuel flow meter that meets the requirements of Condition F.2.2.1.

2.1.5. Each stack test shall consist of 3 one-hour runs conducted while operating within 5% of the following three loads: 95%, 65%, and 40%. Alternative loads for testing each emission unit may be proposed by the permittee in the test plan by providing justification for the proposed operating loads. Operating load shall be determined by expressing the electrical power produced (kWe-hr) in terms of percentage compared to the engine rated capacity. An alternative method for determining operating load may be proposed per Condition E.1.12.

2.1.6. During each test run, the permittee shall monitor and record the following information:

2.1.6.1. Quantity of fuel used (in gallons) by the emission unit being tested;

2.1.6.2. Percent load based on electrical power produced (in kWe-hr) or alternative method per Condition E.1.12.

2.1.6.3. Fuel injection timing.

2.1.7. Testing shall comply with all general testing requirements under Condition E.1 of this permit.

2.2. Emission Factor Derivation Procedure for Engines.

2.2.1. A worst-case emission factor for each pollutant shall be determined in units of pounds of pollutant per gallon of fuel combusted for each emission unit, as follows:

2.2.1.1. The pounds of pollutant per gallon of fuel combusted emission factor shall be determined by dividing the pounds of pollutant emitted during each test run by the gallons of fuel combusted during each test run;

2.2.1.2. The emission factor for all three test runs conducted at each operating load shall be averaged arithmetically to determine the final emission unit specific test derived emission factor (pounds of pollutant per gallon of fuel combusted) for each operating load and pollutant from each emission unit;

2.2.1.3. The permittee shall use the highest emission unit specific test derived emission factor of any load tested as the worst-case emission factor for that pollutant.

2.2.1.4. For groups of emission units, the permittee shall use the highest emission unit specific derived emission factor of any emission unit in the group for that pollutant.

2.2.2. Within 45 days of completing the testing required under Condition E.3, the permittee shall submit to EPA complete documentation of each emission unit specific test-derived emission factor.

2.2.3. The permittee shall begin using each test-derived emission factor to calculate emissions as required by this permit beginning with the drilling season that follows the testing for a specific emission unit.

2.3. Testing Conditions for Incinerators.

2.3.1. Except as otherwise provided for specific emission units, testing shall be conducted by May 1 of the first two drilling seasons in which a specific emission unit is to be used. In addition, beginning with the second performance test, the following shall be used to determine the frequency of any future testing for each emission unit and pollutant: If the worst case emission factor results from the most recent two tests vary by less than 20% from their average, the testing frequency may be reduced thereafter to every 5 years; if the worst case emission factor results vary by 20% or more from their average, testing frequency shall be every 2 years. EPA may require that specific test results be excluded from use for purposes of this procedure if EPA determines in writing that the results are invalid.

2.3.2. During testing, the permittee shall determine the mass of waste being fed to the incinerator by using a weigh scale that shall be accurate to within 1 lb.

2.3.3. Each stack test shall consist of 3 one-hour runs conducted while operating within 10% of the maximum rated capacity. Operating load shall be determined by expressing the feed rate (lb/hr) in terms of percentage compared to the incinerator rated capacity.

2.3.4. During each test run, the permittee shall monitor and record the following information:

2.3.4.1. Quantity of waste consumed (in pounds) by the emission unit being tested;

2.3.4.2. Percent load based on waste feed rate (in lb/hr).

2.3.5. Testing shall comply with all general testing requirements under Condition E.1 of this permit.

2.4. Emission Factor Derivation Procedure for Incinerator.

2.4.1. An emission factor for each pollutant shall be determined in units of pounds of pollutant per ton of waste consumed for each emission unit, as follows:

2.4.1.1. The pounds of pollutant per ton of waste consumed emission factor shall be determined by dividing the pounds of pollutant emitted during each test run by the pounds of waste consumed during each test run;

2.4.1.2. The emission factor for all three test runs conducted shall be averaged arithmetically to determine the final emission unit specific test derived emission factor (pounds of pollutant per ton of waste consumed) for each pollutant from each emission unit;

2.4.2. Within 45 days of completing the testing required under Condition E.3, the permittee shall submit to EPA complete documentation of each emission unit specific test-derived emission factor.

2.4.3. The permittee shall begin using each valid test-derived emission factor to calculate emissions as required by this permit beginning with the drilling season that follows the testing for a specific emission unit.

[40 CFR §§ 71.6(a)(1), 71.6(a)(3)(i)(B), 71.6(a)(3)(ii), 71.6(a)(3)(iii), and 71.6(c)(1), 18 AAC 50.326(a)]

3. Source Test Requirements.

3.1. The permittee shall perform source testing to determine test-derived emission factors for NO_X, $PM_{2.5}$, PM_{10}, CO using the procedures in Conditions E.1, E.2.1 and E.2.2 of this permit for the following emission units: K-1A – 1D, K-2A – 2Z, K-3A – 3Z, K-4A – 4C, IB1-1A – 1Z, IB2-1A – 1Z, RV-1A – 1Z, and OSRV-1A – 1Z. Testing for the following units shall be conducted in accordance with Conditions E.1, E.2.1 and E.2.2 except that testing shall be conducted every 5 years after the first test: K-4A - 4C.

3.1.1. The permittee shall also report the NO_X test results for the highest operating load in terms of pph NO_X emissions for the following emission units: K-2A – 2Z, K-3A – 3Z.

3.1.2. The permittee shall measure, record and report NO_2 emissions in the same units as NO_X for each NO_X test performed.

3.1.3. For each emission unit tested that is controlled by an SCR unit, the permittee shall report the average inlet temperature to the SCR unit recorded during the emission test that represents the worst case emission factor for that emission unit.

3.1.4. For each emission unit tested that is controlled by an oxidation catalyst, the permittee shall report the average inlet temperature to the catalyst recorded during the emission test that represents the worst case emission factor for that emission unit.

3.1.5. The permittee shall measure, record and report visible emissions for the duration of all particulate emission tests.

3.1.6. All tests shall be performed using the test methods specified in this permit.

3.2. The permittee shall perform source testing to determine test-derived emission factors for CO, NO_X, $PM_{2.5}$ and PM_{10} using the procedures in Conditions E.1, E.2.3 and E.2.4 of this permit for the following emission units: K-8, IB1-4, IB2-4 and OSRV-3.

3.2.1. The permittee shall report the average incinerator exit temperature recorded during the emission test.

3.2.2. The permittee shall measure, record and report visible emissions for the duration of all particulate emission tests.

3.2.3. All tests shall be performed using the test methods specified in this permit.

[40 CFR §§ 71.6(a)(1), 71.6(a)(3)(i)(B), 71.6(a)(3)(ii), 71.6(a)(3)(iii), and 71.6(c)(1), 18 AAC 50.326(a)]

F. SOURCE-WIDE MONITORING & RECORDKEEPING CONDITIONS

1. Global Positioning System. The permittee shall use a modern global positioning system on the Kulluk and Associated Fleet (except OSRV WB) as follows:

1.1. Monitor and record the date, time and location of the Kulluk and Associated Fleet at the following frequency and on the following occasions:

1.1.1. Once each hour;

1.1.2. When the Kulluk becomes and ceases to be an OCS source, and

1.1.3. When each vessel in the Associated Fleet enters or leaves the 25 mile radius around the Kulluk.

1.2. Location shall be recorded by providing coordinates in the following formats:

1.2.1. Latitude and longitude; and

1.2.2. Universal Transverse Mercator grid system.

1.2.3. Graphical location representation, including a line or points showing the locations of each vessel, the location of the Kulluk, and circles depicting distances of 5 and 10 miles around the Kulluk.

1.3. For any vessel performing a resupply trip to the Kulluk, monitor and record the following time points for each resupply trip and vessel:

1.3.1. The date and time the vessel approaches within 25 miles of the Kulluk;

1.3.2. The date and time the vessel arrives at the Kulluk;

1.3.3. The date and time the vessel departs the Kulluk; and

1.3.4. The date and time the vessel reaches a distance of 25 miles from the Kulluk upon departure.

[40 CFR §§ 55.8(a), 71.6(a)(1), 71.6(a)(3)(i)(B), 71.6(a)(3)(ii) and 71.6(c)(1), 18 AAC 50.326(a)]

2. Operations and Fuel Monitoring.

2.1. The permittee shall install, calibrate, maintain and operate equipment or systems to measure and record the operation information required by this permit.

2.2. Except as provided in Condition F.2.3, the permittee shall measure continuously and record the hourly, daily and monthly total fuel combusted by each emission unit or group of emission units on the Kulluk and Associated Fleet that combusts fuel, except for the Kulluk emergency generator, seldom used sources and OSRV work boats, using a fuel flow meter such that emissions can be calculated on the required time frames required by this permit.

2.2.1. Each fuel flow meter required under this permit shall meet the following requirements:

2.2.1.1. Each fuel flow meter shall be located so that there are no fuel inflows or outflows between it and the emission unit or emission unit group being served by the meter.

2.2.1.2. Each fuel flow meter shall be totalizing and non-resettable in units of gallons.

2.2.1.3. Each fuel flow meter shall continuously measure the fuel flow rate with accuracy equal to or better than 2 percent of the meter's upper range value.

2.2.1.4. By April 1 of the first drill season, the permittee shall collect and submit to EPA information from the manufacturer of the fuel flow meter so as to determine its accuracy.

2.2.1.5. The permittee shall maintain the accuracy of each fuel flow meter in accordance with manufacturer's recommendations.

2.2.2. The permittee shall measure and record the fuel combusted by the Kulluk emergency generator, each seldom used source and OSRV work boat before and after each use using one of the following methods:

2.2.2.1. Measure the fuel combusted using the fuel tank sight glass;

2.2.2.2. Measure the fuel combusted by manually measuring the amount of fuel in the tank using a graduated dip stick;

2.2.2.3. Measure the fuel combusted using a fuel tank gauge; or

2.2.2.4. Measure the fuel combusted using a fuel flow meter.

2.2.3. For the Kulluk emergency generator, each seldom used source or OSRV work boat, the permittee shall record the start and end times before and after each use.

2.2.4. For the Kulluk emergency generator, each seldom used source or OSRV work boat, the permittee shall determine the average fuel combusted per hour by dividing the total fuel recorded per use in Condition F.2.2.2 by the total hours operated recorded per use in Condition F.2.2.3. The permittee shall use this value for each hour of operation where needed in this permit for compliance purposes.

2.2.5. The permittee shall calculate and record the total gallons of fuel burned each month and each rolling 12-month period by emission units on the Kulluk and Associated Fleet.

2.3. As an alternative to measuring and recording the total fuel combusted by an emission unit that combusts fuel, the permittee may continuously measure and record, on an hourly, daily and monthly basis, the time the emission unit operates using a non-resettable hour meter.

2.3.1. For those emission units that the permittee elects to monitor operating time instead of fuel flow, the permittee shall determine the volume (gallons) of fuel combusted each hour by multiplying the recorded operating time (whole hour or fraction of an hour) by the rated capacity of the unit to consume fuel (gallons per hour). The permittee shall use this value where needed in this permit for compliance purposes.

2.4. The permittee shall obtain representative fuel samples and fuel sulfur content (ppm) as follows:

2.4.1. Prior to mobilizing the Kulluk and combusting any fuel in the Kulluk for the first time at the beginning of a drilling season, determine (by sampling and analysis using one of the sampling methods in 40 CFR § 80.330(b) and the analytical method in ASTM D 5453 09) and record the sulfur content in each fuel oil storage tank on the Kulluk and the Associated Fleet.

2.4.2. After mobilizing the Kulluk, determine the sulfur content of each delivery of fuel to the Kulluk and Associated Fleet as follows:

2.4.2.1. Determine (by sampling and analysis using one of the sampling methods in 40 CFR § 80.330(b) and the analytical method in ASTM D 5453 09) and record the sulfur content of each delivery ; or

2.4.2.2. Obtain from the fuel supplier certification of the sulfur content of the fuel as purchased, and obtain documentation that each storage tank transporting the fuel between purchase and delivery has not caused the fuel delivered to become higher than 100 ppm sulfur content.

2.4.3. Maintain all records of all sampling and analysis including:

2.4.3.1. Sample and analysis locations, dates and times; and

2.4.3.2. Sampling and analytical method used; and

2.4.3.3. Copies of any certifications and documentation relied upon.

2.5. Upon introducing waste to the incinerator, continuously monitor and record every 15 minutes the incinerator exit temperature of each incinerator while operating.

2.5.1. Report as a permit deviation under Conditions A.17 and A.18 any periods during which the exit temperature is 90% or less than the most recent average exit temperature reported in Condition E.3.2.1.

2.6. The permittee shall record the number of hours the Kulluk incinerator operates each day.

2.7. The permittee shall record both the number of hours the Kulluk emergency generator operates each day and the number of days it operates each month.

[40 CFR §§ 55.8(a), 71.6(a)(1), 71.6(a)(3)(i)(B), 71.6(a)(3)(i)(C), 71.6(a)(3)(ii) and 71.6(c)(1), 18 AAC 50.326(a)].

3. **Selective Catalytic Reduction (SCR) Control Device Monitoring**. For any emission unit that is required by this permit to be controlled by an SCR control device, the permittee shall install, calibrate, operate, and maintain (in accordance with manufacturer specifications) continuous monitoring system (CMS) to measure and record inlet temperature in degrees Fahrenheit (ºF), urea feed rate (gallons/min), and catalyst activity (NO_X ppm concentration) as follows:

3.1. Prepare and submit with the source test protocol required by Condition E.1.2 a site-specific monitoring plan that addresses the monitoring system design, data collection, quality assurance, and quality control elements outlined in this condition. The plan shall address the performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, sensor tolerance and sensitivity, and data acquisition and calculations; sampling interface (e.g., thermocouple, flow meter) location such that the monitoring system will provide representative measurements; equipment performance checks, system accuracy audits, or other audit procedures; ongoing operation and maintenance procedures; and ongoing reporting and recordkeeping procedures.

3.2. Upon introducing diesel fuel to the engine and continuing until the flow of diesel fuel to the engine is stopped, the temperature and urea CMS shall collect data at least once every 15 minutes.

3.3. Conduct the CMS equipment performance checks, system accuracy audits, or other audit procedures within 60 days prior to each drilling season and at least once every 3 months for the duration of the drilling season.

3.4. Conduct a performance evaluation of each CMS.

3.5. Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), operate the CMS at all times the affected source is operating. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. Complete monitoring system repairs in response to monitoring system malfunctions and return the monitoring system to operation as expeditiously as practicable.

3.6. Monitor and record NO_X emissions (ppm) from the exhaust of each SCR unit once per week while engine exhaust gases are routed to the SCR unit using a portable NO_X monitor that meets the requirements of EPA OTM 13 found at http://www.epa.gov/ttn/emc/prelim/otm13.pdf.

3.7. Report as a deviation under Conditions 16 A.17 and A.18 any periods during which the urea pump is not operating, the inlet temperature is 90% or less than the most recent average inlet temperature reported in Condition E.3.1.3, or the NO_X concentration is 150% or more than the most recent NO_X concentration measured in Condition E.3.

[40 CFR §§ 55.8(a), 71.6(a)(1), 71.6(a)(3)(i)(B), 71.6(a)(3)(i)(C), 71.6(a)(3)(ii) and 71.6(c)(1), 18 AAC 50.326(a)]

4. **Oxidation Catalyst Control Device Monitoring.** For any emission unit that is required by this permit to be controlled by an oxidation catalyst control device, the permittee shall install, calibrate, operate, and maintain (in accordance with manufacturer specifications) CMS to measure and record inlet temperature (ºF), and catalyst activity (CO ppm concentration) as follows:

4.1. Prepare and submit with the source test protocol required by Condition E.1.2 a site-specific monitoring plan that addresses the monitoring system design, data collection, quality assurance, and quality control elements outlined in this condition. Install, calibrate, operate, and maintain each CMS. The plan shall address the performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, sensor tolerance and sensitivity, and data acquisition and calculations; sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements; equipment performance checks, system accuracy audits, or other audit procedures; ongoing operation and maintenance procedures; and ongoing reporting and recordkeeping procedures.

4.2. Upon introducing diesel fuel to the engine and continuing until the flow of diesel fuel to the engine is stopped, the temperature CMS shall collect data at least once every 15 minutes.

4.3. Conduct the CMS equipment performance checks, system accuracy audits, or other audit procedures within 60 days prior to each drilling season and at least once every 3 months for the duration of the drilling season.

4.4. Conduct a performance evaluation of each CMS.

4.5. Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), operate the CMS at all times the affected source is operating. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. Complete monitoring system repairs in response to monitoring system malfunctions and return the monitoring system to operation as expeditiously as practicable.

4.6. Monitor and record CO emissions (ppm) from the exhaust of each oxidation catalyst unit once per week using a portable CO monitor that meets the requirements of EPA OTM 13 found at http://www.epa.gov/ttn/emc/prelim/otm13.pdf.

4.7. Report as a permit deviation under Conditions A.17 and A.18 any periods during which the inlet temperature is 90% or less than the most recent average inlet temperature reported in Condition E.3.1.4, or the CO concentration is 120% or more than the CO concentration measured during the most recent previous source test that produced compliance data or emission factors for this permit.

[40 CFR §§ 55.8(a), 71.6(a)(1), 71.6(a)(3)(i)(B), 71.6(a)(3)(i)(C), 71.6(a)(3)(ii) and 71.6(c)(1), 18 AAC 50.326(a)]

G. NESHAP & NSPS CONDITIONS[q]

1. **NESHAP ZZZZ & NSPS IIII for K-1A – 1D, K-2A – 2Z, K-3A – 3Z, K-6**. The permittee shall comply with the applicable requirements of 40 CFR 63, Subpart ZZZZ and 40 CFR 60, Subpart IIII for Units K-1A – 1D, K-2A – 2Z, K-3A – 3Z and K-6 as follows:

1.1. All engines installed as Units K-1A – 1D, K-2A – 2Z, K-3A – 3Z and K-6 shall be units that are subject to 40 CFR Part 60, Subpart IIII based on their per-cylinder displacement and model year. [40 CFR §§ 71.6(a) and 71.6(b)]

1.2. For Units K-1A – 1D, the permittee shall purchase or lease an engine certified to the emission standards in 40 CFR 60.4201(a), for the same model year and maximum engine power. [40 CFR 60.4201(a), 60.4204(b) and 60.4211(c)]

1.3. For Unit K-6, the permittee shall purchase or lease an engine certified to the emission standards in 40 CFR 60.4202(a)(2), for the same model year and maximum engine power. [40 CFR 60.4202(a)(2), 60.4205(b) and 60.4211(c)]

1.4. For Units K-2A – 2Z and K-3A – 3Z, if the permittee purchase or lease an engine that is a 2007 or later model year engine, it must be certified to the emission standards in 40 CFR 60.4201(a), for the same model year and maximum engine power. If the permittee purchase a pre-2007 model year engine, it must be certified to the emission standards in Table 1 to 40 CFR 60, Subpart IIII. [40 CFR 60.4201(a), 60.4204(b) and 60.4211(c)]

1.5. Compliance with Conditions G.1.2 through G.1.4 shall be determined based upon recordkeeping required by Condition G.1.5.1.

1.5.1. Keep records documenting that the engine is certified to meet the applicable emission standards.

[40 CFR §§ 71.6(a)(3)(i)(B), 71.6(a)(3)(ii) and 71.6(c)(1)]

1.6. Install and configure the engine according to the manufacturer's specifications. [40 CFR §§ 60.4211(c), 63.6590(c)]

1.6.1. Compliance with Condition G.1.6 shall be determined based upon recordkeeping required by Condition G.1.6.2.

1.6.2. Keep records documenting that that the engine was installed and configured according to the manufacturer's specifications. Such records shall include, but not be limited to, the manufacturer's specifications.

[40 CFR §§ 71.6(a)(3)(i)(B), 71.6(a)(3)(ii) and 71.6(c)(1)]

1.7. Operate and maintain the engine and control device according to the manufacturer's written instructions or the procedures developed by the permittee that are approved in writing by the engine manufacturer. The permittee shall only change those

[q] 18 AAC 50.326(a)(2), 50.040(a) and 50.040(c)

settings that are approved by the manufacturer. [40 CFR §§ 60.4211(a) and 63.6590(c)]

1.7.1. Compliance with Condition G.1.7 shall be determined based upon recordkeeping required by Conditions G.1.7.2, G.1.7.3 and G.1.7.4.

1.7.2. Keep records of the manufacturer's written instructions for operation and maintenance of the engine and control device or the procedures the permittee developed that are approved in writing by the manufacturer. Such records shall include, but not be limited to engine and control device settings established or approved in writing by the manufacturer.

[40 CFR §§ 71.6(a)(3)(i)(B), 71.6(a)(3)(ii) and 71.6(c)(1)]

1.7.3. If the permittee is implementing procedures or settings developed to operate and maintain the engine and control device, keep records of the manufacturer's written approval of those procedures and settings.

[40 CFR §§ 71.6(a)(3)(i)(B), 71.6(a)(3)(ii) and 71.6(c)(1)]

1.7.4. At least once each day, observe and record the actual instrument settings that reflect the performance of the engine and control device. The settings that the permittee is to observe are identified by either the manufacturer or the permittee in the records required by Condition G.1.7.2.

[40 CFR §§ 71.6(a)(3)(i)(B), 71.6(a)(3)(ii) and 71.6(c)(1)]

1.8. For storage tanks serving Units K-1A – 1D, K-2A – 2Z, K-3A – 3Z and K-6 and for diesel fuel intended to be combusted in these units while the Kulluk is an OCS source, deliver into these tanks diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel as follows: (1) maximum sulfur content of 15 ppm by weight, and either (2a) minimum cetane index of 40 or (2b) maximum aromatic content of 35 percent by volume. [40 CFR §§ 60.4207(b), 63.6590(c)]

1.8.1. Compliance with Condition G.1.8 shall be determined as follows:

1.8.1.1. Determine and record the sulfur content, cetane index and aromatic content of each delivery in accordance with one of the sampling methods in 40 CFR § 80.330(b), and by analyzing the fuel in accordance with the following analytical methods: ASTM D 5453 09 for sulfur content, ASTM D 976-80 for cetane index and ASTM D 1319-03 for aromatic content; or

1.8.1.2. Obtain from the fuel supplier certification of the sulfur content and either the cetane index or aromatic content of the fuel as purchased, and obtain documentation that each storage tank transporting the fuel between purchase and delivery has not caused the fuel delivered to become higher than 15 ppm sulfur content.

1.8.2. Maintain all records of all sampling and analysis including:

1.8.2.1. Sample and analysis locations, dates and times; and

1.8.2.2. Sampling and analytical method used; and

1.8.2.3. Copies of any certifications relied upon.

[40 CFR §§ 71.6(a)(3)(i)(B), 71.6(a)(3)(ii) and 71.6(c)(1)]

1.9. Comply with the requirements of 40 CFR 89 and 1068 as they apply to the permittee.

[40 CFR §§ 60.4211(a), 63.6590(c)]

1.10. Comply with the applicable provisions of Subpart A as specified in Table 8 to 40 CFR 60, Subpart IIII

[40 CFR § 60.4218 and Table 8 to 40 CFR Part 60, Subpart IIII]

2. **NESHAP ZZZZ for K-7A – K-7D5**. Beginning May 3, 2013, the permittee shall comply with the applicable requirements of 40 CFR 63, Subpart ZZZZ for Units K-7A, K-7B, K-7C and K-7D1 – 7D5 as follows:

2.1. Change the oil and filter annually, or (a) for Units K-7B, K-7C and K-7D1 – K-7D5, every 500 hours of operation or (b) for Unit K-7A, every 1,000 hours of operation, whichever comes first, or at a frequency determined by an oil sample and analysis program as follows:

2.1.1. Sample and analyze the oil annually, or (a) for Units K-7B, K-7C and K-7D1 – K-7D5, every 500 hours of operation or (b) for Unit K-7A, every 1,000 hours of operation, whichever comes first, to determine total base number, viscosity, and water content by volume.

2.1.2. Change oil and oil filter within the applicable time period specified in Condition G.2.1.3 if the oil analysis confirms any of the following conditions:

2.1.2.1. The total base number of the oil sample is less than 30 percent of the total base number of the oil when new;

2.1.2.2. The viscosity of the oil sample has changed by more than 20 percent from the viscosity of the oil when new; or

2.1.2.3. The water content of the oil sample is greater than 0.5 percent by volume.

2.1.3. Change oil and oil filter within 2 days of receiving the results of the oil analysis unless the engine is not in operation when the results of the analysis are received. If the engine is not in operation when the results of the analysis are received, the permittee must change the oil and oil filter within either 2 days of receiving the results or before commencing operation, whichever is later.

2.1.4. Keep records of the oil analysis results and the engine oil and filter changes.

[40 CFR 63.6595(a), 63.6603(a), 63.6625(i), and Table 2d to 40 CFR 63, Subpart ZZZZ.]

2.2. The permittee shall inspect air cleaner every 1,000 hours of operation or annually, whichever comes first.[40 CFR 63.6603(a) and Table 2d to 40 CFR 63, Subpart ZZZZ.]

2.2.1. Keep records of the air cleaner inspections. [40 CFR 71.6(a)(3)(i)(B)]

2.3. The permittee shall inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. [40 CFR 63.6603(a) and Table 2d to 40 CFR 63, Subpart ZZZZ.]

2.3.1. Keep records of the hose and belt inspections and the hose and belt replacements. [40 CFR 71.6(a)(3)(i)(B)]

2.4. For Units K-7B, K-7C and K-7D1 – 7D5, the management practices required by Conditions G.2.1, G.2.2 and G.2.3 can be delayed as follows:

2.4.1. If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice on schedule, the management practice can be delayed until the emergency is over.

2.4.1.1. Report any failure to perform management practice on the schedule required.

2.4.2. If performing the management practice on schedule would otherwise pose an unacceptable risk under Federal law, the management practice can be delayed until unacceptable risk is over or the unacceptable risk under Federal law has abated.

2.4.2.1. Report any failure to perform management practice on the schedule required and report the Federal law under which the risk was deemed unacceptable.

[40 CFR 63.6603(a) and Table 2d to 40 CFR 63, Subpart ZZZZ]

2.5. During periods of startup, the permittee shall minimize the engine's time spent at idle and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes. [40 CFR 63.6603(a), 40 CFR 63.6625(h) and Table 2d to 40 CFR 63, Subpart ZZZZ]

2.6. The permittee shall be in compliance with the emission limitations and operating limitations in this subpart that apply to the permittee at all times. [40 CFR 63.6605(a)]

2.7. At all times the permittee shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the permittee to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR 63.6605(b)]

2.8. For Units K-7B, K-7C and K-7D1 – 7D5, the permittee shall install a non-resettable hour meter if one is not already installed. [40 CFR 63.6625(f)]

2.8.1. The permittee shall keep records of the hours of operation of the engine. The permittee shall document how many hours are spent for emergency operation, including what classified the operation as emergency. [40 CFR 63.6655(f)]

2.8.2. The permittee shall document how many hours are spent for non-emergency operation, including the reason for non-emergency operation. [40 CFR 63.6655(f) and 71.6(a)(3)(i)(B)]

2.9. The permittee shall operate and maintain the engine and after-treatment control device (if any) according to the manufacturer's emission-related operation and maintenance instruction; or develop and follow the permittee's own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. [40 CFR 63.6625(e), 63.6640(a) and Table 6 to 40 CFR 63, Subpart ZZZZ]

2.9.1. The permittee shall keep records of either the manufacturer's emission-related operation and maintenance instruction, or the permittee's own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. [40 CFR 63.6655(d)]

2.9.2. The permittee shall keep records of the maintenance the permittee conducted on the engine in order to demonstrate that the permittee operated and maintained the engine according to the permittee's own maintenance plan. [40 CFR 63.6655(e)]

2.10. The permittee shall report each instance in which the permittee did not meet each emission limitation or operating limitation in Table 2d to this subpart that apply to the permittee. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in 40 CFR 63.6650. [40 CFR 63.6640(b)]

2.11. The permittee shall report each instance in which the permittee did not meet the requirements in Table 8 to this subpart that applies to the permittee. [40 CFR 63.6640(e) and Table 8 to 40 CFR 63, Subpart ZZZZ]

2.12. For Units K-7B, K-7C and K-7D1 – D5, the permittee shall operate the engine as follows in order to be considered an emergency engine under 40 CFR 63, Subpart ZZZZ:

2.12.1. There is no time limit on the use of engine in emergency situations.

2.12.2. Except as provided for in Condition G.2.12.2.3, the permittee may operate the engine for up to a combined 100 hours per year in non-emergency situations to perform the following activities:

2.12.2.1. Maintenance checks and readiness testing that is recommended by the Federal government, the manufacturer, the vendor, or the insurance company associated with the engine; and

2.12.2.2. Any other activity not associated with maintenance checks and readiness testing, except that the duration of activities not associated with maintenance checks and readiness testing shall not exceed the lesser of the following time periods:

2.12.2.2.1. 50 hours per year; or

2.12.2.2.2. 100 hours per year less any hours utilized to conduct maintenance checks and readiness testing pursuant to Condition G.2.12.2.1.

2.12.2.3. The permittee may operate the engine to conduct maintenance checks and readiness testing that is recommended by Federal government, the manufacturer, the vendor, or the insurance company associated with the engine beyond 100 hours per year if either:

2.12.2.3.1. The permittee maintain records indicating that Federal standards require maintenance and testing beyond 100 hours per year; or

2.12.2.3.2. EPA approves a written request from the permittee to do so.

[40 CFR 63.6640(f)]

3. **NESHAP ZZZZ for K-4A – K-4C**. Beginning May 3, 2013, the permittee must comply with the applicable requirements of 40 CFR 63, Subpart ZZZZ for Units K-4A – 4C as follows:

3.1. Emission Limitation. At all times except during periods of startup, limit the concentration of CO in the engine's exhaust to 49 ppmvd at 15 percent O_2; or reduce CO emissions by 70 percent or more. Compliance is based on the results of testing, the average of three 1-hour runs using the testing requirements and procedures in 40 CFR 63.6620 and Table 4 to 40 CFR 63, Subpart ZZZZ.

[40 CFR 63.6595(a), 63.6603(a), 63.6605(a) and Tables 2d and 5 to 40 CFR 63, Subpart ZZZZ]

3.2. Initial Compliance Demonstration.

3.2.1. Except as specified in Conditions G.3.2.1.1 and G.3.2.1.2, conduct an initial performance test between May 3, 2013 and October 30, 2013 in accordance with the applicable requirements in 40 CFR 63.6620 and Table 4 to 40 CFR 63, Subpart ZZZZ. [40 CFR 63.6612(a) and 63.6620]

3.2.1.1. The permittee is not required to conduct a performance test on an emission unit for which a performance test has been previously conducted if all of the following conditions are met:

3.2.1.1.1. The previous test was conducted using the same methods specified in 40 CFR 63, Subpart ZZZZ, and these methods were followed correctly,

3.2.1.1.2. The previous test was conducted after May 3, 2011 but before May 3, 2013,

3.2.1.1.3. EPA Region 10 accepts the previous test results, and

3.2.1.1.4. Either no process or equipment changes have been made since the previous test was performed, or the permittee demonstrates that the results of the previous test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[40 CFR 63.6612(b)]

3.2.1.2. The permittee does not need to start up the engine solely to conduct the performance test if the engine is non-operational. Conduct the performance test for the non-operational engine when the engine is started up again.

[40 CFR 63.6620(b)]

3.2.2. Demonstrate initial compliance with the emission limitation according to Table 5 to 40 CFR 63, Subpart ZZZZ. [40 CFR 63.6630(a)]

3.2.3. Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements of 40 CFR 63.6645 and 40 CFR 63.9(h)(2)(ii). [40 CFR 63.6630(b) and 63.6645(h)]

3.3. Emission Limitation. During periods of startup, minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitation in Condition G.3.1 applies. [40 CFR 63.6603(a) and Table 2d to 40 CFR 63, Subpart ZZZZ]

3.4. Crankcase Ventilation System.

3.4.1. Install one of the following crankcase ventilation systems:

3.4.1.1. A closed crankcase ventilation system that prevents crankcase emission from being emitted to the atmosphere.

3.4.1.2. An open crankcase filtration emission control system that reduces emission from the crankcase by filtering the exhaust stream to remove oil mist, particulates, and metals.

3.4.2. Follow one of the following maintenance requirements:

3.4.2.1. The manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation system and replacing the crankcase filters.

3.4.2.2. The maintenance requirements approved by EPA that are as protective as manufacturer requirements.

[40 CFR 63.6625(g)]

3.5. Fuel Requirement. Combust diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel as follows: (1) maximum sulfur content of 0.0015 percent by weight, and either (2a) minimum cetane index of 40 or (2b) maximum aromatic content of 35 percent by volume. [40 CFR 63.6604]

3.5.1. Diesel Fuel Sampling and Analysis Procedures.

3.5.1.1. A representative fuel sample is obtained by following any of the sampling methods listed in 40 CFR 80.330(b);

3.5.1.2. The sulfur content of a fuel sample is determined by following ASTM D 5453-09;

3.5.1.3. The cetane index of a fuel sample is determined by following ASTM D 976-80; and

3.5.1.4. The aromatic content of a fuel sample is determined by following ASTM D 1319-03.

3.5.2. Prior to mobilizing the Kulluk for the first time at the beginning of a drilling season, determine the sulfur content, cetane index and aromatic content in each fuel oil storage tank on the Kulluk serving Units K-4A – 4C. The permittee must obtain a representative sample of the fuel and analyze the sample for sulfur content, cetane index and aromatic content using the procedures in Condition G.3.5.1.

3.5.3. Thereafter, determine and record the sulfur content, cetane index and aromatic content upon receiving each fuel shipment, as follows:

3.5.3.1. Obtain a representative sample of the fuel delivered and analyze the sample for sulfur content, cetane index andaromatic content using the procedures in Condition G.3.5.1; or

3.5.3.2. Obtain a single certification of sulfur content, cetane index and aromatic content for each shipment of fuel from the fuel supplier based on an analysis of the fuel, provided that the certification indicates that the sulfur content, cetane index and aromatic content have been determined by the methods listed in Condition G.3.5.1.

3.5.4. Within 3 business days of identification, report to EPA any instance of a liquid fuel with sulfur content greater than 0.0015 percent by weight being combusted in Units K-4A – 4C.

[40 CFR 71.6(a)(3)(i)(B)]

3.6. General Compliance Requirements. At all times the permittee must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the permittee to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to EPA which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR 63.6605(b)]

3.7. Comply with the requirements of 40 CFR 63.1 through 63.15 that apply as specified in Table 8 to 40 CFR 63, Subpart ZZZZ.[40 CFR 63.6665]

3.7.1. Report each instance in which the requirements in Table 8 to 40 CFR 63, Subpart ZZZZ were not met.[40 CFR 63.6640(e)]

3.8. Submit all of the notification in 40 CFR 63.7(b) and (c), (f)(4), and (f)(6), 63.9(b) through (e), and (g) and (h) that apply by the dates specified. [40 CFR 63.6645(a)]

3.9. Submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in 40 CFR 63.7(b)(1). [40 CFR 63.6645(g)]

3.10. Submit the information specified in 40 CFR 63.6650(c) and Table 7 to 40 CFR 63, Subpart ZZZZ as part of the annual compliance report required in Condition A.19 of this permit. [40 CFR 63.6650]

3.11. Keep records of the following documents:

3.11.1. A copy of each notification and report submitted to comply with 40 CFR 63, Subpart ZZZZ, including all documentation supporting any Initial Notification or Notification of Compliance Status that the permittee submitted, according to the requirement in 40 CFR 63.10(b)(2)(xiv).

3.11.2. Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.

3.11.3. Records of performance tests and performance evaluations as required in 40 CFR 63.10(b)(2)(viii).

3.11.4. Records of all required maintenance performed on the air pollution control and monitoring equipment.

3.11.5. Records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

[40 CFR 63.6655(a)]

3.12. Keep records as follows:

3.12.1. Records must be in a form suitable and readily available for expeditious review according to 40 CFR 63.10(b)(1).

3.12.2. Keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record as specified in 40 CFR 63.10(b)(1).

3.12.3. Keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or recording according to 40 CFR 63.10(b)(1).

[40 CFR 63.6660]

4. **NESHAP JJJJJJ for K-5A – K-5Z**. Area Source Boiler MACT. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart JJJJJJ for emission units in Source Group K-5 as follows:

4.1. Conduct an initial performance tune-up that meets the requirements of Condition G.4.2 and in accordance with the following: [40 CFR 63.11214(b)]

4.1.1. If the boiler is an existing boiler, the permittee must achieve compliance with the work practice standard of a tune-up no later than March 21, 2012. [40 CFR 63.11196(a)(1)]

4.1.1.1. The boiler is subject as an existing source if construction or reconstruction commenced on or before June 4, 2010. [40 CFR 63.11194(b)]

4.1.1.2. If the boiler is not operating on the required date for a tune-up, the tune-up must be conducted within one week of startup. [40 CFR 63.11223(b)(7)]

4.1.1.3. The permittee must submit a signed statement in the Notification of Compliance Status Report that indicates the permittee conducted a tune-up of the boiler. [40 CFR 63.11214(b)]

4.1.2. If the boiler is a new boiler, the permittee must achieve compliance with the provisions of this subpart upon startup. [40 CFR 63.11196(c)]

4.1.2.1. The boiler is subject as a new source if construction or reconstruction commenced after June 4, 2010. [40 CFR 63.11194(c)]

4.1.2.2. If the boiler is not operating on the required date for a tune-up, the tune-up must be conducted within one week of startup. [40 CFR 63.11223(b)(7)]

4.1.2.3. The permittee must submit a signed statement in the Notification of Compliance Status Report that indicates the permittee conducted a tune-up of the boiler. [40 CFR 63.11214(b)]

4.2. Conduct an initial and biennial performance tune-ups, subject to the following: [40 CFR 63.11223(a), (b)]

4.2.1. Each biennial performance tune-up shall be no later than 25 months following the previous tune-up. [40 CFR 63.11223(a)] If the boiler is not operating on the required date for a tune-up, the tune-up must be conducted within one week of startup. [40 CFR 63.11223(b)(7)]

4.2.2. As applicable, inspect the burner and clean or replace any components of the burner as necessary (the permittee may delay the burner inspection until the next scheduled unit shutdown, but the permittee must inspect each burner at least once every 36 months). [40 CFR 63.11223(b)(1)]

4.2.3. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available. [40 CFR 63.11223(b)(2)]

4.2.4. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly. [40 CFR 63.11223(b)(3)]

4.2.5. Optimize total emissions of carbon monoxide. This optimization should be consistent with the manufacturer's specifications, if available. [40 CFR 63.11223(b)(4)]

4.2.6. Measure the concentrations in the effluent stream of carbon monoxide in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). [40 CFR 63.11223(b)(5)]

4.3. Maintain the following records onsite and submit, if requested by EPA:

4.3.1. A copy of each notification and report that the permittee submitted to comply with this subpart and all documentation supporting any Initial Notification or Notification of Compliance Status that the permittee submitted. [40 CFR §§ 63.10(b)(2)(xiv), 63.11223(a) and 63.11225(c)(1)]

4.3.2. Records to document conformance with the tune-up requirements. Records must identify each boiler, the date of tune-up, the manufacturer's specification to which the boiler was tuned, records documenting the fuel type used monthly by each boiler (including, but not limited to, a description of the fuel, including whether the fuel has received a non-waste determination by the permittee or EPA), and the total fuel usage amount in gallons. [40 CFR 63.11225(c)(2)]

4.3.3. Records of the occurrence and duration of each malfunction of the boiler, or of the associated air pollution control or monitoring equipment. Records of actions taken during periods of malfunction to minimize emissions in accordance with Condition G.4.5, including corrective actions to restore the malfunctioning boiler, air pollution control or monitoring equipment to its normal or useful manner of operation. [40 CFR 63.11225(c)(4), (5)]

4.3.4. A biennial report containing the following information:

4.3.4.1. The concentrations in the effluent stream of carbon monoxide in parts per million, by volume, and oxygen in volume percent, before and after each tune-up of the boiler. [40 CFR 63.11223(b)(6)(i)]

4.3.4.2. A description of any corrective actions taken as part of the tune-up of the boiler. [40 CFR 63.11223(b)(6)(ii)]

4.3.4.3. The type and amount of fuel used over the 12 months prior to the biennial tune-up of the boiler. [40 CFR 63.11223(b)(6)(iii)]

4.3.5. The permittee's records must be in a form suitable and readily available for expeditious review. The permittee must keep each record for 5 years following the date of each recorded action. The permittee must keep each record onsite for at least 2 years after the date of each recorded action. [40 CFR §§ 63.10(b)(1) and 63.11225(d)]

4.4. Submit the following to EPA:

4.4.1. An Initial Notification to EPA no later than 120 days after the Kulluk becomes an OCS source in its first drilling season. The Initial Notification shall include: [40 CFR 63.9(b)(2)]

4.4.1.1. The name and address of the owner or operator.

4.4.1.2. The physical location of the affected source.

4.4.1.3. An identification of the requirement which is the basis of the notification and the source's compliance date.

4.4.1.4. A brief description of the nature, size, design and method of operation of the source and an identification of the types of emission points within the affected source subject to the relevant standard and types of hazardous air pollutants emitted.

4.4.1.5. A statement of whether the affected source is a major source or an area source.

4.4.2. Notification of Compliance Status to EPA no later than 120 days after the applicable compliance date established under Condition G.4.1 and no later than 60 days after each biennial tune-up. Each Notification shall include the following: [40 CFR §§ 63.9(h), 63.9(h)(3), 63.11225(a)(1) and 63.11225(a)(4), (b)]

4.4.2.1. Company name and address. [40 CFR 63.11225(b)(1)]

4.4.2.2. Each notice shall be signed by the Responsible Official and shall certify its accuracy, attesting to whether the source has complied with the relevant standard (tune-up). [40 CFR §§ 63.9(h)(2)(i), 63.225(b)(2)]

4.4.2.3. The methods that were used to determine compliance. [40 CFR 63.9(h)(2)(i)(A)]

4.4.2.4. The results of any performance tests, opacity or visible emission observations, CMS performance evaluations, and/or other monitoring procedures or methods that were conducted. [40 CFR 63.9(h)(2)(i)(B)]

4.4.2.5. If the source experiences any deviation from the applicable requirements since the previous Notification of Compliance Status, include a description of the deviations, the time periods during which the deviations occurred and the corrective actions taken. [40 CFR 63.11225(b)(3)]

4.4.2.6. The methods that will be used for determining continuing compliance, including a description of monitoring and reporting requirements and test methods. [40 CFR 63.9(h)(2)(i)(C)]

4.4.2.7. The type and quantity of hazardous air pollutants emitted by the source (or surrogate pollutants if specified in the relevant standard), reported in units and averaging times and in accordance with the test methods specified in the relevant standard. [40 CFR 63.9(h)(2)(i)(D)]

4.4.2.8. A description of the air pollution control equipment (or method) for each emission point, including each control device (or method) for each hazardous air pollutant and the control efficiency (percent) for each control device (or method). [40 CFR 63.9(h)(2)(i)(F)]

4.4.2.9. A statement by the owner or operator of the affected existing, new, or reconstructed source as to whether the source has complied with the relevant standard or other requirement. [40 CFR 63.9(h)(2)(i)(G)]

4.4.2.10. The following statement shall be included in the initial Notification of Compliance Status: “This facility complies with the requirements in §63.11214 to conduct an initial tune-up of the boiler”. [40 CFR 63.11225(a)(4)(i)]

4.4.3. If the permittee intend to switch fuels, and this fuel switch may result in the applicability of a different subcategory or a switch out of subpart JJJJJJ due to a switch to 100% natural gas, the permittee must provide 30 days prior notice of the date upon which the permittee will switch fuels. This notification must include: [40 CFR 63.11225(g)]

4.4.3.1. The name of the owner or operator of the affected source, the location of the source, the boilers that will switch fuels and the date of the notice. [40 CFR 63.11225(g)(1)]

4.4.3.2. The currently applicable subcategory under this subpart. [40 CFR 63.11225(g)(2)]

4.4.3.3. The date on which the permittee became subject to the currently applicable standards. [40 CFR 63.11225(g)(3)]

4.4.3.4. The date upon which the permittee will commence the fuel switch. [40 CFR 63.11225(g)(4)]

4.5. At all times the permittee must operate and maintain the boiler in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the permittee to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to EPA that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records and inspection of the source. [40 CFR 63.11205(a)]

5. **NSPS CCCC for K-8**. NSPS Subpart CCCC Exemption. The permittee shall comply with the applicable requirements of 40 CFR Part 60, Subpart CCCC for Unit K-8 as follows:

5.1. Exemption**.** The permittee shall comply with the applicable requirements of 40 CFR 60, Subpart CCCC for Unit K-8 as follows in order to be exempt from the substantive requirements of 40 CFR 60, Subpart CCCC:

5.1.1. Install and operate an incineration unit that has the capacity to burn less than 35 tons per day of municipal solid waste or refuse-derived fuel (MSW/RDF), as defined in 40 CFR 60 subparts Ea, Eb, AAAA, and BBBB of 40 CFR 60.

5.1.1.1. Compliance with Condition G.5.1.1 shall be determined based upon recordkeeping as required by Condition G.5.2.

5.1.2. Burn commercial/industrial solid waste, as defined in 40 CFR 60 subpart CCCC, with a MSW/RDF concentration greater than 30 percent by weight.

5.1.2.1. Compliance with Condition G.5.1.2 shall be determined each day and is based upon monitoring and recordkeeping as required by Condition G.5.2.

[40 CFR 60.2020(c)(2)]

5.2. Monitoring, Recordkeeping and Reporting: The permittee shall:

5.2.1. Keep records of documentation from the manufacturer showing that the incinerator is incapable of burning 35 tons per day or greater of MSW/RDF.

[40 CFR 60.2020(c)(2)(i)]

5.2.2. For each batch of waste charged to the incinerator:

5.2.2.1. Record the date and time that each batch of waste was charged to the incinerator;

5.2.2.2. Weigh the mass of each batch of waste as follows:

5.2.2.2.1. Segregate and separately weigh MSW/RDF by using a weigh scale used that shall be accurate to within 1 lb;

5.2.2.2.2. Weigh the entire waste stream including MSW/RDF.

5.2.2.3. Record the mass of each batch and record the mass of MSW/RDF based upon observations conducted pursuant to Condition G.5.2.2.2.

[40 CFR §§ 55.8(a), 71.6(a)(3)(i)(B), 71.6(a)(3)(ii) and 71.6(c)(1)]

5.2.3. Each day after the last batch of waste has been charged to the incinerator, calculate the percent of MSW/RDF incinerated for that day by summing the recorded mass of MSW/RDF charged to the incinerator for that day, summing the recorded mass of all material charged to the incinerator for that day, dividing the summed mass MSW/RDF by the summed mass of the entire waste stream, and multiplying the quotient by 100. [40 CFR §71.6(a)(3)(i)(B)]

5.2.4. Keep records on a calendar quarter basis of the weight of municipal solid waste burned, and the weight of all other fuels and wastes burned in the unit. [40 CFR 60.2020(c)(2)(i)]

5.2.5. Report to EPA pursuant to Condition A.18 those occasions in which the value calculated pursuant to Condition G.5.2.3 does not exceed 30 percent. [40 CFR 71.6(a)(3)(iii)]

ATTACHMENT A: EPA NOTIFICATION FORM

Excess Emissions and Permit Deviation Reporting

OCS Source (Facility) Name **Air Quality Permit Number**

Company Name

When did you discover the Excess Emissions/Permit Deviation?
Date: / / Time: :

When did the event/deviation?
Begin: Date: / / Time: : (please use 24hr clock)
End: Date: / / Time: : (please use 24hr clock)

What was the duration of the event/deviation: : (hrs:min) or days
(total # of hrs, min, or days, if intermittent then include only the duration of the actual emissions/deviation)

Reason for notification: (please check only 1 box and go to the corresponding section)
☐Excess Emissions Complete Section 1 and Certify
☐Deviation from Permit Conditions Complete Section 2 and Certify
☐Deviation from COBC, CO, or Settlement Agreement Complete Section 2 and Certify

Section 1. Excess Emissions

(a) Was the exceedance ☐Intermittent or ☐Continuous

(b) Cause of Event (Check one that applies):
☐Start Up/Shut Down ☐Natural Cause (weather/earthquake/flood)
☐Control Equipment Failure ☐Scheduled Maintenance/Equipment Adjustments
☐Bad fuel/coal/gas ☐Upset Condition ☐Other

(c) Description:
Describe briefly what happened and the cause. Include the parameters/operating conditions exceeded, limits, monitoring data and exceedance.

(d) Emission Units Involved:
Identify the emission units involved in the event, using the same identification number and name as in the permit. Identify each emission standard potentially exceeded during the event and the exceedance.

Unit ID	Emission Unit Name	Permit Condition Exceeded/Limit/ Potential Exceedance

(e) Type of Incident (please check only one):

☐Opacity % ☐Venting (gas/scf) ☐Control Equipment Down
☐Fugitive Emissions ☐Emission Limit Exceeded ☐Record Keeping Failure
☐Marine Vessel Opacity ☐Flaring ☐Other:

(f) Unavoidable Emissions:
Do you intend to assert that these excess emissions were unavoidable? ☐YES ☐NO
Do you intend to assert the affirmative defense of 18 AAC 50.235? ☐YES ☐NO

Certify Report (go to end of form)

Section 2. Permit Deviations

(a) Permit Deviation Type (check one only) (check boxes correspond with sections in permit):
☐ Source Specific
☐ Failure to monitor/report
☐ General Source Test/Monitoring Requirements
☐ Recordkeeping/Reporting/Compliance Certification
☐ Standard Conditions Not Included in Permit
☐ Generally Applicable Requirements
☐ Reporting/Monitoring for Diesel Engines
☐ Insignificant Source
☐ Facility Wide
☐ Other Section: (title of section and section # of your permit)

(b) Emission Units Involved:
Identify the emission units involved in the event, using the same identification number and name as in the permit. List the corresponding Permit condition and the deviation.

Unit ID	Emission Unit Name	Permit Condition /Potential Deviation

(c) Description of Potential Deviation:
Describe briefly what happened and the cause. Include the parameters/operating conditions and the potential deviation.

(d) Corrective Actions:
Describe actions taken to correct the deviation or potential deviation and to prevent future recurrence.

Certification:
Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.

Printed Name	**Title**	**Date**

Signature	**Phone number**

NOTE: *This document must be certified in accordance with 18 AAC 50.345(j)*

To Submit this Report:

1. Fax this form to: Facsimile no. 206-553-0110

   Or

2. E-mail to: R10OCSAirPermits_Reports@epa.gov

   Or

3. Mail to: OCS/PSD Air Quality Permits
   U.S. EPA - Region 10, AWT-107
   1200 Sixth Avenue, Suite 900
   Seattle, WA 98101

ATTACHMENT B: VISIBLE EMISSIONS FIELD DATA SHEET

Permit No. R10OCS030000

Certified Observer: ______________________

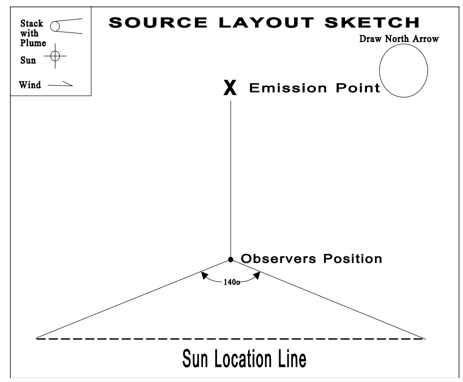
Company & Stationary Source: ______________________

Location: ______________________

Test No.: __________ Date: ______________

Emission Unit: ______________________

Operating Rate: ______________________



Clock Time	Initial				Final
Observer location Distance to discharge					
Direction from discharge					
Height of observer point					
Background description					
Weather conditions Wind Direction					
Wind speed					
Ambient temperature					
Relative humidity					
Sky conditions: (clear, overcast, % clouds, etc.)					
Plume description: Color					
Distance visible					
Water droplet plume? (Attached or detached?)					
Other information					

Page ___ of ___

Company & Stationary Source______________________________ Certified Observer____________________

Test Number ___________________________ Clock time__________________

Date:		Visibility Reduction Every 15 Seconds (Opacity)				Steam Plume (check if applicable)		Comments
Hr	Min	0	15	30	45	Attached	Detached	

Additional information:

____ ___________________________________

Observer Signature and Date Certified By and Date

Data Reduction:

Duration of Observation Period (minutes) ________ Duration Required by Permit (minutes)_________

Number of Observations ______________________ Highest Six –Minute Average Opacity (%)______

Number of Observations exceeding 20 % ________

Average Opacity Summary

Set Number	Time Start—End	Opacity	
		Sum	Average

ATTACHMENT C: EMISSION INVENTORY REPORTING

EPA Reporting Form

Emission Inventory Reporting

Emission Inventory Year – [ ]

Mandatory Information is Highlighted

Inventory Start Date: ______

Inventory End Date: ______

Inventory Type: ______

Facility Information:

(Stationary Source) Facility Name: ______

AFS ID: ______

Census Area/Community: ______

Line of Business (NAICS): ______

Contact/Owner Name: ______

Contact Owner Address: ______

Contact/Owner Phone Number: ______

Facility Physical Address: ______

Lat: Long: ______

Mailing Address: ______

Emission Unit:

ID: ______

Description: ______

Manufacturer: ______

Model Number: ______

Serial Number	
Year of Manufacture:	
Maximum Nameplate Capacity:	
Design Capacity (BTU/hr):	
Control Equipment (List All)	
	Control Equipment Type (Primary or Secondary):
	ID:
	Type:
	Manufacturer:
	Model:
	Control Efficiency (%):
	Capture Efficiency (%)
	Total Capture Efficiency (%)
	Pollutants Controlled
	-
	-
	-
	-
Process (List All):	
	PROCESS
	SCC Code:
	Materials Processed:
	Operational Periods:
	FUEL INFORMATION
	Ash Content (weight %):
	Elem. Sulfur Content (weight %):
	H_2S Sulfur Content (ppmv):

Heat Content (MMBtu/1000 gal or MMBtu/MMscf):

Heat Input (MMBtu/hr):

Heat Output (MMBtu/hr):

THROUGHPUT

Total Amount:

Summer %:

Fall %:

Winter %:

Spring %:

Days/Week of Operation:

Weeks/Year of Operation:

Hours/Day of Operation:

Hours / Year of Operation:

EMISSIONS					
Pollutant	**Emission Factor**	**Emission Factor Numerator**	**Emission Factor Denominator**	**Emission Factor Source**	**Tons Emitted**
CO					
NH_3					
NO_X					
PM_{10}- PRI					
$PM_{2.5}$- PRI					
SO_2					
VOC					
Lead and Lead Compounds					

Stack Description:	Stack Details:
	ID:
	Type:
	Measurement Units:
	Base Elevation:
	Stack Height:
	Stack Diameter:
	Exit Gas Temp:
	Exit Gas Velocity:
	Actual Exit Gas Flow Rate:
	Data Source:
	Description:
	Latitude:
	Longitude:
	Location Description:
	Accuracy (m):
	Datum:

Certification:
Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.

Printed Name:______________________________ Title:_____________________ Date:________

Signature:_________________________________ Phone Number:____________________________

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION 10

SEATTLE, WASHINGTON

RESPONSE TO COMMENTS

FOR

OUTER CONTINENTAL SHELF

PERMIT TO CONSTRUCT AND

TITLE V AIR QUALITY OPERATING PERMIT

CONICAL DRILLING UNIT KULLUK

SHELL OFFSHORE INC.
BEAUFORT SEA EXPLORATION DRILLING PROGRAM
PERMIT NO. R10OCS030000

Table of Content

Abbreviations and Acronyms

AAC	Alaska Administrative Code
ADEC	Alaska Department of Environmental Conservation
AERMOD	American Meteorological Society/EPA Regulatory Model
BACT	Best Available Control Technology
BOEMRE	Bureau of Ocean and Energy Management and Regulatory Enforcement
CAA	Clean Air Act
CFR.	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
COA	Corresponding Onshore Area
COARE	Coupled Ocean-Atmosphere Response Experiment
Discoverer	Noble Discoverer Drillship
Draft Permit	Draft Permit to Construct and Title V Air Quality Operating Permit No. R10OSC030000
EAB	Environmental Appeals Board
EPA	United States Environmental Protection Agency
Fed. Reg.	Federal Register
GHG or GHGs	Greenhouse Gas or Greenhouse Gases
ICAS	Iñupiat Community of the Arctic Slope
km	Kilometers
Kulluk	Kulluk Conical Drilling Unit
kW-h	KiloWatts Hour
$\mu g/m^3$	Microgram per Cubic Meter
LCC	Logging, Cementing and Casing
MLC	Mud Line Cellar
MMS	Minerals Management Service
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_X	Oxides of Nitrogen
NSB	North Slope Borough
NSR	New Source Review

OCD .... Offshore and Costal Dispersion
OCS .... Outer Continental Shelf
OCSLA...................... Outer Continental Shelf Lands Act
OSRV........................ Oil Spill Response Vessel
OxyCat...................... Oxidation Catalyst
PM .... Particulate Matter
$PM_{2.5}$ .... PM with an Aerodynamic Diameter less than 2.5 Microns
PM_{10} .... PM with an Aerodynamic Diameter less than 10 Microns
ppm........................... Parts Per Million
PTE.............................Potential to Emit
PDF........................... Portable Document Format
PSD .... Prevention of Significant Deterioration
PVMRM .... Plume Volume Molar Ration Method
QAPP........................ Quality Assurance Project Plans
Region 10 .... Environmental Protection Agency, Region 10
SCR .... Selective Catalytic Reduction
Shell.......................... Shell Offshore Inc.
SILs........................... Significant Impact Levels
SO_2 .... Sulfur Dioxide
tpy .... Tons per Year
ULSD .... Ultra Low Sulfur Diesel
VOC .... Volatile Organic Compound

I. INTRODUCTION

On October 21, 2011, pursuant to Clean Air Act (CAA) section 328, 42 U.S.C. § 7627, the Environmental Protection Agency (EPA) Region 10 (Region 10) issued an Outer Continental Shelf (OCS) Permit to Construct and Title V Air Quality Operating Permit, Permit Number R10OCS030000 (Kulluk Permit), to Shell Offshore, Inc. (Shell).

The permit authorizes Shell to conduct air pollutant emitting activities for the purpose of oil exploration with the conical drilling unit Kulluk on lease blocks in the Beaufort Sea off the North Slope of Alaska, as authorized by the United States Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE).[1] The Kulluk Permit provides for the use of an associated fleet of support vessels (Associated Fleet), such as icebreakers, oil spill response vessels (OSRV), and a supply ship, in addition to the Kulluk.

Shell submitted an initial application to Region 10 for three air permits to cover air pollution from its exploratory drilling operations on OCS lease blocks in the Beaufort Sea: an OCS/Title V permit under 40 CFR Parts 55 and 71 for operations beyond 25 miles of Alaska's seaward boundary; an OCS/minor permit for air quality protection under 40 CFR Part 55 and 18 Alaska Administrative Code (AAC) 50.502 and for owner-requested limitations under 40 CFR Part 55 and 18 AAC 50.508 for operations within 25 miles of Alaska's seaward boundary; and an OCS/Title V permit under 40 CFR Part 55 and 18 AAC 50.326 for operations within 25 miles of Alaska's seaward boundary. Shell requested that the three permits be consolidated into a single permit (hereinafter "Kulluk Permit" or "OCS/Title V Permit").

Following the receipt of Shell's completed permit application, Region 10 published notice of the issuance of a draft permit on July 22, 2011 (Draft Permit), and requested public comment on the Draft Permit by September 6, 2011. An informational meeting and public hearing on the Draft Permit were held in Barrow, Alaska on August 23, 2011, and a second public hearing was held in Anchorage, Alaska on August 26, 2011.

Region 10 received written comments on the Draft Permit from Shell (the applicant); the Alaska Eskimo Whaling Commission, the Iñupiat Community of the Arctic Slope, and the North Slope Borough in a combined comment letter (collectively the "North Slope commenters"); the Native Village of Point Hope; Alaska Wilderness League, Audubon Alaska, Center for Biological Diversity, Defenders of Wildlife, Greenpeace, Earthjustice, EYAK Preservation Council, National Wildlife Federation, Natural Resources Defense Council, Northern Alaska Environmental Center, Ocean Conservancy, Oceana, Pacific

[1] The Secretary of the U.S. Department of Interior (DOI) regulates and manages the development of mineral resources on the OCS. *See* 42 U.S.C. § 1334 (authorizing Secretary to administer leasing on the OCS). In particular, the BOEMRE is responsible for overseeing the safe and environmentally responsible development of energy and mineral resources on the OCS. BOEMRE was established as a result of Secretarial Order 3302, signed on June 18, 2010, by the Secretary of Interior. Secretary of Interior, U.S. Department of Interior, Secretarial Order No. 3302, *Change of the Name of the MMS to the Bureau of Ocean Energy Management, Regulation and Enforcement* (June 18, 2010), *available at* http://elips.doi.gov/app_so/index.cfm?fuseaction=chroList/.

Environment, REDOIL, Sierra Club, Wilderness Society, and World Wildlife Fund in a combined comment letter (collectively, the "Conservation commenters"); the Alaska Department of Natural Resources; the Alaska Oil and Gas Association; the Center for Water Advocacy; Alaska's Big Village Network; and other individual commenters. Region 10 also received more than 14,500 identical or similar comments resulting from a campaign sponsored by environmental organizations.

In addition to receiving written comments, Region 10 received numerous comments on the Draft Permit as oral testimony during the public hearings in Barrow and Anchorage. This testimony was transcribed and has been included in the permit record.

This Response to Comments document summarizes the written and oral comments received by Region 10 pertaining to the Draft Permit. After Region 10's careful review and consideration, responses to these comments are presented below. Comments have been condensed and similar comments have been combined for purposes of this document. Complete copies of all comments are in the administrative record for the Kulluk Permit.

RESPONSE TO COMMENTS

A. CATEGORY – COMMENTS OF GENERAL SUPPORT

Comment A.1: Several commenters, including the State of Alaska, express general support for issuance of the permit and urge Region 10 to issue the permit without further delay. The commenters, several of whom submitted identical or similar form comments, stated that other countries are moving ahead to develop Arctic resources and expressed concern that the United States was behind in these efforts. Some commenters support private sector-led energy development to the fullest extent possible and assert the benefits of such development to Alaska and Alaska's rural communities. The commenters also cite to a study titled, Potential National-Level Benefits of Alaska OCS Development by Northern Economics and Institute of Social and Economic Research, University of Alaska Anchorage, which projects that drilling on Alaska's OCS could make Alaska the eighth largest oil resource province in the world. Commenters also contend that the Alaska OCS region is a vast, yet untapped resource which has the potential to increase the United States' energy security, provide thousands of high-paying jobs in Alaska and the rest of the United States, and generate billions of dollars in revenue.

Response: Region 10 is proceeding with issuance of the final permit based on Region 10's determination that all Clean Air Act requirements will be met. Region 10 understands that some individuals support this project due to the expected benefits to the economy and the potential for additional oil and gas resources. Region 10 notes, however, that the potential for economic benefits to Alaska or the United States does not affect the standards for issuing this permit.

Region 10 also notes that Shell needs a number of other regulatory approvals before it is authorized to engage in exploration operations in the Beaufort Sea. These include approvals of Applications for Permits to Drill from BOEMRE, Marine Mammal Protection Act authorization from the National Marine Fisheries Service and the U.S. Fish and Wildlife Service and a corresponding Endangered Species Act Incidental Take Statement, as well as other approvals. See, e.g., Letter from Jeff Walker, BOEMRE, to Susan Childs, Shell, re: 2012 Revised Camden Bay Exploration Plan, dated August 4, 2011.

Comment A.2: A commenter states that it is important to remember that the Draft Permit does not provide Shell authorization to drill and only authorizes air pollutant emissions from the Kulluk and the Associated Fleet. The commenter asserts that Shell must also obtain at least 10 other federal permits and authorizations in order to proceed with an exploratory drilling program and that this drilling project is not occurring without adequate oversight and necessary approvals.

Response: As discussed in response to comment A.1, Region 10 agrees that this permit does not authorize Shell to conduct exploratory operation, but rather authorizes emissions from any such operations, and that several other regulatory approvals are needed before Shell is authorized to conduct exploratory operations in the Beaufort Sea.

Comment A.3: In its comment, Shell states that a significant amount of effort has gone into obtaining the Draft Permit. Shell states that it has committed to many operational restrictions and measures to ensure its operation's emissions are as low as the practicable application of current technology affords, including the commitment to use ultra-low sulfur diesel fuel in all of its vessels, not just the Kulluk, as well as installing selective catalytic reduction (SCR) and other control technologies on not only the Kulluk but also its ice management and anchor handling vessels. Finally, Shell states that it has voluntarily agreed to reduce the number of potential drilling days to further confirm that operations will be conducted with emissions as low as is practicably allowable. These emissions are low enough, Shell continues, that the Kulluk will meet the EPA's minor source permitting thresholds.

Response: Region 10 agrees that the permit terms and conditions should ensure that the Kulluk and the Associated Fleet operate as a minor source (that is, that emissions will be less than the PSD major source thresholds). Note that, although the use of ultra-low sulfur diesel, SCR, and other control technologies, as well as the limits on the number of drilling days, were initially requested by Shell in its permit application, they are not "voluntary." Instead, they are included in the permit as terms and conditions needed to assure compliance with Clean Air Act requirements.

B. CATEGORY – COMMENTS OF GENERAL OPPOSITION

Comment B.1: Region 10 received over 14,500 identical and similar comments during the public comment period for this permit opposing issuance of OCS air permits in the Arctic Seas. A number of comments of general opposition were also made during the public hearings on the Draft Permit. The commenters ask Region 10 to adopt the strongest and most protective standards for this and other drillship air permits and to permit the proposed emissions only when their impact to the health and welfare of North Slope residents is minimized to the greatest extent possible. The commenters state that air emissions from large scale and long term oil and gas activities in the Arctic Seas, including drillships and icebreakers, result in a large amount of air pollution that puts workers and nearby communities at risk, and accelerates already rapid climate change in the region. The commenters encourage EPA and other federal agencies to consider the impacts of oil and gas development on the ecosystem of the Arctic because they believe there is a lack of sufficient scientific data to demonstrate that oil development in this remote area is safe. The commenters are concerned that an oil spill in these waters would be catastrophic for endangered and threatened species and would devastate nearby subsistence communities, and assert that no technology currently exists that safely and effectively contains and cleans up oil spilled in icy waters. Many of these commenters point to the oil spill in the Gulf of Mexico in 2010 as evidence of the risk of offshore drilling and assert that the risks of drilling in the Arctic are even higher than the risks of drilling offshore in the Gulf of Mexico. The commenters encourage Region 10 to consider the cumulative impacts of this and other dangers prior to moving forward with oil drilling in the Arctic Ocean.

Response: As an initial matter, it is important to note that issuance of this Clean Air Act permit does not provide Shell authorization to drill on the OCS. Rather, issuance of this permit authorizes air emissions from Shell's operations and requires compliance with air quality regulations and permit terms and conditions when and if drilling commences. BOEMRE is the federal agency that provides authorization to drill. See also response to comment A.1.

After thorough review and careful consideration of the comments requesting that this permit be denied, Region 10 is proceeding to issue the permit. The permit complies with the requirements of CAA § 328 (governing air pollution from OCS sources), EPA's OCS regulations at 40 CFR Part 55 (OCS regulations), Title V regulations in 40 CFR part 71 and the regulations of the Corresponding Offshore Area (COA), including the COA regulations for minor new source review. As discussed in more detail in the response to comments for Categories Q through Y, Section 4 of the Statement of Basis, and Appendix A to the Statement of Basis (Technical Support Document),[2] Region 10 has conducted an extensive analysis of the air quality impacts of the project and has determined that issuance of the permit will not cause or contribute to a violation of currently applicable NAAQS.

Comments and concerns with noise and the possibility of oil spills are outside the scope of the Clean Air Act OCS and Title V programs.

Comment B.2: One commenter states that, even though this permit is for experimental arctic drilling, eventually it really becomes an oilfield or production facility that will emit dangerous gases that can kill people or animals.

Response: Shell will need to apply for additional permits to operate a production facility if such facility will involve any equipment or activities not authorized under this permit. The air quality impacts from such production facility will be considered at that time.

C. CATEGORY – PUBLIC COMMENT PROCESS

Comment C.1: Commenters note that CAA regulations require a minimum of 30 days for public comment on permits, but that a comment period of more than 30 days may be necessary to provide additional time for complicated proceedings. Commenters also note that the Environmental Appeals Board (EAB) has recognized the adequacy of public participation as an important factor and found inadequate participation as a basis for objecting to a permit. Commenters state that an inadequate public comment period opens the door to raising issues on appeal that were not raised during the comment period and that this can complicate the permitting process.

Response: Region 10 agrees with the commenters that CAA regulations require a minimum of 30 days for public comment on the Draft Permit, and that the regulations

[2] Technical Support Document: Review of Shell's Ambient Air Quality Impact Analysis for the Kulluk OCS Permit Application, dated July 18, 2011.

acknowledge a period of more than 30 days may be necessary for complicated proceedings. Region 10 proposed the Draft Permit for public comment on July 22, 2011, and requested that comments be submitted by September 6, 2011. The 46-day comment period provided for the Draft Permit complies with the 30-day public comment period required by 40 CFR §§ 71.11(d)(2) and 124.10(b)[3] and provides an additional 16 days for the submission of comments. Region 10 believes that the length of the comment period provided the public a reasonable opportunity to comment on the Kulluk Draft Permit.

The commenters are correct that the EAB has recognized the important role public participation plays in the permitting process, and has remanded permits for inadequate public participation. However, EAB remands for inadequate public participation typically involve the permit issuer's failure to comply with applicable public participation requirements. *See In re Russell Energy Center*, PSD Appeal Nos. 10-01 to 10-05 (EAB Nov. 18, 2011)(remanding for failure to comply with notice requirements); *In re Rockgen Energy Center*, 8 E.A.D. 536 (EAB Aug. 25, 1999)(remanding because the record did not show that the permit issuer considered comments before issuing the permit); and *In re Atochem N. Am.*, 3 E.A.D. 498 (EAB Jan. 24, 1991)(remanding for failure to respond to comments). Region 10 has complied with its statutory and regulatory obligations regarding public notice and comment and believes that the public participation process was adequate.

Region 10 takes seriously its responsibility to ensure that the public has a meaningful opportunity to participate in permitting decisions. Prior to and during the public comment period, Region 10 took a number of affirmative steps to promote meaningful public involvement. To inform the North Slope community of the Draft Permit and to describe opportunities for public participation, Region 10 conducted three separate informational meetings in Barrow and Kaktovik, Alaska from June 15 – 17, 2011, more than a month prior to the start of the public comment period. At the start of the comment period, Region 10 distributed copies of the Draft Permit and supporting materials to a number of information repositories located in North Slope communities and made these documents available on its website. In addition, documents that will be contained in the administrative record were burned onto compact discs and provided to commenters who requested the documents during the comment period. On August 23, 2011, Region 10 held an informational meeting and a public hearing on the Draft Permit in Barrow,

[3] The portion of this permit that is a Part 71 permit (e.g., the portion of the permit that applies on the Outer OCS) is issued under 40 CFR Part 55 and 40 CFR Part 71 and subject to the procedural requirements of 40 CFR Part 71 as provided in 40 CFR § 71.4(d). The portion of this permit that is a COA Title V permit and a COA minor source permit (e.g., the portion of the permit that applies on the Inner OCS) is issued under 40 CFR Part 55 and, in the absence of other applicable procedures, subject to the permit issuance procedures for PSD permits under 40 CFR Part 124, Subpart A and C. See 40 CFR §§ 55.6(a) (3) and 124.1. Note that the Statement of Basis (at 10) erroneously stated in discussing the public participation requirements that this permit is a Part 71 permit subject to the procedures of 40 CFR Part 71. The Statement of Basis makes clear in other discussions (at page 4 and Section 2) that this permit is in fact a permit issued under Parts 55 and 71 as well as under the COA regulations for minor permits and Part 70 permits. Requirements for issuance of permits under 40 CFR Parts 71 and 124 are the same or very similar in most respects.

Alaska. On August 26, 2011, a second public hearing was held on the Draft Permit in Anchorage, Alaska.

Commenters cite to 40 CFR § 71.11(*l*)(1) as support for the statement that an inadequate public comment period opens the door for raising issues on appeal that were not raised during the comment period. Region 10 disagrees with the commenters characterization of this regulatory provision. The pertinent question is not the adequacy of the public comment period but whether it was impracticable for commenters to raise objections during the public comment period. Although the commenters object to the length of the comment period, Region 10 is not aware of any circumstances that would have made it impracticable for commenters to raise objections to the Kulluk Draft Permit during the comment period provided.

Comment C.2: Commenters contend that the public comment period for the Draft Permit was inadequate. As support for this contention, the commenters reference the fact that the 46-day public comment period for the Draft Permit, which ran from July 22 to September 6, overlapped with the comment period for the 2011 Discoverer Permits, which ran from July 6 to August 5. Commenters also note that the comment period for ConocoPhillip's air permit ran from July 22 to September 21. The commenters calculate that Region 10 has provided a total of 60 calendar days to review four different air permits, all of which are technically and legally complex. The commenters contend that this schedule effectively limits stakeholders to 15 days to review each permit. The commenters request a minimum of 45-day comment periods for each air permit, without overlap, to conduct a comprehensive review of the permits and for residents most impacted by the permits to adequately engage in the public process. Finally, commenters state that there does not seem to be a reason for Region 10 to rush the permits and that the Region has eighteen months to review Title V permits once applications are complete. Commenters reference the July 19, 2011 date on which Region 10 issued its completeness determination for the permit application and state that there is plenty of time remaining to extend the public comment period for the Draft Permit.

Response: The 46-day comment period provided adequate opportunity for meaningful public involvement and exceeded the 30 day comment period required by 40 CFR §§ 71.11(d)(2) and 124.10(b). Region 10 understands that the commenters would like additional time for public participation. However, the commenters have not demonstrated that a period of more than 46 days is necessary to give the public a reasonable opportunity to comment. See 40 CFR §§ 71.11(g) and 124.13.

Although Region 10 denied the North Slope commenters' request to hold non-overlapping 45-day comment periods for each draft air permit in a letter dated July 21, 2011, the Region did subsequently extend the comment period on the ConocoPhillips draft permit for an additional two weeks in response to the fact, noted by the commenters, that ConocoPhillips does not intend to begin operations until July 2013. On September 26, 2011, Region 10 received notification from ConocoPhillips that it was withdrawing its permit application and would resubmit a new application in the future. Shell, on the other hand, intends to begin its exploratory drill operations with the Kulluk in July 2012.

The Region agrees with the commenters that some aspects of the Draft Permit are technically and legally complex. The comments submitted, however, demonstrate that the public was able to review, evaluate, and comment on many complex issues during the comment period provided. The Region received more than 14,500 public comments. Although a majority of these comments were practically identical and contained general statements of support or opposition, the Region received a number of substantive comments on, among other issues, the definition of OCS Source, limits on the source's potential to emit, choice of model, modeling data, ambient air boundary, source testing, emission factors, air quality analysis, applicability of increments and visibility, and cumulative impacts. The volume of comments received and the substantive issues addressing technically and legally complex issues demonstrate that the public was able to meaningfully review and comment on the Draft Permit.

Region 10 agrees that 40 CFR § 71.7(a)(2) requires that it take a final action on a Title V permit application within 18 months of receiving a complete application. That the Region may be able to take a final action on a permit application prior to the end of the 18-month period cited by the commenters does not mean that the permitting process was rushed. Although Shell's application was not deemed complete until July 2011, the Region has been carefully reviewing components of the application since it was first submitted in February 2011. In conducting the permitting process, Region 10 must strike a balance between its obligation to provide for meaningful public participation and its responsibility to make a final permitting decision in a timely manner. The Region has complied with the applicable requirements for public involvement and provided more than the required amount of time for public comment.

Comment C.3: Commenters contend that expert review of the new algorithms used in the modeling analysis proved impossible. To support this statement, commenters contend that they were unable to hire a consultant with the requisite expertise to review the algorithms and were told by the experts they talked to that it would be very difficult to conduct a comprehensive review in the time allowed. As a result, commenters state that it was impossible to identify potential problems or shortcomings with the modeling or to conduct a comprehensive review.

Response: It is important to note that the revised modeling approach was used for both the Shell Kulluk and Discoverer draft permits, and both public notices refer to the same supporting documentation. The commenters who raised this issue on the Draft Permit also commented on the modeling supporting the Discoverer permits. Therefore, the commenters in fact had a period of 60 days to review AERMOD-COARE prior to submitting comments on the Draft Permit. The inability to hire someone to assist with the preparation of comments does not mean that the public process provided was inadequate. In fact, the Region received substantive comments on a number of complex modeling issues, including the use of the new algorithms. The model used to support the permits, AERMOD, is an EPA guideline model that has, after notice and comment rulemaking, been approved as a guideline model. See 40 CFR Part 51, Appendix W, Section 4.2.2(b). Region 10 approved partial changes to AERMOD for purposes of this permitting action, comprised of two permit-specific algorithms for use with the guideline model: Coupled Ocean-Atmosphere Response Experiment (COARE) for the pre-processing of meteorological data and the Plume Volume Molar Ratio Method (PVRM) that is considered on a case-by-case basis as a non-regulatory default option under Section 5.2.4.d of Appendix W. Region 10 believes that the public was provided with sufficient time to review and comment on the use of the new algorithms.

Comment C.4: Commenters contend that the August 23, 2011 public hearing for the Draft Permit held in Barrow was problematic because the teleconference system that Region 10 established for other North Slope villages to participate proved problematic. Commenters state that the telephone connection was poor on both ends which is not uncommon for the North Slope, and that all parties involved acknowledged difficulty hearing the participants. The commenters also state that Region 10 did not make the PowerPoint presentation available to those attending the hearing by teleconference. The commenters urge Region 10 to give thought to how to effectively engage communities on the North Slope and, ideally, to visit each of the communities to hear directly from the residents.

Response: Region 10 recognizes that the Draft Permit is of interest to individuals and communities dispersed over a broad geographic area, and it made a concerted effort to foster public participation at the Barrow public hearing by providing a teleconferencing option. It is not practical for Region 10 to hold public hearings in each of the North Slope communities that have an interest in the Draft Permit. The rules governing the issuance of the permit do not require, if a hearing is held, that a hearing be held in more than one location. In this case, Region 10 determined that Barrow was the most appropriate location for the hearing. Barrow is an important center for the North Slope communities and a location with the infrastructure to hold and broadcast the hearing. Entities such as the Inupiat Community of the Arctic Slope and the Arctic Slope Regional Corporation have offices in Barrow, and members of the Alaska Eskimo Whaling Commission come from Barrow as well as other villages. To increase the opportunity for participation in the hearing, Region 10 made arrangements for North Slope communities outside of Barrow to participate by teleconference. Region 10 acknowledges that there were some problems with the teleconference, and, as the commenters acknowledge, telecommunication problems on the North Slope are not uncommon. To address potential issues, Region 10 recorded the public hearing in addition to having the hearing transcribed by a court reporter. From these two sources, Region 10 was able to capture the comments provided during the public hearing.

Comment C.5: A number of oral comments concerning public participation were received during the public hearing. Commenters said that the public comment period was insufficient and requested that it be extended to at least 45 days, and two commenters specifically requested that it be extended to September 19, 2011. A number of commenters described the permits as confusing and difficult to decipher and noted that an additional public process for ConocoPhillips was being conducted during the same time as the public process for the Draft Permit. Commenters referenced the highly technical nature of the permit and the use of a new model as reasons to extend the comment period.

One commenter stated that the public process schedule lends the appearance that the Region is checking a box and not working with the communities on the Draft Permit and that this decreases public confidence in the Region's permitting decisions. Two commenters requested that the ConocoPhillips permit be delayed because they are not planning to drill until 2013.

Commenters also addressed the Region's public hearing process. One commenter expressed appreciation for the steps Region 10 took to set up the teleconference line but stated that the communities have a right to meet with the Region in person. A number of commenters stated that the Region should hold hearings in other communities, especially Nuiqsut, to hear from the people who will be most affected. One commenter noted that technology is sometimes a problem on the North Slope and another commenter stated that the presenters at the public hearing kept fading in and out over the phone line and that the Region has not made improvements to how it conducts public hearings. Another commenter suggested that there were other ways to hold a public hearing and suggested that the Region use a video teleconference system. One commenter noted that communities of the Arctic are bilingual and that Inupiak is the first language for many people and it is difficult for these people to understand the issues and provide meaningful testimony.

Response: Region 10 appreciates the comments provided during the public hearing and recognizes that members of the North Slope communities have a significant interest in the permitting process. As described in response to comment C.2, the 46-day comment period for the Draft Permit provided meaningful opportunity for public participation. The Draft Permit involves consideration of complex issues but the commenters have not demonstrated that additional time is necessary to address these issues. As described in response to comment C.1, Region 10 has taken a number of affirmative steps to facilitate public involvement by the North Slope communities in the permitting process. With respect to the public comment process for ConocoPhillips, as described in response to comment C.2, Region 10 extended the public comment period by two weeks. On September 27, 2011, Region 10 received notification from ConocoPhillips that it was withdrawing its permit application and would submit a new application in the future.

As described in response to comment C.4, Region 10 conducted an inclusive public hearing process and selected Barrow as the most appropriate location for a public hearing. The Region understands that commenters would prefer that public hearings be held in other villages as well and that there may be better technological options for remote participation. However, considering the logistical limitations of holding a public hearing on the North Slope, the Region believes that the Barrow hearing provided an adequate opportunity for public participation.

Prior to the Barrow public hearing, Region 10 contacted the Iñupiat Community of the Arctic Slope to arrange for an Iñupiat speaker to be available to provide Iñupiat interpretation at the hearing if requested by any participant. At the beginning of the hearing, participants were provided the opportunity to request Iñupiat interpretation during the hearing. No participant requested translation and therefore an interpreter was not used. Region 10 encourages public participation of North Slope communities and is open to additional suggestions from community members as to the best way to ensure meaningful participation of individuals who speak Iñupiat as a primary language.

D. CATEGORY – DEFINITION OF OCS SOURCE

Comment D.1: Commenters requested that because Shell is currently proposing only exploration for offshore oil and gas resources, that Region 10 classify Shell's operations as a new "exploratory OCS source."

Response: Region 10 agrees that the Kulluk is a new exploratory OCS source. 40 CFR § 55.2 defines the term "exploratory source" or "exploratory OCS source" as "any OCS source that is a temporary operation conducted for the sole purpose of gathering information. This includes an operation conducted during the exploratory phase to determine the characteristics of the reservoir and formation and may involve the extraction of oil and gas." Shell has identified its activities in its permit application as exploratory. See OCS Permit Applications, Conical Drilling Unit Kulluk, Beaufort Sea – Supplemental Information, dated June 29, 2011 (Permit Application Supplement) at 1 and 9.

Note that the Kulluk is considered "temporary" under the Title V program because it is expected that the Kulluk will change locations over the life of this permit.

Comment D.2: Some commenters disagree with Region 10's proposal that the Kulluk be considered an OCS source only when its attachment to the seabed by an anchor occurs at a drill site. The commenters note that under section 328 of the CAA, an OCS source is any equipment, activity or facility which: 1) has the potential to emit air pollutants, 2) is regulated or authorized under OCSLA, and 3) is located on the OCS or in the waters above the OCS and specifically includes "drillship exploration." The commenters also cite to the regulatory definition of OCS source in the case of vessels. The commenters assert that because a vessel is an OCS source when it is "temporarily" attached to the seabed, "may be used" for the purpose of exploring for oil and gas resources, and is in an area authorized by OCSLA (*i.e.* Shell's lease blocks), the Kulluk should be considered to be an OCS source whenever it drops a single anchor within Shell's lease blocks. As support for this conclusion, the commenters cite to the EAB's discussion of OCSLA § 4(a)(1) in *Shell Gulf of Mexico, Inc. and Shell Offshore, Inc.*, Frontier Discoverer Drilling Units, OCS Appeal Nos. 10-01 through 10-04, Order Denying Review in Part and Remanding Permits, dated December 30, 2010 (Remand Order I), and to A*lliance to Protect Nantucket Sound, Inc. v. United States Dep't of the Army*, 288 F. Supp. 2d 64, 75 (D. Mass. 2003). The commenters also contend that Region 10 cannot argue both that Shell is "authorized" to operate at all of its lease blocks, which is necessary for CAA jurisdiction, and then limit Shell to being a source only where it has a permit to drill. The commenters request that Region 10 change the permit to read: "A drill site is any location at which Shell is the leaseholder of a lease from BOEMRE."

Response: Region 10 proposed that the Kulluk be considered an OCS source any time it is attached to the seabed at a drill site by at least one anchor. A drill site is defined in the Kulluk Permit as any location at which Shell is authorized to operate under the applicable permit and for which Shell has received from BOEMRE an authorization to drill. Region 10 continues to believe this interpretation is consistent with the relevant statutes and regulations as applied to this specific permitting action.

Both EPA's regulatory definition of OCS source at 40 CFR § 55.2 and Section 4(a)(1) of the Outer Continental Shelf Lands Act (OCSLA)—which is referenced in EPA's regulatory definition of OCS source in the case of vessels—discuss more than attachment to the seabed. Both EPA's regulatory definition in the case of vessels and OCSLA § 4(a)(1) reference the additional considerations that the source be "erected" on the seabed as well as the purpose of the attachment. These additional elements in EPA's regulatory definition and the explanatory clause in OCSLA § 4(a)(1) make clear that attachment to the seabed at any location on the OCS is not sufficient to render the Kulluk an OCS source.[4] Region 10 continues to believe that, as in OCSLA § 4(a)(1), the reference to "erected thereon" in 40 CFR § 55.2 is intended to reflect the process by which a vessel becomes situated at the location where it will be used for the purpose of exploring, developing, or producing resources from the seabed. For the activities authorized under this permit, this requires that the location of the attachment occur at a location where the Kulluk is authorized to engage in such activities, namely at a drill site for which Shell has obtained an authorization for the Kulluk to drill.

The commenters do not argue that any attachment to the seabed alone is sufficient to render the Kulluk an OCS source. Instead, the commenters argue that the Kulluk should be considered an OCS source whenever it is attached to the seabed at any location within a Shell lease block. A review of the facts underlying this permitting action and the legal requirements for conducting exploratory operations under Shell's leases, however, reveals that the commenters' suggestion that the Kulluk be considered an OCS source whenever it is attached to the seabed in a Shell lease block is an overly broad approach that, if applied, could produce illogical results.

Shell's lease blocks in the Beaufort Sea comprise an area of approximately 1145 square miles. Under the commenters' proposed interpretation, the Kulluk could be considered an OCS source even though it was anchored many miles from a location in the same sea where it had authorization from BOEMRE to drill as long as the anchor location was in a Shell lease block. In contrast, the Kulluk would not be considered an OCS source under the commenters' proposed interpretation if it was located one mile from an authorized drill site waiting to move into location at the drill site if the location at which it was anchored was not in a Shell lease block. It makes little sense to regulate the Kulluk as an OCS source when it is a hundred miles or more from a location where it is authorized to engage in exploratory activities, as the commenters' approach would require, but not to

[4] Region 10 is aware that the First Circuit has held that OCSLA § 4(a)(1) is not restricted to structures related to mineral extraction. *Alliance to Protect Nantucket Sound, Inc. v. United States Dep't of the Army*, 398 F.3d 105, 107 (1st Cir. 2005). There is nothing in that case to suggest, however, that a vessel that is simply anchored anywhere on the OCS or on leases that it holds is subject to OCSLA's jurisdiction.

regulate the Kulluk as an OCS source when it is not located on a lease block but is one mile from a location where it is authorized to engage in exploratory activities.

The fact that the Kulluk could potentially obtain authorization to drill anywhere within any valid lease block and that this permit would at that point authorize air emissions at such location is not a compelling basis for a different result. Even at locations where Shell holds leases, Shell would need to submit and obtain BOEMRE approval of an exploration plan and an application to drill (as well as obtain other approvals) before it would be authorized to conduct exploratory operations at a particular location in its lease holdings, a process that takes a minimum of several months. In this respect, a location on the OCS where Shell holds a lease but does not have authorization to drill is more similar to a location on the OCS where Shell does not hold a lease than it is to a location where Shell is the holder of a current authorization to drill from BOEMRE: it is not authorized to engage in exploratory operations at that time except at locations at which it holds a current authorization to drill from BOEMRE. Nor, as the commenters allege, is there an inconsistency in the fact that the permit authorizes operations at all identified lease blocks, provided that Shell is complying with all other federal requirements (see Condition A.4.1 of the Kulluk Permit), but then limits the location at which the Kulluk is considered an OCS source to those locations where the Kulluk is attached to the seabed at a location where it has a current authorization to engage in exploratory operations at the time of the attachment. Region 10 believes it is not the lease rights held by a company but the authorization to drill that determines the area where a drillship may be erected and used for the purpose of exploring, developing, or producing resources from the seabed.

Region 10 therefore rejects the commenters' suggestion that attachment of the Kulluk to the seabed at any location in a Shell lease block is sufficient to consider the Kulluk an OCS source within the meaning of 40 CFR § 55.2.

Comment D.3: Commenters state that, for the same reasons discussed in comment D.2, if any other vessel associated with Shell's operations anchors to the seabed floor, it should be considered an OCS source. The commenters note that Shell says the Oil Spill Response vessel and quartering vessel will be anchored. The commenters contend that anchored vessels have the potential to emit air pollutants, are authorized and regulated under OCSLA, are located on waters above the OCS, and are attached to the seabed and erected thereon for the purpose of aiding in the exploration of oil and gas.

Response: Based on the information in the permit application, as well as the regulatory definition of OCS source in the case of vessels and the language and legislative history of the statutory definition of OCS source and OCSLA § 4(a)(1), Region 10 does not agree that the other vessels that have been identified as associated with Shell's operations in this case are themselves "OCS sources" by the mere fact that they are anchored to the seabed. The vessels that comprise the Associated Fleet consist of icebreakers, supply ships, oil spill response vessels, and barges for removing drilling muds, as well as oil tankers and other support vessels associated with the Kulluk that will not be operating within 25 miles of the Kulluk when it is an OCS source.

In promulgating the regulatory definition of OCS source in the case of vessels, EPA required that a vessel be not only permanently or temporarily attached to the seabed, but also that it be erected on the seabed and used for the purpose of exploring, developing, or producing resources from the seabed. 40 CFR § 55.2. The commenters appear to be seeking an interpretation that a vessel is "used for the purpose of exploring, developing, or producing resources" from the seabed if it is, in the words of the commenters, "aiding" the effort of exploring, developing, or producing resources even though it is not itself directly engaged in such activities.

However, such a broad interpretation of OCS source is inconsistent with the distinction in the statutory definition of OCS source between the "OCS source" and a "vessel servicing or associated with an OCS source." As the EAB recognized, Section 328(a)(4)(c) maintains a distinction between support vessels and the OCS source. Remand Order I at 25 ("Specifically, without making the support vessels part of the OCS source, the statute directs that emissions from those vessels while within twenty-five miles of the OCS source "shall be considered direct emissions from the OCS source."). In promulgating the regulatory definition of OCS source in Part 55, EPA recognized this distinction, noting a drillship as an example of a vessel used for the purpose of exploring, developing, or producing resources, and discussing that the emissions of other vessels "related to OCS activity" would be included in the "potential to emit" of the OCS source, but be more appropriately regulated under Title II of the Act, and not regulated as an OCS source unless they were attached to an OCS source. 57 Fed. Reg. 40,792, 40,793-94 (September 4, 1992). Region 10 believes that the term "used for the purpose of exploring, developing, or producing resources" from the seabed is best interpreted in this instance as not encompassing the support vessels at issue in this permit that are used for activities such as icebreaking, resupply, and oil response activities conducted in support of the Kulluk drillship.

Important policy considerations also lead Region 10 to conclude that the anchoring of a vessel that aids or supports OCS activities but is not more directly engaged in exploration, development, or production—as is a jackup rig or drillship—is not sufficient to render the support vessel an OCS source. First, because support vessels may at times be used to support OCS activities and at other times to support other activities, it would require the agency to engage in complex decisions regarding when a vessel was sufficiently related to exploration, development, or production activity to become an OCS source upon anchoring to a seabed. Would, for example, an oil spill response vessel that had been stationed near a port in Washington State but was heading north to Alaska to provide support for a drill rig in Alaska be considered an OCS source if it anchored off the coast of Alaska to wait out a storm? Under Region 10's interpretation, decision-making would be more straight-forward: 1) vessels that support an OCS source but are more than 25 miles from the OCS source are not regulated in any respect under CAA § 328; 2) the emissions of vessels that support OCS activity are considered emissions of the OCS source when within 25 miles of the OCS source; and 3) the stationary source activities of vessels that support OCS activity are regulated as part of the OCS source when they are themselves attached to the OCS source.

In addition, considering vessels that support OCS sources to be themselves OCS sources if they are anchored on the OCS could lead to more emissions. This is because the operators of support vessels might decide to avoid anchoring and instead use their propulsion engines to hold position if anchoring would render the vessel an OCS source within the meaning of 40 CFR § 55.2. For example, Shell's application states that the oil spill response vessel will be stationed near the Kulluk and there is also likely to be a quartering vessel for the oil spill response vessel, and that these vessels will anchor when practicable. See Permit Application Supplemental at 38. A determination that the oil spill response or quartering vessels are themselves OCS sources if they anchor to the seabed could encourage a decision in which such vessels continue to use their propulsion engines to maintain position within 25 miles of the Kulluk. This would result in more emissions than would occur if such vessels were anchored.

In summary and for the reasons discussed above, Region 10 does not agree that the support vessels described in Shell's application will become OCS sources if they anchor on the seabed. Region 10's has determined that these vessels are not used for the purpose of exploring, developing, or producing resources from the seabed (as those terms are used in the definition of OCS source in 40 CFR § 55.2), but instead are being used to support such activity. Region 10 made this decision based on the specific support vessels at issue in this permit being used as described in the application materials.

E. CATEGORY – OPERATIONS IN SAME SEA

Comment E.1: Commenters request that Region 10 change Draft Permit Condition D.4.8. to read: "the permittee shall not operate the Kulluk in the Beaufort Sea within the same drilling season as its operation of any other drillship or its lease of any other drillship, including the Noble Discoverer, to any other lessee with lease blocks in the Beaufort Sea." The commenters contend that this condition is necessary to clarify two points: 1) that Shell may not operate any two drillships in the Beaufort Sea at the same time, since such operations were not contemplated by the permit and supporting documents, and 2) Shell cannot work around this permit condition by leasing its drillships to another company that also holds leases in the Beaufort Sea.

Response: Region 10 has proposed permits for Shell projects in the Beaufort and Chukchi Seas. The Discoverer drillship is a major source subject to the PSD permitting program. On September 19, 2011, Region 10 issued one permit covering operation of the Discoverer in the Beaufort Sea and one permit covering operation of the Discoverer in the Chukchi Sea. In the current permitting action, Region 10 has proposed to issue Shell's Kulluk drilling unit a Title V permit for operation in the Beaufort Sea that contains "synthetic minor" limits that would allow the Kulluk to avoid the PSD permitting program and assure compliance with other applicable CAA requirements.

For two activities (such as drilling operations) to be considered one "source" for PSD applicability purposes, the two drilling operations must: belong to the same industrial grouping ("Major Group" Standard Industrial Classification code); be located on one or more contiguous or adjacent properties; and be under the control of the same person. See

40 CFR §§ 52.21(b)(5) and (6). Shell's Discoverer and Kulluk drilling operations meet the first and third criteria. To ensure that the Kulluk would not be on "contiguous or adjacent properties" with the Discoverer's operations and thus considered a single source with the Discoverer for PSD applicability purposes, the Kulluk Permit restricts the permittee from operating the Kulluk in the Beaufort Sea within the same drilling season as the Discoverer. See Permit Condition D.4.8.

With respect to the concern that Shell could work around this permit condition by leasing its drillships to another company that also holds leases in the Beaufort Sea, Region 10 believes the current permit languageis sufficient to address this concern. This permit authorizes Shell Offshore Inc. to operate the Kulluk under the terms and conditions of this permit. See Kulluk Permit (cover page). Similarly, the permit for the operation of the Discoverer in the Beaufort Sea authorizes Shell Offshore Inc. to operate the Discoverer. A permit revision would be required for a different entity to operate the Kulluk or Discoverer under either permit, at which time Region 10 would consider whether any additional permit changes are needed to ensure compliance with all applicable requirements. See 40 CFR § 71.7(d)(1)(iv). Alternatively, a new owner or operator could submit an application for a new permit.

With respect to the concern regarding other drillships or drilling mechanisms, the permits for the Discoverer and the Kulluk only authorize the operation of the equipment specified in those permits. A new permit application would need to be submitted to obtain authorization for air emissions in the Beaufort Sea from some other drillship or drilling mechanism. If such an application is received, Region 10 would address at that time any issues regarding whether the Kulluk and such other vessel would be considered the same "source" for PSD applicability purposes and the cumulative impacts of the operations.

F. CATEGORY – REQUIREMENT TO OPERATE AIR POLLUTION CONTROLS

Comment F.1: Commenters express concern that Shell may not be able to demonstrate compliance with control requirements. As support for this concern, commenters reference Draft Permit Conditions D.6.14 and D.6.15 which specify that Shell must use uncontrolled emission factors for any period of control equipment deviations. The commenters next note that Draft Permit Conditions D.5.15 and D.6.15 allow for reporting under the emergency provisions of Draft Permit Condition A.16 when control devices do not operate according to the parameters specified in the Draft Permit. The commenters believe that this is a loophole that undermines the requirement to operate controls by enabling Shell to report deviations as emergencies. The commenters request that if Region 10 relies on the use of controls for NAAQS analysis, Shell be required to operate controls at all times, with no exception, and that if the controls fail Region 10 should consider it a violation that is not excusable under the emergency provisions in the Draft Permit.

Response: Permit Condition F.3.7 requires Shell to report to Region 10 those periods during which the selective catalytic reduction (SCR) control is not properly operating (urea pump is not operating, the inlet temperature is 90% or less than the most recent reported average inlet temperature, or the NO_X concentration is 150% or more than the most recent reported concentration). In writing this permit condition, Region 10 inadvertently made reference to the permit's emergency provisions rather the permit's deviation reporting obligations as was intended. This permit condition has been amended to correct the typographical error. With this correction, the SCR monitoring deviation reporting obligation is now consistent with the deviation reporting obligation for oxidation catalyst monitoring under Permit Condition F.4.7. Permit Condition F.3.7 now states:

F.3.7 Report as a deviation under Conditions A.17 and A.18 any periods during which the urea pump is not operating, the inlet temperature is 90% or less than the most recent average inlet temperature reported in Condition E.3.1.3, or the NO_X concentration is 150% or more than the most recent NO_X concentration measured in Condition E.3.

The Region also notes that an additional typographical error in the Draft Permit condition has also been addressed so that the amended condition now references Permit Condition E.3 as was intended.

Region 10 disagrees that the permit conditions cited by the commenters undermine the requirement to operate the controls at all times. Permit Conditions D.10 and D.11 require Shell to direct the exhaust from certain engines to an operating control device. Permit Conditions F.3 and F.4 further require Shell to monitor the control devices to help assure that the emission factors Shell uses to calculate emissions are representative. In the event that control device monitoring detects a deviation from normal operation Shell is required to report the occurrence to Region 10 pursuant to Permit Conditions F.3.7 and F.4.7. This reporting will help determine whether Shell remained in compliance with Permit Conditions D.10 and D.11 during the periods of time in question. In addition, emissions for any time period identified as a deviation are required to be calculated and recorded assuming that the control device achieves <u>no</u> emission reductions pursuant to Permit Conditions D.6.14 and D.6.15. And if those calculations indicate emissions in excess of an emission limit, Shell is required to report each occurrence as a deviation pursuant to Permit Conditions A.17 and A.18. Thus, rather than undermining enforcement, these conditions require Shell to use a higher emission factor during those periods where the control equipment may not be controlling emissions effectively, and will require Shell to report higher emissions than would be the case without this requirement.

The conditions relating to permit deviations and emergencies (Permit Conditions A.16, A.17, and A.18) are required conditions in Part 71 permits, and in Alaska minor NSR and Part 70 permits, and are therefore required to be included in the permit. Region 10 will review all deviation reports and take enforcement action as appropriate. While Shell may submit information to Region 10 pursuant to Permit Condition A.16, claiming that noncompliance with a permit condition was due to an emergency, submittal of such a claim does not mean it qualifies as an emergency. Region 10 will carefully review each claim of emergency on a case-by-case basis. Similarly, Region 10 will carefully review each report of a permit deviation to determine if the deviation is also a violation of a permit requirement.

G. CATEGORY – ULTRA LOW SULFUR DIESEL

Comment G.1: Commenters explain that their understanding is that Shell has committed to using Ultra Low Sulfur Diesel Fuel (ULSD) for its OCS exploration activities north of the Bering Strait. The commenters characterize this as a huge reduction in anticipated sulfur dioxide (SO_2) emissions that will reduce not only localized emissions of $S0_2$ but $PM_{2.5}$ pollution as well. However, the commenters continue, the Draft Permit does not include a requirement to use ULSD fuel for the Kulluk and the Associated Fleet. The commenters reference Draft Permit Condition D.4.5 which requires the use of liquid fuel with a sulfur content less than or equal to 100 parts per million (ppm), by weight, in any emission unit on the Kulluk or on the Associated Fleet. The commenters request that the permit require use of ULSD (15 ppm sulfur) in accordance with Shell's commitment to use ULSD and with EPA's June 6, 2006 Final Rule: Control of Air Pollution from Motor Vehicles and Nonroad Diesel Engines: Alternative Low-Sulfur Diesel Fuel Transition Program for Alaska. The commenters contend that this rule requires marine vessels to comply with a 15 ppm fuel sulfur standard as of June 1, 2010, and therefore applies to Shell's proposed operations.

The commenters note that Shell has acknowledged that, upon delivery, the fuel may have a higher sulfur content because the hull of the barge in which the fuel is transported will not be cleaned out. The commenters request that Region 10 explain how use of fuel with a sulfur content as high as 100 ppm is acceptable given the regulatory requirement to use fuel with a sulfur content of 15 ppm. The commenters further request that if the Region determines an exception must be allowed due to the logistics of transporting fuel, then the Region should fully evaluate whether Shell can comply with a limit lower than 100 ppm.

Response: Region 10 created Permit Condition D.4.5 at Shell's request. In its permit application, Shell requested the following source-wide potential to emit (PTE) restriction: "The permittee shall purchase only ultra low sulfur diesel (ULSD) and not combust any liquid fuel with sulfur content greater than 0.01 percent by weight in any emission unit on the Kulluk or a support vessel." This fuel sulfur content limit (Permit Condition D.4.5), coupled with the permitted restriction to combust only 7,004,428 gallons of diesel fuel during any rolling 12-month period (Permit Condition D.4.6), results in an SO_2 PTE of 4.9 tons per year.[5] This is less than 2 percent of the 250 ton per year (tpy) PSD major source threshold. Limiting the fuel sulfur content further from 100 ppm to 15 ppm is not necessary to establish the permitted activity as a PSD minor source.

The NSPS regulation referenced by the commenter (Stationary Compression Ignition Internal Combustion Engines - subpart IIII) was revised on June 28, 2011 (76 Fed. Reg. 37,954), and now requires sources that operate compression ignition engines ordered

[5] 4.9 ton SO_2/yr = (7,004,428 gal diesel/yr) x (7.0 lb diesel/gal diesel) x (1 lb S/10,000 lb diesel) x (2 lb SO_2/1 lb S) x (ton/2000 lb)

after July 11, 2005, and manufactured after April 1, 2006, to purchase diesel (beginning October 1, 2010) that meets the specification of 40 CFR § 80.510(b) which includes a fuel sulfur content of 15 ppm or less. 40 CFR § 60.4207(b). The NSPS allows a transition for engine fuel tanks with existing higher sulfur content diesel to continue burning the old fuel until it is used up as long any additional fuel added to the tank meets the 15 ppm limit. 76 Fed. Reg. 37,961. Over time, with batches of clean fuel being added to old fuel tanks, the fuel sulfur content will eventually meet the 15 ppm sulfur content limit. The NSPS only applies to newer engines on the Kulluk and not to engines on the Associated Fleet. Statement of Basis at 27 (NSPS apply to the "OSC Source"). The permit requires, however, that all of the fuel combusted by engines on the Kulluk or the Associated Fleet must meet the 100 ppm sulfur content limit to comply with the limit requested by Shell.

The permit should ensure that all diesel fuel delivered to the Kulluk for combustion in the NSPS-subject engines (Kulluk electricity generation engines, MLC HPU engines, MLC air compressor engines and the emergency generator engine) meets the 15 ppm sulfur content limit and all fuel combusted by all engines on the Kulluk or associated fleet meets the 100 ppm sulfur limit. Region 10 agrees with the commenters that the permit fails to expressly require and make enforceable Shell's request to be limited to purchasing ULSD for all emission units on the Kulluk and Associated Fleet. The Region has therefore included in the final permit the following condition:

D.4.9 All fuel purchased for use in the Kulluk and Associated Fleet shall have a maximum sulfur content of 15 ppm by weight for all emission units on the Kulluk and Associated Fleet.

4.9.1 Compliance with Condition D.4.9 shall be determined for each diesel fuel purchase based upon recordkeeping required by Condition D.4.9.2

4.9.2 Keep diesel fuel purchase records for each batch of fuel that documents sulfur content.

[40 CFR §§ 52.21, 71.6(a)(1) and 71.6(b), 18 AAC 50.326(a), 18 AAC 50.225, 18 AAC 50.508]

Together, Conditions D.4.5, D.4.6, and D.4.9 should better ensure that all diesel fuel delivered to the Kulluk for combustion in the NSPS-subject engines (Kulluk electricity generation engines, MLC HPU engines, MLC air compressor engines, and the emergency generator engine) meets the 15 ppm sulfur content limit and that all fuel combusted by engines on the Kulluk and the Associated Fleet meets the 100 ppm sulfur limit.

Note that NESHAP requirements (Stationary Reciprocating Internal Combustion Engines 40 CFR Part 63, Subpart ZZZZ) also apply to some equipment on the Kulluk. These requirements do not extend to the Associated Fleet because the support vessels are not part of the OCS source. Statement of Basis at 28. NESHAP ZZZZ applies to older engines on the Kulluk as discussed on page 46 of the Statement of Basis. For a subset of these older engines, Shell is prohibited from combusting any diesel fuel other than diesel fuel that meets the requirements of 40 CFR § 80.510(b) for nonroad diesel fuel. This requirement to combust a fuel satisfying ULSD specifications as it enters the engine applies only to the deck crane engines, and compliance is required beginning May 3, 2013. See Permit Condition G.3.5 for language assuring compliance with 40 CFR § 63.6604. Compliance with the 15 ppm fuel sulfur content limit is determined based upon information gathered in accordance with monitoring and recordkeeping requirements established in Permit Condition G.3.5. Prior to the drilling season, the sulfur content of diesel fuel in each storage tank serving the Kulluk deck crane engines is to be determined and recorded. For each fuel shipment received thereafter, Shell is to determine and record the sulfur content of the shipment as received.

H. CATEGORY – PERMITTING THE KULLUK AS A MINOR SOURCE

H.1 SUBCATEGORY – IN GENERAL

Comment H.1a: Several commenters contend that the project should be permitted as a major source rather than a minor source. Commenters question why the Draft Permit authorizes Shell to operate the Kulluk as a minor source when the Discoverer was permitted as a major source subject to the PSD program. The commenters describe the Draft Permit as establishing less stringent protections and setting a precedent that will impair the Arctic environment as oil and gas activity intensifies.

Response: In its permit application Shell requested that the permit contain federally enforceable restrictions to limit its potential to emit CO, SO_2, and NO_x to below PSD major source thresholds, and its potential to emit for GHGs to below the level at which GHGs become subject to regulation under the Tailoring Rule. See 75 Fed. Reg. 31,514 (June 3, 2010). A source that would otherwise exceed the applicable PSD major source threshold, and therefore be subject to PSD requirements may, as Shell has done here, seek to avoid PSD regulation as a major source by requesting that the permitting authority impose federally enforceable limits on the source's capacity to emit. *In re Shell Offshore, Inc. Kulluk Drilling Unit and Frontier Discoverer Drilling Unit*, 12 E.A.D. 357, 391-92 (EAB Sept. 14, 2007).

The Kulluk Permit includes enforceable limits that will restrict Shell's emissions to below PSD major source thresholds. If, as suggested by the commenters, Shell is permitted as a major source subject to PSD it would not be subject to enforceable limits to ensure minor source status and instead could be authorized to emit pollutants in excess of the PSD major source threshold. For this reason, Region 10 disagrees with the commenters' characterization of the Kulluk Permit as setting less stringent protections, and the assertion that it will set a bad precedent that impairs the environment. As a PSD synthetic minor source, Shell must comply with federally enforceable limits intended to limit its emissions to levels below applicable PSD major source thresholds, whereas sources permitted as major sources subject to PSD can, depending on the permit requirements, emit pollutants at levels that exceed applicable major source thresholds.

Comment H.1.b: Commenters contend that Shell's synthetic minor source status is based on arbitrary assumptions concerning Shell's operations. To support this contention, the commenters reference the NO_x emission limit of 240 tpy and state that this limit prevents Shell from operating its icebreakers for more than 38% of the operational period authorized under the Draft Permit, or roughly 46 days. The commenters note that unpredictable Arctic conditions may require more than 46 days of icebreaking during the operational period, and that it is unreasonable and arbitrary for Region 10 to expect that Shell can pack up and leave once emissions approach the permit limitations.

Response: As an initial matter, the 240 tpy NO_x limit referenced by the commenters does not limit the operation of the icebreakers to only 38% of the operational period. The NO_x limit is a source-wide limit that applies to all emission units in aggregate. Permit Condition D.4.1. Compliance with this limit will be determined through the monitoring, recordkeeping, and reporting requirements established in the permit.

As noted by the commenters, the frequency and intensity of ice conditions in the Arctic is difficult to predict. In its application, Shell relied on multi-year ice data from 2003-2005 to estimate that its icebreakers could be conducting ice management activities within 25 miles of the Kulluk for up to 38% of the time the Kulluk is an OCS Source. Permit Application Supplement at 37. Shell used this assumption along with many others (including the assumption that icebreakers would be operating at maximum load at all times while managing ice within 25 miles of the Kulluk) to estimate the maximum expected emissions for the purpose of assessing its ability to conduct exploratory operations while at the same time limiting emissions to less than PSD major source thresholds. OCS Permit Applications, Conical Drilling Unit Kulluk, Beaufort Sea – Application Forms (Permit Application), Appendix G. Shell estimates that icebreaking activity will account for 92 of the 229 tons of allowable NO_X emissions. For additional discussion of ice management see response to comments in Category FF.

The commenters concern appears to be that the assumption Shell relied on for ice management may not reflect actual ice conditions during operations. This may be the case. However, in requesting synthetic minor limits and relying on this assumption Shell has accepted the risk that, if ice conditions are greater than assumed, Shell may be required to reduce emissions from other units or curtail its drilling season to comply with the NO_x limit. See Response to comment FF.3. Furthermore, the ice management assumption relied upon by Shell does not necessarily mean that Shell would be effectively limited to 46 days (38% of 120 days) of ice management activities. In conjunction with the 38% ice management assumption, Shell assumed the icebreakers would be operating at maximum capacity when actual operations will likely be conducted at less than maximum capacity, and actual emissions would therefore be less than assumed. In addition, Shell's Camden Bay Exploration Plan includes an Ice Management Plan that describes how it will forecast and track ice and weather conditions, and describes procedures for operational curtailment. Therefore, the Region does not think it is arbitrary or unreasonable to expect that Shell will be able to forecast ice management needs and curtail or cease operations if necessary to comply with the NO_x limit.

Comment H.1.c: Commenters express concern that restrictions on the source's PTE are not consistent with Shell's representations to other agencies. The commenters refer to EPA guidance concerning a permittee's request for limits to avoid new source review when in reality the requested limits are not how the permittee intends to conduct operations. The commenters request that Region 10 ensure Shell will abide by the restrictions in the Draft Permit and cite to representations made by Shell to BOEMRE and in its Incidental Harassment Authorization that differ from representations made in its application to Region 10. Commenters further state that, based on information submitted in the Camden Bay Exploration Plan and its air permit application, Shell could only drill one well in Camden Bay this year and ask that Region 10 either confirm Shell will drill only one well or issue a major source PSD permit to Shell.

Response: The fact that Shell's Camden Bay Exploration Plan or some other authorization might authorize operation in a different manner or for a longer period of time than authorized under the Kulluk Permit does not relieve Shell of its obligation to comply fully with the Kulluk Permit. As an initial matter, the operational restrictions on drilling in the permit are not established by days but by hours of operation. See Permit Conditions D.3.3 and D.3.4. In its permit application, Shell assumes that it is engaged in the identified drilling activity for 24 hours a day for the specified number of days. The Environmental Impact Assessment cited by the commenters already includes the five additional days to construct the MLC in the estimate of 44 drilling days for the Torpedo prospect drill site and 34 drilling days for the Sivulliq prospect site. In addition, Shell's permit application describes scenarios in which it would not drill a well to depth but might only establish the MLC or any other portion of a well. Permit Application Supplement at 25. These factors make it possible that Shell could construct wells, or portions of wells, at both the Torpedo and Sivulliq prospects in a single season. Shell acknowledged in its permit application that it could only drill as many wells, or portions of wells, as ice conditions or the requested limits in the permit allow. Id. For these reasons, Region 10 does not agree with the commenters that it is necessary to confirm that Shell will only drill one well, or issue a major source PSD permit in the absence of this confirmation.

The discussion in the guidance cited by the commenters is a discussion of "sham operational limits" whereby a source applies for a permit as a minor source so as to be able to begin construction without obtaining a major source permit (such as a PSD permit) and then subsequently increases its emissions once it has received a major source permit. Limiting Potential to Emit in New Source Permitting, dated June 13, 1989, at 10-11 (1989 PTE Guidance). Although Shell has requested synthetic minor source limits, there is no indication in the permit record that Shell intends to later apply to Region 10 to remove these synthetic limits. Moreover, Shell must comply with all requirements of the Kulluk Permit and failure to do so is a violation of the CAA. See Permit Condition A.3. As explained in the 1989 PTE Guidance, "attempts to expedite construction by securing minor source status through the receipt of operational restrictions from which the source intends to free itself shortly after operation are to be treated as circumvention of the preconstruction review requirements." Whether an original request for a synthetic minor permit is a "sham" may be evaluated when a request to remove such limits is received by the permitting authority. If Shell submits an application for a major source permit after it commences operations, Region 10 will evaluate the application consistent with the 1989 PTE Guidance, as well as other authorities.

Comment H.1.d: Commenters state that the permit must include a requirement that if the synthetic minor limits are relaxed the source will be subject to the requirements of 40 CFR § 52.21(r)(4), and that if the permit limits are exceeded the source will trigger PSD requirements and should be required to obtain a PSD permit.

Response: It is not necessary to include 40 CFR § 52.21(r)(4) as a condition in the Kulluk Permit. This regulatory provision requires that if a source becomes a major source solely by virtue of a relaxation of any enforceable limitation on its capacity to emit a pollutant, the source will be subject to the PSD requirements at 40 CFR §§ 52.21(j) to (s) as though the source had not commenced construction. Region 10 has no information that Shell intends to request that any enforceable limitation be relaxed during the term of the Kulluk Permit. Shell is required to comply fully with the Kulluk Permit. If Shell requests a permit change or modification that relaxes an enforceable limit such that it becomes a PSD major source it will be subject to 40 CFR § 52.21(r)(4). In addition, Region 10 will evaluate any operation in excess of PSD-avoidance limits consistent with the 1989 PTE Guidance and the Memorandum from Eric V. Schaeffer, EPA, re: Guidance on the Appropriate Injunctive Relief for Violations of Major New Source Review Requirements, dated November 18, 1999.

Comment H.1.e: A commenter at the Barrow public hearing stated that all Region 10 permits for operations in the Arctic should require BACT.

Response: OCS sources are required to comply with the provisions of PSD program at 40 CFR § 52.21. 40 CFR § 55.13. The PSD program requires, among other things, that new or modified major stationary sources apply BACT. Shell will be a PSD minor source, not a PSD major source, and therefore is not required to apply BACT.

Comment H.1.f: Commenters at the Anchorage and Barrow public hearings stated that as a minor source Shell is not required to undergo a BACT analysis. One commenter noted that as a PSD minor source the Kulluk will have lower emissions than if it were permitted as a PSD major source, and that Shell has installed emission controls that are extensive. One commenter noted that Shell is currently replacing the main engines and other sources on the Kulluk with newer, more efficient and cleaner systems. The commenter contends that the intent of BACT is to ensure best currently available technology and that Shell has done this with the updates to the Kulluk emission units.

Response: Region 10 agrees with the commenters that as a minor source Shell is not required to conduct a BACT analysis or be subject to BACT, and may have lower emissions than if it were permitted as a PSD major source. As a BACT analysis for the Kulluk has not been conducted, the Region disagrees with the commenter's implication that the updated emission units constitute BACT.

H.2 SUBCATEGORY – PSD APPLICABILITY THRESHOLD FOR GREENHOUSE GASES

Comment H.2.a: Commenters contend that Region 10 applied the wrong major source threshold for CO_2e in the Draft Permit. The commenters note that the Tailoring Rule provides that if a source is not major for any other pollutant the major source threshold is 100,000 tpy, but if the source is major for another pollutant the threshold is 75,000 tpy. The commenters reason that because Shell's pre-permitted PTE for NO_x, CO, and SO_2 would make it a major source for these pollutants, the applicable major source threshold for CO_2e is 75,000 tpy.

Response: The Tailoring Rule referenced by the commenters establishes applicability criteria that determine when GHGs emitted from stationary sources and modification projects become subject to regulation under the PSD and Title V programs. 75 Fed. Reg. 31,514 (June 3, 2010). The rule provides that GHGs emitted from a stationary source will be subject to regulation if the source is a new major source for a regulated NSR pollutant that is not GHG, and emits or has the potential to emit 75,000 tpy CO_2e or more, or if the new source would otherwise emit or have the potential to emit 100,000 tpy CO_2e or more. See 40 CFR § 52.21(b)(49)(iv); 75 Fed. Reg. at 31,523-24. The Tailoring Rule also explained that in order for a source's GHG emissions to trigger PSD or Title V requirements, the GHG emissions "must equal or exceed both the applicability thresholds established in this rulemaking on a CO2e basis and the statutory thresholds of 100 or 250 tpy on a mass basis." 75 Fed. Reg. at 31,518.

Under the PSD program, as applied to Shell's stationary source, a "major stationary source" is any source which emits or has the potential to emit any pollutant subject to regulation under the CAA in amounts equal to or greater than 250 tpy. 40 CFR § 52.21(b)(1). The PSD regulations define potential to emit as the maximum capacity of a source to emit under its physical and operational design, including any physical or operational limitation on the capacity of the source to emit if the limitation is federally enforceable. 40 CFR § 52.21(b)(4).

As noted by the commenter, Shell's pre-permitted PTE exceeds the 250 tpy threshold for non-GHG for three pollutants. However, Shell requested, and Region 10 has included, federally enforceable limitations in the Kulluk Permit that reduce the source's potential to emit to below 250 tpy for all non-GHG pollutants subject to regulation for purposes of NSR. Accordingly, Shell is not a new major source for a non-GHG regulated NSR pollutant and thus is not subject to the 75,000 tpy CO_2e applicability threshold for such sources. Instead, Shell would be considered a major source for PSD permitting purposes if it emits or has the PTE 100,000 tpy CO_2e and 250 tpy GHG on a mass basis. Its requested limits for CO_2e keep it below the applicable threshold, therefore the source's GHG emissions are not "subject to regulation" for PSD permitting purposes and PSD requirements do not apply.

I. CATEGORY – ENFORCEABILITY OF PTE LIMITS

I.1 SUBCATEGORY – GENERAL

Comment I.1.a: Commenters request that Region 10 add to the list of "Prohibited Activities" the operation of the vessels between December 1 and June 30 because the Draft Permit specifies that the "permittee shall only conduct exploration drilling operations in the Beaufort Sea between July 1 and November 30 each year (referred to hereafter as the "drilling season")."

Response: The Kullulk Permit clearly states that "The permittee shall only conduct exploration drilling operations in the Beaufort Sea between July 1 and November 30 each year (referred to hereafter as the "drilling season")." Permit Condition D.3.1. This condition adequately prohibits operation of the Kulluk as an OCS source in the Beaufort Sea between December 1 and June 30 of each year, and the additional condition suggested by the commenters is not necessary.

Comment I.1.b: Commenters state that Region 10 fails to explain why monthly limits could not be imposed in the Draft Permit and why Shell was provided 12-month rolling emission limits for certain pollutants. The commenters reference EPA guidance providing that production and operational limits must be stated as conditions that can be enforced independently of one another and that EPA recommends a one month limit as the maximum time EPA should generally accept for avoiding a PSD threshold. The commenters also point to EPA guidance and state that Region 10 should first consider the possibility of imposing month-by-month limits, and only if that is not feasible should the Region impose a 12-month rolling time period. The commenters reference the following statement that they cite as originating from the Statement of Basis: "because the annual NAAQS are set based on calendar years, the restriction can similarly apply on a calendar year basis (or, in the case of these permits, a drilling season which is limited by the permit to a specific 5-month period out of any calendar year)." The commenters contend that this statement is misleading because it implies that Shell is complying with the NAAQS and other standards during the limited drilling season instead of taking a rolling 12-month timeframe in which to document compliance.

Response: Agency guidance provides that production or operational limits expressed on a calendar year basis cannot be considered capable of legally restricting potential to emit, and that such limits should generally not exceed one month, but can include longer rolling limits (*e.g.*, on a 12-month rolling basis). 1989 PTE Guidance at 10. This guidance applies to limiting a source's potential to emit and does not explicitly address limits established to protect the NAAQS. Region 10 believes that in this case limits imposed to ensure compliance with annual NAAQS standards can reasonably be expressed on a calendar year basis because compliance with the annual standard is determined based on calendar year or multi-year averages of calendar years.

The commenters' concern appears to relate to the fact that the Draft Permit includes PTE limits set on a rolling basis even though Shell is prohibited from operating under the permit between December 1 and June 30 of each year. The rolling PTE limits in Permit

Condition D.4 of the Draft Permit were established assuming zero emissions during the period when operations are prohibited (December through June of each year). In addition, each of the limits in the permit applies independently. In other words, even though the limits in Permit Condition D.4 could—on their own—allow the source to emit pollutants between December 1 and June 30 of each year, Permit Condition D.3.1 prohibits operation during that time period, and the permittee must comply with both requirements.

The commenters are correct that EPA guidance does express a general preference for shorter time periods rather than 12-month rolling limits. See 1989 PTE Guidance at 9. As the commenters acknowledge, however, EPA has also recognized that longer rolling limits are appropriate for sources with substantial and unpredictable annual variations in emissions, as well as for those sources that curtail operations during part of a year on a regular seasonal cycle. Id. at 9-10. Such is the case here. Shell's planned exploratory operations are atypical as compared to other sources because the emission units consist of multiple engines and generators with variable emissions on the Kulluk and a fleet of numerous support vessels. Operations will vary from hour-to-hour, day-to-day, month-to-month, and season-to-season based on factors such as the number of wells drilled, the activity being undertaken (drilling mud cellar lines, other drilling activity, or activity that does not involve drilling), the depth of the wells drilled, whether emergency engines are being run for testing, and ice conditions. Given the variability in operations, and thus emissions expected from this source, and after considering a full range of options for limiting the source's potential to emit, Region 10 determined that it was appropriate to establish longer-term rolling limits. In short, the Kulluk Permit does not set PTE limits on a calendar year basis, but instead establishes rolling 365-day limits for NO_x and CO, and 12-month rolling limits for SO_2 and GHG emissions. Region 10 determined that these limits are appropriate considering the nature of the source and are consistent with the 1989 PTE Guidance. See also response to comment I.1.c.

Similar to the 2011 Revised Permits for the Discoverer, the limit on the number of days in the drilling season in the Kulluk Permit is a limit set to ensure compliance with the annual NAAQS and therefore can reasonably be established, as was done here, on a calendar year (drilling season) basis. Region 10 also notes that the statement quoted by the commenters concerning setting annual NAAQS compliance limits on a calendar year basis is not contained in the Kulluk Statement of Basis. This statement is from the Supplemental Statement of Basis for the Discoverer Permits.

Comment I.1.c: Commenters contend that the owner-requested limits and other provisions designed to limit Shell's potential to emit are unenforceable as a practical matter and unlawful. Commenters note that absent enforceable permit limitations, Shell's yearly potential to emit exceeds the applicable major source threshold of 250 tpy for NO_x, CO, SO_2, and GHG emissions. The commenters reference that Shell's pre-permitted PTE for NOx is 2,339 tpy and that the Draft Permit limits NO_x emissions to 240 tpy determined on a rolling 365-day basis. Commenters further contend that although the Draft Permit describes how to calculate NO_x emissions it fails to specify how the emissions will be limited through an operational limit, a production limit, or the installation of controls or other mechanisms. As a result, the commenters state that the limit is not enforceable and fails to serve the intended purpose of restricting Shell's emissions of NO_x. The commenters assert that the same is true for potential to emit limits for CO and CO_2e.

Response: The commenters are correct that, absent enforceable permit limits, Shell's yearly potential to emit would exceed the applicable PSD major source thresholds for NO_x, CO, SO_2, and GHG emissions. See Statement of Basis, p. 24. 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, is treated as part of its design if the limitation or the effect it would have on emissions is enforceable. See 40 CFR §§ 52.21(b)(4) and 55.2. Region 10 believes that the limits established in the Kulluk Permit to restrict the source's potential to emit are both federally enforceable and enforceable as a practical matter.

Title V of the CAA and Part 71 provide a mechanism to create limits in a Title V permit that restrict a source's potential to emit. The Environmental Appeals Board (EAB) has specifically acknowledged that "Title V permits (and other permits as well) may function as vehicles for establishing such PTE limits, potentially allowing a source to avoid more burdensome permitting requirements for 'major sources' by instead qualifying as a 'synthetic minor' source for purposes of some other regulatory programs." *In re Peabody Western Coal Company*, 12 EAD 22, 31 (EAB Feb. 18, 2000). Limits established in a Title V permit are federally enforceable. See 42 U.S.C. § 7661a, 40 CFR § 71.6(b), Permit Condition A.3.4. See also 18 AAC 50.225 (COA authority to impose owner-requested limits on PTE).

Region 10 determined that, given the variable nature of Shell's proposed operations and the number, types, and location of emission sources spread across the Kulluk and Associated Fleet, the most effective means to limit Shell's potential to emit was through the application of enforceable source-wide emission limits for NO_X, CO, SO_2 and CO2e. The proposed exploratory drilling operations will involve variable operations from well-to-well and season-to-season due to factors such as weather, sea state, remoteness of the drilling site, and the exploratory nature of the operations (i.e. the speculative nature of exploratory drilling). Emissions from many units will also vary depending on the activity being conducted. For example, emissions from drilling equipment on the Kulluk will depend on the stage of drilling activity (*e.g.*, drilling mud cellar lines versus other drilling activities), and emissions from the propulsion engines on the icebreakers will depend on the frequency, thickness, and location of ice. Such considerations require a level of operational flexibility that makes it impractical to establish unit-specific limits or operating parameters for some pollutants that might typically be applied to limit a stationary source's potential to emit. For these reasons, Region 10 determined that, for this permit, the most effective and reliable way to limit potential to emit was through a combination of emission limits and specified emission factors, supported by stringent monitoring, frequent emission calculations, recordkeeping requirements, and operating limitations. This approach accounts for variability in operations and emissions, yet still provides assurance that limits on potential to emit can be enforced as a practical matter.

The Kulluk Permit establishes an emission limit for SO_2 (10 tpy) that is well below the applicable PSD major source threshold as determined on a 12-month rolling basis. This emission limit is supported by operational limits on both the type and amount of fuel combusted that ensure emissions remain below the applicable emission limit. The permit restricts the sulfur content of fuel combusted on the Kulluk and Associated Fleet to 100 ppm. Permit Condition D.4.5. Compliance with this operational limit is determined by Permit Condition D.4.9 which requires that all fuel purchased have a maximum sulfur content of 15 ppm. The permit also establishes an aggregate fuel limit for all emission sources that limits the total amount of fuel combusted during any 12-month rolling period to 7,004,428 gallons. Permit Condition D.4.6. Compliance with the fuel limit is determined through stringent fuel monitoring requirements. For the majority of emission units, fuel usage is monitored continuously using a fuel flow meter. For the units where a fuel flow meter is not required (Kulluk emergency generator, seldom used sources, and OSRV work boats) the permit requires that fuel usage be measured using a fuel sight glass, tank gauge, or graduated dip stick. Under Permit Condition F.2.2.2. Shell is required to record fuel usage for each emission unit on an hourly, daily, and monthly basis. Permit Condition F.2.2. Together, the limits on the type and amount of fuel combusted, along with the fuel monitoring requirements, assure compliance with the emission limit for SO_2.

The Kulluk Permit establishes an emission limit for CO2e (80,000 tpy) below the threshold at which GHGs become "subject to regulation" for a new stationary source under the Tailoring Rule as determined on a 12-month rolling basis. This emission limit is supported by the operational limit on the amount of fuel combusted over a 12-month rolling period and an operational limit on the amount of waste combusted each day that, together, ensure emissions remain below the applicable emission limit, so the source's GHG emissions are not "subject to regulation" for PSD permitting purposes and PSD permitting requirements do not apply. Permit Conditions D.4.6 and D.4.7. The permit requires Shell to monitor total fuel usage, as described above, and to monitor and record the operation of the incinerators on the Kulluk and Associated Fleet. Emissions are calculated by applying emission factors specified in Tables D.2.1 and D.2.2 to the amount of fuel combusted and the assumed maximum operation of the incinerators. Each month, Shell is required to calculate and record the rolling 12-month emissions of GHGs to ensure that emissions of CO2e remain below 80,000 tpy. For a discussion of methane emissions see response to comment I.3.b.

The Kulluk Permit establishes emission limits for NO_X (240 tpy) and CO (200 tpy) below the applicable PSD major source threshold, as determined on a rolling 365-day basis.
Compliance with the emission limits for NO_X and CO is determined by calculating daily NO_X and CO emissions from each emission unit using emission factors derived from stack testing conducted pursuant to specified requirements (Permit Condition E) or specifically identified in the permit (Permit Condition D.1). The permit requires Shell to

conduct stack tests for the majority of emission units to develop reliable emission factors for NO_X and CO. Stack testing is conducted across multiple load conditions for each emission unit or group of emission units. The highest emission factor determined through stack testing is used to calculate all emissions from the unit regardless of actual operating load conditions. For groups of the emission units, the highest emission factor observed for the group is used for all emission units in the group. For emission units that are not subject to stack testing for NO_X and CO (Kulluk emergency generator, seldom used sources, OSRV workboats, heaters and boilers), the permit specifies emission factors which are either the AP-42 emission factor or the 90^{th} percentile value derived from source tests of corresponding emission units on Shell's Discoverer drillship and Associated Fleet. For more discussion of emission factors see response to comment I.3.a.

Compliance with the emission limits for NO_X and CO is determined by applying the relevant emission factor to the amount of fuel combusted by each emission unit (or hours of operation for incinerators). The fuel monitoring requirements, described above, and the specified emission factors for individual emission units allow for source-wide emission calculations to be made. Shell is required to calculate and record on a weekly basis the daily emissions of NO_X and CO from each emission unit, and to calculate and record on a weekly basis the daily rolling 365-day emissions of NO_X and CO. In this way, Shell is required to provide a continuous assessment of daily NO_X and CO emissions to ensure that the source complies with its PTE limits. Determining NO_X and CO emissions from each unit on a daily basis provides a reliable and timely mechanism that will allow Shell to frequently assess compliance and to determine whether it is approaching the emission limits established to limit its potential to emit and to adjust its operations accordingly.

In addition to emission limits, the Kulluk Permit includes a combination of operational limits which effectively limit potential to emit as well. In addition to the limits on the type and amount of fuel combusted, the Kulluk Permit imposes hourly operational limits on MLC drilling and overall drilling activity. Permit Conditions D.3.3 and D.3.4. Shell is required to record the date and hour the Kulluk becomes an OCS Source and the date and hour of drilling and incineration activities. Permit Conditions D.3.6 to D.3.8. To limit emissions of NO_x and CO from larger emission units, the Kulluk Permit requires the installation and operation of add-on controls. Exhaust from emission units with the highest PTE for NO_x – the Kulluk electricity generation engines and the propulsion and generation engines on both icebreakers – will be directed to an operating selective catalytic reduction (SCR) control device that is evaluated at all times the affected source is operating using a continuous monitoring system (CMS). In addition, exhaust from the Kulluk electricity generation engines, MLC HPU engines, MLC air compressor engines, Kulluk deck cranes, and the propulsion and generation engines on both icebreakers are directed to an oxidation catalyst control device that controls combustible substances such as CO and PM and is evaluated using a CMS. Permit Conditions F.3 and F.4.

The 1989 PTE Guidance recognizes exceptions to the statement that emission limits alone are not generally sufficiently enforceable as a practical matter so as to limit PTE. While the situation presented by the Kulluk and Associated Fleet was not contemplated at the time the 1989 PTE Guidance was issued, Region 10 believes that this situation is sufficiently analogous to the rationale for recognizing the exception for the VOC surface coating. As in the case of VOC coating operations, the operational and production parameters for the emission units on the Kulluk and Associated Fleet are not readily limited due to the uniqueness of the source which includes a wide variety of emission units and varying emission factors for NOx and CO for the various emission units, resulting from the unpredictable nature and variability of operations, and the need for operational flexibility on fuel usage. Therefore, Region 10 has required the use of emission limits and specific emission factors based on conservative assumptions, coupled with a requirement to calculate hourly and/or daily emissions, to restrict potential to emit. In this way, the combination of emission limits and specified emission factors has an effect similar to operational limits because the operational parameters that are linked to the emissions are continuously tracked and used for compliance.

Region 10 believes the permit appropriately limits Shell's potential to emit in a manner that is both legally enforceable and enforceable as a practical matter. Moreover, Shell is aware that operations must be suspended when necessary to avoid exceeding the limits. In the unlikely event that PTE limits are exceeded, not only may Shell need to apply for and obtain a PSD permit, but it may be considered to have been in violation of PSD requirements from the time it was initially constructed.

I.2 SUBCATEGORY – APPROPRIATENESS OF EMISSION LIMITS

Comment I.2.a: Commenters cite to a letter from EPA Region 9 to the Nevada Division of Environmental Protection as support for the proposition that EPA's position is that a 5-10% buffer is appropriate for synthetic minor source air permits. The commenters apply the 5-10% buffer to the potential to emit NO_x under the Draft Permit and note that the 240 tpy emission limit provides less than a 5% buffer. The commenters assert that, at the very least, the final permit needs to provide a 5% buffer, but that given the unknowns associated with the Draft Permit and the Arctic conditions, Region 10 should ensure a 10% buffer for all owner requested restrictions.

Response: The letter cited by the commenters involved a revision to a Title V permit to allow the source to install and operate additional emission units that would have increased the source's potential to emit CO above the applicable major source threshold of 250 tpy. In the draft permit, the state permitting authority established a facility-wide emission limit for CO of 249 tpy, just below the major source threshold. Region 9 did not object to the emission limit, but encouraged the permitting authority to provide a larger buffer of between 5-10% in that case.

Congress established specific thresholds to determine when a source would be considered major for purposes of PSD review. 42 U.S.C. § 7479(1). Although establishing a 5-10% buffer where an emission limit is just below the major source threshold may increase confidence that a source will not exceed the applicable threshold, the commenter does not cite anything to suggest that this is a legal requirement.

Moreover, the Kulluk Permit differs from the permit at issue in the Region 9 letter because it establishes a NO_x limit of 240 tpy, which provides a greater cushion and more confidence with respect to the PSD major source threshold than the 249 tpy limit at issue in the Region 9 letter. In addition, the permit includes requirements to ensure that emissions do not exceed this threshold, including but not limited to source testing of engines that are anticipated to generate approximately 91 percent of emissions, calculating emissions from these engines based upon worst-case emission factors (lb/gal) and continuously measuring and recording hourly the flow of diesel fuel to these engines (gal/hr). For those engines employing SCR to reduce emissions, the permit requires that a CMS measure and record operating parameters associated with the control device. On those occasions when the CMS detects operation of the control device in a manner different from that observed during stack testing, the permit requires that an uncontrolled emission factor be employed to calculate NO_X emissions. The application of a CMS and the use of uncontrolled emission factors increase confidence that the source's actual emissions will not be greater than reported.

Furthermore, the Kulluk Permit contains adequate and enforceable monitoring, recordkeeping, and reporting requirements to ensure that Shell complies with the NO_x and other emission limits. As noted in the Region 9 letter, if a major source threshold is exceeded a facility may trigger PSD requirements and may be treated as a source that should have obtained a PSD permit. Memorandum from Eric V. Schaeffer, EPA, re: Guidance on the Appropriate Injunctive Relief for Violations of Major New Source Review Requirements, dated November 18, 1999, at 5-6. For these reasons, Region 10 disagrees with the commenters that a buffer calculated as a percentage of the major source threshold is necessary in this case.

I.3 SUBCATEGORY – DETERMINING COMPLIANCE WITH PTE LIMITS

Comment I.3.a: Commenters state that limits on emissions of criteria pollutants are not practically enforceable because adequate monitoring is not in place to assure compliance. As an example, the commenters cite to the Statement of Basis (p. 38) which states: "[c]ompliance with the CO and NO_X emission limits is determined by multiplying measured fuel by periodically confirmed emissions factors." The commenters contend that the Draft Permit authorizes the use of default emission factors until unit-specific emission factors are determined through testing, and for some emission units there is no requirement to test for unit-specific factors. The commenters state that because the permittee has failed to identify the emission units it will use, this approach creates inherent uncertainty that necessitates thorough source testing. This inherent uncertainty remains unresolved, the commenters continue, because some emission units will not be tested. The commenters contend that because there will be no way to determine whether the default emission factors are wrong, the emission limits for CO and NO_X will be unenforceable as a practical matter. The commenters further state that the failure to obtain unit-specific data for all units is particularly problematic because the AP-42 emission factors that Region 10 relies on are notoriously inaccurate. The commenters cite to AP 42, Volume I, Fifth Edition for support that EPA does not recommend the use of AP-42 factors as source-specific permit limits and/or as emission regulation compliance determinations.

Response I.3.a: The permit requires the use of emission factors to determine compliance with both NAAQS- and PTE-based NO_X and CO emission limits and requires source-specific verification of emission factors through source testing for the emission units that make up most of the allowed NO_X and CO emissions. Some smaller or infrequently used emission units, representing a small portion of the total NO_X and CO emissions, are not required to be tested. For those units that are not required to be tested, the NO_X and CO emission factors are based on either AP-42 emission factors or, when available, source test data from Shell's Discoverer drillship and Associated Fleet.

In consideration of the comments received, and to be sure there is a reasonable margin of safety that assures compliance, Region 10 is adding a requirement to test NO_X and CO emissions from each incinerator. Permit Condition E.3.2. Given the unique applications of the incinerators on these vessels, Region 10 believes this additional emission factor verification is appropriate and reasonable. After adding this additional incinerator testing, the permit will require emission testing of emission units that constitute 91% of the total NO_X emissions and 97% of the total CO emissions.

For emission units for which the permit does not require testing (emergency generators, seldom-used sources and OSRV work boats) and that rely on NO_X emission factors based on Discoverer test data, in response to comments received, Region 10 is adjusting the emission factors to reflect very conservative 90th percentile (or higher) values from the test data. See response to comment M.2.c. The only units that rely on AP-42 for NO_X emission factors are the heaters and boilers, which constitute only one percent of total NO_X emissions. Region 10 expects AP-42 emissions factors for heaters and boilers to be a conservative representation of actual emissions. EPA expects AP-42 emissions factors for heaters and boilers to be a conservative representation of actual emissions. While AP-42 predicts an emission factor of 0.02 lb/gal for heaters and boilers, Shell testing of its boilers residing on the Discoverer shows a range of values between 0.011 lb/gal and 0.015 lb/gal.[6]

The emission units that will not be tested to verify CO emissions factors (heaters and boilers, emergency generators, seldom-used sources and OSRV work boats) rely on AP-42 emission factors. While AP-42 emission factors are considered average values for the size-specific categories of emission units the emission factors represent, Region 10 believes that the emission factors are reasonable for use in this permit given that AP-42 emission factors will represent only 3% of the total CO emissions. Actual emissions from some emission units may be higher and some lower than the AP-42 emission factors predict.

[6] 0.11 lb/gal = (8.33 x10^{-2} lb/MMBtu) x (MMBtu/1x10^6 Btu) x (131180 Btu/gal)
0.15 lb/gal = (1.18 x10^{-1} lb/MMBtu) x (MMBtu/1x10^6 Btu) x (131180 Btu/gal) See June 16, 2011 email from Rodger Steen to Dan Meyer.

Emission testing conducted by Shell on two Discoverer boilers showed CO emissions very near what AP-42 predicts. The tests conducted by Shell resulted in CO emission factors of 0.004 and 0.007 lb/gal, while AP-42 predicts an emission factor of 0.005 lb/gal.[7] In response to the comments received, EPA has decided to use the higher of the two test values (0.007 lb/gal) in place of the AP-42 emission factor.

According to Shell, OSRV work boats will be deployed 5 days a week for 6 hours a day to conduct exercises. See "Anticipated Kulluk Operating Maximum" in Permit Application Supplement at 326. Emissions data supplied by Shell for one of the potential work boats to be deployed suggests the actual emission factor for the propulsion engines is one-tenth the value AP-42 predicts. The engine manufacturer's data provided by Shell suggests an emission factor of 0.006 lb/gal, while AP-42 suggests an emission factor of 0.112 or 0.125 lb/gal, depending on the engine rating.[8] Shell intends to install a brand new emergency generator on the Kulluk; it is predicted operations will be two hours each month to exercise the generator. Seldom-used sources consist of equipment such as life boats and are, as the name suggests, expected to operate infrequently. Region 10 believes the permit strikes an appropriate balance between the need for accurate emission factors to reliably calculate emissions for comparison to permit limits and the complexity of testing numerous emission units in a short period of time.

Comment I.3.b: Commenters assert that the CO_2e emission limit of 80,000 tpy is not practically enforceable because Region 10 neglected to require monitoring or controls for emissions of methane. Commenters contend that methane is a powerful greenhouse gas with a warming potential 21 times greater than CO_2, and methane emission must be included in calculating whether a source is subject to the Clean Air Act's greenhouse gas controls. When a rig drills into porous, the commenters state, hydrocarbon bearing rock, methane mixes into the drilling muds and is brought to the surface. The commenters state that some of this methane will be emitted through a vent, and therefore must be counted toward Shell's potential to emit CO_2e. The commenters state that Region 10 assumes that the drilling mud system will vent no more than 399 pounds of methane per month (4 tons per month of CO_2e), and makes this assumption on assurances from Shell based on its past drilling experience. The commenters state that ConocoPhillips estimated methane emissions at 183 tons per month, which the commenters calculate as 46 times Shell's estimate. The commenters take issue with Region 10's determination not to require Shell to control, monitor, or report methane emissions, and assert that the lack of monitoring or reporting makes the owner-requested limit for CO_2e unenforceable as a practical matter.

Response: EPA has recognized that there are sources for which inherent physical limitations for the operation restrict the potential emissions of individual emission units.

[7] 0.004 lb/gal = (0.0311 lb/MMBtu) x (MMBtu/1x10^6 Btu) x (131,180 Btu/gal)
0.007 lb/gal = (0.05 lb/MMBtu) x (MMBtu/1x10^6 Btu) x (131,180 Btu/gal) See June 16, 2011 email from Rodger Steen to Dan Meyer.

[8] Support Vessel Parameters, Permit Application Supplement at 154. 0.006 lb/gal = (0.155 g/hp-hr) x (hp/7000 Btu) x (lb/453.592 g) x (131,180 Btu/gal)

Where these inherent physical limitations can be documented by the source and confirmed by the permit issuer, the permit issuer has the authority to make such judgments and factor them into estimates of stationary source potential emissions. See Memorandum from John S. Seitz, EPA, re: Options for Limiting the Potential to Emit (PTE) of a Stationary Source Under Section 112 and Title V of the Clean Air Act (CAA), dated January 25, 1995 (Options for Limiting PTE) at 8.

Methane emissions from the drilling mud system are subject to operational restrictions that limit operations to 120 days between July and November, and limit drilling activity to 1,632 hours. These operational limits are accompanied by monitoring in the form of recordkeeping. See Permit Condition D.3.6. In this case, Shell calculated the potential methane emissions from the drilling mud system based upon the maximum expected capacity over the five-month period of operation taking into consideration inherent physical limitations and actual well data. See Permit Application, Appendix E. EPA has acknowledged that where inherent physical limitations exist, it may be appropriate to rely on a reasonable and realistic "upper-limit" projection in identifying the "maximum capacity" of a source for the purpose of estimating their PTE. See e.g., Memorandum from John Seitz, EPA, re: Calculating Potential to Emit (PTE) and Other Guidance for Grain Handling Terminals, dated November 14, 1995, at 4-5; Options for Limiting PTE at 8.

To add a measure of safety in issuing the Draft Permit, Region 10 assumed all of the emissions from the drilling mud system (which includes the cuttings/mud disposal barge) will be point source emissions whereas, in actuality, a significant amount of the emissions from the drilling mud system and all of the emissions from the cuttings/mud disposal barge meet the definition of fugitive emissions and do not have to be counted for this source category in determining a source's potential to emit under the PSD program. See 40 CFR § 52.21(b)(1)(iii).

In response to these comments, Region 10 contacted Shell on September 8, 2011, to discuss the methane estimation and request additional well information previously-claimed by Shell as confidential to confirm that the estimate of methane potential to emit it previously provided to Region 10 is a reasonable upper-bound estimation. Shell provided the additional documentation of actual well data. See email from Susan Childs, Shell, to Doug Hardesty, Region 10, re: Shell Mud and Cuttings Degassing Emissions, dated September 16, 2011. The information provided shows that Shell relied on actual well pressure, temperature, porosity, and depth of the hydrocarbon bearing zone from past Arctic exploration projects in its estimation.

In reviewing Shell's new information, Region 10 identified an error in the methane emission factor in the draft Kulluk permit. As in the Shell Discoverer permits, Region 10 conservatively assumed that Shell's estimation represented only one well and adjusted the monthly emission factor by a factor of four to represent four wells (a reasonable upper-bound estimate of the number of wells that could be drilled in a single season). The emission factor is the draft Kulluk permit was missing this adjustment. The final Kulluk permit will include the adjusted methane mission factor (1,596 pounds CH_4 per month) to be consistent with the Discoverer permits. Region 10 has also amended the synthetic minor12-month rolling diesel fuel combustion limitation (Condition D.4.6) to account for the revised estimate of CO_2e potential emissions attributed to mud degassing. Because mud degassing GHG emissions are relatively insignificant compared to fuel combustion GHG emissions, the 12-month rolling diesel fuel usage limit has only decreased 0.1% from 7,011,323 gallons to 7,004,428 gallons.[9]

As in the case of the reasonable, upper-bound projections that EPA believes are appropriate for determining the PTE of grain terminals, Region 10 believes that the emission estimate for methane emissions from Shell's mud drilling system (17 tons per month of CO_2e) assumed in the emission limit on total GHGs is a reasonable upper-bound projection for Shell's operations and is not expected to be exceeded under any reasonably anticipated operating scenario. This is especially true given the other conservative assumptions that Region 10 is applying to Shell's estimate to provide a wide margin of safety (considering both point source and fugitive emissions in the estimate and assuming the yearly estimate is emitted in each of the five months).[10]

For comparison purposes, EPA recommends grain terminals apply a safety factor of 1.2 to the highest of the previous five years of throughput to constitute a realistic upper-bound potential to emit. See Memorandum from John Seitz, EPA, re: Calculating Potential to Emit (PTE) and Other Guidance for Grain Handling Terminals, dated November 14, 1995, at 5. It is important to emphasize that, even with these conservative assumptions, the GHG emissions (85 tons per year CO_2e) from the drilling mud system represent only 0.11% of the total GHG emissions (80,000 tons per year CO_2e) allowed under the permit.

Region 10 believes that assuming such a conservatively high estimate of the methane emissions that would be emitted from the drilling mud system operating at its maximum design operation rate, coupled with the operational limit on the duration of the operations and other permit restrictions, are collectively sufficient to ensure methane emissions from the drilling mud system do not exceed 17 tons per month of CO_2e, and that overall CO_2e emissions do not exceed 80,000 tpy on a 12-month rolling basis. Because of the inherent limitations that exist, and considering the small contribution from the mud drilling system to overall GHG emissions from the Kulluk and Associated Fleet as a whole, Region 10 does not believe it is necessary or appropriate to monitor emissions from, or operations of the drilling mud system, aside from the monitoring already required in the permit

[9] 79,080 ton CO_2e = 80,000 ton CO_2e (ORL) – 835 ton CO_2e (waste incineration) – 85 ton CO_2e (mud degassing)
7,004,428 gallons = (79,080 tons CO_2e) x (2000 lb CO_2e/ton CO_2e) x (gal diesel/22.58 lb CO_2e)

[10] Region 10 is aware that ConocoPhillips provided an estimate of emissions from its mud drilling system that is much higher than that provided by Shell to support this permit. Region 10 has closely examined the estimates provided by both companies along with a comparison of the methodologies offered by Shell in its September 20, 2011 comments to EPA regarding the permitting of ConocoPhillips jackup drill rig. Shell's estimate is based on well information from past arctic exploration projects. The fact that one company has chosen to rely on even more conservative assumptions in estimating its potential to emit from similar operations does not undermine the validity of another company using less conservative, but still reasonably conservative assumptions in estimating its emissions where it has a reasonable basis to do so.

including monitoring the duration of operations. Moreover, Region 10 believes that the monitoring, recordkeeping, and reporting included in the permit for the limits on emissions, fuel, waste, and operations that collectively limit emissions to below the Tailoring Rule "subject to regulation" threshold for GHGs together constitute a "verifiable method to attain and maintain each limit" within the meaning of 18 AAC 50.225 of the COA regulations.

J. CATEGORY – LIMITS TO PROTECT THE NAAQS

J.1 SUBCATEGORY – ENFORCEABILITY OF EMISSION LIMITS

Comment J.1.a: Commenters state that EPA guidance provides that emission limits are "sufficient to limit potential to emit" when they include "requirements to install, maintain, and operate a continuous emission monitoring (CEM) system and to retain CEM data, and specifies that CEM data may be used to determine compliance with the emission limit." The commenters contend that the present circumstances warrant CEM to ensure permit conditions are enforceable, and are concerned that the Region has not required CEM where permit provisions are based on a new model and new algorithms that have not been tested for the Arctic. The commenters believe that only monitoring the combustion of fuel or waste is not sufficient to protect air quality given the modeling uncertainties underlying the permit provisions.

Response: The commenters have provided no support for the assertion that fuel and waste combustion monitoring is not sufficient to protect air quality. In fact, the waste monitoring required in the permit is needed to confirm NSPS applicability rather than for monitoring compliance because waste combustion rates are conservatively assumed to be at the maximum any time an incinerator operates. For a discussion on why Region 10 believes the requirements established in the permit are both legally enforceable and enforceable as a practical matter and sufficient to limit potential to emit see responses to comments in Subcategory I.1. With respect to the concern that fuel and waste combustion monitoring is not sufficient to protect air quality, the commenters have provided no support for this assertion. Although there is some uncertainty inherent in all modeling analyses (because it is by nature predictive), Region 10 believes the modeling underlying the NAAQS requirements and the compliance assurance provisions in the permit are sufficient to ensure the NAAQS will be protected.

Continuous Emission Monitoring System (CEMS) are a means of ensuring compliance with emission limits and may be an appropriate alternative if setting enforceable operational parameters for control equipment is infeasible. See 1989 PTE Guidance at 7-8. CEMS may also be appropriate where sources are experiencing regular compliance problems. CEMS are not the only means, however, of assuring compliance with limits on potential to emit and NAAQS-based emission limits. Shell's proposed exploratory operations are unusual as compared to other sources because the emission units consist of numerous engines and generators with numerous release points (stacks) on the Kulluk and a fleet of many support vessels. SCR and OxyCat controls are required on multiple engines on three different vessels. CEMS are expensive to purchase, maintain, and operate, but more importantly, there are practical considerations that Region 10 had to consider in this case, including the fact that emission units, control equipment, and monitoring equipment will be operating in a remote, harsh, Arctic environment, and deck space on board the vessels is limited. Furthermore, potential to emit is determined on a source-wide basis making it less critical to be precise on an individual emission unit basis. Similarly, NAAQS compliance is in jeopardy when the total emissions impacting a receptor point are higher than allowed. Higher than expected emissions at one stack, are offset by other stacks emitting less than expected. Region 10 believes that the permit assures compliance with the PTE and NAAQS limits through an appropriate level of monitoring that reflects the unique attributes of this source.

The permit requires a regimen of stack testing and emission calculations, in conjunction with a continuous monitoring system for parametric monitoring of control equipment to ensure compliance with emission limits. This is in addition to other operational restrictions that will have the effect of restricting the source's emissions and help ensure compliance with the NAAQS-based limits. Region 10 believes that the control equipment parametric monitoring required by the permit – temperature, urea feed, catalyst activity for SCR (Permit Condition F.3) and temperature and catalyst activity for the oxidation catalyst device (Permit Condition F.4) – are effective means for ensuring that the controls are working properly and achieving the projected emission reductions. For uncontrolled emission units, the permit requires monitoring and reporting operational rates including fuel and hours of operation. The commenters have provided no information to indicate that the required monitoring of fuel, hours of operation, and control equipment will not be accurate. Multiplying the tracked fuel rates by source-specific emission factors determined by source testing for most of the emission units will provide a reasonable assurance of compliance with emission limits in the permits. The commenters have provided no information to the contrary, nor have the commenters identified any specific requirement to use CEMS in this circumstance. Contrary to the commenters' assertion, monitoring emissions using CEMS has no bearing on the accuracy of the new algorithms used by Shell for modeling. Region 10 continues to believe that CEMS are not necessary to provide a reasonable assurance of compliance with the emission limits in this permit. See also response to comment M.3.c.

Comment J.1.b: Commenters assert that limits established to ensure compliance with the NAAQS are not enforceable. The commenters take issue with the establishment of limits on pounds per hour or day, and state that it is inappropriate to assess NAAQS compliance with pound per hour calculations without any underlying, enforceable measure (e.g., operational or production limits) to assure that those emissions limits are met.

Response: The commenters have not specified why they believe it is necessary to create operational and production limits in addition to mass emission limits for NAAQS compliance, and cite no legal authority requiring such limits. The permit contains enforceable conditions to address NAAQS compliance.

The NAAQS-based emission limits are based on predicted emission rates used in modeling to demonstrate compliance with NAAQS. Compliance with the emission rates is determined by multiplying the measured operational rates (fuel or waste feed rates) by emission factors that are specified and developed through testing under the permit. Because the emission limits are specified in the permit and the emission factors are set through procedures in the permit, the maximum amount of operation (fuel or waste feed) is effectively restricted as well.

For instance, Permit Condition 6.1.1.1 limits NO_x during drilling from emission units K-1A through K-1D to 19.0 pounds per hour. The emission factor for NO_x emissions from these same emission units, found in Table D.2.1 of the permit, is 0.049 pounds per gallon of fuel combusted. If Shell operates these units such that they combust more than 388 gallons of fuel in any hour during drilling, they will be out of compliance with the 19.0 pound per hour emission limit (388 x 0.049 = 19.0).

The emission factor for these same emission units is determined through specific testing performed before each drilling season. If the same emission unit is tested the following year and the new emission factor is determined to be 0.059 pounds per gallon, then the same group of emission units will be effectively restricted to 322 gallons per hour. This type of operational limit exists for each pollutant, and the most stringent operational limit sets the overall operational limit for Shell. As long as Shell maintains their operations below the back-calculated operational rate, they will be in compliance with the emission limit.

This group of emission units will be controlled by selective catalytic reduction controls to reduce NO_x emissions. The permit requires control device monitoring including catalyst inlet temperature, urea feed rate and catalyst activity. If any of the parameters are outside the specifications set in the permit, the emission factor for NO_x from the group of emission units increases by a factor a 10 or from 0.049 to 0.49 pounds per gallon because the SCR unit is assumed to be 90% effective in reducing NO_x. The effective operational limit then becomes 39 gallons per hour to assure NAAQS are protected while the control device is not operating correctly.

Overall, Region 10 believes the permit contains terms and conditions sufficient to protect the NAAQS and that additional operational or production limits to protect the NAAQS in this permit are not necessary. The commenters have not shown why short term operating limits are a necessary addition to assure compliance with the NAAQS.

J.2 SUBCATEGORY – ADEQUACY OF $PM_{2.5}$ LIMIT

Comment J.2.a: Commenters state that the compliance demonstration for $PM_{2.5}$ leaves no room for uncertainty because modeled impacts are predicted to be at 97 percent of the 24-hour average $PM_{2.5}$ NAAQS. Region 10 must be able to demonstrate compliance with the NAAQS considering a margin of error based on the accuracies of the input data. Specifically, the commenters state that compliance demonstration must account for uncertainty in stack test data used to determine the emission factors. Since the emissions inputs for the modeling analysis are based, in general, on multiplying the applicable emission factor by the associated operating factor *(e.g.,* fuel usage rate) then the accuracy of this input is determined by the sum, in quadrature, of the fractional uncertainties associated with each factor. The commenters state that if, as has been indicated by Shell previously, the uncertainty in the stack test data is upwards of 15%, then Shell must be able to demonstrate compliance with the NAAQS considering a margin of error no less than 15 percent. The commenters calculate that this requires the predicted 24-hour $PM_{2.5}$ concentration to be less than 29.8 $\mu g/m^3$, when considering the background concentration, and the predicted 1-hour NO_2 concentration must be less than 160 $\mu g/m^3$. The commenters note that the modeling prediction of the highest 24-hour $PM_{2.5}$ was 34 $\mu g/m^3$, well above 29.8 $\mu g/m^3$ (114 % of the 29.8 µg/m3 level). The commenters request that Region 10 establish permit limits that demonstrate compliance with the NAAQS with a margin of error no less than the accuracy of the input data.

Response: While the commenter has indicated there will be an inherent uncertainty in the value of stack-derived emission factors, the commenter has not shown that the uncertainty will be biased low. Shell is required to operate in compliance with the permit and accepts the risk of the uncertainties involved. However, there are some additional considerations that offset the inherent uncertainty.

Given that most of the NAAQS-based emissions limits in the permit apply to groups of emission units, the relative uncertainty in any one test will be reduced. Similarly, the eventual ambient impacts are dependent on the emissions from all of the operating emission units, which again means the uncertainty of any one test or for any one emission unit will have less effect when translated to ambient impacts. Source testing is required to follow a source test protocol which will help to ensure procedural consistency from test-to-test and year-to-year.

The permit also has several conservative elements which work to protect ambient air. Testing of individual engines will be performed at multiple load levels and the emission factors from the worst-case load will be used in compliance determinations regardless of the load at which the engines actually operate. This conservatism is increased for groups of emission units because the highest emission factor of any unit in the group must be used for all units in the group. For emission units where hours of operation are tracked in place of fuel monitoring, the emission unit is assumed to be operating at its maximum operating rate. As discussed in response to comments V.1.c and V.2.a, there is additional conservatism built into the modeling analyses that will help to ensure protection of ambient air quality. All of these factors result in over-prediction of calculated emissions or over-prediction of modeled results which should result in actual emissions being lower than calculated and actual impacts lower than predicted.

K. CATEGORY – OPERATIONAL LIMITS TO MAKE PSD UNNECESSARY AND THE PROTECT THE NAAQS

Comment K.1: Commenters assert that key operating parameters relied on to calculate potential to emit and demonstrate compliance with the NAAQS must be included as permit conditions because the Region relies on these parameters to demonstrate compliance with the synthetic minor permit limits and the NAAQS. The commenters identify the following as enforceable operating restrictions that should be included in the permit:

Table 5: Additional Required Permit Limits: Operating Parameters

Permitted Source	Permit Limit	Compliance Demonstration
Cementing and Logging Activity	1,248 hours/activity 52 days/activity	Add provisions to condition D.3 to limit hours of operation and require sufficient recordkeeping
Deck Cranes (all 3 units combined)	Shall not operate more than 30% of the time in any given day during MLC and Well Drilling Activities	Add provisions to condition D.3 to limit hours of operation and require sufficient recordkeeping
Deck Cranes (all 3 units combined)	Shall not operate more than 50% of the time in any given day during Cementing and Logging Activities	Add provisions to condition D to limit fuel usage and require sufficient monitoring and recordkeeping
Resupply Ship – in transport	Limit to 1,200 gallons of fuel 1-way	Add provisions to condition D to limit fuel usage and require sufficient monitoring and recordkeeping
Resupply Ship – in DP mode	Limited to 4,800 gallons per event	Add provisions to condition D to limit fuel usage and require sufficient monitoring and recordkeeping
OSR Vessel	Limited to 2,800 gal/day	Add provisions to condition D to limit fuel usage and require sufficient monitoring and recordkeeping
OSR Work Boats	Limited to 3,789 gal/day	Add provisions to condition D to limit fuel usage and require sufficient monitoring and recordkeeping

Response K.1: The commenters are requesting that Region 10 create operating restrictions in the permit that reflect the assumptions that were used in Shell's emission inventory because the Region relies on the operating parameters to demonstrate compliance with the synthetic minor permit limits and the NAAQS. Contrary to commenters' views, Region 10 is not relying on the assumed values of the operating parameters, but on the actual values of the operating parameters. The permit creates emission limits and stipulates the emission factors that must be used to demonstrate compliance. The permit also requires that specific operating parameters be monitored, recorded, and used with the specified emissions factors to confirm compliance with the emission limits.

Shell's application described anticipated exploratory operations such that they could accurately predict emissions that were in turn used in modeling and eventually were turned into emission limits in the permit. Shell's modeling addressed worst-case operational scenarios involving various combinations of operations to ensure that actual operations comply with the NAAQS. Where assumptions were necessary to assure compliance under all scenarios, Region 10 created operational limits in the permit. The commenters do not explain why these additional assumptions used to predict emissions should become restrictions in the permit.

Comment K.2: Commenters state that Shell assumed certain control device efficiencies in the emissions inventory, and request that Region 10 include these efficiencies as enforceable permit limits to demonstrate compliance with the NAAQS and synthetic minor permit limits. Specifically, the commenters identify Draft Permit Condition D.11 which requires that Shell operate SCR and/or OxyCat control devices at all times for the Kulluk generators, MLC engines (including HPU and air compressor engines), Kulluk deck crane engines, and the generator and propulsion engines on the icebreakers. The commenters request that the permit conditions be expanded to include the following control efficiencies that are assumed in the inventory for the modeling and PTE calculations:

Table 6: Additional Required Permit Limits: Control Efficiencies

Control Device	Restriction	Compliance Demonstration
SCR for NO_X control	1.6 g/kW-hr	Continuous monitoring
Oxy-Cat for PM control	50%	Periodic monitoring
Oxy-Cat for CO control	80%	Periodic monitoring
Oxy-Cat for VOC/HAP (except metals) / HCHO control	70%	Periodic monitoring

Response K.2: Similar to the response to comment K.1, the control efficiencies noted by the commenter in the above table were employed to calculate emission rates that were used in modeling. Region 10 then turned the emission rates into emission limits and required testing, monitoring, and recordkeeping to assure compliance with the permit terms and conditions. Engines with control devices will be tested to establish emission factors that reflect the control efficiencies of the control devices. Specific control device monitoring is required in the permit to ensure that the control devices are operated as they were during testing which in turn assures that the emission factors developed from the tests remain representative. Unlike a PSD permit, which requires emission limits that reflect best available control technology, this permit is not required to contain control technology-based restrictions. The commenters have not explained why it is necessary to include the control device efficiencies as permit limits. The permit, as written, assures compliance with the PTE limits.

Comment K.3: Commenters state that capacity limits for source operations identified by Shell as system limitations must be included as enforceable permit conditions to ensure operations do not exceed the capacity limits. The commenters note that stack testing for many sources require testing at 100 percent capacity (with a 10 percent buffer) which indicates that these units can operate at, or very near, 100 percent capacity. The commenters are unclear what system limitations will keep the company from operating above the assumed levels, and assert that Region 10 must include provisions limiting operation to modeled capacities. The commenters believe this is critical because future modeling analyses are required to be conducted using the same assumptions as used in the initial modeling analysis. The commenters request that the following capacity limits be included in the permit.

Table 7: Additional Required Permit Limits: Capacity Limits

Permitted Source	Capacity Limit	Compliance Demonstration
Kulluk Generators	85%	Continuous load monitoring
Deck Cranes (all 3 units combined)	40%	Continuous load monitoring
Cementing/Logging Units	60%	Continuous load monitoring

Response K.3: There are no cementing and logging engines on the Kulluk. The capacity limits noted in the above table, with the exception of the capacity limit for cementing and logging units, were employed to calculate emission rates. The commenters have not shown why it is necessary to require Shell to limit capacity as noted in the table above. The permit requires emission testing at multiple loads to identify the worst-case operating load and the emission factor that represents that worst-case operating load. That emission factor is then used to calculate emissions for all operating loads during actual operation. This approach results in a conservative recording of emissions and obviates the need for tracking actual engine load or percentage of capacity. If Region 10 had determined that the use of load-specific emission factors to calculate and record emissions was necessary, the permit would have required load tracking. Furthermore, if Region 10 determined that it was necessary to avoid a particular operating capacity, the permit would have included limits on capacity and load tracking to confirm compliance. The permit assures compliance with emission limits without the need to limit or track load or engine capacity.

L. CATEGORY – SOURCE TESTING

Comment L.1: The commenters note that the Draft Permit does not require source testing for some emission units. Specifically, source testing is not required for the boilers and heaters, the emergency generators or the seldom-used engines on the Kulluk and its Associated Fleet, or the OSRV workboats. The commenters assert that because the Draft Permit does not specify equipment make, model, and capacity, it is critical that Region 10 require source testing for all emission sources.

Response: The source testing required under the permit covers the sources responsible for the majority of emissions. See response to comments I.3.a. The Region disagrees with the commenters that source testing is necessary or required for all permitted emission units, which include seldom used sources such as life boats and emergency equipment. In addition, in most cases, knowing the make or model of an emission unit would not influence EPA's decision to require testing because the emission factors normally represent ranges of units for any particular category of source types. Shell provided adequate information for Region 10 to apply appropriate emission factors to emission units and create enforceable emission limits. However, as discussed in response to comment I.3.a, Region 10 has imposed additional source testing requirements for incinerators and required the application of more conservative emission factors for sources not subject to source testing. For more discussion on source testing see responses to comments in I.3.a and M.2.a-c.

M. CATEGORY – MONITORING AND RECORDKEEING REQUIREMENTS

M.1 SUBCATEGORY – GENERAL

Comment M.1.a: Commenters express concern about monitoring provisions with respect to pollutants for which Shell is a synthetic minor source and request that Region 10 require monitoring of actual emissions and not just fuel usage.

Response M.1.a: The commenters have provided no information to indicate that the required monitoring of operations (e.g. fuel usage) will not be adequate. Region 10 believes that the fuel monitoring requirements and use of permit-derived and specified emission factors provide a reliable basis for determining emissions and thus compliance with emission limits. For those emission units employing air pollution control equipment, Permit Conditions F.3 and F.4 require continuous parametric monitoring – temperature, urea feed, and catalyst activity for SCR and temperature and catalyst activity for the oxidation catalyst. See responses to comments J.1.a and M.3.b. Region 10 believes the monitoring prescribed is an effective means for ensuring that the controls are working properly and achieving the required emissions reductions.

Comment M.1.b: Commenters state that, in the event actual emissions are not monitored, Region 10 should require monitoring of fuel consumption using a fuel flow analyzer device.

Response M.1.b: The Draft Permit required that a fuel flow meter be employed to continuously measure fuel combusted by each combustion source or common group of combustion sources except for the Kulluk emergency generator, heaters and boilers (all vessels), seldom used sources (all vessels), and OSRV work boats. In response to comments, Region 10 has revised the fuel monitoring requirements so that Shell is now required to use a fuel flow meter to measure fuel combusted by heaters and boilers. The remaining excepted sources are expected to generate less than 10% of NO_X emissions. For the combustion sources not equipped with fuel flow meters, the permit requires Shell to quantify fuel combusted by other means as specified in Permit Condition F.2.2.2. Specifically, Shell must measure the fuel combusted using the fuel tank sight glass, by manually measuring the amount of fuel in the tank using a graduated dip stick, or by measuring the fuel combusted using a fuel tank gauge. Shell is also required to make note of the start and end times of the activity during which the fuel is consumed (Permit Condition F.2.2.3) so that a fuel consumption rate (gal/hr) can be calculated (Permit Condition F.2.2.4). The alternative methods for measuring fuel use by the small and seldom used emission units in this case are reliable and the commenters have provided no information to indicate that the required techniques for monitoring fuel usage will not be sufficiently accurate to ensure compliance with permit requirements

Comment M.1.c: Commenters note that the Draft Permit establishes hourly emission limits for NO_X and daily emission limits for PM in order to ensure compliance with the NAAQS. The commenters assert that the corresponding monitoring and reporting requirements are not adequate to demonstrate compliance with these hourly and daily limits. Specifically, the commenters take issue with the requirement that Shell report hourly and daily calculations once each week. The commenters contend that this is not sufficient to demonstrate compliance with hourly and daily limits on a weekly basis, and request that, at a minimum, compliance with PM emission limits be demonstrated on a daily basis.

Response M.1.c: Although Shell is required to calculate and record the quantity of emissions generated for a given week by the Friday following the conclusion of the week, the calculations Shell performs each week are to determine the NO_X emissions for each hour and the PM emissions for each day for the previous week. In other words, although Shell is required to perform the calculations on a weekly basis, the data generated will be in the same terms as the emission limits—hourly or daily, as applicable. Moreover, the relevant data used in the calculations is generated more frequently than weekly. For example, Shell is generally required to continuously measure and record, on an hourly basis, the fuel consumed by each emission unit or group of emission units. Data for the SCR and oxidation catalyst systems are collected once every 15 minutes to assess whether the control device is operating as intended. This means that Shell is collecting data each hour to determine emissions for that hour. Sometime each week, Shell is required to check the CO and NO_X concentration in the exhaust stack downstream of the control equipment to assure that emission reductions are being achieved that are representative of the emission factor being employed. The permit requires Shell to perform the calculations to quantify hourly NO_X emissions and daily $PM_{10/2.5}$ emissions between Sunday morning (beginning of the following week) and Friday night. Shell is required to process data from numerous emission units across multiple vessels for 168 individual hours (24 hrs. x 7 days). Region 10 imposed the weekly requirement to allow Shell adequate time to perform all calculations, record the results, and organize the results in a central location. As soon as emission rates are recorded each Friday, Shell is required to report any exceedances as a deviation consistent with Permit Conditions A.17 and A.18. The commenters have not provided any information to show how conducting and recording calculations on a weekly basis, where the resulting calculations are in terms of the relevant emission limits, does not assure compliance with the emission limits.

Comment M.1.d: Commenters state that because the NO_X emission rates presumably vary hour by hour, using emission factors based on a one-time stack test conducted at the beginning of (in some cases only the first) the drilling season does not ensure continuous compliance with an hourly limit. The commenters assert there is no guarantee that these hourly limits can be complied with for each hour of operation and that the hourly emissions will stay at the emission rates modeled without more precise monitoring requirements.

Response M.1.d: Of the emission units required to be tested, only the deck cranes engines are to be tested only prior to the first season. All other engines that are to be tested will be tested prior to each of first two drilling seasons.

For those emission units that together constitute 91 percent of the NO_X emissions, the Region is requiring Shell to employ a stack test-derived emission factor to determine NO_X emissions. The emission factor is based upon worst-case emissions observed across three load conditions. For those engines for which Shell is not required to develop and employ a stack test-derived emission factor, Region 10 is revising the final the permit (Tables D.2.1 and D.2.2) in response to comments to require Shell to employ a more conservative emission factor. This emission factor is the 90th percentile value of stack test results for similar engines on the Discoverer and its Associated Fleet.

In response to comments, Region 10 has also reconsidered the 3 lb/ton NO_X emission factor for incinerators. The origin of this emission factor is AP-42. After further consideration, the Region is requiring Shell to stack test the incinerators to be installed at maximum capacity to determine PM, CO, and NO_X emission factors. This approach will better assure that the emission factor used to calculate emissions captures short-term fluctuations in emissions that could influence 1-hour ambient impacts.

M.2 SUBCATEGORY – EMISSION FACTORS

Comment M.2.a: Commenters notes that for emission units that are not subject to source testing, the Draft Permit relies on emission factors set forth in Tables D.2.1 and D.2.2. Because this Draft Permit does not specify equipment make, model, and capacity, the commenters believe that it is critical to require source testing for all permitted emission sources at the beginning of the drill season. In the absence of source testing for all emission sources, the commenters state that Region 10 must ensure that the emission factors are the overall worst-case emission factors in order to ensure adequate protection of the NAAQS, and to ensure a reasonable margin of safety in demonstrating compliance with the NAAQS and synthetic minor permit limits. Commenters add that if CEMS are not feasible, Region 10 must require more frequent stack testing (*e.g.,* at the beginning of *each* season from every source).

Response: The commenters are correct that the permit does not authorize construction and operation of specific emission units down to the make, model and capacity. However, Shell has provided Region 10 with information that identifies the general purpose of each unit or group of emission units and the expected capacities of each emission unit or group of units. As described in response to comments I.3.a and M.2.c, Region 10 is using reasonably conservative emission factors for calculating emissions from those units that are not required to be tested. Regarding the frequency of testing, if stack test results show 20% or more variability in the emission factor results from the most recent two tests, Shell is required to conduct stack tests every 2 years. If variability is less than 20 percent, testing shall be conducted every 5 years. In the absence of information suggesting otherwise, Region 10 believes that the testing schedule established in the Kulluk Permit will result in updated emission factors that, when used as required to calculate emissions, will provide a reasonable assurance of compliance.

Comment M.2.b: Commenters question whether the emission factors for the boilers and heaters in Tables D.2.1 and D.2.2 of the Draft Permit will ensure adequate protection of the NAAQS. The commenters cite to the BACT limit for boilers in the Discoverer permit as higher than the NO_X and PM emission factors used in the Draft Permit. Specifically, the NO_X and PM BACT limits in the Discoverer permit are equivalent to 26.6 lb/10^3 gal of NO_X and 3.1 lb/10^3 gal of PM, and are based on stack test data from the actual units. In comparison, the emission factors in the proposed permit for the Kulluk are 20 lb/10^3 gal of NO_X and 3 lb/10^3 gal of PM, and are based on AP-42. The commenters state that it is not reasonable to assume a lower emission rate for boilers on the Kulluk and Associated Fleet when the Discoverer permit represents what the Region determined to be the best available controls for these units. The commenters assert that Region 10 must require source-specific emission factors for these units, or revise the emission factors upward to reflect the worst-case boilers that could potentially be used onboard the Kulluk and Associated Fleet.

Response: Regarding the PM emission factors, the commenters incorrectly reference the Draft Permit's PM emission factor for boilers and heaters as 3 lb/10^3 gal; the emission factor in Tables D.2.1 and D.2.2 is 3.3 lb/10^3 gallons which is slightly higher than the boiler and heater emission factor in the Discoverer permit. The 3.3 lb/10^3 gal PM emission factor in the Kulluk Permit is also much greater than the 0.5 lb/10^3 gal emission factor Shell observed while testing the boilers on the Discoverer.[11] The emission factor is used to quantify emissions from each specific unit. Therefore, the use of a higher emission factor will result in reporting a greater amount of emissions than may in fact be emitted. The commenters have not shown how overestimating emissions jeopardizes protection of the NAAQS.

Regarding the boiler and heater NO_X emission factor, the commenter is correct that the emission factor used in the Kulluk permit is lower than the emission factor in the Discoverer permit. Stack testing of boilers made available by Shell subsequent to the setting of the Discoverer BACT limit shows an average emission factor of 13.1 lb/10^3 gal which is less than the 20 lb/10^3 gal AP-42 emission factor used in the Kulluk Permit which reflects some conservatism.[12] The Kulluk emission factor is lower than the Discoverer BACT limit for similar equipment, but is higher than available test data for a similar source. This data suggests that Shell will actually be emitting less PM than reported by employing a higher emission factor. Therefore, the commenters have not shown how the Kulluk emission factor jeopardizes protection of the NAAQS.

Comment M.2.c: Commenters question whether the emission factors for the emergency generators, seldom-used engines, and oil spill response vessel (OSRV) workboats are

[11] 0.5 x10^3 lb/gal = (3.55 x10^{-3} lb/MMBtu) x (MMBtu/1x10^6 Btu) x (131180 Btu/gal) x (1000). See June 16, 2011 email from Rodger Steen to Dan Meyer.
[12] 13.9 x10^3 lb/gal = (1.06 x10^{-1} lb/MMBtu) x (MMBtu/1x10^6 Btu) x (131180 Btu/gal) x (1000). See June 16, 2011 email from Rodger Steen to Dan Meyer.

sufficiently conservative. Because the NO_X and PM emission factors for these units are based on stack testing for Discoverer sources, the commenters doubt that the data truly reflect the worst-case emissions sources for these source types. The commenters believe that this is particularly important considering that these units are not subject to source testing requirements. The commenters note that the sources contribute between 5-10 percent of NO_X and PM emissions, with the OSRV workboats representing a significant share of these emissions. The commenters state that considering that the maximum modeled concentration for $PM_{2.5}$ is near the NAAQS (within 3% of the 24-hour average NAAQS) there is little room for uncertainty.

Response: In response to comments received, Region 10 reevaluated the NO_X and PM stack test results for the Discoverer and Associated Fleet, which Region 10 relied on to establish emission factors for similar units on the Kulluk and the Associated Fleet. To add a measure of conservatism to Shell's emission calculations for those engines which are not required to be tested, Region 10 has revised the emission factors for engines greater than 600 hp to reflect a value at least equal to the 90^{th} percentile value for the tests conducted by Shell on the Discoverer and Associated Fleet. Kulluk Permit Tables D.2.1 and D.2.2. This change results in a 7.8 and 113 percent increase to the NO_X and PM emission factors, respectively, for engines greater than 600 hp. For engines less than 600 hp, Region 10 determined that the NO_X and PM emission factors in the permit already exceed 90^{th} percentile values, which provides an adequate margin of safety.

M.3 SUBCATEGORY – CONTINUOUS EMISSION MONITORING

Comment M.3.a: Commenters contend that the only way to adequately ensure compliance with hourly limits is through the use of continuous emissions monitoring systems (CEMS), and assert that the Region must require the use of CEMS, or equivalent, for NO_2 compliance.

Response: As discussed in response to comment J.1.a, CEMS are an effective means of ensuring compliance with short-term emission limits, but CEMS are not the only means. Shell's planned exploratory operations are unusual as compared to other sources because the emission units consist of more than 50 engines and generators on the Kulluk and a fleet of numerous support vessels. There are practical considerations to requiring CEMS including that the emission units, control equipment, and monitoring equipment will be operating in a remote, harsh, Arctic environment, deck space on board the vessels is limited, and CEMS are expensive to purchase, maintain, and operate.

Region 10 is confident that the monitoring and recordkeeping prescribed in the permit assures compliance with emission limits.

Comment M.3.b: Commenters express support for the use of SCR controls, but are concerned about how the controls will function in Arctic conditions. The commenters note that Region 10 believes the SCR and OxyCat systems will be effective if inlet temperatures are high enough, the urea feed is operating, and the catalysts are active. Commenters explain that the proper functioning of these controls is essential to compliance with the NO_2 and PM NAAQS, and request that CEMS be used for these systems instead of weekly measurements with a portable monitoring device.

Response: Region 10's determination that the monitoring required in the permit will verify that the control devices are operating properly takes into account that the Kulluk will be operating in arctic conditions. Region 10 believes that the continuous monitoring system required by the permit will ensure the control equipment is operating properly. Temperature and urea feed will be monitored. Temperature measurements will be compared against temperatures measured during emission factor verification source testing. The weekly concentration checks using a portable monitor are not considered alternatives to CEMS, but instead serve as a verification that the control equipment is operating properly. As discussed in the Statement of Basis (at 45), weekly concentration checks should be an effective frequency for confirming whether the catalysts are still active. Temperature or concentration deviations from those measured during testing must be corrected and reported. The overall monitoring strategy is a reasonable and appropriate alternative to CEMS in this specific application. See response to comments in subcategories M.1 and M.2 and response to comment O.1.

Comment M.3.c: A commenter at the public hearing requested that Region 10 require the use of CEMS. The commenter expressed concern about self-monitoring of pollution in the OCS, and cited to limits on fuel use and the amount of waste combusted. Another commenter stated that because of uncertainties in the model, Region 10 should require installation and operation of CEMS for at least nitrogen dioxide, particulate matter and carbon dioxide.

Response: Region 10 would first like to clarify that the permit does not allow Shell to consider the amount of waste combusted in calculating emissions generated by waste incineration. The permit requires Shell to calculate emissions assuming the incinerators are operating at maximum capacity for all time periods that operation is allowed. Permit Condition D.4. Contrary to the commenter's assertion, monitoring emissions using CEMS will have no bearing on the accuracy of the new model or algorithms used by Shell. See comment J.1.a regarding the need for CEMS given model uncertainty. See comment O.1 regarding Shell self-monitoring. See comment I.1.c with respect to how fuel monitoring is an integral part of a monitoring and recordkeeping system that provides for a reasonable assurance of compliance with emission limitations.

N. CATEGORY – REPORTING REQUIREMENTS

Comment N.1: Commenters request that Region 10 add a condition to the permit requiring Shell to submit all of its monitoring results to Region 10, citing to Section 504(a) of the Clean Air Act. The commenters further request that, in light of the 120 day operating window for this permit, these submissions be made every 60 days (or twice) while the operations are occurring so that Region 10 has time to take enforcement action if a problem arises during the course of the operations.

Response: The permit requires the permittee to submit to Region 10 a semi-annual operating report by August 31 and February 28 of each year. Permit Condition A.19.1. That report must include reports of any required monitoring, including all emission calculations required by the permit. Permit Condition A.19.1.3. This is consistent with the statutory and regulatory requirements for Title V permits. See CAA § 504(e); 40 CFR § 71.6(a)(3)(iii)(A). With respect to the request that Region 10 require reporting twice during the period of operations so that Region 10 has timely information if problems arise during the course of operations, Region 10 notes that the permit also requires the reporting of all excess emissions and deviations from permit requirements no later than 30 days after the end of the month in which the deviation occurs, and in many cases sooner than that. See Permit Conditions A.17 and A.18. Region 10 believes these conditions ensure that Region 10 will have timely information in the event problems arise during the drilling season and that the requirement to submit monitoring reports more frequently than currently provided for in the permit is therefore unnecessary.

O. CATEGORY – COMPLIANCE MONITORING AND ENFORCEMENT

Comment O.1: Commenters request that Region 10 exercise its authority to inspect Shell's exploration fleet to ensure compliance with permit requirements both well in advance of and during the operating season. The commenters state that when North Slope Borough staff toured the Kulluk in March 2011, the rig was not in a drill ready condition and that upgrades and improvements that had been announced were not complete. An inspection prior to the first drilling season, the commenters continue, would provide adequate time to undertake appropriate repairs or upgrades if the inspectors identify problems with any source or equipment and would be easy to conduct because the Kulluk is currently in Seattle. The commenters contend that a robust inspection program is necessary to ensure that the air emission controls are actually implemented and effective and that there is independent verification of compliance with permit provisions.

Response: Region 10 has authority to conduct inspections of the Kulluk. See CAA § 114; 40 CFR § 55.8(a). Because Shell is not required to meet the emission limits and control requirements in the permit until the Kulluk becomes an OCS source in the Beaufort Sea, however, Region 10 does not necessarily agree with the commenters that inspecting the Kulluk before the first drilling season is the most effective use of agency resources. Such an inspection would only indicate how far along Shell is in installing identified emission units and required control equipment and would not necessarily indicate whether that equipment will meet permit requirements while the Kulluk is an OCS source.

In addition, inspections are not the only way to determine whether Shell is operating in compliance with permit requirements. The permit contains testing, monitoring, recordkeeping, and reporting requirements to provide information regarding whether Shell is operating in compliance with permit conditions. For example, the permit requires stack testing of most emission units prior to initial operation. Permit Condition E. Shell is required to report all permit deviations to Region 10 and to submit a semi-annual operating report that includes reports of all required monitoring. Permit Conditions A.17, A.18, and A.19.

In addition, the Kulluk Permit includes mechanisms that enhance the reliability of Shell's self-monitoring. The permit requires Shell to install, maintain, and operate devices to measure and record fuel usage, operating loads, and other emissions-related data. Permit Condition F. Under Section 113(c)(2)(C) of the CAA, it is a criminal offense to falsify, tamper with, render inaccurate, or fail to install any monitoring device or method required under the Clean Air Act. All reports and records required to be submitted to Region 10 under the permits must be certified by a responsible official for Shell as to their truth, accuracy, and completeness. Permit Condition A.12. Again, Shell could be subject to criminal liability for falsifying these records or reports.

Although self-monitoring by Shell is a component of ensuring Shell is operating in compliance with the permit, as indeed it is for other sources subject to Clean Air Act requirements, Region 10 will have an active oversight role. In the event Shell violates its permit, Region 10 has broad authority under Section 113 of the CAA to issue compliance orders, assess administrative penalties, and request the Attorney General to bring a civil or criminal action, as appropriate. Region 10 intends to conduct comprehensive compliance evaluations, including on-site inspections, as appropriate and consistent with EPA policies. See Clean Air Act Stationary Source Compliance Monitoring Strategy, April 2001, http://www.epa.gov/compliance/resources/policies/monitoring/cmspolicy.pdf

In addition, Region 10 has authority to observe the conduct of source tests of any emission unit and will review all source test reports to verify that the proper procedures and equipment were used to measure emissions from the emission units and to evaluate compliance with the permit terms and conditions. Region 10 will also be reviewing periodic reports and episodic (e.g. deviation) reports submitted under the permit. Key compliance information will be available via EPA's Enforcement and Compliance History Online (ECHO) website. http://www.epa-echo.gov/echo/ The public also has a right to request this information under the Freedom of Information Act (FOIA), 5 U.S.C. **§** 552. In some instances, Region 10 may withhold all or a portion of inspection reports and other information in accordance with FOIA, 5 U.S.C. **§** 552(b).

Comment O.2: Commenters state that if Region 10 does not have the requisite resources to dedicate to the arctic OCS, Region 10 should coordinate with BOEMRE or other federal agencies to ensure compliance with air permit conditions.

Response: Region 10 will coordinate with other federal agencies as necessary and appropriate to ensure appropriate oversight of Shell's operations under the permit.

Comment O.2.a: Commenters request that Region 10 promptly share the records, reports, and information gained from physical inspections of the Kulluk and Associated Fleet with the public as authorized by regulation.

Response: As discussed above in response to comment O.1, key compliance information will be available via EPA's ECHO website. http://www.epa-echo.gov/echo/ The public also has a right to request this information under FOIA.

Comment O.4: One commenter asked who was going to be monitoring Shell's operations and whether it is going to be self-monitoring. The commenter also asked whether there are going to be marine mammal or other observers.

Response: As discussed in response to comment O.1 above, monitoring of Shell's operations under the permit will be conducted through a combination of self-monitoring by Shell, inspections by Region 10, and the review of reports, source test data, and other information by Region 10. Marine mammal observers or other observers may be required by other regulatory programs or agreements but are not a component of compliance assurance under this Clean Air Act permit.

P. CATEGORY – AMBIENT AIR BOUNDARY

Comment P.1: Commenters contend that Region 10's decision to set the ambient air boundary at 540 meters from the center of the Kulluk is arbitrary and unlawful and conceals the true maximum impacts of Shell's emissions. The commenters state that, to comply with EPA's longstanding policy on ambient air, Region 10 must set the ambient air boundary at the hull of the Kulluk, noting that EPA has defined "ambient air" as "that portion of the atmosphere, external to buildings, to which the general public has access." The commenters state that, under EPA policy, an exemption from ambient air is available only for the atmosphere over land owned or controlled by the source and to which public access is precluded by a fence or other physical barriers, and that Shell does not own or control the area within the 540 meter radius (500 feet from the hull of the Kulluk) and it cannot effectively prevent public access. The commenters continue that Shell's proposal to implement a public access control program to "locate, identify and intercept the general public" does not constitute the fence or other physical barrier excluding the public that EPA's policy requires.

Response: Ambient air is defined as "…that portion of the atmosphere, external to buildings, to which the general public has access." 40 CFR § 50.1(e). Region 10 agrees with the commenters that EPA's longstanding interpretation is that "exemption from ambient air is available only for the atmosphere over land owned or controlled by the source and to which the public access is precluded by a fence or physical barrier." See Letter from Administrator Douglas M. Costle, EPA, to Senator Jennings Randolf, Chairman, Environment and Public Works Committee, re: Ambient Air, dated December 19, 1980. EPA has observed that "control" under this criterion means that "the source has certain rights to use of the land/property, including the power to control public access to it." Memorandum from Steven D. Page, Office of Air Quality Planning and Standards (OAQPS), re: Interpretation of "Ambient Air" in Situations Involving Leased Land under the Regulations for Prevention of Significant Deterioration, Attachment at 3, dated June 22, 2007 (Leased Land Guidance). Region 10 believes that excluding the area within a safety zone established by the United States Coast Guard from ambient air is consistent with this interpretation.

As discussed in the Statement of Basis (at p. 40), Shell modeled emissions from the Kulluk beginning 500 meters from the hull of the Kulluk and assumes that the Coast Guard will impose a safety zone of this distance around the Kulluk to exclude the public from the area in which Shell will be conducting its main operations. Shell therefore agreed that Region 10 would require as a condition of operation under the permit that Shell have in place at all times of operation as an OCS source a safety zone of at least 500 meters from the hull of the Kulluk within which the Coast Guard prohibits public access. See Permit Condition D.5 and D.6.

The conditions of the permit provide sufficient assurance that the general public will not have access to the area inside the safety zone, consistent with the two primary criteria EPA has used to determine when such an exclusion may apply. Given that the permitted activities occur over open water in the Arctic, these criteria must be adapted to some extent when applied to this environment, but they are still satisfied in this instance in a manner sufficient to effectively preclude public access from the safety zone.

Region 10 recognizes that Shell does not “own” the areas of the Beaufort Sea on which the Kulluk will be operating as might be the case for a stationary source on land. Shell has a lease authorizing the company to use these areas for the activities covered by the permit. A Coast Guard safety zone establishes legal authority for excluding the general public from the area inside the zone. EPA has previously recognized a safety zone established by the Coast Guard as evidence of sufficient ownership or control by a source over areas over water so as to qualify as a boundary for defining ambient air where that safety zone is monitored to pose a barrier to public access. Letter from Steven C. Riva, EPA Region 2, to Leon Sedefian, New York State Department of Conservation, re: Ambient Air for the Offshore LNG Broadwater Project, dated October 9, 2007 (Broadwater Letter).

To meet the second of the criteria applied by EPA and ensure the source actually takes steps to preclude public access, Shell proposed and Region 10 required as a condition of operation under the permit that Shell develop in writing and implement a public access control program to locate, identify, and intercept the general public by radio, physical contact, or other reasonable measures to inform the public that they are prohibited by Coast Guard regulations from entering the area within 500 meters of the hull of the Kulluk. Region 10 believes that, for the overwater locations in the arctic environment at issue in this permitting action, such a program of monitoring and notification is sufficiently similar to a fence or physical barrier on land such that the area within the Coast Guard safety zone qualifies for exclusion from ambient air. See Broadwater Letter at 2.

Shell therefore appropriately excluded the area within 500 meters of the hull of Kulluk from the source impact analysis it conducted to meet the requirements of the applicable CAA regulations.

Comment P.2: Some commenters contend that Region 10's approach to setting the ambient air boundary for the Kulluk is inconsistent with the approach Region 10 took in setting the ambient air boundary for Shell's Discoverer drillship in previous determinations. The commenters state that, when Shell initially applied for air permits for the Discoverer drillship, the company's application materials included an ambient air boundary of 900 meters and that Shell assumed that the ambient air would begin at this distance because it had "submitted a request to the US Coast Guard, for issuance of a safety exclusion and equipment protection zone surrounding the Discoverer . . . ." Nevertheless, the commenters state, in issuing permits to Shell for the Discoverer drillship in 2010, Region 10 required Shell to model impacts from the hull of the Discoverer, outward, yet Region 10 is now indicating that it will allow Shell to model impacts for the Kulluk starting 540 meters from the center of the Kulluk. The commenters allege that if Region 10 were to recognize that the edge of the hull is the appropriate boundary, Shell has not demonstrated that its operations will not cause a violation of air quality standards in the "ambient air" and that Shell has in fact stated that maximum modeled impacts occur on or near the 540 meter boundary, indicating likely greater impacts inside of that boundary.

Response: The commenters are correct that Shell's February 2009 application for an OCS/PSD permit for operations for the Discoverer in the Chukchi Sea did request an ambient air boundary based on a Coast Guard safety zone. Shell later withdrew that request and the 2010 Permits for the Discoverer drillship issued by Region 10 therefore did not base the ambient air boundary on a Coast Guard safety zone, but instead assumed that ambient air began at the hull of the Discoverer. In response to the remand from the Environmental Appeals Board, Shell subsequently submitted modeling for the Discoverer demonstrating compliance with the NAAQS based on a Coast Guard safety zone and the final permits issued by Region 10 for the Discoverer in response to the remand require Shell to obtain a Coast Guard safety zone as a condition of operation under the permits. See Supplemental Response to Comments for the Discoverer Drillship permits, dated September 19, 2011, at 41.

Similarly, in its application for a permit for the Kulluk, as discussed in the Statement of Basis (at p. 40), the application materials submitted by Shell modeled emissions from the Kulluk beginning 500 meters from the hull of the Kulluk and assumes that the Coast Guard will impose a safety zone of this distance around the Discoverer to exclude the public from the area in which Shell will be conducting its main operations. The permit therefore authorizes operation only if the Kulluk is subject to a currently effective safety zone established by the Coast Guard. Because the area within the safety zone is not considered ambient air, demonstrating compliance with the NAAQS within that zone is not required. Thus, Region 10 acted consistently with Shell's application materials for the Discoverer permits, Shell's application materials for this permit, legal requirements, and EPA guidance in determining the ambient air boundary based on a Coast Guard safety zone. See also response to comment P.1.

Comment P.3: Several commenters express concern that Shell had not provided and Region 10 has not required an analysis showing what air quality would be within the safety zone and state that the size of the zone is arbitrary. Commenters assert that workers within that zone will not be protected and that the federal agencies are not working together to ensure healthy air. Commenters state that residents of the North Slope serve as marine mammal observers and members of the communications team on the drillship and will be subjected to below standard air quality. These commenters contend that emission levels throughout the OCS, including within the safety zone, should meet lawful levels and express concern that winds would take air pollution farther than 500 meters from the ship. Commenters state their concern for what this decision means for air quality on the OCS where local communities hunt and fish.

Response: Region 10's understanding is that Marine Mammal Observers will be employees of Shell or Shell contractors. 2012 Revised Camden Bay Exploration Plan at 11-4 (Marine Mammal Observers provide an opportunity for local hire). Under established EPA policy, contractors, subcontractors, and employees that are expressly granted access to a site by the entity with control over the site are not considered the general public vis-à-vis that entity, but instead are considered "business invitees." See Memorandum from Stephen D. Page, Director OAQPS, re: Interpretation of "Ambient Air" in Situations Involving Leased Land Under the Regulations for Prevention of Significant Deterioration (PSD), dated June 27, 2007, Attachment at p. 5. Their presence within the Coast Guard safety zone thus does not deprive that area from qualifying for exclusion from ambient air. See also response to comments P.1 and P.4.

Comment P.4: Commenters contend that allowing OCS sources to establish ambient air boundaries in the Arctic based on safety zones raises concerns regarding the cumulative impacts to offshore air quality that several such operations with ambient air quality boundaries would have on air quality. The commenters cite to a Government Accounting Office Report, GAO, EPA's Ambient Air Policy Results in Additional Pollution, July 1989 (available at: http://archive.gao.gov/d26t7/139340.pdf) and assert that that EPA has been subject to scrutiny for creating ambient air boundaries in the first instance because they allow for greater air quality deterioration. The commenters ask Region 10 to explain why this boundary works in the Arctic and how Region 10 arrived at the decision to allow more pollution instead of less, particularly in light of the heavy use of offshore areas by subsistence communities. Commenters expressed concern about what Region 10's decision means for air quality on the OCS where people hunt and fish.

Response: Safety zones are established by the Coast Guard based on safety considerations, not air quality considerations. See, e.g., 75 Fed. Reg. 803 (January 6, 2010) ("The purpose of the temporary safety zone is to protect the DRILLSHIP from vessels operating outside normal shipping channels and fairways. Placing a temporary safety zone around the DRILLSHIP will significantly reduce the threat of allisions, oil spills, and releases of natural gas, and thereby protect the safety of life, property, and the environment")(capitalization in original). However, because such a safety zone combined with Shell's public access control program has the effect of restricting the general public's access to the relevant area, as discussed in response to comment P.1, Region 10 believes the presence of a safety zone supports excluding the area inside the zone from ambient air for air quality purposes consistent with prior EPA interpretations of its regulations.

The GAO report cited by the commenters focused primarily on concerns with land acquisition to increase the size of the ambient air boundary and thus as a pollution control technique, which is not implicated in the application for and the establishment of a Coast Guard safety zone based on safety considerations. As discussed above in response to comment P.1, EPA has previously determined that a Coast Guard safety zone is an appropriate basis for establishing an ambient air boundary within which demonstration of compliance with the NAAQS is not required. As discussed in Sections 4 and 5.4 of the Statement of Basis and the Technical Support Document, emissions under this permit are not expected to cause or contribute to violations of the NAAQS in any area that constitutes ambient air, including in areas where local communities regularly conduct subsistence activities. With respect to cumulative impacts, please see the responses to comments in Category Y.

Comment P.5: Commenters request that, if the ambient air boundary remains in place, Region 10 examine options for requiring monitoring at 500 meters from the Kulluk for the first two weeks of the drilling season. The commenters state they are not aware of any reasons why it would not be technologically feasible to operate monitoring equipment from a moored vessel.

Response: Region 10 believes that the background monitoring data that have been collected in conjunction with the air quality modeling conducted to support this permit action adequately demonstrates that emissions under the permit will not cause or contribute to a violation of the NAAQS. The emission limits and associated monitoring, recordkeeping, and reporting requirements in the permit are adequate to verify that the NAAQS will not be exceeded and Region 10 therefore does not believe the additional monitoring requested by the commenters is warranted. Given the challenges of conducting ambient air monitoring in harsh, remote arctic conditions, Region 10 does not believe it is appropriate to require monitoring to be conducted on a vessel at the ambient air boundary. Region 10 believes collection of background air quality data within a closer proximity to a community provides more beneficial information on potential health-based exposure than a monitor located well offshore.

Q. CATEGORY – GENERAL COMMENTS ON AMBIENT AIR QUALITY ANALYSIS AND SUPPORTING DATA

Comment Q.1: Commenters state that the statute and applicable regulations dictate that Region 10 may not issue Shell a Title V operating permit unless it "includes conditions that will assure compliance with all the requirements of [the Clean Air Act] at all authorized locations, including, but not limited to, ambient standards and compliance with any applicable increment or visibility requirements . . . ," citing to 42 U.S.C § 7661c(e) and § 7661c(a); 40 CFR §§ 71.2, 71.6(a)(1), 71.6(e)(1). These commenters contend that Shell has not demonstrated its ability to comply with all applicable requirements and that Region 10—which premised the draft permit conditions on Shell's modeling assumptions—has not established adequate permit conditions sufficient to guarantee compliance.

Response: As discussed in the responses to comments in Categories Z and GG, in the Statement of Basis, and in the Technical Support Document, the permit includes conditions that assure compliance with all applicable requirements of the Clean Air Act at all authorized locations. Contrary to the commenters' assertion, there is no requirement that permit conditions be sufficient to "guarantee" compliance. Rather, the permit must contain terms and conditions that provide a reasonable assurance of compliance with all applicable requirements.

Comment Q.2: A commenter states that the modeling used to support the permits is unproven and asks that Region 10 ensure that the model is statistically sufficient to justify the permitting decision.

Response: The basic model used to support the permits, AERMOD, is an EPA guideline model that has been approved for use after notice and comment rulemaking. See 40 CFR Part 51, Appendix W, Section 4.2.2(b). Region 10 approved two permit-specific algorithms for use with the guideline model: COARE for the pre-processing of meteorological data and the Plume Volume Molar Ratio Method (PVRM) that is considered on a case-by-case basis as a non-regulatory default option under Section 5.2.4.d of Appendix W. Approval of these alternatives was subject to rigorous review. See also the responses to comments in Category R.

Comment Q.3: Commenters state, although the amount of pollution that will be released under the permit has been greatly reduced, it is still very close to exceeding the air quality standards and there are still significant concerns about whether the permits comply with EPA's legal obligations. The commenters are concerned about the modeling that was done for this permit and that the pollution that will be emitted could potentially impact not just the 500 meters around the Kulluk itself but the communities throughout the Arctic, including the offshore areas where local communities spend much of their time throughout the year.

Response: As discussed in the Technical Support Document, the modeling that has been conducted demonstrates that the NAAQS will be protected in all areas that are considered ambient air, including areas where local communities regularly conduct subsistence activities. Although it is true that the highest modeled concentrations are close to the NAAQS for some pollutants, it is also true that these results reflect many conservative assumptions, such as the Kulluk remaining in the same location for three years, a situation that is unlikely to occur, and the use of onshore background data to reflect offshore air quality. See responses to comments V.1.c and V.2.a

Comment Q.4: A commenter states that the models show that the concentration of air pollutants in the local communities resulting from Shell's operations would be well below the national ambient air quality standards. The commenter asserts that this is true even when taking into account background concentrations of air pollutants that are not related to Shell's operations and the use of conservative assumptions such as all four proposed exploratory wells being drilled at the same location, which would not actually occur.

Response: Region 10 agrees that, considering the emissions from Shell's operations in conjunction with background air quality, concentrations will be well below the NAAQS in the onshore communities and will be below the NAAQS in all areas that are considered ambient air.

Comment Q.5: A commenter from Point Hope expressed a general concern with the air quality analysis and whether the analysis supporting the permits had considered ship traffic in the baseline. The commenter states that there was no background air monitoring being conducted in Point Hope and asks that such monitoring be conducted so the community could better understand concerns. The commenter also asserts that the results of previous nuclear tests that shows that emissions stay up in the Arctic within the jet stream and accumulate, and is referred to as Arctic Haze. The commenter also expressed concern about the impact of emissions on subsistence users and notes that other oil companies with leases have expressed interest in getting permits. The commenter also asks where the data used is from.

Response: As discussed in Section 4 of the Statement of Basis, the Technical Support Document, and throughout this Response to Comments, the permit is supported by a demonstration that the authorized emissions will not cause or contribute to a violation of the NAAQS in all locations that constitute ambient air, including where subsistence activities are regularly conducted. The data relied on to support these permits comes from a variety of sources, and includes background monitoring data collected by Shell and other sources, emission data from stack tests and other available sources, and meteorological data collected by Shell and other sources, including the National Weather Service. Issuance of the permit does include consideration of existing emissions in the area through the use of background air quality data in the general vicinity of the proposed operations. Region 10 notes that Point Hope is located on the southern edge of the Chukchi Sea, hundreds of miles from the locations where operations will be conducted under the permit in the Chukchi Sea. Region 10 therefore does not believe it is appropriate to rely on background air quality monitoring in Point Hope in support of this permit action. Emissions from operations of other leaseholders will be considered if and when such leaseholders apply for Clean Air Act permits, and the public will have an opportunity to review and comment on any such permits. For discussion on subsistence activities, see response to comments in Category DD.

Comment Q.6: A commenter stated at a public hearing that he had tried looking into information in regards to the inventory and had inquired about other modeling information and had not received a response.

Response: The Region received a request from the commenter for modeling information and replied by contacting the commenter to discuss the request. The Region informed the commenter that the modeling files were stored electronically on multiple hard drives comprising more than 150 gigabytes of electronic storage space. The Region provided the commenter a summary list of all the modeling files to assist the commenter in identifying specific files for review, and also informed the commenter of the large size of the modeling files and inquired as to the best way to deliver the files to the commenter. The Region did not receive a follow-up response from the commenter, but contacted the commenter again after receiving the comment.

R. CATEGORY – CHOICE OF MODEL

Comment R.1: A commenter states that EPA's use of the Coupled Ocean Atmosphere Response Experiment Meteorological Modeling Algorithm and the Plume Volume Molar Ration Method Nitrogen Dioxide Algorithm to predict the concentration of air pollutants emitting from Shell's operations and in the local communities is appropriate and that EPA has approved use of these models, albeit on a case-by-case basis.

Response: As described in more detail in response to Comment R.2, Region 10 agrees with the commenter that the use of AERMOD-COARE and PVMRM is appropriate.

Comment R.2: Noting that Region 10 is soliciting comments on the use of the non-guideline AERMOD-COARE model in these proposed revised permits, commenters state that given the limited comment period and the overlap with the Discoverer permits comment period, it is not feasible to provide comprehensive and appropriately technical comments on the model. The commenters contend that new COARE model is highly involved and explain that to review the details of the model and be able to provide technical comments and broader peer review would take more time than is being provided. The commenters assert that public input on this new model would be a valuable opportunity for broad peer review of the models used but that this opportunity is lost because Region 10 did not provide adequate time for review.

Response: Consistent with the requirements of 40 CFR § 52.21(l)(2),[13] Region 10 approved the use of the non-guideline COARE meteorological algorithm to predict air pollutant concentrations in the open-water arctic environment. Memorandum from Herman Wong, Region 10, to Tyler Fox, OAQPS, re: COARE Bulk Flux Algorithm to Generate Hourly Meteorological Data for Use with the AERMOD Dispersion Program; Section 3.2.2.e Alternative Refined Model Demonstration Approval Memorandum, dated April 1, 2011 (Region 10 AERMOD-COARE Approval Memorandum). The use of this algorithm was approved under the case-by-case alternative modeling provisions specified in EPA's modeling guidelines, 40 CFR Part 51, Appendix W, Section 3.2. Region 10 then sought and obtained concurrence from the EPA Model Clearing House on the Region's approval. See Memorandum from George Bridgers, OAQPS, to Herman Wong, Region 10 re: Model Clearinghouse Review of AERMOD-COARE as an Alternative Model Application in an Arctic Marine Ice Free Environment, dated May 6,

[13] As discussed in the Technical Support Document (pages 5-7), the COA rules require the use of 40 CFR Part 51, Appendix W for a modeling analysis under the COA minor permit program. In addition, Region 10 believes it is appropriate to use the regulations and guidance for conducting an air quality analysis under the PSD program as a guide for an analysis submitted in connection with a Title V permit for a Title V temporary source. See Id. and Statement of Basis at 26-27. Subsequent references to the PSD regulations and guidance are cited for this same purpose.

2011 (Model Clearinghouse Concurrence Memo). As provided in 40 CFR §§ 52.21(l)(2) and 52.21(q), Region 10 then provided notice and an opportunity for public comment on its approval of COARE in the context of this specific permit action. This included a 46-day period for public comment, longer than the 30-day comment period provided for in 40 CFR § 71.11(d) and 124.10. As explained in the response to comments for Category C, the 46-day period complies with all legal requirements. As demonstrated by the thoughtful comments received, Region 10 believes it provided sufficient time for commenters to address the issues in the Draft Permit, including the COARE algorithm.

Moreover, this model was used in support of both the draft Discoverer permits and the Kulluk Draft Permit, and both public notices refer to the same supporting documentation. Therefore, for those who chose to comment on both the Kulluk and Discoverer permits, including these commenters, the overlap provided a total of 60 days to review AERMOD-COARE prior to submitting comments on the Kulluk Draft Permit.

Comment R.3: Commenters question whether the performance evaluations used to assess the model are representative. After looking at the results from the three tracer sites, the commenters state that there is significant variation in model performance and contend that, if there is that much difference between the California and Louisiana sites, it stands to reason that conditions in the Arctic may be a lot different. Commenters state that differences in sea surface temperature, depth of the marine layer, sea surface roughness, among other things, could give substantially different results in an arctic environment, particularly with respect to the 1-hour NO_2 NAAQS. Based on the results of the performance evaluation presented in the Model Clearinghouse review and because this is the first time using this nonguideline modeling approach in the Arctic, the commenters ask Region 10 to require Shell to conduct additional tracer experiments off the North Slope before the final permit is issued and to include a permit condition that requires Shell to collect data for use in evaluating the performance of the AERMOD-COARE model. The commenters cite to language in EPA's approval memo stating that the EPA Model Clearinghouse recommended further investigation to "determine if other tracer gas experiments are available to evaluate AREMOD-COARE, especially for Arctic conditions."

Response: As discussed in the response to comment R.4 below, evaluation of AEROMD-COARE using the three tracer gas experiments indicate that the meteorological variables such as those mentioned by the commenters do not bias the model towards underestimates. Section 3.2.2.e in Appendix W states that an alternative refined model may be used provided that five criteria are met, including (a) that the necessary data bases (*e.g.*, tracer gas experiments) be available (Element 3); and (b) that appropriate performance evaluations have shown that the alternative refined model (*e.g.*, AERMOD-COARE in this case) is not biased toward underestimation (Element 4). 40 CFR Part 51, Appendix W, § 3.2.2(e)(iii)-(iv). Region 10 determined that the tracer gas experiments conducted at Cameron, Louisiana, and Carpinteria and Pismo Beach, California, are representative of arctic conditions. The basis for this finding is that the experiments simulate over water dispersion, tracer gas concentrations were measured at the shoreline, and there was a range of positive air-sea temperature differences (i.e., stable conditions) like what would be expected in the Arctic. Consequently, Region 10 concluded that these three tracer gas experiments were adequate for the AERMOD-COARE performance evaluation. Region 10 AERMOD-COARE Approval Memorandum, Section B.3; see also Model Clearinghouse Concurrence Memo.

Regarding the commenters' concern that the tracer gas experiments were not conducted in the Arctic, Region 10 recognizes that there are not tracer gas experiments for every geographic region, climatic region, or synoptic region for use in a performance evaluation. Region 10 AERMOD-COARE Approval Memorandum, Section B.3. This is particularly true for the Arctic given the harsh environmental and meteorological conditions in which such an experiment would have to be conducted. Nevertheless, Region 10 concluded that the tracer gas experiments relied on to support approval of the model are acceptable based on the similarity of the tracer gas experiments and the marine arctic air-sea temperatures. Id.

After evaluating Shell's demonstrations with respect to the five elements under Section 3.2.2.e in 40 CFR Part 51, Appendix W, Region 10 approved the AERMOD-COARE model as an alternative refined model to estimate emission impacts from marine located combustion sources. AERMOD-COARE was subsequently used by Shell to make the required modeling analysis.

When approving Shell's use of this model, Region 10 determined that "Approval to use this alternative model is made on a case-by-case basis. Should a project proponent desire to use AERMOD-COARE in an Arctic marine ice free environment air permit project, a request must be made to R10 prior to the submission of an ambient air quality impact analysis…." Region 10 AERMOD-COARE Approval Memorandum, Section C.1. Hence, should other OCS projects be proposed in the Beaufort or Chukchi Seas, Region 10 will require each project proponent to justify the use of AERMOD-COARE and, if necessary, update the elements under 40 CFR Part 51, Appendix W, Section 3.2.2.e.

The commenter is correct that Region 10 recommended additional investigations to determine if other tracer gas experiments are available to evaluate AERMOD-COARE, particularly for arctic conditions, but none to date have been identified that have occurred in an arctic environment. Region 10 has accepted the Section 3.2.2.e demonstration and determined that the existing experiments provide an adequate basis for accepting the alternative model. Region 10 therefore does not believe it is reasonable to require Shell to conduct a tracer gas experiment in the Arctic followed by another performance evaluation.

Response to comment R.4 discusses the performance criteria and goals for an acceptable performance evaluation

Comment R.4: Commenters state that it is unclear from the permit record whether Shell tuned the COARE model with the available data sets and then used the same tuned model in the performance evaluation and that Region 10 must ensure, and make it known to the public, that Shell tested the model with an independent data set. The commenters assert that there is very little discussion of performance goals in the modeling evaluation so it is difficult to assess the model performance presented by Region 10. The commenters assert that, from a scientific perspective, the use of AERMOD-COARE is far superior to the OCD model, but state that does not necessarily mean it is accurate in this particular application. The commenters state that Region 10 must make it clear, from the outset, what the acceptable performance results must be, based on the available data (*e.g.*, is it good enough to get within a factor of two or are the data good enough to demand results within 30 %) and be able to clearly demonstrate that the model is accurately predicting impacts to a reasonable degree and that the model is not under-predicting impacts.

Response: The commenters do not provide specific cases or examples of what they mean by tuning. The meteorology associated with Pismo Beach, California, and Cameron, Louisiana tracer gas experiments are shown in Table 2 and Table 4, respectively, of the Region 10 AERMOD-COARE Approval Memorandum. For example, in the Revised Air-Sea Temp (K) column, there are several hours of values highlighted in red because of inconsistencies between the air-sea temperature difference and the virtual temperature potential lapse rate. The virtual potential temperature lapse rate sometimes indicates a stable boundary layer (positive) when the air-sea temperature difference is unstable (negative). Either there was a low mixed layer not reflected by the mixing height measurements in the tables, or one of the measurements is not representative of the boundary layer profile. The previous Ocean Coastal Dispersion (OCD) model evaluation relied on a measured vertical temperature lapse rate and, so to be consistent with the earlier studies, this performance evaluation adjusted the air-sea temperature difference to be at least as stable as indicated by the virtual temperature lapse rate. Region 10 agreed that this adjustment by Shell was appropriate. This adjustment to the two data sets was carried over to all of the performance evaluations. Region 10 is not aware of other adjustments and the commenter has not identified any others.

As in previous model evaluations and analyses, Region 10 followed certain design criteria to determine model acceptability. In this particular case, the predicted AERMOD-COARE model concentrations, and the Cameron, Louisiana, and the Carpinteria and Pismo Beach, California, tracer gas experiment measurements were sorted and plotted as well as statistically analyzed. These plots and statistical analyses were used by Region 10 to conclude that AERMOD-COARE is not biased towards underestimates as provided in Element 4 in Section 3.2.2.e under Appendix W of 40 CFR Part 51. The procedures are used to evaluate how well the modeling method explains the frequency distribution of the observed concentration and measures the model's ability to explain the temporal variability of the observations. Generally, the approach with the least scatter would be preferred. See Region 10 AERMOD-COARE Approval Memorandum, Section B.4.b for additional description of the statistical evaluation procedures.

The texts, tables and graphics of the performance evaluation for five cases conducted by Shell using the three experiments are included with the Region 10 AERMOD-COARE Approval Memorandum in Section B.4. Table 1 lists the five cases. The graphics or figures reflect the scatter of the prediction-to-observation ratio results, including over predictions and under predictions, when comparing the model results to actual predictions. Quantile-quantile (Q-Q) plots are shown in Figures 6 to 19 and details a 1:1 line and a factor of 2 line (i.e., 0.5 < ratio < 0.5) about the 1:1 line for prediction-to-observation ratios. A ratio on the 1:1 line reflects a perfect match. Ratios between the factor of 2 lines are preferred by EPA. The four plots in Figures 20 to 23 display the bias of the geometric mean (MG) and against scatter (VG). In each plot, there is MG = 1 line and a factor of 2 lines (i.e., 0.5 < MG < 2.0). On the horizontal axis, the MG = 1 separates model ratios (in terms of over prediction and under prediction). Table 8 provides a statistical summary of each data set (including all three data sets combined) for the five cases. The statistics analyzed and presented included geometric mean, standard deviation of geometric mean, bias about the geometric mean, scatter, geometric correlation coefficient, fraction within a factor of 2, and robust highest concentration (RHC). The RHC is frequently used by EPA to assess the model's ability to characterize the upper end of the frequency distribution. Section B.4.c in the Region 10 AERMOD-COARE Approval Memorandum summarizes the results in text format. Based on the plots and statistical analyses for the five cases, Region 10 believes AERMOD-COARE is not biased towards underestimates and better represents over water transport such as in the Beaufort Sea as compared to the OCD model. Region 10 agrees with the commenter that AERMOD-COARE is a "far superior" model from a scientific perspective.

With respect to concerns with the adequacy of time to review the model, please see response to comment R.2.

Comment R.5: Commenters state that the AERMOD-COARE model does not account for platform building downwash. Because the Kulluk is described as a conical drilling platform, the commenters assert, Region 10 must ensure that the model sufficiently stimulates cavity effects next to the Kulluk.

Response: The permit authorizes air emissions only from the equipment identified in the permit and the underlying applications, and no platform is included in these documents. Therefore, AERMOD-COARE does not need to account for platform building downwash in this application. In regards to potential cavity effects, AERMOD-COARE uses the same Plume Rise Model Enhancement (PRIME) algorithm as used in AERMOD for calculating impacts within a cavity zone. However, the issue is not relevant in this permitting action because the 500-meter safety zone precludes the need for modeling ambient impacts next to the Kulluk.

Comment R.6: Commenters state that the AERMOD-COARE model does not account for shoreline fumigation. The commenters also assert that it is not clear whether those conditions were included in any of the tracer data sets. The commenters contend that shoreline fumigation can cause higher short-term concentrations and that, given the proximity of the Kulluk’s operations to on-shore communities along the Beaufort Sea coast (14 kilometers from the closest lease block to Kaktovick), Region 10 must include an assessment of potential shoreline fumigation impacts on pollutant concentrations.

Response: Shoreline fumigation occurs when a plume from a tall stack travels in an over-water stable layer and reaches the land-sea interface, resulting in the plume being mixed down to the ground in an unstable layer. The commenters are correct that AERMOD-COARE does not account for shoreline fumigation and that shoreline fumigation can cause higher short term concentrations. In Shell's case, its stacks are not near the shoreline (greater than 3 miles or 4.8 kilometers) and the highest concentrations are predicted to occur closer to the Kulluk. In response to a Region 10 Second Information and Data Request dated March 7, 2011 asking Shell to address this issue, Shell responded as follows in a submittal dated March 11, 2011:

> Shell has presently made no provisions for this analysis within the COARE-AERMOD approach. However, it should be noted that the distance between the drilling locations and the shore where potential fumigation could occur is over 50 kilometers for all locations in the Chukchi Sea and for the Beaufort Sea, the locations are still on the order of many kilometers from any of the villages. The AERMOD model has no provision for fumigation calculations. Further AERMOD has no provision for the internal boundary and subsequent changes in mixing that might occur due to changes in land use for terrestrial applications. Given the long distances to the villages, it seems appropriate that the CALPUFF model should be used in the event EPA requests that this issue be addressed. The CALPUFF model does contain an algorithm for addressing fumigation or spatial changes in terrain, land use or meteorology in general. Another factor to be considered is that the real purpose of fumigation analyses is to treat cases where very elevated plumes are mixed rapidly to the ground when passing over a change in surface regime (i.e.; from stable to unstable boundary layers). The classic fumigation case is a power plant located on a coastline. For exploratory drilling sources, however, not only are the sources located far from the shoreline, but also, the plumes from Shell's sources are relatively low and would be expected to have reached the surface by the time they reach the shore.

Region 10 agrees that there was no need to address shoreline fumigation in connection with Shell's air quality analysis given the vessels and their locations at issue in this permit.

It is true that, in approving the model, Region 10 recognized that, "While AERMOD-COARE is acceptable to R10 for the current application in the Arctic marine ice free environment, it lacks two features found in OCD: platform building downwash and a shoreline fumigation algorithm. These two features should be coded into the AERMOD dispersion program for wider application in lieu of using OCD." Region 10 AERMOD-COARE Approval Memorandum, Section 3.2.2.e. That the AERMOD-COARE model currently does not account for shoreline fumigation is irrelevant for purposes of this permitting action, however, because the conditions giving rise to shoreline fumigation are not present in the project to be authorized in this permitting action.[14]

[14]Fumigation studies were conducted during the Carpinteria, California, tracer gas experiment on October 1, 3, 4 and 5, 1985. Bureau of Ocean, Energy Management, Regulation and Enforcement, Development of the Next Generation Air Quality Models for Outer Continental Shelf (OCS) Application, Final Report:

S. CATEGORY – PRORATING IMPACTS

Comment S.1: Commenters note Region 10's statement that:

> Shell prorated the period averages in order to estimate the annual average impacts. For example, to estimate the annual average NO_2, $PM_{2.5}$ or SO_2 impacts, Shell multiplied the 120-day average impact by 0.329 (120 drilling days out of 365 days in a year). Shell's approach for estimating the annual average impact is reasonable since the impact during non-drilling periods will be zero.

The commenters disagree that period averages can be prorated, particularly for pollutants such as NO_2 that have rolling 12-month emissions limits. The commenters contend that the permit cannot rely upon a 12-month period in which to demonstrate compliance with air quality standards and at the same time prorate those very same emissions. By allowing the prorating, commenters continue, Region10 is allowing Shell to average out the impacts of its air emissions twice. The commenters request that Region 10 update the permit analysis so that the impacts for NO_2, $PM_{2.5}$, and SO_2 are not prorated and then update any relevant permit conditions as necessary to ensure compliance with relevant standards.

Response: The use of the term "prorated" in the Technical Support Document has introduced some confusion about what Shell actually did. Shell modeled each of the 120 drilling days using the estimated emissions for each day. Shell did not model the remaining 245 days since there are no emissions from the Kulluk or the Associated Fleet during these days (*i.e.*, the modeled concentration would be zero). Therefore, multiplying Shell's period average by 0.329 (120 period days divided by 365 calendar days) provides the same annual average value as what would occur if one added 245-days worth of zeros to the 120-days worth of modeled concentrations, and then divided the total by 365 days. The equivalency is illustrated below, where the term "Sum" means the total modeled concentration over the 120 days that Shell modeled. As illustrated by these equations, the period average times 0.329 *is* the annual average concentration.

Shell then added the resulting annual average value to the annual average background concentration to determine the total annual average impact. Because the modeling approach reflects concentrations based on permitted emissions and provides estimates of

Volume I dated March, 2006. Hence, while Region 10 continues to believe that a shoreline fumigation algorithm is not needed in the modeling supporting this permit, a tracer gas experiment is available for a project proponent to evaluate shoreline fumigation when the situation arises.

the annual average impacts, Region 10 does not believe any additional modeling analysis is needed. The permit requirements ensure compliance with the relevant annual standards and use the appropriate averaging period for the modeling analyses. The fact that the annual emission limits are 12-month rolling limits does not in any way authorize Shell to operate outside of the five month drilling season. See response to comment I.1.b.

T. CATEGORY – METEOROLOGICAL DATA

Comment T.1: Commenters contend that Region 10's statement that Shell's Reindeer Island data are site specific data is not consistent with EPA's own guidance and past practice. According to the commenters, EPA guidelines state that site specific data are data collected on-site (citing to EPA, Ambient Monitoring Guidelines for Prevention of Significant Deterioration at 48 (May 1987)) and the data collected at Reindeer Island do not satisfy this condition because they are not within any of Shell's leases and do not represent open water conditions. The commenters contend that Region 10's own past statement confirms this understanding because many of these data Shell and Region 10 are relying on here were available in 2010 when Region 10 was considering Shell's Discoverer permit for the Beaufort Sea, yet Region 10 maintained that they were not site-specific or characteristic of the open Beaufort Sea. *See* 2010 Discoverer Beaufort Sea Statement of Basis at 102 ("Because meteorological data representative of the open Beaufort Sea was not available, Shell used screening meteorology").

Response: The meteorological measurements relied on in the modeling analyses include numerous site specific components that were supplemented as appropriate by representative National Weather Service (NWS) data, consistent with Section 8.3.3.2(c) of Appendix W to 40 CFR Part 51. The analysis included surface measurements of wind, temperature, delta-T, solar radiation, and pressure from Reindeer Island, buoy data from Reindeer Island and Sivulliq, profiler data from Endeavor Island, and NWS upper air data from Barrow.

At the outset, it is important to emphasize the unique challenges of collecting any data in this environment. Temperatures are extremely cold, winds can be strong, and the drilling operations are occurring miles offshore. This harsh, remote environment presents obvious challenges to the siting and installation of data collection instruments, the operation of those instruments, and the collection of complete, quality-assured data. The scale of the area in which activities are to be authorized under these permits is also unique. Shell's lease blocks in the Beaufort Sea cover an area of more than 1145 square miles. The sets of meteorological data used in these analyses were also designed to account for an issue of representativeness that is somewhat unique to this area, *i.e.*, the influence of ice vs. ice-free conditions on "over-water" dispersion.

The issue of representativeness of meteorological data is complex and its determination will depend on several factors, including the four factors listed in Appendix W: 1) the proximity of the monitoring site to the area under consideration; 2) the complexity of the terrain; 3) the exposure of the monitoring site; and 4) the period of time during which the data are collected. See 40 CFR Part 51, Appendix W. § 8.3(a). Representativeness may also vary greatly across different meteorological parameters. For example, upper air soundings used in calculating mixing heights are generally considered to be representative over a much larger geographical area than measurements taken near the surface. Among the surface meteorological parameters, representativeness can also vary significantly. For example, surface ambient temperatures (nominally measured between about 2 and 10 meters above ground) are generally representative over a larger area than surface wind speed and direction (nominally measured about 10 meters above ground).

Section 8.3(b) of Appendix W to 40 CFR Part 51 indicates that "[m]odel input data are normally obtained from the National Weather Service or as part of a site specific measurement program." Section 8.3.1.2 of Appendix W also recommends that "[t]he meteorological data should be *adequately representative*, and may be site specific or from a nearby NWS station" (emphasis in original). While Section 8.3.3.1(a) of Appendix W states that "[s]patial or geographical representativeness is best achieved by collection of all of the needed model input data in close proximity to the actual site of the source(s)," it further clarifies that "while site specific measurements are frequently made 'on-property' (*i.e.*, on the source's premises), acquisition of adequately representative site specific data does not preclude collection of data from a location off property. Conversely, collection of meteorological data on a source's property does not of itself guarantee adequate representativeness." Since Appendix W recommends in section 8.3.1.2(a) that meteorological data should be adequately representative, regardless of whether NWS or site specific data are being used, the main distinction between the two types of data is the length of record provided for in section 8.3.1.2(b), which states that "[t]he use of 5 years of NWS meteorological data or at least 1 year of site specific data is required. If one year or more (including partial years), up to five years, of site specific data is available, these data are preferred for use in air quality analyses."

The commenter's statement that site specific meteorological data must be collected "on site" because of EPA's PSD Ambient Monitoring Guidelines is simply incorrect. The guidance document cited by the commenters dates from 1987 and does refer to one year of "on site data" That guidance document has been revised on this issue, however, by revisions to Appendix W in 2003. Prior to promulgating those revisions, EPA solicited comment on the terminology and meaning of "site-specific'' meteorological data, and based on public comments subsection 9.3.3.1 (renumbered to section 8.3.3.1 in 2005) was revised "to clarify that, while site-specific measurements are frequently made 'on-property' (*i.e.*, on the source's premises), acquisition of adequately representative site-specific data does not preclude collecting data from a location off property. Conversely, collection of meteorological data on property does not of itself guarantee adequate representativeness." 68 Fed. Reg. 18,444, 18,446 (April 15, 2003). Specifically, the term "on-site" in reference to meteorological data has been removed from Appendix W. Because Appendix W modified the recommendations of the 1987 guidance after notice and comment and is the later statement from EPA on this issue, it is not true that site specific data must be collected on site.

The Reindeer Island station was specifically established to collect representative meteorological data for this permitting action and other Shell permitting actions in the

Beaufort Sea. Reindeer Island is located about 10 kilometers (roughly 6 miles) offshore and approximately 15 kilometers (roughly 10 miles) southeast of the nearest lease block where Shell is authorized to drill under this permit. The offshore distance is greater than the nearest offshore distance of some lease blocks. The Reindeer Island site is the most distant offshore meteorological station to date that has operated year-round in the extremely harsh Beaufort Sea environment. Given the lack of topographical influence, the minimal meteorological influence of the gravel bar itself, and wide homogeneous nature of offshore surface conditions, the station is representative of the meteorological conditions expected over an extremely large offshore area.

Region 10 recognizes that the distance between the Reindeer Island station and portions of Shell's proposed operations in the Beaufort Sea are far greater than in most other cases where monitoring sites have been considered to be site specific or representative. Region 10 believes that the scale of the area in general as well as the scale of the area over which operations are to be authorized under this permit are relevant and unique factors such that, in conjunction with the other factors discussed above, the data from Reindeer Island are appropriately considered both adequately representative and site specific within the meaning of Appendix W. One final point worth noting when considering the proximity and representativeness of the collected meteorological data in this permitting application is that there is less directional dependency in the modeling analysis in these applications as compared with most other cases since the modeled ambient air boundary distance is uniform (a circle of 500 meters from the hull of the Kulluk) and there are no directionally dependent terrain features near the source, thus limiting the importance of some of the key aspects of representativeness of wind direction in the modeling analysis.

Regarding the 2010 Statements of Basis for the Discoverer Permits referenced in the comment, although the data collection began in 2009, the complete measured meteorological data used in the Kulluk modeling analysis were not available to Shell for use at the time Shell submitted its Beaufort Sea application for the Discoverer on January 18, 2010. Consequently, for the Discoverer Permits, Shell used the ISC-PRIME model with screening meteorology and upper end scaling factors to derive averaging period concentration estimates for periods greater than one hour for compliance with the NAAQS. Region 10 has determined that a sufficient and adequately representative set of meteorological data are now available to support a refined dispersion modeling analysis using AERMOD, and therefore use of a screening technique is not necessary or appropriate for modeling the Kulluk and Associated Fleet.

Comment T.2: Commenters assert that Shell has not met minimum regulatory requirements for the amount of site specific meteorological data that Shell must obtain to demonstrate that Shell's operations will not violate air standards. The commenters point to 40 CFR Part 51, Appendix W, § 8.3.1.2, which Region 10 also cited in the Technical Support Document. That section states, under the heading "Recommendations," that "The use of 5 years of NWS data or 1 year of site-specific data is required."

Response: Shell's meteorological monitoring effort at Reindeer Island has been on-going since April 25, 2009, and Shell therefore had more than one year of site specific data to support its permit application and air quality analysis. See also response to comment T.1.

Shell only used the July through November portions of the meteorological data since they are only authorized to operate within this period. See Appendix W, Table 8.2, fn. 2 (discussing that if a source is subject to an enforceable limitation on hours of operation, only the hours of authorized operation are to be modeled with emissions from the source). Because the meteorological data is only used in connection with modeling emissions from the permitted source, meteorological data collected from times other than during the periods of authorized operation are not used in the modeling analysis. Region 10 believes that even if Shell did not have meteorological data for the periods they did not model (i.e., December through June), Shell would still have data of sufficient duration for purposes of Section 8.3.1.2(b) of Appendix W because the data collection period covers one year's worth of the period of authorized operation. In this case, five months worth of data covering July 1 through November 30 is one year of data within the meaning of that section. Since the permit only authorizes operations from July 1 to November 30, emissions and hence contributions to ambient air quality, will both be zero during the remainder of the year.

Comment T.3: Commenters state that the meteorological data Shell has collected do not meet the standard set by EPA's guidelines for the required time period because the buoy data only cover the period from mid-August to mid-October, meaning that Shell has no over-water data for July or November.

Response: Shell deployed the instrumented buoys during the open-water periods. Shell could not collect "over-water" data during those periods when there was no over-water data to be collected (*i.e.*, during those periods where there is no open water due to the presence of ice). It is important to note that while AERMOD-COARE requires the air-sea temperature difference and relative humidity data collected by the buoys, the Guideline version of AERMOD – which Shell used to estimate ambient impacts when sea ice is present – does not. Therefore, Shell collected the meteorological parameters needed by each model for those periods that the given model was used. Because Region 10 considers the data to be site specific, one year's worth of data is sufficient to support Shell's analysis. See the response to comments T.1 and T.3.

U. CATEGORY – BACKGROUND AIR MONITORING DATA

Comment U.1: Commenters question Region 10's initial assumption that the use of onshore data is "conservative" because "onshore monitoring stations will be influenced by local sources that are not present in the vicinity of Shell's offshore operations." The commenters explain that emissions from Shell's operations will be influenced by local sources which include the associated vessels that are stationed more than 25 miles from the drillship, barge and shipping traffic in the Arctic OCS, as well as scientific research vessels and accompanying ice breakers and other vessels. The commenters conclude that the presence of these local sources of offshore emissions undermines expectations that onshore data is automatically conservative. The commenters assert that this is an important consideration because the most conservative background data was not necessarily used for the modeling.

Response: Region 10 agrees that emissions from vessels operating in the vicinity of Shell's exploratory operations will contribute to the air pollution levels in the area. However, Region 10 disagrees that this would mean that the concentrations measured onshore would not be conservative for offshore locations where Shell will be operating under the permit. First, the Kulluk is a portable source and will be at different locations during any drilling season and during subsequent drilling seasons. It is not possible to determine where and for how long the Kulluk will be operating near other vessels in the area so trying to determine the background contribution of vessels operating near the Kulluk would be difficult. Second, other vessels will also be moving in relation to the Kulluk so their contribution to the ambient levels in the immediate vicinity of the Kulluk when it is at a drillsite will be transitory. The effect of these two overlapping scenarios, along with the statistical form of the relevant short-term NAAQS, is that the contribution to background concentrations from vessel activity at the location of the Kulluk's maximum impacts is expected to be minimal, if anything. The concentrations measured by the onshore background monitoring locations, however, are regularly impacted by nearby sources, including mobile sources and other fuel combustion sources, such as the villages' diesel generators. The concentrations at on onshore monitoring locations that are regularly impacted by nearby sources are expected to be significantly higher than the concentrations at a drillsite that would be occasionally impacted by passing vessels. Region 10 has therefore determined that the concentrations measured onshore at monitoring sites are conservatively representative of concentrations offshore at the project locations.

Comment U.2: Commenters assert that there is significant confusion in the permit record regarding the datasets used for different background concentrations, most notably the datasets for background concentrations of NO_2. The commenters refer to the air quality impact analysis for the draft permit in which Region 10 proposes using NO_2 data from the Prudhoe Bay A-Pad monitoring site as representative of background concentrations for both the 1-hour and annual NAAQS. The commenters also refer to Region 10's June 23, 2011 determination of background concentrations for the Beaufort Sea which states: "Since some of the lease blocks for the Kulluk permit are very near to the Prudhoe Bay area it was deemed appropriate to utilize the Deadhorse $PM_{2.5}$ data set for determining a background value and CCP for NO_2 and SO_2." The commenters contend that there is no further discussion about the NO_2 dataset from the Prudhoe Bay CCP monitoring site, and that the Region must use the CCP data if they represent a more conservative background dataset. The commenters state that annual average NO_2 concentrations from the CCP site are one and a half times higher than those monitored at the A-Pad location, and conclude that it is like that the hourly average concentrations are also higher. The commenters conclude that Region 10 must use the dataset with the highest monitored 1-hour average and annual average NO_2 concentrations, particularly for the1-hour average NAAQS if the modeling will be based on an analysis of data paired in time.

Response: As Region 10 explained on page 29 (footnote 7) of the Technical Support Document, the monitoring site ultimately used for the NO_2 analysis (A-Pad) is different than the site recommended in the June 23, 2011 memo (CCP). The requirements for the background data used in an air quality modeling analysis are described in Section 8.2 of the Guideline on Air Quality Models (40 CFR Part 51, Appendix W). There is no requirement that the data be conservative and there is certainly no requirement that it must be the most conservative of available data. In this case, there is no offshore ambient air data, so an onshore site was used to represent the background concentrations expected within the vicinity of the Kulluk lease blocks. However, as discussed below and in the response to comment Y.2, the onshore monitoring site used in this analysis is expected to be impacted by similar natural and distant man-made sources, but more heavily impacted by the local sources than what would likely occur at the project locations. As such, Region 10 believes that it is conservatively representative of the background concentrations at the project location.

The requirements for the background data used in an air quality modeling analysis are described in Section 8.2 of the Guideline on Air Quality Models (40 CFR Part 51, Appendix W). Section 8.2.2.b and c provide:

> b. Use air quality data collected in the vicinity of the source to determine the background concentration for the averaging times of concern….
> c. If there are no monitors located in the vicinity of the source, a "regional site" may be used to determine background. A "regional site" is one that is located away from the area of interest but is impacted by similar natural and distant man-made sources.

The A-Pad and CCP monitoring sites are located in close proximity to the onshore sources in the Prudhoe Bay area so both are conservatively representative of offshore concentrations at the Kulluk lease blocks. Background concentrations from both locations reflect contributions from the onshore sources in varying amounts depending upon their location with respect to those onshore sources. The CCP monitor is located within 100-meters of the CCP facility, which has just over 14,000 tpy of potential NO_x emissions. The adjacent CGF facility (which is part of the CCP/CGF stationary source) has almost 11,000 tpy of potential NO_x emissions. The air quality impacts of these facilities are also strongly dominated by downwash of the plumes, which leads to the maximum impacts occurring in the immediate area. This conclusion can be deferred from existing documentation regarding this monitoring effort and source. For example, the Quality Assurance Project Plan (QAPP) for the CCP and A Pad monitoring stations states:

> The CCP monitoring site is located between the Central Compressor Plant and the Central Gas Facility; approximately 100 meters west and southwest of the CCP [reference to figures]. This site is located at or near the point identified by dispersion modeling as the maximum NO_2 impact receptor…"

Quality Assurance Project Plan for the Prudhoe Bay Unit Facilities Ambient Air and Meteorological Monitoring Project, February 2011, at 27.

As another example, in the Technical Analysis Report (TAR) issued for Construction Permit AQ0270CPT04 (CGF) and AQ0166CTP04 (CCP), ADEC stated, "The maximum cumulative impacts (for the given H_2S and fuel-sulfur assumptions) occur in the CGF/CCP near-field" (Exhibit B, pg 14). While the statement related to H_2S related impacts, the same finding would be true for NO_x impacts since combustion-related plumes do not vary by pollutant.

The CCP monitoring station was therefore sited close to the CCP/CGF facilities in order to capture the maximum impact of these facilities. As such, CCP data would be overly conservative for representing the background concentrations at offshore locations. Even the A-Pad monitoring site, which Region 10 relied on, is expected to be a conservative representation of the background air quality concentration at the offshore locations where Shell will be operating.

Comment U.3: Commenters express concern about the use of different background concentrations for the Shell Beaufort Discoverer and Shell Kulluk permits, and express support for use of the Kulluk permit datasets which the commenters state are more conservative. The commenters provided the following table to show the difference in background values between multiple permits:

Table 8: Information from "EPA Region 10 Determination of Appropriate Background Values for the Chukchi and Beaufort Sea OCS Permits" (June 23, 2011)

	Shell Kulluk	**Shell Discoverer Beaufort**	**ConocoPhillips Jackup Rig**	**Shell Discoverer Chukchi**
PM2.5 24hr	Deadhorse	Badami	Wainwright permanent	Wainwright permanent
PM2.5 annual	Deadhorse	Badami	Wainwright permanent	Wainwright permanent
PM10 24 hr	Prudhoe Bay CCP	Prudhoe Bay CCP (Same as Kulluk)	Wainwright permanent	Wainwright permanent
NO2 1 hr	Prudhoe Bay A Pad	Badami	Wainwright temporary	Wainwright temporary
NO2 annual	Prudhoe Bay CCP (text) Badami (chart)	Badami	Wainwright temporary	Wainwright temporary
SO2	Prudhoe Bay CCP	SDI	Wainwright temporary	Wainwright temporary
CO	SDI	SDI (same as Kulluk)	Wainwright temporary	Wainwright temporary
O3	No information	No information	No information	No information

The commenters provided the following table to show the different background concentrations used for the Kulluk and Discoverer:

Table 9: Comparison of Background Concentrations from Maximum Modeled Impact Charts from the Kulluk and Discoverer Statement of Bases

Air Pollutant	Shell Kulluk	Shell Discoverer Beaufort
NO2 1hour	41	9
NO2 annual	11	1
PM2.5 24-hour	17	6
PM2.5 annual	4	3
PM10 24-hour	53	53
SO2 1-hour	29	13
SO2 3-hour	29	11
SO2 24-hour	22	4
SO2 annual	4	2
CO 1-hour	1,742	1,742
CO 8-hour	1,094	1,094

The commenters contend that Region 10's justification for the use of different data is unconvincing. Commenters reference a Region 10 statement that “some of the lease blocks for the Kulluk permit are very near to the Prudhoe Bay area” making it “appropriate to utilize the Deadhorse PM2.5 data set.” However, the commenters contend, the lease blocks that were “removed from [the Kulluk] application” are those that are closest to Prudhoe Bay, while some of those same lease blocks (lease blocks 6562, 6512, 6510) are still included the draft Discoverer Beaufort permit. Therefore, the commenters conclude that Region 10 should have used the Prudhoe Bay data for both the Kulluk and the Discoverer Beaufort permits.

Response: The comments regarding the data used for the Discoverer permits are not relevant to this permit action and Region 10 is therefore not responding to them in this action. The Discoverer permits and this action are separate permitting actions, covering different lease areas, and supported by separate analyses.

Region 10 did rely on the Prudhoe Bay data for the Draft Permit and therefore there is no need to respond to these comments in this permit proceeding. Region 10 does want to note that lease blocks 6562, 6512, and 6510 are included in both the Discoverer and Kulluk permits (they were not removed from the Kulluk permit). These three lease blocks are the closest lease blocks to the Prudhoe Bay area included in the Discoverer permit and they are over 80 kilometers from Deadhorse. The Kulluk Permit, however, authorizes Shell to drill on lease blocks which are as close as 44 kilometers from Deadhorse, and 42 kilometers and 35 kilometers, respectively, from the A-Pad and CCP monitoring sites (which sites are almost 100 km from the leases included in the Discoverer permit).

Comment U.4: Commenters express support for the use of the highest dataset to represent background concentrations because modeling must be based on a worst-case scenario in order to allow for the flexibility in the sources used by Shell, and because the background concentrations must represent secondary pollutant formation and other offshore background sources that are not modeled. The commenters state that these background offshore sources include significant shipping traffic in the area, the associated fleet when it is beyond 25 miles from the drillship, and emissions associated with the Kulluk and Associated Fleet before the Kulluk is determined to be an OCS source. The commenters believe that Region 10 must use the highest values as representative of background concentrations and must not exclude certain days in a monitoring record that may be due to onshore sources (e.g., emissions events due to wind-blown dust, fire, etc.). The commenters state that Region 10 is using $PM_{2.5}$ data from Deadhorse "to better account for the potential impacts from existing onshore sources," but discounts days with high recorded concentrations due to these events such as wind-blown dust and fire. The commenters conclude that if high value concentrations are discounted, Region 10 must include impacts from the additional offshore sources that are not included in the background concentrations monitored onshore.

Response: Region 10 disagrees with the commenter that an ambient air quality impact analysis must use the highest background concentrations from any monitoring site across a broad area or that it must be based on a worst-case scenario. Such conservative assumptions may be appropriate for a screening analysis, but they are not necessary for a refined impact analysis where more representative background concentrations and more reasonable operating scenarios are appropriate. As stated in the Technical Support Document (pages 28-29), Region 10 believes that any of the onshore monitoring sites are conservatively representative with respect to the concentrations we expect to see at the offshore locations where the maximum impacts from Shell's operations would occur. The choices as to which onshore sites were used as background in the Kulluk modeling analysis were not based on the relative concentrations at each site but rather on which sites would best represent the contributions of existing (onshore) sources which were not explicitly included in the modeling analysis. Finally, although Shell excluded days in calculating the background concentrations for its analysis, the Deadhorse $PM_{2.5}$ background values that Region 10 ultimately used in its impact analysis did not exclude any days with events such as wind-blown dust or forest fires. All valid data was included in the calculation of the $PM_{2.5}$ design values reflected in the Technical Support Document and Section 4 of the Statement of Basis. Memorandum from Christopher Hall, Region 10, to Herman Wong, Region 10, re: EPA Region 10 Determination of Appropriate Background Values for the Chukchi Sea and Beaufort Sea OCS Permits, dated June 23, 2011 (Background Data Memo).

Comment U.5: Commenters note that a Quality Assurance Project Plan (QAPP) was approved for the monitoring station in Kaktovik in May-June of 2011. The commenters request a comparison between the datasets from the Badami and Endicott monitors, and the data from the Kaktovik monitor to determine whether the Badami and Endicott data sets accurately represent background concentrations of air pollutants in Kaktovik. The commenters also request a similar comparison of the recent air quality monitoring data collected from Nuiqsut.

Response: Even though a QAPP was approved for the Kaktovik monitoring station in May-June 2011, the site did not begin collecting data until July 1, 2011. The site does not have data yet for a complete drill season or a calendar year, so there is not enough data to use in a NAAQS analysis. Only a few weeks of data would have been available at the time Region 10 proposed the Draft Permit even if it had been submitted to Region 10 for review. With respect to monitoring data from a site operated by ConocoPhillips at Nuiqsut, this data has not be submitted to Region 10 for review or use in a regulatory analysis.

Comment U.6: Commenters express concern that the most conservative data from the North Slope is not being used. The commenters cite as an example data from Point Lay which the commenters characterize as showing much higher background levels of certain pollutants.

Response: Both Wainwright and Point Lay are on the Chukchi Sea, not the Beafort Sea. The data that was used in the Chukchi Sea (presumably for the Discoverer PSD permits) is not relevant to the air quality impact analysis for the Draft Permit, which only authorizes operations in the Beaufort Sea. This comment appears to relate to the recently issued permit for the Discoverer and, as such, Region 10 is not responding to it here.

V. CATEGORY – AIR QUALITY ANALYSIS FOR 1-HOUR NO_2 NAAQS

V.1 SUBCATEGORY – IN GENERAL

Comment V.1.a.: Commenters state that the new 1-hour NO_2 NAAQS was set at a level recognizing the substantial body of scientific evidence demonstrating that the previous annual NO_2 NAAQS was alone sufficient to protect human health. The commenters also state that short term spikes in NO_2 concentrations are associated with a range of negative human health effects. The commenters note that the new 1-hour NO_2 NAAQS includes a new "form" for the standard that is based on the 3-year average of the 98^{th} percentile of the yearly distribution of 1-hour daily maximum concentrations. The commenters conclude that Shell has not demonstrated that it will comply with the 1-hour NO_2 NAAQS and that Region 10 therefore cannot issue the permits.

Response: As discussed in Section 4 of the Statement of Basis and in the Technical Support Document, when operating in compliance with the terms and conditions of this permit, emissions authorized under the permit will not cause or contribute to a violation of the NAAQS, including the NO_2 NAAQS. The NAAQS are health-based standards, set at a level to protect public health with an adequate margin of safety, including sensitive populations such as children, the elderly, and asthmatics.

Comment V.1.b: Commenters acknowledge EPA's new "data handling conventions for NO_2" whereby NAAQS compliance is "based on the 3-year average of the 98^{th} percentile of the yearly distribution of 1-hour daily maximum concentrations," but assert that the new data handling convention is specific to determining "area-wide" compliance with the revised NAAQS. The commenters contend that there is no basis in the Clean Air Act or the new standard itself for the permitting approach that Region 10 has adopted here which allows a proposed new source to discount its highest projected impacts. The commenters conclude that such an approach ignores both the importance of the absolute value of the NAAQS standard—which they assert must be set at the requisite level to protect human health—as well as the Title V requirement that a proposed permit include sufficient conditions to prevent a NAAQS exceedance, citing to CAA § 165(c) and (e), 40 CFR §§ 71.2, 71.6(c)(a)(1) and 71.6(e)(1).

Response: The commenters appear to be arguing that a source must demonstrate that the impact of its emissions does not exceed the level of the NAAQS. Region 10 disagrees with this position.

Shell's modeling analysis for the 1-hour NO_2 standard is consistent with the form of the NAAQS and EPA guidance on demonstrating compliance with the 1-hour NO_2 NAAQS. See Memorandum from Stephen Page, OAQPS, re: Guidance Concerning the Implementation of the 1-Hour NO_2 NAAQS for the Prevention of Significant Deterioration Program, dated June 29, 2010 (June 2010 1-hour NO_2Modeling Guidance); Memorandum from Tyler Fox, OAQPS, re: Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-Hour NO_2 NAAQS, dated March 1, 2011 (March 2011 1-Hour NO_2 Modeling Guidance). The commenters have provided no specific information showing how Shell's approach "discount[ed] its highest projected impacts" in a manner that is inconsistent with the form of the NAAQS.

Although it is true that the modeling showed individual 1-hour impacts higher than the 100 ppb (188 $\mu g/m^3$) level of the 1-hour NO_2 NAAQS, the 98th percentile point of the annual distribution of daily maximum 1-hour concentrations does not exceed 100 ppb (188 $\mu g/m^3$) at any location that constitutes ambient air. The commenters cite to CAA § 165 and 40 CFR §§ 71.2, 71.6(c)(a)(1) and 71.6(e)(1) in support of their argument that the permittee must demonstrate that the level of the NAAQS is not exceeded. The cited statute, however, applies to issuance of PSD permits, not to Title V permits such as this, and the regulation promulgated by EPA to implement that statutory provision plainly states that a source must demonstrate that it will not cause or contribute to "a violation of" any NAAQS, and does not refer to "an exceedance." See 40 CFR § 52.21(k)(1). The Title V regulations cited by the commenters do not support the commenters position, and the commenters have provided no other information to support their contention that, for an air quality analysis submitted in connection with a Title V permit application or an Alaska minor source permit application, the applicant must establish that they will not cause or contribute to ambient concentrations that exceed the level of a NAAQS.

Comment V.1.c: Commenters state that Shell has understated maximum 1-hour NO_2 impacts by failing to accurately calculate the multiyear average of the 98th percentile of the annual distribution of daily maximum 1-hour values. The commenters continue that EPA estimated that, when evaluating the measured concentrations for a year's worth of monitoring data, the 98th percentile would be equivalent to the 7th or 8th highest daily maximum for the 365-day period. In calculating its compliance with the 1-hour NO_2 standard, the commenters assert, Shell selected the 8th highest daily maximum but that this is an underestimate of the true 98th percentile associated with its operations because Shell's drilling season is only 120 days long, and it modeled only that many days. The commenters conclude that selecting the 8th highest daily maximum from 120 days corresponds roughly to the 93rd percentile, not the 98th percentile, and that Shell has therefore failed to demonstrate that its proposed operations will not cause a violation of the NAAQS.

Response: Region 10 continues to believe that the air quality analysis performed by Shell in connection with the 1-hour NO_2 NAAQS is consistent with 40 CFR Part 51, Appendix W (Guideline on Air Quality Models) and EPA guidance for implementing the 1-hour NO_2 NAAQS. In practice, a modeling analysis performed for the 1-hour NO_2 NAAQS can generally be summarized as a three step process involving the collection and preparation of appropriate background data, pairing background data with modeled impacts, and finally comparing the resulting total concentration to the NAAQS. Because the form of the 1-hour NO_2 NAAQS is the 3-year average of the 98th percentile of the daily maximum 1-hour averages, there can be a certain number of hourly values each year that exceed the NAAQS threshold. In Shell's analysis, two years of monitoring data are available and one year of modeled results are available and were used in the modeling analysis.

For the first step, Shell calculated diurnal hourly background values (that is, a background value for each hour of day) for the drilling season (a 5 month period) using background monitoring data collected in 2009 and 2010 for the Beaufort Sea. Shell took all available hourly NO_2 data during the drilling season period for a particular hour and calculated, for that hour, the 98th percentile NO_2 concentration recorded for that hour in each of the two years of available monitoring data. 40 CFR Part 50, Appendix S, Table 1 prescribes the rank associated with the 98th percentile value based on the number of available valid samples within a period.[15] Following this procedure for determining a 98th percentile of the monitoring data for each hour, Shell used a 2nd, 3rd or 4th high, depending on the number of available data points, to determine the hourly 98th percentile value (*i.e.*, if 153 hourly values were available, the 4th high represented the 98th percentile for this hour, while a data set with only 100 hourly values would use the 2nd high to represent the 98th percentile for that hour). For each hour, the 98th percentile result for each year is averaged and this average hourly value is then used to pair with the respective modeled result for that hour. The result of this approach is a generic day's worth of NO_2 background data that represents the 98th percentile value for each hour in a drilling season. Results of this procedure are found in a spreadsheet entitled "Shell_Diurnal_NO2_Background_Kulluk_04182011-stats.xls" submitted by Shell's consultant on May 4, 2011. The spreadsheet was part of a larger submittal transmitted under a technical memorandum entitled "UPDATES TO AIR QUALITY IMPACT ANALYSIS – KULLUK DRILLSHIP." Region 10 determined that this approach

[15] The 1-hour NO_2 standard is based on the 98th percentile (8th highest) of the annual distribution of maximum daily 1-hour values. March 2011 1-Hour NO_2Modeling Guidance at 1, fn. 1.

followed EPA guidance and provides a representative monitored hour by season diurnal profile for the drilling season.

For the second and third steps, Shell paired, for each modeled hour and receptor location (again, over a 5 month period), the result of the modeled impact with the hourly monitored background value for that hour calculated in step 1 above. The highest hourly total concentration (paired modeled and monitored impact) in a calendar day was then calculated, and the 8^{th} highest paired modeled/monitored impact for each receptor was used to compare with the NAAQS. Using the 8^{th} highest value that occurred over the 5 month drilling season is appropriate because emissions from Shell's operations during periods other than the drilling season are zero (so the total concentration consists only of the background value, yet the form of the standard is a 3-year average of the 98^{th} percentile daily 1-hour maximums). The time period during which no drilling will be occurring is therefore considered in determining the annual 98^{th} percentile value for each year and the 3-year average of annual 98^{th} percentile values, but, because there will be no emissions from Shell's operations in the total concentration during the periods of no drilling, the 8 highest total concentrations for a given year are not predicted to occur during this period, but instead are predicted to occur during the drilling season for that year. In other words, although there are 365 days used in the 98^{th} percentile calculation, the majority of these days (7 months worth) will have no Shell impacts because Shell is not permitted to operate outside of the 5 month drilling season. Because of this, the 8 highest values, and thus the 98^{th} percentile value, are all days that fall within the drilling season. The commenters have not identified any day outside of the drilling season that would have had a higher total concentration than the 8^{th} highest total concentration during the drilling season.

In summary, Region 10 disagrees with the commenters that selecting the 8^{th} highest daily maximum from 120 days corresponds to the 93rd percentile, not the 98^{th} percentile. For the monitored background data, Shell was required to use a 2^{nd}, 3^{rd}, or 4^{th} high value depending on the available data because the monitored data relied on in the modeling analysis consisted of less than a year (approximately 5 months). For the modeled impacts, which are paired with the monitored data, however, Shell appropriately used the 8^{th} high modeled-plus-background value, which is the 98^{th} percentile among the 365 days of the year (the timeframe averaged as part of the standard) and evaluated this value against the NAAQS. This approach is consistent with EPA guidance for the 1-hour NO_2 standard. March 2011 1-Hour NO_2 Modeling Guidance at 2 (discussing the procedure for demonstrating compliance with the NAAQS) and 17-21 (describing the appropriate methodology for incorporating background concentrations into a 1-hour impact analysis).

It is important to note that there are several conservative assumptions that will likely result in substantially lower total concentrations than those predicted by the model. One such assumption is that the modeling assumed the Kulluk will be located at the same drill site for the entire three year period considered in the modeling analysis for the 1-hour NO_2 standard. In the more likely event that Shell will be operating at a different drill site in each of the three years (and possibly more than one drill site in each year), the expected 3-year average of the 98^{th} percentile concentrations at each drill site would be much lower. Another conservative assumption underlying the modeling analysis is the fact that the background data used to represent offshore conditions was collected onshore, where it is influenced by local sources. See response to comments in Category U.

Comment V.1.d Commenters contend that Region 10 has failed to ensure that Shell's modeling assumptions reflect actual operating conditions because Shell does not establish that its modeling captures all realistic combinations of allowable operations, background levels, and meteorological conditions that may result in maximum impacts. In modeling its effect on 1-hour NO_2 standards, the commenters assert, Shell assumes a perfect choreography of closely-timed events and favorable conditions and lines up events and conditions in an unrealistically precise manner by varying—for every hour of its proposed 2,880 hours of operation— meteorological conditions, background concentrations, and fleet operations. This method of modeling operations, the commenters continue, is therefore likely not representative of actual operating conditions, does not capture a full, realistic range of potential operations and conditions, and is vulnerable to missing maximum impacts. Thus, the commenters conclude, Shell has not demonstrated compliance with applicable standards, including the 1-hour NO_2 NAAQS. For example, the commenters state that Shell has used day to day meteorological conditions from 2009 and 2010 to determine the future positions of its ships hour by hour, rotating its vessels in accordance with the wind direction from those prior years, but that it is unlikely the wind will behave in the same manner on a daily basis in future years and that by shifting the position of its vessels, Shell could be diluting concentrations in a way that masks even greater impacts. For example, the commenters continue, Shell will miss maximum 24-hour $PM_{2.5}$ impacts if Shell assumes the ships will be shifting position every hour when in fact the wind is steady and the vessels operate in one position. The commenters assert that Shell's modeling should be based instead on scenarios in which meteorological conditions, background concentrations, and vessel operations combine to maximize impacts and reproduces the full range of operating scenarios and impacts.

Response: Region 10 believes the combinations of operating conditions modeled by Shell accurately reflect the expected emissions that will occur with the permitted operations. It is not possible to model all potential combinations of emissions scenarios, thus the need to select conservatively representative emissions scenarios that conform to the permitted emission rates.

Region 10 carefully reviewed the emissions scenarios and required several model iterations using two different drilling start times such that all hours during the drilling season are accounted for. While Region 10 acknowledges the actual operations will not exactly mirror what was modeled, the approach taken is expected to conservatively represent permitted emissions during a drilling season. The comment does not identify any realistic range of potential operations and conditions that have not been captured in the conservatively representative emissions scenarios used in the modeling supporting these permits.

Region 10 also disagrees that there is a "perfect choreography of closely-timed events and favorable conditions" and that Shell's modeling "lines up events and conditions in an unrealistically precise manner." The emissions sequences used in the modeling reflect the general sequence of drilling operations as they would be expected to occur. Obviously, the sequence will not exactly mirror that modeled but the general order is correct and reflective of what is allowed in the permit. The other conditions the commenters discuss, such as lining up meteorological and background values, are reflective of actual collected data which, when coupled with conservative assumptions, such as orienting the Associated Fleet with hourly modeled wind direction and using emission release characteristics based on actual meteorological conditions, result in a conservative analysis which has demonstrated compliance with the NAAQS. The meteorological data relied on by Shell adequately reflects representative meteorological conditions. Applicants are not required to demonstrate compliance under non-representative conditions. The commenters present a hypothetical concern regarding persistent wind directions, but they do not provide information showing that this concern is realistic and, if so, whether it is a condition that was not represented in the modeled data set. Moreover, the wind roses provided in Shell's application shows the frequency of winds from any given direction. See Permit Application Supplement, Figure 3-5, at 61. As shown by these figures, the meteorological data used by Shell contains frequent easterly winds. Therefore, the concern expressed by the commenters was in fact, addressed in Shell's modeling analysis.

Moreover, as discussed in response to comment V.1.c and V.2.b, there are several other conservative assumptions underlying the modeling that are not related to the operating scenarios. These assumptions, in conjunction with the reasonable operating scenarios modeled by Shell, make it very unlikely that actual impacts will in fact cause or contribute to a violation of the NAAQS.

Comment V.1.e: Commenters state that Shell has not demonstrated that it will comply with the health based standards for NO_2 and that Shell's own modeling shows that its operations could cause pollution levels to reach 81% of allowable concentrations of NO_2 The commenters also note that high levels can cause breathing problems, particularly asthma, and impacts the elderly and small children.

Response: See response to comment V.1.a. By stating that Shell's modeled emissions (which in this case include background concentrations) could cause pollution levels to reach 81% of allowable 1-hour concentrations of NO_2, the commenters appear to concede that emissions from Shell's proposed operations will not cause or contribute to a violation of the 1-hour NO_2 NAAQS.

Region 10 also notes that in its permit application Shell requested an aggregate limit for the three Kulluk deck cranes. However, the modeling initially provided by Shell did not support aggregate limits. During the public comment period, Shell again requested an aggregate limit for the Kulluk deck crane engines and provided modeling to support this request. This modeling, which was reviewed by Region 10, showed a minimal increase in the maximum modeled concentration to 86% of the 1-hour NO_2 NAAQS. This change does not increase the source's potential to emit. For additional discussion of the modeling and revised limit see response to comment HH.4.

V.2 SUBCATEGORY – BACKGROUND DATA FOR 1-HOUR NO_2/ USE OF PAIRED DATA

Comment V.2.a: Commenters note that Shell used day-to-day meteorological conditions from 2009 and 2010 to determine the future positions of its ships, rotating its vessels in accordance with wind direction from those prior years. The commenters state that the wind will not behave in the same manner on a daily basis in future years, and that by shifting the position of the vessels, Shell could be diluting concentrations in a way that masks even greater impacts. As an example, commenters state that Shell would miss maximum 24-hour $PM_{2.5}$ impacts if it assumes the ships will be shifting position every hour, when in fact the wind is steady and the vessels operate in one position.

Response: While Region 10 acknowledges the actual operations will not exactly mirror what was modeled, the approach taken is expected to conservatively represent permitted emissions during a drilling season. The commenters present a hypothetical concern regarding persistent wind directions, but they do not present information showing that this concern is realistic and, if so, whether it is a condition that was not represented in the modeled data set. See response to comment V.1.d.

Comment V.2.b: Commenters state that Shell has understated 1-hour NO_2 impacts by using background data in a manner that understates health and environmental risks and does not demonstrate compliance with the 1-hour NO_2 NAAQS because Shell has used background ambient air data in a manner that systematically understates the impact of its operations. The commenters contend that Shell has neglected to use the highest background pollution levels measured in the vicinity of its proposed operations and has instead adjusted background ambient air data by using multiyear averages of the 98th percentile background concentrations for each hour of the day. The commenters argue that Shell has made two downward adjustments: in addition to discounting the highest concentrations caused by its operations, Shell has assumed that such concentrations will not occur at a time when background concentrations are at their highest observed levels. The commenters contend that this has the effect of "compounding" the 98th percentile adjustment, thereby understating the true maximum impacts that may occur as a consequence of Shell's operations. Although acknowledging that EPA has indicated that this technique may be appropriate in some circumstances, the commenters contend that this guidance is not consistent with the 1-hour NO_2 standard itself, which they claim is evaluated with a single adjustment for the 98th percentile, and that even that adjustment may not be applicable to this permitting action. According to the commenters, Shell's manner of selecting 1-hour NO_2 background data for use in its model disregards the highest possible background levels, underestimates the true maximum impact of Shell's operations, and fails to demonstrate that it will not cause a violation of air quality standards.

Response: The 98th percentile of the monitored background concentrations based on the Deadhorse monitors along the Beaufort Sea is a conservative estimate of the background levels at the location of the 98th percentile of the modeled concentrations, and therefore provides a conservative estimate of cumulative NO_2 impacts from Shell's operation. Using background concentrations from onshore monitors is a conservative estimate of offshore NO_2 concentrations, where Shell's operations will be located because the onshore monitors are influenced by local sources. See responses to comments in Category U.

The modeled to monitored pairing approach is also appropriate as there may be changes in NO_2 values throughout the season or time of day. Take, for example, space heating using propane or diesel, which will occur more during the colder months than in the 5 month season of July through November when operations are authorized under the permits. Combustion of propane or diesel for space heating may cause higher monitored NO_2 values in onshore locations (and thus higher background values reflected in the background monitoring data incorporated into Shell's analysis), and this may occur during the 7 month period Shell is not authorized to operate under the permit. Conversely, there may be more activity of other types during the summer months associated with NO_2 emissions. If this is the case, this should be reflected in the background monitoring data incorporated into the modeling analysis. These simple examples help illustrate why, consistent with EPA guidance on modeling for the 1-hour NO_2 NAAQS, using a seasonal monitored value is appropriate for this NAAQS standard. A similar argument will hold for hourly readings during the day. At any one time, a monitor may be impacted by a single source. For that impact to occur and be captured by the monitor the wind has to move or transport the emissions from the source to the monitor. At this point in time the monitor may read a high value, but another location in the vicinity may be experiencing no impacts. By using an average 98th percentile by hour of the day, Region 10 is attempting to account for systematic variations in activities and transport that may be occurring and that would lead to a higher or lower monitoring concentration in any one hour. Region 10 is also attempting to use an appropriate background monitoring value for the entire offshore modeled area. The averaging approach by hour and season used by Shell provides a more realistic but still conservative background value to use for such a large area.

It is also important to consider the form of the standard, which is based on probability. The modeling/monitoring pairing approach used by Shell uses a background concentration for all receptors, again, that is based on a two-year average of the annual 98th percentile value by hour and season. In reality, the actual NO_2 monitoring data indicates there are many hours with zero monitored concentrations. So the pairing approach Shell has used is already increasing the probability of a high modeled value corresponding to a relatively high background value, when in reality the actual monitoring values show many hours of zeros. When this pairing approach is coupled with other assumptions, such as the Kulluk remaining at a single drill location for 3 years, which also increases the probability of high modeled results at a receptor, the end result is a conservative analysis. Even with these conservative assumptions, the analysis has demonstrated that the NAAQS is protected.

Finally, there is no requirement that even a PSD modeling analysis for compliance with the NAAQS be based on "the true maximum impacts that may occur," and using the overall highest 1-hour monitored 1-hour NO_2 concentration as a background value would be overly conservative in this case. Region 10 strongly disagrees with the commenter that compounding adjustments have occurred which will understate the potential maximum impacts. Region 10 believes instead that it is more likely that compounding assumptions actually increase the probability that the analysis Shell submitted would overstate actual impacts at any single receptor. These assumptions include such things as a single well location for three years, having the Associated Fleet always aligned with the prevailing wind directions, not averaging across three years of meteorological data, and using onshore monitoring data to represent overwater locations while using a diurnal pattern of background monitoring values for all hours when monitoring shows many hours of lower concentrations. All of these assumptions compound to form an analysis weighted towards conservatism. See also responses to comments V.1.c, V.2.b, and U.2.

Comment V.2.c: Some commenters support Region 10's decision not to allow a $PM_{2.5}$ modeling analysis that pairs modeled data with monitored data (in time) to determine compliance with the NAAQS, and contend that EPA has in the past said, that pairing data does not ensure protection of the air quality standards, citing to a letter from EPA Region 8. The commenters assert that this approach is needed to ensure that a violation will not occur in the future, not simply to determine that a violation occurred over the period of time modeled. The commenters state that even in recently allowing limited, case-by-case situations where paired data can be modeled to demonstrate compliance with the 1-hour NO_2 NAAQS, EPA is admitting that this type of analysis results in "a less conservative" estimate of impacts, citing to EPA's March 1, 2011 NO_2 Modeling memo. Although these commenters support Region 10's decision not to allow pairing of NO_2 data as Shell originally proposed (*i.e.*, hour-by-hour pairing of modeled concentrations with background concentrations), the commenters do not agree that the diurnal pairing of the 2-year average of the 98^{th} percentile NO_2 concentrations by hour (based on the number of samples) between July 1 and November 30 with corresponding modeled concentrations for that hour is protective enough of the NAAQS. The commenters state that a more protective approach would be to use the 98^{th} percentile of the annual distribution of daily maximum 1-hour average values averaged across the 2-year meteorological data period used in the dispersion modeling and that a more conservative approach is warranted in this case given the fact that the modeling is not based on source specific data and Shell may be under-predicting impacts. The commenters conclude that the use of diuernal pairing results in a less conservative analysis and, given that modeling is based on generic source parameters, this approach does not seem warranted.

Response: The pairing approach used in the 24-hour $PM_{2.5}$ modeling analysis uses the maximum modeled 24-hour $PM_{2.5}$ concentrations averaged over modeled drilling seasons 2009 and 2010, and this value is paired with a representative 98^{th} percentile monitored background concentration for evaluation against the NAAQS. This approach follows EPA guidance and is conservative.

Concerning pairing for the 1-hour NO_2 standard, Region 10 acknowledges the approach taken is potentially "a less conservative" approach than using the 98^{th} percentile annual distribution. The Region believes the approach taken, however, is still protective of the NAAQS and is consistent with EPA guidance. The commenters also fail to address the difference between the two standards, mainly the averaging period of 1-hour versus 24-

hours, and offer no explanation why the pairing approach used for the 1-hour NO_2 standard is not valid and conservative. In addition, it is appropriate to account for diurnal (daily) and seasonal patterns in pairing modeled concentrations with monitored background concentrations. Pairing the 98th percentile of the annual background with the 98th percentile modeled contribution, irrespective of these diurnal or seasonal patterns, may impose additional conservatism that is not warranted. The seasonal pattern is especially relevant in this case because the permits limit operations to a defined period (or season.) Please also see response to comments V.3.a and V.3.b.

V.3 SUBCATEGORY – NO_2/NO_X RATIO

Comment V.3.a: Noting that that the Plume Volume Molar Ratio Method (PVMRM) algorithm used in the ambient analysis to determine the atmospheric conversion of NO_X to NO_2 requires estimates of in-stack ratios of NO_2/NO_X, some commenters assert that these in-stack ratios appear to be important parameters in the modeling. The commenters go on to state that Region 10 must therefore ensure the ratios used are protective of the NAAQS since small changes to the ratios used could have a significant impact on modeled concentrations. The commenters contend that this is especially important in this case given the fact that Shell is requesting approval for the least-conservative options for modeling 1-hour NO_2 impacts (*i.e.*, using the non-regulatory-default PRVRM option – a Tier 3 application under Section 5.2.4, App W that requires Regional approval – and pairing NO_2 data in time.

Response: While EPA has placed greater emphasis on the in-stack NO_2/NO_X ratios required for the PVMRM and OLM Tier 3 options in relation to the 1-hour NO_2 NAAQS as compared to the annual NO_2 NAAQS, due to both the increased stringency and 1-hour daily maximum form of the new standard, the relative importance of this parameter will vary from one application to another. Region 10 cautions against overstating the importance of this input parameter. The relative importance of the in-stack ratios will depend on several factors, including source characteristics, meteorological conditions and background ozone concentrations, but the commenters have provided no support for their broad statement that "small changes to the ratios used could have a significant impact on modeled concentrations." In the extreme case, in terms of the relative importance of the in-stack ratio, with significant ozone-limiting conditions, stable worst-case meteorological conditions and very close ambient air boundary, a small change in the in-stack ratio would only result in a correspondingly small change in the modeled concentrations.

The commenters are correct that Region 10 required Shell to do several iterations of modeling with varying in-stack ratios based on engine testing (*See* 4/29/11 Shell modeling submittal Alternate_NO_2_Modeling_Disco_04_29_2011.pdf). This additional analysis did not indicate significant changes in the modeled 1-hour NO_2 concentrations. Region 10 believes Shell has demonstrated the ratios used are protective of the NAAQS.

See also response to comment V.3.b.

Comment V.3.b: Commenters state that Region 10 must reject Shell's use of Plume Volume Molar Ratio Method (PVMRM) to demonstrate compliance with the 1-hour NO_2 standard because, the commenters assert, in predicting ambient air impacts, the PVMRM significantly understates the extent to which nitric oxide (NO) will convert to NO_2 in the presence of ozone. The commenters note that Region 10 has specifically requested public comment on Shell's use of the PVMRM as a component of its ambient air modeling. The commenters contend that PVMRM fixates on the short-term rates of conversion, even though nearly all NO is eventually converted to NO_2. In reaching this conclusion, the commenters state that the NO_X emissions created during combustion (as occurs in Shell's ship engines and other equipment) are emitted partly as NO and partly as NO_2. Once in the atmosphere, the commenters continue, NO interacts with ozone and is ultimately converted to NO_2, but compliance with the final 1-hour NO_2 NAAQS is calculated by measuring NO_2 alone. The commenters assert that the use of PVMRM also contradicts and undermines the underlying assumptions of the NO_2 standard itself. Although NO_2 was chosen as the indicator, the commenters state that EPA intended for the 1-hour standard to not only reduce NO_2 levels, but to provide a corresponding reduction in other harmful nitrogen oxides as well. The commenters contend that PVMRM is necessarily unacceptable because it allows modelers to hide other harmful nitrogen oxides in low NO_2/NO_X ratios, resulting in a substantial understatement of total concentrations. Thus, in order to maintain consistency with EPA's declared purpose of using NO_2 as an indicator to reduce total NO_X, the commenters conclude, Region 10 must reject Shell's use of PVMRM.

Response: The modeling conducted by Shell is consistent with EPA's June 2010 1-hour NO_2 Modeling Guidance recognizing PVMRM as a Tier 3 modeling approach. The commenters have provided no information to show that Shell's use of PVMRM is inconsistent with that guidance. Moreover, the commenters have provided no information to support the assertion that "PVMRM significantly understates the extent to which NO will convert to NO_2 in the presence of ozone." The statement that "PVMRM fixates on the short-term rates of conversion" is incorrect. PVMRM determines the amount of available ozone on a receptor-by-receptor basis, which means the resulting NO_2 to NO_X ratio can vary on a receptor-by-receptor basis and on an hourly basis. PVMRM also includes an assumed upper limit of 0.9 for the resulting ambient NO_2 to NO_X ratio, which means "nearly all" of the NO could be converted to NO_2 under certain circumstances.

Concerning the commenters' concern with NO in connection with the NO_2 standard itself, this issue is beyond the scope of this permitting action. NO is not included directly in the regulatory NAAQS analysis because the NAAQS is written in terms of NO_2 and not NO. This analysis has considered conversion of NO to NO_2, which meets the regulatory permitting requirements at issue in this permitting action.

Comment V.3.c: Commenters assert that Region 10's reliance on the NO_2/NO_x ratios obtained from the Discoverer tests is not reasonable. A comparison of the emission units on the Discoverer and the Kulluk demonstrates that even if Shell potentially could use data from other vessels as source specific data—which it cannot—it would nevertheless be barred from doing so by an absence of similarity. The commenter notes that some of the Discoverer's and Kulluk's emission units are not only of different size and make, but also have varying emission controls installed – something that Shell found affects NO_2/NO_X ratios. For instance, the Discoverer's deck cranes have catalytic diesel particulate filters installed, while the Kulluk's cranes have oxidation catalyst installed.

Response: Region 10 disagrees that there is an absence of similarity between the Discoverer emission units and the Kulluk emission units. Emission units have similarity at a much higher level than the very specific make/model level. Emission units are routinely classified and grouped by scholars, industry, and EPA according to what the units are or how they operate. Examples of these various groupings can be found throughout technical literature, including engineering textbooks or even EPA's *Compilation of Air Pollutant Emission Factors* (AP-42). Units can be grouped in this manner because of known similarities in one or more factors.

Shell used commonly used groupings in developing their NO_2-to-NOx ratio approach. They classified their emission units as: reciprocating engines with post-combustion controls; reciprocating engines without post-combustion controls; boilers (without post-combustion controls): and incinerators (without post-combustion controls). While not highlighted in their application, it is important to note that all units within each classification also burn the same fuel (diesel).

Shell's level of classification would not be adequately refined for all aspects of a permit application. However, it is suitable for purposes of developing an NO_2-to-NOx ratio for purposes of submitting a modeling analysis for the <u>probabilistic</u> 1-hour NO_2 standard. The probabilistic form of the standard creates a challenge when modeling emission units with numerous and variable exhaust parameters (including the NO_2-to-NOx ratio). The March 2011 1-Hour NO_2 Modeling Guidance provides that the in-stack NO_2-to-NOx ratio could be accepted "provided some reasonable demonstration can be made..." Shell has made this demonstration by using the in-stack ratios obtained from 90 sources tests of similar emission units. This is a much larger data set than what Region 10 has seen from any other applicant. Region 10 therefore considers it adequate for purposes of modeling 1-hour NO_2 impacts.

A sensitivity analysis conducted by Shell in support of the Discoverer permit adds further credence for using the Discoverer data for the Kulluk. Region 10 asked Shell to compare the 1-hour NO_2 impacts from an analysis using Shell's generic ratios, derived in a similar manner as what was done for the Kulluk, with the 1-hour NO_2 impacts from an analysis using the actual tested ratios for individual permitted equipment. The modeled results were not only similar between the two runs, but it was actually the generic ratios that provided the higher modeled concentrations in the worst case (the Chukchi Sea). With all the testing Shell has performed for similar engine types, it is reasonable to conclude, using professional judgment and experience, that Shell's in-stack ratios are representative of the proposed emission units, especially in light of the conservative nature of their other modeling assumptions.

Given the probabilistic form of the standard and the large number of engines involved, even though the testing shows varying ratios it is very unlikely that all the engines that are permitted to operate concurrently would operate at their individual worst case ratio, while at the highest permitted emission rate, during worst case meteorological conditions, over three consecutive years. The conservatism of these assumptions becomes even greater considering that the Kulluk is unlikely to be operating at the exact same location for three consecutive drilling seasons.

Comment V.3.d: Commenters state that Shell failed to demonstrate that its stack tests generated reliable data for the Discoverer operations, and therefore Shell cannot claim the data are reliable for use with the Kulluk operations. The commenters contend that Shell's Kulluk and Discoverer operations both would be highly complex, involving a large number of emission units and many operating scenarios, and that the NO_2/NO_X ratio for each emission unit could vary widely depending on the load at which Shell operates it. Yet, the commenters continue, Shell conducted only 90 stack tests to determine the various NO_2/NO_X ratios associated with the Discoverer operations. The commenters note that Region 10 required Shell to perform additional modeling for the Discoverer, but that these tests were insufficient to reveal the full range of emission ratios that might actually occur during Shell's operations. The commenters state that even Shell admits that its results are not trustworthy, stating that its results contained unexplained high ratios. The commenters state that Shell compounded this problem by averaging the high ratios with the lower ratios, rather than performing more tests to either explain the results or actually gather real source-specific data. Thus, the commenters believe that Shell's ratios are not dependable for use with its Kulluk operations because they are not even dependable for use with its Discoverer operations.

Response: Region 10 disagrees with the comment. As noted in our response to comment V.3.c, 90 is an unusually large number of source tests to support a permit application. While more data is always desirable, this data pool is adequate for purposes of deriving in-stack NO_2-to-NOx ratios for the Discoverer and the Kulluk emission units. Region 10 further notes that while some of the results may be unexplained, that does not make those data points wrong. In addition, the probabilistic form of the 1-hour NO_2 standard is explicitly intended to mitigate the impact from possible outliers, and on that basis alone it would be inappropriate to combine a worst-case in-stack ratio with a worst-case emission rate as the basis for demonstrating compliance with the NAAQS in the absence of a clear linkage between the in-stack ratio and emission rate for a particular source that would justify such an approach.

Region 10 asked Shell to perform additional modeling for the Discoverer in order to determine how sensitive the 1-hour NO_2 modeling results are to small variations in the in-stack ratios. Shell's analysis showed that generic ratios and actual ratios provide similar results. This analysis further confirms that Shell's reliance on the generic conclusions obtained from the Discoverer sources tests is reasonable and does not compromise the adequacy of the 1-hour NO_2 modeling analysis conducted for the Kulluk.

Comment V.3.e: Commenters contend that Region 10 and Shell have not provided any basis for concluding that the NO_2/NO_x ratios used in Shell's modeling are representative of the ratios that actually may result from Shell's operations. Due to the importance of these ratios to assessing 1-hour NO_2 impacts, the commenters state, Shell cannot say that it has demonstrated compliance with the standard. The commenters request that, if Shell refuses to gather source-specific data, Region 10 direct Shell to use the default in-stack ratio of 0.5.

Response: As stated in EPA's March 2011 1-Hour NO_2 Modeling Guidance , EPA recommends 0.5 as a default in-stack ratio *in the absence of more appropriate source-specific <u>information</u> on in-stack ratios* (emphasis added). EPA did not state, or intend, that only unit-specific source test data may be used to justify a non-default value. The guidance clearly indicates a preference for the use of "<u>more appropriate</u> source-specific information (emphasis added)" when available, and also acknowledges that "well-documented data on in-stack NO_2/NO_x ratios is still limited for many <u>source categories</u> (emphasis added)." As discussed in Region 10's response to comments V.3.c and V.3.d, the Kulluk emission units are not only similar to the Discoverer emission units, but the large number of Discoverer source test data provides a very adequate basis for justifying the Kulluk in-stack ratios as being "more appropriate source-specific information" than the default ratio used in these modeling analyses.

Comment V.3.f: Commenters note that Region 10 relied on the source-specific test data from the Discoverer for the Kulluk as a reasonable approach given the similarity in emission units. The commenters disagree that source-specific test data from a source applying BACT is sufficiently representative of the range of possible units used as part of the Kulluk operations. The commenters contend that because the Kulluk permit does not specify equipment make and model, Region 10 must use the most conservative generic ratio to represent the worst-case operating scenario. Commenters note that when source-specific data is not available, EPA recommends the use of 0.50 as a default in-stack ratio for purposes of modeling 1-hour NO2 impacts. In the Technical Support Document Region 10 claims that Shell is using the preferred approach of obtaining source-specific data, rather than the 0.5 default. The commenters further state that Region 10 contradicts this statement by relying on data from source tests of the Discoverer's drillship and associated fleet.

Response: The commenters have not shown why the in-stack ratio must be make/model-specific, or why source-test data from similar emission units would be inadequate when demonstrating compliance with the 1-hour NO_2 NAAQS. As previously noted in response to comment V.3.e, EPA said that the 0.5 in-stack ratio should be used "in the absence of more appropriate source-specific information." EPA did not rule out the use of class- or category-specific data as an allowed source of more appropriate information. See also the other responses to comments in this Subcategory V.3.

Comment V.3.g: Commenters state that it is unclear how the generic ratio compares to the ratios used in Shell's modeling for the Kulluk that is based on source testing from the

Discoverer drilling operations. The commenters contend that there are no supporting data presented in the air quality impact analysis for the Kulluk or included in the administrative record files that specify the ratios used in the Kulluk modeling. The commenters note that the source test data provided as part of the revised Discoverer permits (and included in the administrative record files for the Kulluk*)* shows that the equipment-specific ratios are consistently significantly lower than the generic value of 0.5. Given the significance of this parameter in the modeling, the commenters believe that Region 10 should use the most protective values and request that the Region use the generic ratio value of 0.5 for the PVMRM modeling algorithm.

Response: The 0.5 value is characterized in EPA's guidance as "a reasonable upper bound based on the available in-stack data" from a *wide variety* of source categories that can be used without additional justification. EPA never stated that 0.5 is "representative" of *all* source categories. Therefore, it is not surprising that actual source test data from any given sub-set (e.g., diesel-fired reciprocating engines without post-combustion controls) leads to a smaller value, as is the case here. The March 2011 1-Hour NO_2 Modeling Guidance also clearly indicates a preference for the use of "more appropriate source-specific information" when it is available.

With respect to the comment regarding the lack of supporting data, Shell provided the Discoverer source test data as part of the Kulluk application (as acknowledged by the commenter). They summarized the data and source group averages at pages 125-128 of the Permit Application Supplement, and provided a discussion regarding these data and how they were applied to their NO_2 modeling analysis in Section 3.9.2 on pages 67-68 of the Permit Application Supplement.

V.4 SUBCATEGORY – AREA POLYGONS

Comment V.4.a: Commenters assert that Shell's use of area polygons to model the emissions of associated vessels underestimates impacts and that Shell has therefore not demonstrated compliance with applicable NAAQS and increments, as required by the Title V program. The commenters state that Shell's modeling dilutes Shell's associated vessel emissions over a large area, artificially reducing projected maximum impacts and that Region 10 should direct Shell to remodel impacts using a method that does not bias modeled impacts in this manner. Commenters assert that Shell's use of area polygons rather than volume sources to represent the emissions of associated vessels results in the distribution of associated vessel emissions over large areas and that the ice breaker emissions appear to be distributed over an area of roughly eight square kilometers, while the emissions of other support vessels distributed over four square kilometers. By treating the associated vessel emissions in this manner, the commenters continue, Shell likely overestimates how much its ships will be moving and, further, underestimates short-term impacts to air quality. The commenters contend that the potential for underestimating impacts is particularly significant with short term standards like the 1-hour NO_2 standard.

Response: Region 10 carefully considered the assumptions and model settings used in Shell's air quality analysis. In any modeling analysis, the applicant has choices in configuring the model inputs to best reflect its operations. In AERMOD, there are various ways to characterize emissions, such as a point, volume, area circle, area polygon, open pit, or flare. The applicant must choose how to best characterize all their permitted emissions, and the permitting authority conducts a review to ensure the applicant's approach appropriately characterizes emission sources.

An area source is generally used to model low-level or ground level releases with no plume rise (such as storage piles, lagoons, etc), while a volume source is used to characterize releases from building roof vents, conveyer belts, etc. In this case, Shell chose to characterize its moving Associated Fleet as an area source, or more specifically, as an area polygon. The only difference between an area source and an area polygon is the ability to specify an arbitrary shape in the case of the area polygon.

Conceptually, the effect of using an area polygon is that the source's emissions during a given hour are treated as if emitted equally across the area of the polygon, rather than at a single point in the polygon. When applied to the Associated Fleet, this treats the vessels in the fleet as moving during an hour such that each vessel spends an equal portion of the hour in each possible position in the polygon. It appears that the commenters believe that each vessel should have been assumed to hold a single position during the hour, and that these positions be ones that would maximize the Associated Fleet's aggregate impact on 1-hour concentrations by aligning the vessels in the Fleet with each other and with the Kulluk's emissions along the same wind path. Alternatively, the commenters suggest that if an area polygon is used the size of the polygon should have been smaller so that the emissions from the Associated Fleet would have been more concentrated spatially, causing higher ambient concentrations.

Because the Associated Fleet emissions are associated with engines that have plume rise, which as stated above is not addressed in an area source configuration, Shell also had to characterize area source release parameters for every hour for their area polygons. Shell did this by running AERMOD in diagnostic mode using the lowest ice management vessel stack height with a line of receptors extending out to 5 km from the Kulluk. Shell then took the resulting plume height and sigma Z values for the maximum modeled receptor and used these parameters as the initial inputs for the area polygon sources. While this approach is novel and would not generally be performed due to the complexity of its implementation, Region 10 believes it does provide an accurate characterization of the Associated Fleet, which is an unusual source. The area polygon configuration was one of the areas carefully reviewed and considered. Region 10 believes the area polygon configuration along with the hourly emissions release characterizations provide an accurate representation of the moving Associated Fleet and will result in a conservative impact analysis that is protective of the NAAQS.

It would be inappropriate to require Shell to use fixed positions for vessels in the Associated Fleet or to use an area polygon configuration that is so small as to not reflect the reality of a moving support fleet. In fact, Shell states in its application that OSR vessels would generally operate within 1 to 5 km from the Kulluk, but were modeled as if they only operated within a 2 km by 2 km area. Shell stated, "This source characterization is conservative since the OSR sources are continuously located much closer to the *Kulluk* than what would occur in reality." Permit Application Supplement at 50. In addition, for each hour the polygons—both for the ice management vessels and OSR—are aligned with the modeled wind direction using the maximum permitted emissions with worst case release characteristics as described above, which results in a conservative analysis. Given that the vessels in the Associated Fleet have particular tasks to perform whenever they are within 25 miles of the Kulluk, it is unreasonable to assume that they all would hold fixed positions for a full hour. In addition, as discussed above in response to comments V.1.c and V.2.b several conservative assumptions, such as a single drilling location over a period of three years, underlie Shell's modeling analysis.

Comment V.4.b: Commenters contend that due to the size of the area sources, associated vessels will never be modeled directly upwind or downwind of major Kulluk emission units. The commenters believe that the configuration of the area source prevents an accurate assessment of the maximum impacts that would be expected during alignment of the Kulluk and associated icebreakers.

Response: The size of the area sources reflects the expected range of operation for the Associated Fleet. It is unreasonable to assume that the vessels will only be located in a line immediately upwind or downwind of the Kulluk for the entire period of operation.

W. CATEGORY – AIR QUALITY ANALYSIS FOR $PM_{2.5}$ NAAQS

W.1 SUBCATEGORY – IN GENERAL

Comment W.1.a: Commenters state that the 24-hour $PM_{2.5}$ NAAQS was set at a level due to the large body of evidence that fine particulate is harmful to human health. The commenters also state that EPA found that $PM_{2.5}$ exposure causes cardiovascular problems and can even cause death. The commenters note that the 24-hour $PM_{2.5}$ NAAQS is based on the 3-year average of the 98^{th} percentile of the 24-hour concentrations. The commenters conclude that Shell has not demonstrated that it will comply with the 24-hour $PM_{2.5}$ NAAQS and that Region 10 therefore cannot issue the permits.

Response: As discussed in the Statement of Basis and the Technical Support Document, the permit includes terms and conditions to ensure that emissions authorized under this permit will not cause or contribute to a violation of the NAAQS, including the $PM_{2.5}$ NAAQS. The NAAQS are health-based standards, set at a level to protect public health with an adequate margin of safety, including sensitive populations such as children, the elderly, and asthmatics.

Comment W.1.b: Commenters state that Shell has not demonstrated compliance with NAAQS because it unlawfully underestimated its maximum impacts. In issuing the 24-hour $PM_{2.5}$ NAAQS, the commenters contend, EPA determined that NAAQS compliance would be based on "the 98th percentile of the annual 24-hour concentrations at each population-oriented monitor within an area, averaged over three years . . . .," citing to 71

Fed. Reg. 61,144, 61,164 (Oct. 17, 2006). The commenters assert that EPA repeatedly indicated that this form was specific to determining area compliance by reviewing data from population-oriented monitors, and that there is no basis in the Clean Air Act nor the 24-hour $PM_{2.5}$ standard itself for the permitting approach Region 10 has adopted here, namely, allowing a proposed new source to discount its highest projected impacts. The commenters continue that such an approach ignores both the importance of the absolute value of the NAAQS standard—which they state must be set at the requisite level to protect human health, as well as the Title V program requirement that a proposed permit include sufficient conditions to prevent a NAAQS exceedance. Commenters state that this issue is important because Shell's modeling indicates it could cause pollution concentrations to exceed the NAAQS limit of 35 $\mu g/m^3$ because adding Shell's maximum modeled impact of 20.5 $\mu g/m^3$ to Shell's background value of 17.0 yields a value of 37.5 $\mu g/m^3$.

Response: The commenters appear to be arguing that a source must demonstrate that the impact of its emissions does not exceed the level of the NAAQS. Region 10 disagrees with this position for the reasons discussed in response to comment V.1.b.

Comment W.1.c: Commenters state that Shell's emissions of particulate matter could exceed health based limits and increments, and also contribute to climate change. The commenters state that Shell's modeling indicates that the particulate matter emissions could cause pollution levels to reach 97 % of health based standards and almost double the fine particulate matter increment.

Response: The modeling does indicate that Shell's emissions, when added to background concentrations of $PM_{2.5}$, may come close to the NAAQS at the point of maximum modeled impacts, but the modeling also demonstrates that Shell is not expected to cause or contribute to a violation of the NAAQS at any location that constitutes ambient air. As discussed in the response to comments in Category Z, the permit does not need to assure compliance with the $PM_{2.5}$ increment as a condition of obtaining this permit. With respect to climate change, please see the responses to comments in Subcategory BB.4.

Comment: A commenter states that they are not sure how the ocean air is going to distribute the particulates and expressed concern about the modeling.

Response: The modeling conducted in this case took into account the impact of Shell's emissions in over water conditions. Technical Support Document at 27-28.

W.2 SUBCATEGORY – BACKGROUND DATA FOR 24-HOUR $PM_{2.5}$ NAAQS

Comment W.2.a: Commenters state that, in its 24-hour $PM_{2.5}$ analysis, Shell has understated its 98th percentile impact. Even if Shell could calculate its 24-hour $PM_{2.5}$ impact by finding the 3-year average of its 98th percentile impacts, the commenters continue, Shell has not calculated that value correctly because, in selecting the background value for its 24-hour $PM_{2.5}$ modeling, Shell eliminated days that had "high windblown dust values." The commenters state that Shell has not offered persuasive reasons for excluding these values which only may be excluded by EPA itself and only pursuant to the requirements of EPA's "exceptional events rule" (citing 72 Fed. Reg. 13,560 (Mar. 22, 2007)), which Region 10 has not invoked here. After eliminating these days, the commenters assert, Shell then selected the 98th percentile value of the remaining days. The commenters conclude that Region 10's apparent approval of this method plainly underestimates even the 98th percentile impact and that, instead of obtaining representative data and then finding the true 98th percentile, Shell has used unrepresentative data and then used the low quality of these data as an excuse to eliminate measurements until Shell gets the result it wants.

Response: Region 10 acknowledges that Shell excluded certain days from its determination of $PM_{2.5}$ background values. However, Region 10 did not rely on Shell's background values for its determination of compliance with the $PM_{2.5}$ NAAQS. Rather, Region 10 independently determined the annual and 24-hour $PM_{2.5}$ background values for the Deadhorse monitoring site (as well as the Badami monitoring site). While Shell's approach of excluding days that were impacted by either wildfire or windblown dust might be appropriate depending on the circumstances, Region 10 took the more conservative approach of including those days in the dataset. As described in the Memorandum from Christopher Hall, Region 10, to Herman Wong, Region 10, re: EPA Region 10 Determination of Appropriate Background Values for the Chukchi Sea and Beaufort Sea OCS Permits, dated June 23, 2011 (Background Data Memo), and shown in Table 6 of that memo, as well as in Table 11 of the Technical Support Document (at 33), Region 10 used background values of 17 ug/m3 and 4 ug/m3 for the 24-hour and annual standards, respectively, calculated according to EPA's regulations and guidance.

In conclusion, Region 10 did not exclude days with windblown dust events in determining the appropriate background concentration in connection with its review of the ambient impacts of Shell's operations. Region 10 therefore disagrees with the commenter that the ambient impact analysis has understated the impact of Shell's $PM_{2.5}$ emissions.

W.3 SUBCATEGORY – SECONDARY $PM_{2.5}$ FORMATION

Comment W.3.a: Commenters state that Region 10's analysis of potential secondary $PM_{2.5}$ formation remains insufficient because, despite the EAB's clear direction on the issue, neither Shell nor Region 10 has performed a proper analysis of Shell's potential contribution to secondary $PM_{2.5}$. Noting the EAB remanded the permits for the Discoverer to Region 10, in part, based on deficiencies in Region 10's analysis for secondary $PM_{2.5}$, the commenters state that Shell cannot demonstrate compliance with NAAQS until it has performed a sufficient secondary $PM_{2.5}$ analysis. The commenters contend that, in remanding the permitting decisions for the Discoverer to Region 10, the EAB specifically instructed that "the Region should . . . provide an explanation of why modeling secondary $PM_{2.5}$ is necessary or not after determining whether $PM_{2.5}$ precursors will be emitted in significant quantities." The commenters conclude that Region 10 has ignored the EAB's order noting that the Technical Support Document states that "Region

10 has not made a determination of whether $PM_{2.5}$. precursor emissions from the project are significant . . . ." The commenters state that Region 10's refusal to make a finding on the significance of Shell's precursor emissions is noteworthy given that the Technical Support Document states that Shell's emissions will exceed the regulatory "significant emission rate" for the precursor NO_X by many times and that Shell's modeling already indicates it may cause 24-hour $PM_{2.5}$ concentrations to reach 97% of the NAAQS. The commenters contend that Region 10's approach does not provide any margin of safety in the $PM_{2.5}$ NAAQS modeling analysis because the draft permit allows for only an additional 1 µg/m3 (an additional 3%) before the impacts of the Kulluk operations would be at the level of the NAAQS so a relatively small amount of secondary formation could cause a violation. The commenters also assert that, if Region 10 does not determine whether those precursor emissions are significant, it certainly cannot accurately estimate the amount of potential secondary $PM_{2.5}$ formation and that Region 10 must assess directly whether Shell will emit a significant quantity of $PM_{2.5}$ precursors. Instead, the commenters contend, Region 10 has based its determination primarily on a rough comparison of Shell's potential emissions to North Slope emissions and the observations that North Slope sources do not currently appear to be contributing to substantial secondary formation in onshore communities. If a quantitative assessment of secondary $PM_{2.5}$ impacts is not completed, the commenters assert, then Region 10 must, at the very least, provide for NAAQS compliance with a greater margin of safety that better reflects the uncertainty in secondary $PM_{2.5}$ contributions to overall $PM_{2.5}$ concentrations and is sufficient to ensure that potential secondary $PM_{2.5}$ impacts would not cause or contribute to NAAQS violations.

Response: The EAB order referred to by the commenters is an order issued in connection the EAB's remand to Region 10 of permits for Shell's Discoverer drillship. See Shell Gulf of Mexico, Inc and Shell Offshore, Inc., Frontier Discoverer Drilling Units, OCS Appeal Nos. 10-01 through 10-04, Order on Four Additional Issues dated March 14, 2011 (Remand Order II). It is therefore not directly applicable to this permit proceeding. In any event, Region 10's determination that secondary $PM_{2.5}$ formation associated with precursor emissions from the Kulluk and the Associated Fleet is not expected to cause or contribute to a violation of the $PM_{2.5}$ NAAQS is consistent with current EPA guidance for addressing $PM_{2.5}$ precursor emissions and the EAB Orders.

Acknowledging that EPA's preferred dispersion model for near-field $PM_{2.5}$ modeling (AERMOD) does not account for secondary formation of $PM_{2.5}$, EPA issued guidance on appropriate modeling procedures for demonstrating compliance with the $PM_{2.5}$ NAAQS that relies upon ambient monitored concentrations to adequately account for the contribution of secondary $PM_{2.5}$ to the cumulative impact assessment for demonstrating compliance with the NAAQS, in most cases. Memorandum from Stephen D. Page, OAQPS, re: Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS, dated March 23, 2010, at 9 (March 23, 2010 $PM_{2.5}$ Guidance Memo). In issuing this guidance, EPA took into consideration the regional nature of secondary $PM_{2.5}$ levels, and the fact that peak ambient impacts due to facility emissions of primary $PM_{2.5}$ and secondarily-formed $PM_{2.5}$ due to facility emissions of $PM_{2.5}$ precursors are not likely to be well-correlated in space or time. The portion of EPA's guidance at issue here states that "[w]hile representative background monitoring data for $PM_{2.5}$ should adequately account for secondary contribution from background sources in most cases, if the facility emits significant quantities of $PM_{2.5}$ precursors, some assessment of their potential contribution to cumulative impacts as secondary $PM_{2.5}$ may be necessary." Id.

There are several points worth highlighting in relation to the March 23, 2010 $PM_{2.5}$ Guidance Memo. Firstly, and at issue here, EPA does not explicitly define what "significant quantities of $PM_{2.5}$ precursors" means in this context. In addition, EPA indicated in the March 23, 2010 $PM_{2.5}$ Guidance Memo that "[w]e plan to issue separately additional guidance regarding this issue." Id. In light of these considerations, Region 10 believes that the appropriate place to explain when "some assessment" of "potential" secondary $PM_{2.5}$ contributions "may be necessary" is in the upcoming guidance that EPA plans to issue. As that guidance has not yet been issued, Region 10 here took a conservative approach by presuming that the Kulluk and Associated Fleet do emit "significant quantities" of $PM_{2.5}$ precursors, and then assessing the potential contributions of $PM_{2.5}$ precursor emissions to the formation of secondary $PM_{2.5}$.

In addition, Region 10 disagrees with the commenters' inference that the reference in the March 23, 2010 $PM_{2.5}$ Guidance Memo to "some assessment" of the source's potential contribution to cumulative impacts implies a requirement that modeling be conducted. The fact that the guidance refers to "some assessment" rather than a "modeling demonstration" indicates that an "assessment" could be comprised of qualitative and/or quantitative analyses, including a modeling demonstration if appropriate, but it is certainly not limited to nor dependent on a modeling demonstration.

The commenter is correct that, in issuing the Draft Permit, Region 10 did not make an explicit determination of whether the project emits "significant quantities" of $PM_{2.5}$ precursors as that term is used in the March 23, 2010 $PM_{2.5}$ Guidance Memo. See Technical Support Document at 21, fn.4. Instead, Region 10 took a conservative approach and presumed that the Kulluk and Associated Fleet do emit "significant quantities" of $PM_{2.5}$ precursors, and then conducted an assessment of the potential contributions of $PM_{2.5}$ precursor emissions to the formation of secondary $PM_{2.5}$, consistent with the March 23,2010 $PM_{2.5}$ Guidance Memo. Region 10 then concluded for the reasons explained in the Technical Support Document that modeling is not necessary to demonstrate that secondary $PM_{2.5}$ formation from the Kulluk and the Associated Fleet is not expected to cause or contribute to a violation of the $PM_{2.5}$ NAAQS.

In support of the Draft Permit, Region 10 provided a detailed explanation for why it believes that modeling secondary $PM_{2.5}$ emissions is not needed in order to determine that emissions of $PM_{2.5}$ precursors from the Kulluk and Associated Fleet would not, together with emissions of primary $PM_{2.5}$, cause or contribute to a violation of the 24-hour $PM_{2.5}$ NAAQS. The factors Region 10 relied on to reach this conclusion include:

1) The background $PM_{2.5}$ monitoring data considered in the air quality analysis is quality assured, quality controlled data from Deadhorse that includes impacts from onshore sources. This monitor is expected to have accounted for much of the

secondary formation from existing regional emission sources that will occur in the Beaufort Sea region. Available monitoring data from onshore communities along the Beaufort Sea and in potential transport areas where monitoring is performed show low levels of daily $PM_{2.5}$, generally in the range of 2 $\mu g/m^3$, with the higher $PM_{2.5}$ values generally occurring on days where windblown dust or fires are believed to be contributing factors. Thus, there is no indication that secondary formation of $PM_{2.5}$ from existing sources in the North Slope is currently causing or contributing to exceedances or a violation of the $PM_{2.5}$ NAAQS in the onshore communities.

2) Modeled primary $PM_{2.5}$ impacts from the Kulluk and Associated Fleet that, when using a conservative "First Tier" approach to combining modeled primary $PM_{2.5}$ impacts with monitored background $PM_{2.5}$, concentrations are below the 24-hour $PM_{2.5}$ NAAQS. As the commenters note, the maximum modeled concentration is 97% of the $PM_{2.5}$ NAAQS at the assumed ambient air boundary (500 meters from the hull of the Discoverer), but the levels decrease as the distance from the Kulluk decreases.

3) Secondary $PM_{2.5}$ impacts associated with the Kulluk and Associated Fleet precursor emissions are expected to be low near the emission release points where modeled concentrations associated with primary $PM_{2.5}$ emissions are highest, because there has not been enough time for the secondary chemical reactions to occur. Conversely, secondary $PM_{2.5}$ impacts are more likely to be higher farther from the Kulluk and the Associated Fleet where impacts from primary $PM_{2.5}$ emissions from the Kulluk and the Associated Fleet are expected to be lower. This makes it unlikely that maximum primary $PM_{2.5}$ impacts and maximum secondary $PM_{2.5}$ impacts from the Kulluk and the Associated Fleet will occur at the same time (paired in time) or location (paired in space). See March 23, 2010 $PM_{2.5}$ Guidance Memo at 9.

4) The relatively small amount of NO_X emissions (a $PM_{2.5}$ precursor) that will be authorized under this permit in comparison to existing NO_X emissions in the North Slope area in general, together with the generally low levels of $PM_{2.5}$ recorded at monitoring stations in the area, make it unlikely that NO_X emissions from the Kulluk and the Associated Fleet would cause or contribute to a violation of the $PM_{2.5}$ NAAQS.

5) The background concentrations of certain chemical species that participate in photochemical reactions to form secondary $PM_{2.5}$, including ammonia and volatile organic compounds, are expected to be negligible in the offshore air masses where the Kulluk will be permitted to operate. The emissions authorized under this permit of approximately 40 tpy of VOC along with the minimal expected ammonia increases (2.16 tpy) would also not be expected to result in the conversion of significant quantities of NO_X emissions to secondary particles in the areas impacted by primary $PM_{2.5}$ emissions.

6) There are several other conservative assumptions incorporated in the modeling of primary $PM_{2.5}$ emissions. These include the conservatism inherent in using a "First Tier" approach to combining modeled primary $PM_{2.5}$ impacts with monitored background $PM_{2.5}$ concentrations; assuming that the Kulluk will be operating in a single drilling location for 3 years, when it is more likely that the Kulluk will operate in a different location each year (if not more frequently); orienting the Associated Fleet with hourly modeled wind direction and using emission release characteristics based on actual meteorological conditions; and the fact that the background monitored data used to represent offshore conditions was collected onshore, where it is influenced by local sources, and is therefore likely to be a conservative estimate of background $PM_{2.5}$ levels in the area of maximum impact near the Kulluk.

Based on these factors, and consistent with current guidance, Region 10 believes that an adequate and conservative assessment has been made to demonstrate that the $PM_{2.5}$ NAAQS will be protected, accounting for primary $PM_{2.5}$ impacts and potential contributions due to $PM_{2.5}$ precursors from the Kulluk and the Associated Fleet, and that it is not necessary to use a photochemical model to further evaluate secondary $PM_{2.5}$ formation in these permitting actions.

Comment W.3.b: Commenters state that, in analyzing potential secondary $PM_{2.5}$ formation, Region 10 should address additional factors. In particular, commenters assert that Region 10 acknowledges that secondary $PM_{2.5}$ formation can occur at a different time and place than where the precursors were emitted and that Region 10 must therefore account for the emission of precursors from Shell's operation before it has technically become an OCS source and after it has stopped being one, since these non-OCS source emissions could react with OCS source emissions.

Response: Even if Region 10 were to require Shell to conduct photochemical modeling for $PM_{2.5}$ precursors, Shell would not be required to include emissions from vessels before Shell becomes an OCS source. See response to comment Y.1. On-going monitoring for $PM_{2.5}$ that is expected to continue on the North Slope will assist Region 10 in evaluating the significance of secondary formation of $PM_{2.5}$ on a broader scale in the North Slope region.

X. CATEGORY – AIR QUALITY ANALYSIS FOR OZONE NAAQS

Comment X.1: Commenters state that additional information is required for this permit regarding ozone and ask Region 10 to undertake a regional ozone air quality analysis. Noting the causes and health impacts of ozone, the commenters state that Shell will be emitting 240 tpy of NO_X and 40 tpy of VOC, and that other OCS sources permitted this year and possibly in future years will add to these numbers. The commenters contend that Shell's decision not to model ozone is not justified given that Region 10 has stated that "point sources in the North Slope oil and gas fields near Deadhorse contribute approximately 65,000 tpy of NO_X and 1,100 tpy of VOC. Given this level of activity, and the predicted emissions of ozone constituents, commenters assert that Region 10 should be assessing the cumulative impacts of permitting activities together with documented background concentrations. The commenters further state that research conducted on air quality in Nuiqsut (in light of the pollution generated by Alpine Oil Field and Prudhoe Bay) showed elevated ozone levels in the winter months.

Response: Region 10 stands by its decision that regional photochemical modeling for this project is not required. As described in the Statement of Basis and Technical Support Document, Region 10 reviewed ozone monitoring data along with existing precursor emissions that will impact ozone formation. Based on this review, Region 10 determined further analysis of ozone was not warranted. The most recent monitoring data for all pollutants is summarized in a memorandum included in the administrative record. See Background Data Memo. This memo summarized the 2009 and 2010 ozone data from Shell's and ConocoPhillips' Wainwright and Point Lay monitoring sites as well as 2006 to 2009 ozone data from two other industry run sites in the Prudhoe Bay area (A Pad and CCP) which had recently been reviewed and approved by the Alaska Department of Environmental Conservation. As shown in the data below from the Background Data Memo, the most recent data continue to show that ozone levels at sites along the Alaska Arctic Ocean are well below the ozone NAAQS.

Averaging Period	Wainwright	Point Lay	CCP	A Pad
1-hour	0.039 ppm	0.040 ppm	0.040 ppm	0.078 ppm
8-hour	0.037 ppm	0.040 ppm	0.032 ppm	0.034 ppm

Region 10 disagrees with the commenters' statement that arctic ozone levels are high because the available ozone monitoring data does not support this statement. With respect to the research on air quality in Nuiqsut and the comment stating that the monitoring data that showed elevated ozone levels in the winter months, the commenter has provided no information for consideration that would change Region 10's conclusion regarding the necessity of conducting modeling for ozone. The maximum 8-hour ozone levels shown in the referenced document (Attachment 2) are monthly maximums and are not comparable to the NAAQS, which is based on the 98th percentile of annual values. In addition, the maximums are far below the value of the NAAQS and the 98th percentile would be even lower than the monthly maximums. The reference to "elevated ozone levels in the winter months" appears to be referring to the fact that the levels in the winter are higher than in the summer, not that the levels are "elevated" in comparison to some other reference point, such as the NAAQS.

Comment X.2: Commenters emphasize the importance of Region 10's conclusion that no further evaluation for ozone is needed in light of EPA's decision to revise the 8-hour standard. The commenters note that, EPA had proposed to adopt a new primary 8-hour standard of between 0.060-0.070 parts per million (ppm) this summer, lower than the existing 8-hour standard of 0.075 ppm. The commenters ask Region 10 to ensure compliance with the new 8-hour standard for ozone because they allege that 1) current background concentrations of ozone are already as high as 0.050 ppm (8-hour average) on the North Slope and the formation of additional ozone as a result of offshore oil and gas operations could take the North Slope out of attainment; 2) the new 8-hour standard is an important health based standard and this standard should be the one that Shell seeks to comply with in its proposed years of future operations in the Beaufort and Chukchi Seas because the proposed air permits are not time limited and thus support the need for compliance with the most recent legal requirements; and 3) both BOEMRE and Shell rely upon the NAAQS to mitigate the impacts of the air emissions associated with Shell's exploration plans on air quality, marine mammals, and other resources so it is particularly critical that compliance with these emerging standards is ensured.

Response: EPA had proposed to reconsider the 0.075 ppm ozone NAAQS set in 2008 and requested comment on a range between 0.060 and 0.075 ppm. 75 Fed. Reg. 2,935 (January 19, 2010). EPA has recently announced, however, that at the President's direction, EPA will not be taking final action on its current proposal to revise the 8-hour ozone NAAQS. EPA instead intends to consider revisions to the ozone NAAQS in connection with the 5-year mandated revision of the ozone NAAQS in 2013. Statement by the President on the Ozone National Ambient Air Quality Standard, September 2, 2011. There is no requirement that an OCS or Title V permit ensure compliance with requirements that have not even been promulgated at the time of permit issuance.

In any event, based on the most recent ozone data, current ozone levels at the four monitoring sites are well below even the low end of the range of the NAAQS EPA had proposed (0.060 ppm). See also response to comment BB.3 for a discussion of the environmental justice considerations in connection with the proposed 8-hour ozone NAAQS.

Y. CATEGORY – CUMULATIVE IMPACTS

Comment Y.1: Commenters are concerned that the air quality analysis relied upon by Region 10 in issuing the permits does not account for what the commenters contend is the potentially significant contribution of pollutants from vessels/mobile sources that will operate in the same vicinity as the Kulluk and the Associated Fleet. The commenters allege that the air quality analysis does not account for emissions from the Kulluk, the Icebreakers/Anchor Handlers, or the any of the other Associated Fleet before the Kulluk is determined to be an OCS Source and that such emissions are not represented in the existing background air quality data. The commenters also contend that the modeling conducted by Shell and Region 10 fails to account for the emissions from other nearby mobile sources. Over all, the commenters continue, the air quality analysis fails to account for these potentially significant sources of air pollution, which may result in inaccurate predictions of impacts to air quality. The commenters ask Region 10 to clarify whether and how the air quality analysis incorporates the potential emissions from mobile sources related to the drilling program that are not captured in the PTE calculations for the Kulluk and the Associated Fleet. In this regard, the commenters state that they are concerned both with respect to the impacts on short-term standards, including the 1-hour NO_X, but also the annual air quality standards.

Response: Region 10 disagrees with the commenters that emissions from the Kulluk when it is not an OCS source, from vessels in the Associated Fleet when they are more than 25 miles from the Kulluk while it is an OCS source or when it is not an OCS source, or from other mobile sources in the area, whether related or unrelated to Shell's operations, need to be addressed in the air quality analysis for the OCS/Title V permit for the Kulluk. Although some such emissions may occur as a result of the activities of the OCS source, they are emissions from mobile sources. The Clean Air Act and EPA's implementing regulations for PSD, which Region 10 has used as a guide in issuing this permit, are clear with respect to the treatment of mobile source emissions in the PSD permitting process. In the 1990 amendments to the Clean Air Act, Congress clarified that a stationary source does not include emissions from mobile sources. See CAA § 302(z). In the 1990 amendments, Congress also added the OCS provision (CAA § 328), which includes the requirement that emissions from support vessels are considered to be direct emissions from the OCS source when within 25 miles of the OCS source, but does not change any other provisions of the stationary source permitting programs for OCS sources as they relate to mobile sources.

While neither the OCS regulations nor the Part 70/Part 71 regulations specifically address how mobile sources are to be treated in the permitting process, for this permit, Region 10 believes it is appropriate to follow the modeling requirements and guidance for EPA's PSD regulations (which have been incorporated by reference into the OCS regulations at 40 CFR § 55.13(d)) as to what sources of emissions must be included in considering whether Title V permit terms and conditions for a Title V temporary source assure compliance with the NAAQS, as applicable requirements for such sources. 40 CFR § 52.21(k) requires that:

> …the owner or operator of the proposed source or modification shall demonstrate that allowable emission increases from the proposed source or modification, in conjunction with all other applicable emissions increases or reductions (including secondary emissions), would not cause or contribute to air pollution in violation of:
>
> (i) Any national ambient air quality standard in any air quality control region; or
>
> (ii) Any applicable maximum allowable increase over the baseline concentration in any area."

EPA's regulations define "secondary emissions" at 40 CFR § 52.21(b)(18) as:

> …emissions which would occur as a result of the construction or operation of a major stationary source or major modification, but do not come from the major stationary source or major modification itself. Secondary emissions include emissions from any offsite support facility which would not be constructed or increase its emissions except as a result of the construction or operation of the major stationary source or major modification. <u>Secondary emissions do not include any emissions which come directly from a mobile source, such as</u>

emissions from the tailpipe of a motor vehicle, from a train, or from a vessel." (emphasis added).

Therefore, consistent with the analysis that would be conducted in connection with an ambient air quality analysis submitted to support a PSD permit, emissions from mobile sources, specifically vessels that are not part of the Associated Fleet because the vessels are beyond 25 miles from the Kulluk when the Kulluk is an OCS source or vessels from the Associated Fleet when the Kulluk is not yet an OCS source, are not secondary emissions and Region 10 does not believe they are appropriate for consideration in issuing this permit.

Comment Y.2: The commenters state that Shell has not demonstrated that its operations will ensure protection of NAAQS because it has not considered cumulative impacts. The commenters contend that Region 10 must require Shell to perform a full impact analysis that considers numerous local sources of pollution as well as pollution generated by Shell before the Kulluk becomes an OCS Source. As support for this contention, commenters identify source of pollution near the leases on which Shell is seeking approval to drill including BP's Central Compression Plant, BP's Central Gas Facility, and 14 other sources. The commenters also cite to EPA guidelines on air quality modeling which states that "[a]ll sources expected to cause a significant concentration gradient in the vicinity of the source or sources under consideration for emission limit(s) should be explicitly modeled." 40 CFR Part 51, App. W § 8.2.3. The commenters continue that Shell has not complied with the guidelines because it has not properly determined which sources may cause a significant concentration gradient, but instead determined that its background measurements are overly conservative and therefore account for the potential effects of other sources. The commenters also reference Shell's statement that the largest source on the North Slope—BP's Central Compression Plant—is 11.5 kilometers from the monitoring location Shell uses for determining background pollution levels, and that there is no source that could be that distance or less from Shell's operations. From this, Shell asserts that no source could affect pollution levels at its drill site as much as BP's Central Compression Plant affects pollution levels at the background monitoring location, and that as a result no cumulative effects modeling is necessary. The commenters state that Region 10's approval of Shell's method of determining significant gradient areas is arbitrary because the method fails to take into account the grouping of sources and local meteorological conditions. The commenters request that Region 10 determine which sources could have overlapping emissions with Shell's source, and direct Shell to model those sources.

Response: Contrary to the commenter's allegation, Region 10 did consider the local meteorological conditions and source groupings. The Central Compressor Plant (CCP)/Central Gas Facility (CGF) complex is the largest NO_X source in Prudhoe Bay. A Pad lies in the predominate downwind direction of this complex. Since the A Pad station measures the impacts that occur from the CCP/CGF complex at a downwind distance of 11.5 kilometers, and since there are no lease blocks within this distance of the CCP/CGF complex, A Pad does account for the possible impacts from CCP/CGF.

The use of A Pad data does even more than account for the impacts from CCP/CGF. Located in-between A Pad and the CCP/CGF complex lies Gathering Center 3 (GC-3) and the Central Power Station (CPS). The potential NO_X emissions from GC-3 is just under 2,900 tons per year. The potential NO_X emissions from CPS are just under 4,000 tons per year. Therefore, the A Pad station not only measures the downwind impacts from CCP/CGF, it also measures the downwind impacts from two other substantive stationary sources. This is the worst-case alignment of Prudhoe Bay stationary sources. Since the distance between A Pad and CCP/CGF represents the nearest distance between any lease block and North Slope source, the data measured at A Pad does in fact represent the worst-case impact from off-site sources. Thus, Region 10 did consider local sources of air pollution in concluding that the permit will assure compliance with the NAAQS. With respect to emissions from Shell's operations before the Kulluk becomes an OCS source, please see response to comment Y.1.

Comment Y.3: Commenters contend that Region 10 has not assessed the combined impact of multiple drilling operations and question why EPA is assessing permit applications separately. The commenters characterize this as a partial, not complete, analysis and request that the Region assess the cumulative effects of the Kulluk, Discoverer, and ConocoPhillips operations. One commenter stated that these drilling operations could be functioning together in real life but that the draft permits for these operations do not reflect the other operations. The commenter requested that Region 10 take a comprehensive look at the cumulative impacts of all permits.

Response: Region 10 disagrees with the commenter that it is not assessing the cumulative impacts of the three drill rigs. As explained at the informational meeting, the Clean Air Act permitting programs are essentially "first come, first served" programs and each subsequent permitting action needs to account for all of those that went before but not any actions that will occur subsequent to that action. The permits for the Discoverer drill ship in the Chukchi Sea and Beaufort Sea are the first permits in their respective vicinities and they only need to assess their impacts on the existing air quality situation.

The Kulluk drill rig in the Beaufort Sea is the second permit and EPA has addressed cumulative impacts by including conditions in the permit that prevent Shell from operating the Kulluk drill rig and the Discoverer drill ship in the Beaufort Sea during the same drilling season. Permit Condition D.4.8. As such, only one of the two drill rigs can operate in the Beaufort in any year so there will be no overlapping impacts with respect to compliance with short term NAAQS. And since the modeling analyses show that each drill rig individually would not violate ambient standards if they operated in the Beaufort Sea for three consecutive years, any combination of years would also not violate annual NAAQS.

As discussed above, ConocoPhillips has withdrawn its permit application for operation of a jack-up drill rig in the Chukchi Sea.

Z. APPLICABILITY OF PSD INCREMENT AND VISIBILITY PROTECTION

Z.1 IN GENERAL

Comment Z.1.a: Although commenters support Region 10's determination that the Kulluk is a Title V temporary source, commenters state that the draft permit for the Kulluk is unlawful because it does not include conditions that will assure compliance with all applicable requirements of the CAA at all authorized locations. In particular, the commenters contend, Region 10 has failed to assess whether emissions from Shell's Kulluk operations will exceed applicable air increments. The commenters assert that, through the creation of limits called "increments," Congress designed the CAA not only to clean up dirty air but also to prevent the degradation of clean air. The commenters cite to language in CAA § 504(e) and similar language in 40 CFR Part 71 stating that no operating permit shall be issued to a temporary source "unless it includes conditions that will assure compliance with all the requirements of [the Clean Air Act] at all locations, including, but not limited to, ambient standards and compliance with any applicable increment or visibility requirements . . . ." The commenters continue that Region 10 has both identified an offshore "baseline area" to assess increments in the Chukchi and Beaufort Seas and identified a "minor source baseline date" (namely, July 31, 2009) for SO_2, NO_2, and PM. Because the minor source baseline date has passed, the commenters assert, the CAA "places strict limits on aggregate increases in pollution within the baseline area whether the increases come from minor or major sources," citing as support *Great Basin Mine Watch v. EPA*, 401 F.3d 1094, 1096 (9th Cir. 2005), *Reno-Sparks Indian Colony v. U.S. E.P.A.*, 336 F.3d 899, 903 (9th Cir. 2003), and 75 Fed. Reg. at 64,864, 64,868 (October 20, 2010)("After the minor source baseline date, any increase in actual emissions (from both major and minor sources) consumes the PSD increment for that area.")(parenthetical added for emphasis). The commenters state that increments are thus applicable to all sources—both major and minor. The commenters further assert that EPA's interpretation that a demonstration of compliance with increments is not required to issue Title V permits to temporary sources that are not PSD major source is inconsistent with the statutory language of CAA § 504(e), EPA's own Part 70 and Part 71 regulations, and the preamble to the Part 70 regulations. The commenters also state that Region 10 is only interpreting a part of the statutory language, therefore missing both the meaning and the intent behind the provision pertaining to temporary sources. Because Region 10 did not analyze Shell's compliance with applicable increments or impose permit conditions to ensure compliance with them, the commenters conclude, the draft permit does not ensure compliance with increments and the permit violates CAA § 504(e).

Response: EPA agrees with the commenters that all emission increases and decreases from both major and minor sources (with only a few exceptions provided for in the PSD statute[16]) occurring after the minor source baseline date is triggered, will consume or expand available increment. However, EPA does not agree that the CAA and regulations applicable in this instance require that Shell demonstrate that the Kulluk will not cause a

[16] See CAA § 163.

violation of the PSD increments in order to obtain the type of permit issued by EPA in this case.

The fact that minor source emissions consume increment does not necessarily mean that a minor source permit applicant is required to demonstrate that its proposed action will not cause or contribute to a violation of the increment to obtain a minor source construction permit. The criteria that must be met to obtain a minor source construction permit in this case are principally based on the terms of the minor source permitting program approved by Region 10 as part of the COA regulations. In this instance, the applicable Alaska regulations approved by EPA (18 Alaska Administrative Code (AAC) 50.502) do not require that a minor source permit applicant demonstrate that it will not cause or contribute to a violation of the PSD increment in order to obtain this type of permit.

The CAA and EPA regulations do not require that state minor source permitting programs contain criteria that require a minor source permit applicant to demonstrate that proposed construction will not cause a violation of a PSD increment. This is something states have the discretion to require, but is not a mandatory requirement under the provisions of the CAA or EPA regulations applicable to minor source permitting programs.

Section 110(a)(2)(C) of the CAA sets forth the basic requirement for preconstruction permits for both major and minor sources. Specifically, Section 110(a)(2)(C) states that the implementation plan shall:

> (C) include a program to provide for the …. regulation of the modification and construction of any stationary source within the areas covered by the plan as necessary to assure that national ambient air quality standards are achieved, including a permit program as required in parts C and D;

The permit program required in Part C of the CAA applies to major emitting facilities as defined in Section 169(1) of the CAA and the permit program required in Part D of the CAA applies to major stationary sources as defined in Section 302(j) of the CAA and in the various pollutant specific subparts of Part D. Only the major emitting facilities subject to the Part C permitting program (also referred to as the PSD permitting program) are expressly required under the CAA to demonstrate compliance with applicable PSD increments in order to obtain a permit to construct. See CAA § 165(a)(3)(A). New and modified stationary sources that are not major emitting facilities subject to the Part C permitting program are only required to demonstrate that the NAAQS will be achieved unless the applicable implementation plan provides otherwise. See CAA § 110(a)(2)(C); 40 CFR §§ 51.160(a)(2) and (b)(2).

For non-PSD sources, a state air quality management authority has a responsibility to ensure that its state implementation plan contains measures to prevent significant deterioration of air quality in accordance with section 161 of the CAA and 40 CFR §§ 51.166(a)(1) of EPA’s implementing regulations. However, these provisions leave states with the discretion to determine whether it is necessary to require minor sources to demonstrate that they will not cause a violation of any PSD increments as a condition of obtaining a minor source permit. In this instance, Alaska has not adopted minor source permit program regulations that require a showing that a minor source will not cause a violation of an increment in order to obtain the appropriate construction permit. Thus, the minor source COA regulations applicable to this source do not require a source to demonstrate compliance with PSD increments.

Furthermore, as discussed in the Statement of Basis (at 26), EPA does not interpret CAA § 504(e) to create new permitting requirements for temporary sources with respect to demonstrating compliance with increments beyond what would otherwise be applicable to such sources under applicable CAA construction permitting programs. The statute states in relevant part that:

> The permitting authority may issue a single permit authorizing emissions from similar operations at multiple temporary locations. No such permit shall be issued unless it includes conditions that will assure compliance with all applicable requirements of this chapter at all authorized locations, *including but not limited to ambient standards and compliance with <u>any applicable</u> increment or visibility requirements under part C of subchapter I of this chapter*.

CAA § 504(e) (emphasis added).

The difference in phrasing here is important: ambient standards are referenced without qualification, whereas increment and visibility requirements are prefaced with "any applicable" and followed by "under part C of subchapter I of this chapter." Based on this distinction, EPA reads this provision of the Clean Air Act to require that all Title V temporary sources[17] demonstrate that the source will not violate ambient standards (NAAQS) at all authorized locations but that such a source need only assure compliance with increment at all locations where the source is otherwise required to show it will not cause of violation of increments under part C of subchapter I of this chapter, such as through section 165(a)(3) of the CAA and the applicable PSD permitting program in the case of major sources or other provisions in an implementation plan or COA regulation that implement Section 161 of the Act and may also apply to minor sources.

The language used in Section 504(e) is consistent with the provisions in the CAA and EPA's regulations described above that make the ambient standards (the NAAQS) applicable to all stationary sources (both minor and major) at the time of construction permitting, but that make the increment requirements in Part C only applicable to certain stationary sources, that is PSD major sources or minor sources when applicable under an applicable minor source permitting program. This reading of the statute gives meaning to the different language that Congress used when referring to the ambient standards on the one hand and the Part C requirements for increments on the other hand.

[17] This term includes any source that would move more than once during the life of its Title V operating permit. See Memorandum to Docket A-90-33, re: Docketing of Detailed Responses to Comments on the Part 70 Operating Permit Regulations, at 6-34. It thus includes both PSD portable sources and PSD temporary sources.

Similarly, there is no indication in EPA's promulgation of the regulations implementing Section 504(e) that EPA interpreted that section of the CAA to impose on Title V temporary sources that are not also PSD major sources a direct requirement to demonstrate compliance with increment in the Title V permitting process. The thirteenth item in EPA's definition of "applicable requirement" in the Part 70 or Part 71 Title V regulations reads as follows: "Any national ambient air quality standard or increment or visibility requirement under part C of title I of the Act, but only as it would apply to temporary sources permitted pursuant to section 504(e) of the Act." 40 CFR § 70.2; 40 CFR § 71.2. The last clause makes clear that the NAAQS, increment, and visibility requirements are applicable requirements for Title V applicants only to the extent required under section 504(e) of the Act. Thus, this provision of the regulations was clearly not intended to require more than the cited provision of the Clean Air Act would otherwise require. As discussed above, because the reference to the increment in section 504(e) of the CAA is modified by the phrase "any applicable," the regulatory language EPA adopted in section 71.2 is likewise limited to requiring a Title V temporary source to demonstrate compliance with the increment where otherwise applicable under construction permitting programs.

Comment Z.1.b: Commenters state that, in the Statement of Basis (at 25), Region 10 attempts to justify its wholesale failure to address compliance with increments by suggesting that they are applicable only where a source "would otherwise be subject to PSD" and that Region 10 bases this conclusion on the observation that the word "applicable" precedes "increment" in CAA § 504(e). The commenters assert that this interpretation is wrong as a matter of law because, once triggered by a major source permit application in an area, increment limits apply to both major and minor sources. The commenters contend that Section 504(e) does not create a different rule for Title V temporary sources and, indeed, states that a Title V permit shall not be issued to a temporary source "unless it includes conditions that will assure compliance with all the requirements" of the CAA. The commenters state that the term "applicable" as used in CAA § 504(e) is not a reference to the applicability of general PSD requirements to a particular source, but rather refers to whether a major source application has triggered increment requirements for the relevant baseline area within which the temporary source is expected to operate and thus made such requirements "applicable." As support, the commenters state that, in promulgating its Title V implementing regulations, EPA declared that "NAAQS and the increment and visibility requirements under part C of title I of the Act are applicable requirements for temporary sources . . . ." Because in this case, previous major source applications have triggered the increment requirements in the area, the commenters state that Region 10 must ensure that the permit meets those requirements.

Response: EPA agrees that, once a minor source baseline date is triggered, emission increases and decreases of all sources, including minor sources after the minor source baseline date, will consume or expand increment. However, the increments themselves are not directly applicable as permitting criteria for sources that are not otherwise required to demonstrate compliance with increments to obtain a construction permit. As discussed above the state air quality management authority is required under Section 161 of the CAA and 40 CFR §§ 51.166(a)(1) of EPA's implementing regulations to adopt measures in its SIP to prevent significant deterioration. States have the discretion to determine the types of measures that are needed to meet this objective and are not expressly required to mandate that minor sources demonstrate they will not cause a violation of an increment to obtain a construction permit. When an air pollution authority finds that these measures have not been successful and an increment violation has occurred, it must revise its SIP to adopt emission limitations or other control measures to remedy the violation. 40 CFR § 51.166(a)(3).

As discussed in the response to comment Z.1.a above, EPA does not interpret section 504(e) and EPA's Part 71 regulations to require non-PSD sources to demonstrate compliance with increments in order to get a Part 71 operating permit when the applicable state or federal implementation plan does not otherwise require such a demonstration. The commenter quotes the thirteenth item in the definition of applicable requirement, but neglects to reference the last clause of this provision, which reads as follows "but only as it would apply to temporary sources permitted pursuant to section 504(e) of the Act." As discussed above, this clause indicates that EPA's regulations do not create any additional requirements for stationary sources beyond what the Act would require. Thus, EPA is not persuaded by commenter that the "any applicable" language that precedes the reference to increments is only intended to reference circumstances when a major source permit application has triggered increment requirements in a baseline area.

If, at any time after the Kulluk begins operation under its Title V/OCS permit, Region 10 determines that the actual emissions increases from the permitted OCS source cause or contribute to an increment violation,[18] Region 10 has authority to adopt additional requirements to ensure that increments are not violated. See CAA §§ 301 and 328; 40 CFR § 55.13(h). However, as shown in the Technical Support Document (Table 11, at 33) and confirmed by the comments of the North Slope commenters' (see Table 3 at page 13), the modeling analysis for this project shows that the allowable emissions would not cause or contribute to a violation of any increment where the minor source baseline has already been triggered. And, as discussed below in the response to comment Z.2.a, $PM_{2.5}$ emissions from the Kulluk will be part of the baseline concentration and will not consume any of the available $PM_{2.5}$ increment. So, although EPA does not believe that CAA § 504(e) and 40 CFR Part 71 require a demonstration of compliance with increments in this Title V permit issuance process, the modeling analysis supporting this permit actually demonstrates that PSD increments will not be violated.

Comment Z.1.c: Commenters state that EPA's regulations fail to support the interpretation that increment and visibility are not "applicable requirements" for minor sources under CAA § 504(e) and 40 CFR Part 71. According to the commenters, EPA's regulations explain that "[p]ermits for temporary sources shall include the following: (1) Conditions that will assure compliance with all applicable requirements at all authorized

[18] 40 CFR § 52.21(b)(13) (definition of "baseline concentration" is in terms of actual emission increases and decreases).

locations ....," citing to 40 CFR § 71.6(e). The commenters continue that the Part 71 regulations also include a definition of "applicable requirement" that includes thirteen requirements, including "(2) Any terms or condition of the preconstruction permits issued pursuant to regulations approved or promulgated through rulemaking under title I, including parts C and D, of the Act" and "(13) Any national ambient air quality standard or increment or visibility requirement under part C of title I of the Act, but only as it would apply to temporary sources permitted pursuant to section 504(e) of the Act," citing to 40 CFR § 71.2 (definition of applicable requirement). The commenters contend that EPA's interpretation of this definition reads the thirteenth requirement out of the regulations because, under Region 10's interpretation, the thirteenth requirement is subsumed by the second requirement. Thus, the commenters conclude, an interpretation that requires temporary sources to comply with the NAAQS, increments, and visibility standards is the only reading that gives meaning to all the regulatory provisions in the definition of applicable requirement. Commenters also cite to language in the in the preamble to the final Part 70 rule which states that "Temporary sources must comply with these requirements because the SIP is unlikely to have performed an attainment demonstration on a temporary source."

Response: EPA disagrees with the commenter's assertion that its interpretation of the thirteenth requirement does not give meaning to all of the regulatory provisions in the definition of "applicable requirement." The commenters argue that EPA's interpretation would be subsumed by the second requirement – that the permit include the terms and conditions of any preconstruction permit. However, the commenter fails to recognize that the permit for a portable (temporary) source that would be issued pursuant to the PSD regulations, specifically 40 CFR § 52.21(i)(1)(viii), is not required to assure compliance with the NAAQS or increments at all future locations. Rather, the PSD permit must only ensure that, at future locations, emissions from the permitted source would not impact a Class I area or an area where the increment is known to be violated. The PSD permit for a portable source would not thus not be required to ensure that the PSD portable source would not cause a new increment violation at a future location or that it would not have a local visibility impact at a future location. So while EPA's interpretation is that Title V temporary sources that are not PSD sources do not need to demonstrate compliance with PSD increments and visibility requirements unless otherwise required by the applicable implementation plan, Region 10's interpretation does result in the imposition through the Title V permit of additional requirements on PSD sources beyond the conditions that would be included in a PSD preconstruction permit under 40 CFR § 52.21. Region 10's interpretation thus maintains the basic premise of the CAA preconstruction programs—that PSD major sources are subject to NAAQS and increment in the permitting process, where as non-PSD sources are subject only to the NAAQS unless the applicable minor source program also includes the increment—yet still has meaning by imposing on Title V temporary sources the requirement to demonstrate at subsequent locations that they continue to comply with those underlying applicable preconstruction requirements at each subsequent location.

With respect to the language in the preamble to the final Part 70 rule cited by the commenters with respect to Title V temporary sources, there is nothing in that language to suggest that EPA interpreted Section 504(e) of the Clean Air Act to change the basic premise of the Clean Air Act permitting scheme for PSD sources versus non-PSD sources, namely, that PSD sources are directly subject to NAAQS and increment requirements, whereas non-PSD sources are not required to show they will not cause a violation of the increment unless the applicable implementation plan otherwise requires it for such sources. If a non-PSD Title V source applied for a preconstruction permit at one location and then applied for a new preconstruction permit to move to a new location, the source would have to demonstrate compliance with the NAAQS at each location as a condition of obtaining a permit, but would not have to demonstrate compliance with increment at either location absent a similar requirement for minor sources in the applicable implementation plan. In contrast, a PSD source that applied for a preconstruction permit at one location and then applied for a new preconstruction permit to move to a new location would have to demonstrate compliance with the NAAQS and increment at both locations. EPA believes the intent of the Title V temporary source provisions is to relieve sources of the burden of applying for Title V permits for each new location, while at the same time, assuring compliance with all requirements to which the source would be subject if it were a new source at each such new location.

Comment Z.1.d: Commenters assert that, in light of the statutory and regulatory language and the special treatment given to temporary sources in the 1990 amendments to the Clean Air Act, it is appropriate that compliance with both the increments and visibility requirements is ensured for these permits. The commenters state that this is particularly critical because of the proximity of these operations to the Arctic National Wildlife Refuge, (ANWR) and that the OCS regulations provide that EPA "shall not issue a permit to operate to any existing OCS source that has not demonstrated compliance with all applicable requirements of this part."

Response: See the response to comments Z.1.a-Z.1.c above in general with respect to the applicability of increments to Title V temporary sources that are not PSD major sources. EPA has determined that visibility is similarly not an applicable requirement for Title V temporary sources that are not PSD major sources for the reasons set for in the Statement of Basis and response to comments Z.1.a-Z.1.c. In addition, ANWR is not a federal Class I area and as such, the increment and visibility requirements of Part C that apply to federal Class I areas are not relevant for ANWR.

Comment Z.1.e: Commenters state that EPA's regulations for SIPs provide that "[in accordance with the policy of Section 101(b)(1) of the CAA and for the purposes of section 160 of the Act, each applicable State Implementation Plan and each applicable Tribal Implementation Plan shall contain emission limitations and such other measures as may be necessary to prevent significant deterioration of air quality." 40 CFR § 51.166(a). This regulatory provision, the commenters continue, supports the need for the SIP to protect increments. Therefore, the commenters contend, even though the SIP would not have accounted for the temporary sources in assuring protection of the increments, any Title V temporary source permitted under Part 71 must demonstrate compliance with the increments in order to ensure all SIP requirements are met. Commenters contend that the Part 70 regulations pertain to State Implementation Plans and that the oil and gas companies have advocated that such requirements only apply in the inner OCS *(i.e.*, within 25 miles of the State's seaward boundary). The commenters assert, however, that CAA § 328 makes it clear that EPA "shall establish requirements to control air pollution from Outer Continental Shelf sources located offshore ... to attain and maintain Federal and State ambient air quality standards and to comply with the provisions of' the PSD program." The commenters therefore assert that, because the goal of CAA § 328 is attainment of air quality standards, it matters little whether the source is located on the inner or outer OCS, because in both cases the relevant SIP will not have performed an attainment demonstration for such sources. Because the preamble to the Part 71 regulations relies upon the reasoning put forth by EPA in developing the Part 70 regulations, especially in discussing applicable requirements, the statutory and regulatory language for Part 70, as well as EPA's regulatory preambles, all support a finding that the NAAQS, increments, and visibility requirements are all applicable to temporary OCS sources under Part 71.

Response: See the other responses to comments in this Subcategory Z.1 with respect to the applicability of increments and visibility requirements to Title V temporary sources that are not subject to PSD permitting. Region 10 agrees that, in general, there is no intention for the Part 71 federal operating permit program that applies on the outer OCS to be different from the onshore Part 70 operating permit program that Region 10 has incorporated by reference in the COA regulations for application in the inner OCS (the only differences would be the result of differences between the State adopted program and EPA's Part 71 regulations). In this case, the requirements for Title V temporary sources in the inner OCS and outer OCS off of Alaska are the same because Alaska has adopted EPA's Part 71 rules with respect to Title V temporary sources by reference for application onshore and Region 10 has in turn adopted these requirements into the COA regulations for application in the inner OCS.

Region 10 does not agree with the rationale put forth by the commenters, however, that in both cases the relevant SIP will not have performed an attainment demonstration because there is no SIP (or implementation plan equivalent) for the outer OCS. Section 328 does not require EPA to establish an implementation plan or other comprehensive air quality management program for the outer OCS. It only requires EPA to adopt regulations for OCS sources and even then, only for certain purposes. Nonetheless, as discussed in response to comment Z.1.e, EPA does have authority to address violations of increment on the inner and outer OCS.

Z.2 SUBCATEGORY – $PM_{2.5}$ INCREMENT

Comment Z.2.a: Commenters state that the Kulluk operations, as proposed, do not comply with the 24-hour average Class II PSD increment for $PM_{2.5}$. Commenters note that on October 20, 2010, EPA adopted a final regulation that went into effect on December 20, 2010 and that establish new PSD increments for $PM_{2.5}$ that went into effect on October 20, 2011. The commenters assert that Section 328 states that "[n]ew OCS sources shall comply with such requirements on the date of promulgation," citing to CAA § 328. The commenters state that, as a "new OCS source" yet to commence operation, Shell's proposed arctic drilling operations must comply with all NAAQS and PSD program requirements that pre-date commencement of operations, including the new $PM_{2.5}$ increments, citing to 42 U.S.C. §§ 7411(a)(2), 7475(a), 7627(a)(1) and (a)(4)(D). Moreover, with respect to OCS sources, the commenters continue, Congress clearly prohibited grandfathering by directing that even "existing OCS sources shall comply on the date 24 months" after promulgation of standards. Commenters state that application of the $PM_{2.5}$ increment is important for Shell's permit because Shell's modeling indicates that Shell's emissions could increase the 24-hour $PM_{2.5}$ concentrations by 17 ug/m^3, which substantially exceeds EPA's newly enacted $PM_{2.5}$ increment of 9 ug/m^3.

Response: For a discussion of why PSD increments are not applicable to this permit, please see responses to comments in Subcategory Z.1.

With respect to the new $PM_{2.5}$ increments, emissions from the Kulluk and the Associated Fleet, which is a minor source for purposes of the PSD regulations, will be part of the baseline concentration and therefore, will not consume any of the available $PM_{2.5}$ increment. See CAA § 169(4) (definition of "baseline concentrations"); 40 CFR § 52.21(b)(13). Until the $PM_{2.5}$ minor source baseline date is triggered (*i.e.*, any date on or after October 20, 2011—the "trigger date" for $PM_{2.5}$ increments) by submittal of a complete PSD permit application for a source that has significant $PM_{2.5}$ emissions, emissions from minor sources are part of the $PM_{2.5}$ baseline concentration and do not consume increment. Since a complete PSD permit application has not been submitted to Region 10 for a new major source on the Alaska OCS nor to ADEC for a new major source or a major modification to an existing major source in the Northern Alaska Intrastate Air Quality Control Region after the trigger date and prior to the issuance of the Kulluk minor source permit, emissions from the Kulluk will not consume any of the $PM_{2.5}$ increment.

In any event, Region 10 does not interpret the cited language from the Clean Air Act to address when new regulatory standards take effect. Section 328 authorized EPA to issue regulations to establish requirements to control air pollution from OCS sources. It directed that "[n]ew sources shall comply with such requirements on the date of promulgation and existing sources shall comply on the date 24 months after. EPA promulgated the regulations authorized by Section 328 on September 4, 1992, and they became effective on that date. 57 Fed. Reg. 40,792 (September 4, 1992). This is confirmed by the language of 40 CFR § 55.3(d), which mandates that that new sources "shall comply with the requirements of this part by September 4, 1992." The permit fully complies with that provision by requiring the sources to comply with the requirements of Part 55.

Although this permit does not need to include an air quality analysis with respect to the new $PM_{2.5}$ increment, Region 10 has nonetheless considered the new $PM_{2.5}$ increment in connection with Region 10's responsibilities under Executive Order 12898 entitled "Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations." Exec. Order 12898, 59 Fed. Reg. 7,629 (Feb. 16, 1994). As discussed in the Technical Support Document (at 20-22 and 33), the emissions of the

Kulluk and the Associated Fleet, when operating in compliance with permit requirements, will not cause or contribute to a violation of the $PM_{2.5}$ NAAQS. For purposes of the Executive Order on Environmental Justice, the EAB has recently confirmed that "compliance with the NAAQS is emblematic of achieving a level of public health protection that, based on the level of protection afforded by the NAAQS, demonstrates that minority or low-income populations will not experience disproportionately high and adverse human health or environmental effects due to exposure to relevant criteria pollutants." Remand Order I at 73. This is because the NAAQS are health-based standards, designed to protect public health with an adequate margin of safety, including sensitive populations such as children, the elderly, and asthmatics and is supported by the fact that "[t]he Agency sets the NAAQS using technical and scientific expertise, ensuring that the primary NAAQS protects the public health with an adequate margin of safety." Id. Region 10 does not believe there will be a disproportionately high and adverse human health or environmental effects due to exposure to $PM_{2.5}$ emissions because the permit ensures that emissions from the Kulluk and the Associated Fleet will not cause or contribute to a violation of the $PM_{2.5}$ NAAQS anywhere within ambient air to which the public has access and EPA has not made any findings that the current $PM_{2.5}$ NAAQS are inadequate to protect public health. In contrast to the NAAQS, which are set at a level to protect public health, CAA § 109, PSD increments are established to prevent the significant deterioration of air quality, CAA § 166. EPA's consideration of the health and welfare effects of $PM_{2.5}$ in the context of carrying out the statutory requirement to balance the goals of CAA §§ 101 and 160 (to protect public health and welfare, parks, and air quality related values and to insure economic growth) in setting increment does not support a conclusion that $PM_{2.5}$ emissions at levels below the level of the NAAQS have an adverse effect on public health.

Comment Z.2.b: Commenters also state that, for Title V permits, "applicable requirements" include "requirements that have been promulgated or approved by EPA through rulemaking at the time of issuance but have future compliance dates." Because the new increments have already been established by EPA by regulation, the commenters assert, Shell must demonstrate compliance with them. The commenters contend that, with the proposed Kulluk operations, Shell has consumed almost two times the available increment and would not be able to demonstrate compliance with these increments as of the time that the minor source baseline date is established. Even if the permits are issued prior to the establishment of the minor source baseline date, the commenters continue, Shell should be required to demonstrate that it will comply with the $PM_{2.5}$ increments prior to commencement of operations.

Response: As discussed above in the response to comment Z.2.a, the emissions from the Kulluk will not consume $PM_{2.5}$ increment because the Kulluk will be an existing source if and when the minor source baseline date for the $PM_{2.5}$ increment is triggered. Therefore, any $PM_{2.5}$ concentrations attributable to the Kulluk, such as the modeled 17.0 ug/m^3, 24-hour concentration, will simply increase the $PM_{2.5}$ baseline concentration for the area.

AA. CATEGORY – VISIBILITY PROTECTION

Comment AA.1: Commenters state that Region 10 must ensure that the permitted temporary source will not adversely impact visibility in the region including in nearby refuge lands, such as ANWR, located adjacent to Kaktovik, which is as close as 14 kilometers (8 miles) from the nearest lease area. Commenters state that Congress has recognized the "unique wildlife, wilderness and recreational values" of ANWR. Commenters also contend that Part C of the Clean Air Act recognizes the importance of protecting air quality of areas with unique wildlife and recreational values, such as ANWR and that the CAA establishes the need to "preserve, protect and enhance the air quality ... areas of natural, recreational, scenic or historic value" and to "insure economic growth will occur in a manner consistent with the preservation of existing clean air resources." The commenters generally support responsible onshore oil and gas development, including in ANWR, and also agrees with the CAA goal of protecting clean air. Given the proximity of ANWR to the proposed areas of operation, however, the commenters state that Region 10 must consider the air quality impacts, including visibility, to this area.

Response: See the responses to comments in Subcategory Z.1 for Region 10's determination that the visibility requirements of Part C of the CAA are not applicable requirements for purposes of this permit. In addition, the visibility requirements of Part C apply only to federal Class I areas, and ANWR is not a federal Class I area. While the general language in the purpose statement of Part C (specifically CAA § 160) speaks in general of preserving, protecting, and enhancing air quality in areas of special national interest, the statute then goes on to establish the specific provisions for designating certain federal lands as "Class I" areas and establishing stringent requirements for protecting visibility and other air quality related values of the areas . See CAA §§ 162(a), 164(a), 165(a)(5), and 165(d)). Other federal lands, such as ANWR, are not Class I areas under the CAA and therefore receive the same level of air quality protection as any other lands that are not Class I areas.

Similarly, the specific requirements of Part C for the protection of visibility are even more limited – just to the mandatory federal Class I areas established by Congress in section 164(a) of the CAA. See §169A(a)(1). Again, ANWR is not a mandatory federal Class I area and, as such, the visibility requirements of Subpart 2 of Part C of the CAA are not applicable.

Comment AA.2: In addition to the basic provisions for preventing significant deterioration of air quality under the CAA, commenters state that other authorities also seek to protect air quality related values (AQRVs), such as visibility, in areas designated as Class II air sheds. The commenters state that the Fish and Wildlife Service (FWS), the Federal Land Manager (FLM) of ANWR, suggests that "planning, research and monitoring outlined ... for Class I areas can also be applied in Class II areas" and further notes that "information on air quality and AQRVs of a Class II area is important for comprehensive management of these refuge resources." The commenters contend that one of the FWS' broadly stated goals is to "[i]dentify and recommend solutions for external threats to refuge habitats, such as air and water quality." The commenters further state that emissions can be seen at distances greater than the eight miles that Shell will be from ANWR. For example, the commenters contend, the modeling prepared for the Shell oil shale research, development and demonstration (RD&D) Environmental Assessments (EAs) in northwest Colorado predicted that on 8-14 days per year, the visibility "limit of acceptable change" would be exceeded as a direct result of the Shell projects (not considering cumulative sources) at Flat Tops Wilderness Area, roughly 50 miles from the proposed source. The commenters continue that, while this particular project predicted greater emissions than projected emissions from Shell exploration activities with the Kulluk, the distances at which visibility impacts were predicted indicate that, even at lower emission rates, the Kulluk operations have the potential to impact visibility onshore and in ANWR. Given the potential for visibility impacts in the FWS managed area, the commenters conclude, Region 10 must, at a minimum, notify FWS of the potential visibility effects of proposed offshore exploration activities on ANWR.

Response: Region 10 did provide notice of issuance of the draft permit to the FWS office responsible for managing ANWR. Region 10 recognizes that Federal Land Managers of areas that are not Class I areas under the CAA still have an interest in protecting air quality related values (including visibility) of those areas. However, as discussed above in the response to comment AA.1, the Clean Air Act provides no additional protections to such Class II federal lands. EPA and permitting authorities do often work with permit applicants and the Federal Land Managers to assess the effect that new emissions might have on such areas, but there is no requirement to do so.

BB. CATEGORY – ENVIRONMENTAL JUSTICE

BB.1 SUBCATEGORY – IN GENERAL

Comment BB.1.a: Commenters appreciate that Region 10 has conducted an analysis of compliance with the new 1-hour NO_2 NAAQS but are still concerned that the environmental justice analysis omits consideration of important factors that they believe may present a risk to human health and, therefore a disproportionate risk to environmental justice communities on the North Slope. The commenters state Region 10's reliance on a demonstration of compliance with the NAAQS in order to assess environmental justice considerations is inconsistent with the EAB's direction in remanding the permits for the Discoverer drillship to Region 10. The commenters contend that the existing modeling of compliance with the NAAQS appears to exclude any potential impacts from mobile source emissions that occur before the Kulluk is deemed to be an OCS Source and/or take place more than 25 miles from the OCS Source, including emissions while moving to the drill site, the emissions of the icebreaker/anchor handler while setting the anchors for the Kulluk, and the emissions from the fleet of support vessels, including icebreakers, before the Kulluk attaches to the first anchor. Although the commenters acknowledge that these emissions are not deemed to be emissions from the OCS source, they assert that Region 10 must provide a rational basis for whether and how the OCS Source and the Associated Fleet emissions have been analyzed in combination with the mobile source emissions in assessing potential adverse health impacts to local communities, both onshore and in offshore areas used for subsistence purposes. The commenters are concerned that the NAAQS analysis, in and of itself, does not account for the potential combined impacts of the stationary and mobile source emissions, which could be relevant considerations in assessing potential health impacts from short-term and long term exposure to NO_2 as well as exposure to ozone, $PM_{2.5}$, and PM_{10}, among other pollutants. The commenters contend that Region 10 has some leeway in making sure these emissions are considered and that the ships are set up in such a way so as to bring down emissions to where they need to be.

Response: Executive Order 12898 provides that "[t]o the greatest extent practicable and permitted by law, and consistent with the principles set forth in the report on the National Performance Review, each federal agency shall make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations in the United States and its territories and Commonwealth of the [Northern] Mariana Islands." Section 1-101 of Exec. Order 12898, 59 Fed. Reg. 7,629 (February 16, 1994). "Federal agencies are required to implement this order consistent with, and to the extent permitted by, existing law." Id. at 7632. As discussed in the Statement of Basis (at 54), the Title V operating permit program does not generally impose new substantive air quality control requirements and that, therefore, the primary means of addressing environmental justice issues in the Title V program is through increased public participation and review by permitting agencies and conditions to assure compliance with applicable requirements. Because the Title V permit in this case requires compliance with the NAAQS as an applicable requirement and established limits on PTE, Region 10 has considered environmental justice concerns in this action, where possible, in the context of assuring compliance with requirements applicable to the source. Id.

The language of the Executive Order directing federal agencies to identify and address impacts "as appropriate," and "[t]o the greatest extent practicable and permitted by law" imparts considerable leeway to federal agencies in determining how to comply with the spirit and letter of the Executive Order. Avenal Order at 24. In implementing Executive Order 12898, it is appropriate for the Agency to consider the best available data that are germane in light of the scope and nature of the action before the agency in analyzing whether there may be disproportionate adverse impacts on minority communities and low-income communities. Shell Remand Order I at 80, fn. 87; Avenal Order at 24. The EAB has recently confirmed that the Executive Order does not require EPA to reach a determinative outcome prior to issuing a permit, particularly when the available data is inconclusive. Avenal Order at 24.

The commenters acknowledge that the emissions it is asking Region 10 to consider—from the icebreaker/anchor handler while presetting the anchors for the Kulluk and from the fleet of support vessels before the Kulluk attaches to the first anchor—are mobile source emissions that occur before the Kulluk is deemed to be an OCS source and/or take place more than 25 miles from the OCS source. These mobile source emissions are therefore not subject to regulation under this permit and were not required to be addressed in Shell's application materials. Region 10 has nonetheless considered information available to it. While the Kulluk is in transit to the drill site it will be moving, which will reduce the impact of the emissions at any one location. In addition, Shell has committed to using only ultra-low sulfur diesel fuel for its OCS exploration activities north of Bering Strait, although the permit can only require its use while the Kulluk is an OCS source and the Associated Fleet is within 25 miles of the source. This is expected to significantly reduce ambient concentrations of SO_2 well below the NAAQS for SO_2 and will also result in a reduction of particulate matter.

Shell's Exploration Plan discusses vessels relating to the Kulluk's operations that are not considered part of the Associated Fleet because they always will be located more than 25 miles from the Kulluk while the Kulluk is an OCS source. 2012 Revised Camden Bay Exploration Plan, Section 13.0. The Exploration Plan, however, does not include estimates of air emissions from these other vessels during the time they are more than 25 miles from the Kulluk or before the Kulluk becomes an OCS source. Region 10 does not have sufficient information regarding these emissions to conclude with certainty that consideration of these emissions, in conjunction with emissions authorized under the permits, would not cause or contribute to a violation of the NAAQS. However, Region 10 does not expect these additional emissions to do so because the vessels in question are expected to be in transit during this time period. Because compliance with the NAAQS is considered with respect to a specific location and because these vessels are expected to be moving during the activities in question, the impact of emissions from these vessels during these activities would be dispersed during transit and the impact at any one location would not be as great as would be the same level of emissions from a stationary source. To the extent any of these vessels would be stationary for any extended period of time, Region 10 expects that such vessels would be anchored and not using their propulsion engines, the emission units that would be expected to have the highest emissions on these vessels.

In summary, although Region 10 has insufficient information to conclude that consideration of emissions from these different vessels and activities would not, in conjunction with emissions authorized under the permits, cause or a contribute to a violation of the NAAQS, Region 10 also has no information to suggest that they would do so. Region 10 therefore has no basis to conclude that, even considering these other vessels and activities in conjunction with emissions authorized under the permits, issuance of these permits would have a disproportionately high and adverse human health or environmental effects on minority populations and low-income populations.

Comment BB.1.b: A commenter states that the fact that Shell's operations comply with the NAAQS alleviates any environmental justice concerns in the local communities as both EPA and the EAB have repeatedly stated that in the context of an environmental justice analysis compliance with the NAAQS is "emblematic" of achieving the requisite level of public health and environmental protection, with a built-in margin of safety. The commenter also notes Region 10's statements that the concentration of air pollutants in the local communities would be "well below" the NAAQS, including emissions from Shell's operations and background concentration of air pollutants.

Response: Region 10 agrees with the commenter that, in the context of an environmental justice analysis, compliance with the NAAQS is emblematic of achieving a level of public health protection that based on the level of protection afforded by the NAAQS demonstrates that minority and low-income populations will not experience disproportionately high and adverse human health or environmental effects due to exposure to relevant criteria pollutants. Region 10 also agrees with the commenter that the concentration in the local communities of air pollutants authorized under this permit is expected to be well below the NAAQS.

Comment BB.1.c: Commenters state that the environmental justice concerns of communities of federally recognized tribes and peoples that inhabit the Arctic have not been sufficiently considered and that Region 10 should do a more thorough analysis, looking at air pollution impacts on communities.

Response: As discussed in Section 5.4 of the Statement of Basis and Category BB of the Response to Comments, Region 10 believes it has considered environmental justice concerns in a manner consistent with the Executive Order. Region 10's analysis did consider air pollution impacts on local communities. The commenters have not identified any specific deficiencies in Region 10's environmental justice analysis.

Comment BB.1.d: A commenter states that Region 10 must also work harder to make sure the Kulluk and Conoco air permits allow for air pollution levels that do not harm people and the environment, especially as Alaska Native communities will be disproportionately impacted by these activities. The commenter states that there are already high levels of asthma in these communities from the flaring from onshore operations and in Cook Inlet. The commenter contends that EPA's reviewing court previously found that more analysis was needed to assess the impact to Alaska Native communities for Shell's Discoverer drillship permit and the Kulluk and ConocoPhillips permits are the same. As an example, the commenter states that Conoco can emit 39,800 tons per year of carbon dioxide and the Kulluk can emit 80,000 tons of carbon dioxide per year and those equal the greenhouse gas emission levels of about 9,500 households, when there are only 2,800 North Slope Borough households today. The commenter states that this is a huge increase. The commenter also notes concerns about black carbon.

Response: For the reasons discussed in the Statement of Basis, throughout this Response to Comments, and the other documents in the administrative record for this permit, Region 10 is proceeding to issue this permit because it complies with the requirements of CAA § 328, 40 CFR Part 55, and 40 CFR Part 71. Region 10 has conducted an extensive review and analysis of the air quality impacts of the project and has determined that the permit will not cause or contribute to a violation of currently applicable NAAQS. Environmental justice considerations were thoroughly considered to the greatest extent practicable and permitted by law, as discussed in the Environmental Justice Analysis and in this Response to Comments document. Region 10 has concluded that the activities to be authorized under the permit will not have disproportionately high and adverse human health or environmental effects with respect to air pollutants authorized under the permit on minority or low-income populations residing in the North Slope, including coastal communities closest to the proposed operations and including consideration of the impact on communities while engaging in subsistence activities in areas where such activities are regularly conducted. Environmental Justice Analysis at 2. Impacts from Shell's proposed operations in the onshore communities are low, with the highest modeled concentrations occurring at Nuiqsut, constituting 50% of the 1-hour NO_2 NAAQS. With respect to carbon dioxide and black carbon, see the discussion in Category BB.4. The commenter has not identified a legal basis for denying issuance of these permits. Region 10 has complied with the Executive Order on Environmental Justice.

Comment BB.1.e: A commenter states that Region 10 has a new or renewed formal commitment to environmental justice and does not believe that EPA has not demonstrated that Shell Oil will not adversely and cumulatively impact the human health as well as the health of the other living communities in the Beaufort Sea.

Response: Region 10 agrees that EPA is committed to environmental justice and implementing the Executive Order on Environmental Justice. As discussed in Section 5.4 of the Statement of Basis, Region 10 believes that the activities proposed to be authorized under the permit will not have disproportionately high and adverse human health or environmental effects with respect to NAAQS pollutants. See also the responses to other comments in Category BB for a discussion of other environmental justice concerns.

Comment BB.1.f: A commenter states that Region 10 should not permit the air pollution by either one of these companies but that Shell Oil has a larger operation and more emissions in the Beaufort. The commenter also states that the modeling conducted did not take into account from an environmental justice perspective the cumulative impacts to the communities that are already adversely impacted, including the accumulation of multiple sources of pollutants, both from the coast, onshore and offshore.

Response: Region 10 assumes that the reference to "either one of these companies" refers to Shell and to ConocoPhillips, because Region 10 proposed issuing permits to Shell for operation of the Kulluk in the Beaufort Sea and to ConocoPhillips for operation of a jackup rig in the Chukchi Sea on the same day. ConocoPhillips has since withdrawn its permit application and Region 10 will not be giving further consideration to issuance of that permit. In addition, as discussed in the responses to comments in Category Y, Region 10 did consider in issuing this permit the cumulative impacts for projects for which Region 10 has received permit applications. See also response to comment BB.1.a.

Comment BB.1.g: A commenter notes that EPA and Shell have established a solid track record of communication with the local communities regarding air permitting for Shell's exploration activities, including these draft air permits. The commenter further explains that this communication will continue and is in fact required under the draft permits once the permits are issued.

Response: The Kulluk Permit does require Shell to communicate with the local communities on a periodic basis regarding when exploration activities are expected to begin and end at a drill site, the location of the drill site, and any restrictions on activities in the vicinity of Shell's operations. Permit Condition D.5.1.2.2. The permit also requires Shell to submit reports to Region 10. See, e.g., Permit Conditions A.17, A.18, and A.19.

BB.2 SUBCATEGORY – PUBLIC PROCESS FOR EJ ANALYSIS

Comment BB.2.a: Commenters state that the limited public comment period presents serious environmental justice issues for North Slope communities because local communities were not given adequate opportunity to enlist technical support and provide relevant comments on the critical issue of the appropriate model to be used in assessing impacts to air quality as well as the permits more generally. The commenters state that Region 10 specifically requested input on the new air quality model used for the first time in these permit proceedings and that the modeling that went into that work took years to prepare. The commenters continue that evaluation of that work requires an extremely high level of technical expertise, which is both time consuming and resource intensive, and that the agency's decision to provide limited, overlapping comment periods for recognized environmental-justice communities to review, analyze, and then provide comment on a brand new, technical modeling exercise impairs their communities' ability to adequately participate in the process. As a result, the commenters contend, they are unable to submit comments on key aspects of the environmental justice analysis, namely whether the predicted impacts to air quality are accurate and defensible. The commenters ask that Region 10 provide adequate time to obtain an independent technical review of the chosen modeling methodologies and state that Region 10 should have given advanced public notice of this important issue in order to allow for technical review and comment on the modeling.

Response: As discussed above in the response to comments in Category C, Region 10 took a number of steps to provide the opportunity for meaningful involvement and to engage the local communities in this permitting action, including the approval of the model. Region 10 held three separate informational meetings in Barrow and Kaktovik prior to the public comment period to describe the upcoming permitting actions and public comment opportunities. Region 10 also held an informational meeting and a public hearing on the permit and the underlying model and invited the North Slope Borough, the Native Village of Kaktovik, and the Native Village of Nuiqsut to participate in government-to-government consultation in letters dated June 7, 2011. The 46 day public comment period is longer than required under 40 CFR Part 71 and 40 CFR Part 124. Moreover, as discussed in response to comment C.3, these commenters submitted comments on the modeling that was performed to support the Discoverer permits and those permits used the same model. Therefore, the commenters in fact had a period of approximately 60 days in which to review and comment on the model.

Comment BB.2.b: A commenter states that the government has a duty, as stated in Executive Order 12,898 on Environmental Justice, to protect communities and to make sure that the government is providing a meaningful opportunity for people to fully engage in the public process and share their concerns before decisions are made. Commenters contend that the comment period provided did not allow for meaningful public involvement.

Response: Region 10 agrees that the Executive Order on Environmental Justice calls on federal agencies to provide meaningful opportunities for involvement for communities of concern in decisions that potentially impact them. As described in Section 5.4 of the Statement of Basis and in response to comments BB.2.a and C.1, Region 10 believes it has provided North Slope communities potentially impacted by issuance of this permit with the opportunity for meaningful involvement in the decision-making process.

BB.3 SUBCATEGORY – 8-HOUR OZONE NAAQS

Comment BB.3.a: Commenters express concern that Region 10 did not consider a newly revised NAAQS– the 8-hour standard for ozone–in conducting its environmental justice analysis. The commenters note that EPA revised the 8-hour ozone standard because the prior standard did not adequately protect human health and that the agency is well aware of existing data suggesting that existing levels of ozone on the North Slope are as high as .050 ppm (8-hour average), and the Kulluk's operations will add to significant existing and planned sources of VOCs. The commenters continue that the EAB Orders in remanding the Shell Discoverer permits to Region 10 require Region 10 to not only consider compliance with the existing NAAQS, but must also include and analyze other data that is germane to the issue of potential disproportionate adverse health impacts. The commenters assert that the Statement of Basis did not provide for any analysis of the impacts of ozone in analyzing environmental justice concerns and that the environmental justice analysis ignores ozone entirely as a pollutant of concern despite documentation that ozone levels on the North Slope are elevated in regions impacted by existing oil and gas development. Commenters continue that Region 10's passing reference to ozone is arbitrary and inadequate for a number of reasons, including: 1) it does not provide any clarification as to whether Region 10 considered the new 8-hour ozone standard; 2) the statement in the environmental justice analysis mischaracterizes the findings of the air quality analysis, in which Region 10 concluded only that "it is unlikely this small increase in ozone precursors emissions would cause or contribute to violations of the ozone NAAQS; therefore, given the lack of quantified data and modeling, Region 10 appears to concede that violations of the NAAQS could be possible—even if they are unlikely—because Region 10 has not conducted quantified modeling; and 3) given the fact that ozone is a regional pollutant, Region 10 cannot justify its decision to ignore the combined cumulative impacts of proposed drilling operations in the Beaufort and the Chukchi Seas and that without looking at the combined emissions of ozone precursors from the Discoverer, the Kulluk, ConocoPhillip's jackup rig, mobile sources, and onshore sources, Region 10 can only speculate as to whether the Kulluk will contribute to possible violations of the NAAQS in communities like Nuiqsut or subsistence use areas like Cross Island.

Response: As an initial matter, although there may be individual 8-hour concentrations as high as 0.50 ppm, the highest design value for the 8-hour standard for any of the monitoring sites is 0.40 ppm. The design value is in the form of the standard (which for the 8-hour ozone standard is the three year average of the annual fourth highest daily maximum 8-hour concentration), which is the appropriate value for comparison to the NAAQS.

In addition, contrary to the statement by the commenters, the ozone NAAQS had not been revised at the time the comment was submitted, but instead had been proposed for revision. As discussed in response to comment X.2, EPA had proposed to reconsider the 0.075 ppm ozone NAAQS set in 2008 and requested comment on a range between 0.060 and 0.075 ppm. 75 Fed. Reg. 2,935 (January 19, 2010). EPA has recently announced, however, that at the President's direction, EPA will not be taking final action on its current proposal to revise the 8-hour ozone NAAQS. EPA instead intends to consider revisions to the ozone NAAQS in connection with the 5-year mandated revision of the ozone NAAQS in 2013. Statement by the President on the Ozone National Ambient Air Quality Standard, September 2, 2011. In any event, current ozone levels in the area are well below even the low end of the range that had been proposed by EPA (0.060 ppm). As discussed in the response to comments for Category X above, Region 10 does not believe modeling is required to conclude that emissions of ozone precursors from Shell's operations will cause or contribute to ozone levels that would exceed the low range of the proposed NAAQS. Region 10 believes this is true even when considering the combined emissions from the oil and gas activities permitted or proposed to be permitted on the Alaska OCS. See response to comment Y.4.

BB.4 SUBCATEGORY – GLOBAL WARMING AND BLACK CARBON

Comment BB.4.a: Many commenters stated that Region 10's environmental justice analysis was inadequate because it did not consider the impact of this permit on warming in the Arctic. Commenters contend that Region 10's environmental justice analysis is arbitrary and fails to meet Executive Order 12898 because it relies entirely on expected NAAQS compliance and does not consider the effect of Shell's GHG and black carbon emissions on indigenous peoples or lawfully consider the effect of Shell's emissions on subsistence users. The commenters allege that the EAB remanded Region 10's environmental justice analysis on the grounds that reliance on then existing NAAQS was insufficient because EPA had indicated that those standards were insufficient to protect public health. The commenters continue that the Arctic is already warming rapidly and that this warming has resulted in visible changes to Alaska's land, water, wildlife, and people, including the disappearance of sea ice. The commenters state that, as a result of receding and thinning sea ice, scientists have observed polar bears drowning and going hungry, walruses forced onto land, and sharp declines in numbers of ice-dependent sea birds, and that the warming is also threatening indigenous cultures because arctic animals and subsistence hunts are central to Alaska Native cultures. The commenters contend that subsistence hunters have to travel farther to access animals and that the melting permafrost is accelerating coastal erosion and forcing communities to relocate. The commenters note that EPA's Administrator has found that GHGs are "reasonably anticipated to endanger public health, for both current and future generations" and that America's Arctic—home to a large population of Alaska Natives—stands to suffer more than other locations due to the effects of high rates of projected regional warming on natural systems. The commenters assert that Shell stands to contribute to this warming, and resulting harm to indigenous cultures, by emitting GHGs and black carbon and that Region 10 has failed to consider the amount of Shell's GHGs and black carbon emissions that will be emitted over the life of the permits.

Response: Region 10 recognizes that climate change is of particular concern to arctic communities because the Arctic is expected to experience the greatest rates of warming compared with other world regions and there is evidence that climate change is already having observable impacts in the Arctic. Region 10 also acknowledges that black carbon is now recognized as an important climate-forcing agent with particular impact on the arctic region. EPA's Endangerment Finding, Frequently Asked Questions. http://www.epa.gov/climatechange/endangerment/downloads/EndangermentFinding_FAQs.pdf

Although it is clear that GHGs contribute to global warming and other climate changes that result in impacts on the environment, due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHGs are typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. PSD and Title V Permitting Guidance for Greenhouse Gases, EPA Office of Air and Radiation, March 2011.

In this case, the permit limits emissions of GHGs from the Kulluk and the Associated Fleet to below PSD major source thresholds. Furthermore, emissions of GHGs from the Kulluk and the Associated Fleet only account for approximately 0.1 % of the Alaska 2005 total statewide estimated GHGs of 53 million tons and 0.40 % of the Alaska 2005 statewide oil and gas industry estimated GHGs of 15 million tons. 2012 Revised Camden Bay Exploration Plan at 3-3 to 3-4. In light of these facts, Region 10 does not expect that issuance of this permit will have disproportionately high and adverse human health or environmental effects on minority or low income communities on the North Slope based on emissions of GHGs, even when considering emissions over the life of the permit.

With respect to black carbon, see response to comment BB.4.b below.

Comment BB.4.b: Commenters state that Shell's operations also could emit up to 28 tpy of $PM_{2.5}$, a large proportion of which will be black carbon. The commenters contend that black carbon is generally regarded as the second most important driver of arctic warming and cite an EPA report stating that this occurs because black carbon absorbs incoming and outgoing radiation and darkens snow and ice, which reduces the reflection of light back to space and accelerates melting. The commenters state that emissions of black carbon from sources in the Arctic are particularly troubling because arctic emissions can cause substantially more regional warming than similar amounts of black carbon emitted outside the Arctic and cite to numerous studies supporting this conclusion. The commenters also cite to EPA reports that discuss studies showing that black carbon radiative forcing from both atmospheric concentration and deposition on the snow and ice has contributed to arctic surface warming and that black carbon may be the cause of as much as 50 % of arctic sea ice retreat.

Response: EPA recognizes the concerns regarding black carbon and is committed to fully evaluating its role on climate change. Based on available information at this time, Region 10 does not have information on which to reach a conclusion regarding whether emissions of black carbon from the Kulluk and Associated Fleet will have disproportionately high and adverse human health or environmental effects on minority or low income communities on the North Slope. To the extent black carbon is comprised of particulate matter, it is regulated as $PM_{2.5}$ and PM_{10} and emissions of these pollutants are estimated at 28 tpy.

CC. CATEGORY – BASELINE DATA

Comment CC.1: Commenters maintain that Region 10 must account for the substantial lack of data concerning the arctic environment. The commenters note that since the EAB remanded the Discoverer permits back to Region 10, the Secretary of Interior released a major report from the U.S. Geological Survey on the gaps in the scientific understanding of the United States' Arctic, citing to Holland-Bartels, Leslie, and Pierce, Brenda, eds., 2011, An evaluation of the science needs to inform decisions on Outer Continental Shelf energy development in the Chukchi and Beaufort Seas, Alaska: U.S. Geological Survey Circular 1370. The commenters state that this document concludes that there are large information gaps about the Arctic Ocean, and these gaps are a "major constraint to a defensible science framework for critical Arctic decision making." The commenters further note that the Alaska Federal District Court remanded Chukchi Lease Sale 193 because the agency had not fully considered the importance of missing information in its environmental impact analysis. One commenter states that he does not believe any data already collected is accurate enough to be the basis for any real environmental impact assessment and that long term consistent data should be collected before development of the magnitude at issue in these permits is considered so that people can understand what the affects would be. The commenters contend that Region 10 must acknowledge these shortcomings in the scientific understanding of the Arctic and move forward cautiously, ensuring that any permits it issues are designed to provide maximum protection for human health and the environment.

Response: The commenters do not say what type of data is missing or whether the missing data is even applicable to the proposed permit action. This permit is issued under the authority of the OCS regulations, 40 CFR Part 55, and the Title V program, 40 CFR Part 71. As discussed in Technical Support Document (at 6), Region 10 believes it is appropriate to use the regulations and guidance for conducting an air quality analysis with respect to the NAAQS under the PSD program where, as here, the Title V permit requires that the permit assure compliance with the NAAQS. As discussed in Section 4 of the Statement of Basis, the Technical Support Document, and in response to comments in Category T and U above, Region 10 has determined that Shell has met the requirements to have representative background and meteorological data as necessary to assess ambient air quality in the areas that are expected to be affected by Shell's exploratory operations. While other baseline data may be useful or helpful in connection with other regulatory decisions related to Shell's exploration drilling operations in the Beaufort Sea, no other baseline data is required prior to issuance of this permit. Baseline data required for other regulatory determinations is outside the scope of this CAA permitting action.

Comment CC.2: A commenter stated that Region 10 used only data from Point Lay and did not go to Point Hope or the other villages to gather that information. The commenter states that there is not enough specific information in regards to the baseline and the data that is collected. The commenter contends that he had asked about the data that was acquired through the Arctic Monitoring and Assessment Programme which is an international program that has participation by the United States under the National Science Foundation that has been going on since 1991. The commenter questions the accuracy of the data relied on to support this permit action.

Response: Region 10 did not rely on data from Point Lay or Point Hope to support this permitting action. Both of these villages border the Chukchi Sea, not the Beaufort Sea, where the activities to be authorized under this permit will be conducted. As discussed in response to comment CC.1, while other baseline data may be useful or helpful in connection with other regulatory decisions related to Shell's exploration drilling operations in the Beaufort Sea, no other baseline data is required prior to issuance of this permit. The commenter has not identified any specific concerns regarding the accuracy of the data relied on in this permitting action. Region 10 is therefore unable to provide a further response to this comment.

DD. CATEGORY – IMPACT ON LOCAL COMMUNITIES, SUBSISTENCE ACTIVITIES, AND TRADITIONAL USE

Comment DD.1: A number of commenters expressed concerns regarding the negative impact that Shells' specific exploratory operations and increased arctic oil and gas operations in general may have on the local communities, their environment and subsistence lifestyle. These comments include:

- Shell's operations would affect a large region of the Beaufort Sea that contains important habitat for endangered species and that serves as subsistence hunting grounds for Alaska Native communities.

- By relying exclusively on NAAQS, Region 10 has failed to account for effects on subsistence users. Shell's operations would take place close to local villages and within subsistence hunting grounds. In particular, Shell would operate very close to the villages of Kaktovik and Nuiqsut. As a result, Region 10's narrow focus on NAAQS compliance fails to account for the degree to which pollution below NAAQS levels might nonetheless disrupt subsistence activities by dissuading the native population from engaging in hunts due to fear of contamination. Also, Region 10's analysis fails to address how Shell's air pollution might cause a disproportionate impact through non-air pathways. For instance, Shell will emit hazardous air pollutants, and some hazardous air pollutants bioaccumulate, raising the risk of human ingestion of toxic substances.

- Region 10 has not analyzed how Shell's application for air pollution permits in the outer continental shelf region may contribute to Arctic warming that might impact customary and traditional and modern cultural life ways of hunting, fishing, gathering, navigation and commerce of indigenous peoples and communities of the Arctic.

- A commenter stated concern about disproportionate adverse, cumulative toxic pollution impacts to communities of indigenous peoples and communities of birds, mammals, and fishes, and flora downwind from permitting what is definitely a major source of air pollution and sets a dangerous precedent for underestimating and minimizing actual physical impacts of permitted air pollution in the outer continental shelf region of the Beaufort Sea.

- A commenter stated that air pollution can affect the ocean and animals around Point Hope and expressed opposition to any air pollution.

- One commenter stated that the calculations show emissions of 200 tons of carbon monoxide, 240 tons of nitrogen oxides, and 30 tons per year of particulate matter, and stated that this constitutes 60,000 pounds of particulate matter that will enter the food chain.

- A commenter stated that EPA's air permits are not supposed to have adverse effects on minority populations, but that this is occurring in the subsistence zone through the process of biomagnifications, which is the concentration of toxins through the atrophic levels. The commenter explained that pollution will magnify through the food chain to seals, walrus, and polar bears.

- One commenter explained that the bowhead whale, the Beluga, the walrus and all different species of fish are an important part of the ecosystem on which communities rely.

- One commenter stated that Shell has a bad track history and referenced Nigeria, the Shetland Islands, and the North Sea and said Shell's track history is something to watch out for.

- One commenter stated that EPA has a mission statement to protect the health and safety of people in the United States.

- One commenter claimed the walrus, Beluga, bowhead whale, bearded seal and other species are being destroyed by pollution.

- One commenter referenced the good quality of clean air in Alaska.

- A commenter noted that the Arctic is very unique and asked that Region 10 not give a permit to Shell. The commenter noted that the timeframe in July is when animals go to the Arctic to nurse their young and that November is unpredictable and a bad season.

- One commenter referenced seeing a tourist ship in Point Hope and noted that there were additional sources of pollution besides Shell. The commenter was concerned with the pollution associated with the different ships.

- A commenter acknowledged that the country has a national interest in developing energy, but not to the detriment and the disproportionate adverse cumulative impact to the communities who would have to suffer from the air pollution. The commenter expressed concern that the permit would allow Shell to pollute air all over the Beaufort Sea, not in just one place, and it is unclear which communities would be impacted.

- One commenter referenced values taught by Tikigaq whaling captains and stated that bowhead whales and the marine mammals are out there are also very sensitive. The commenter was particularly concerned about noise from the ships and the traffic that will be authorized under the permit.

- A commenter expressed concern about harvesting an animal made sick by pollution.

Response: Region 10 appreciates the commenters' interest in and attention to the draft permit. We recognize the close, integral relationship the local communities have with the arctic environment and its resources and the importance to the local communities of subsistence hunting and fishing and the traditional way of life. However, the potential impact on the subsistence hunting or interference with traditional way of life is not a factor that the CAA requires EPA to evaluate in issuing OCS permits. Therefore, specific evaluation of impacts to subsistence hunting and fishing is beyond the scope of these OCS/PSD permits. *In re Shell Offshore Inc., Kulluk Drilling Unit and Frontier Discoverer Drilling Unit, Order Denying Review In Part and Remanding In Part,* 13 E.A.D. _ (September 14, 2007), slip op. at 68-69, fn. 66 (Kulluk EAB decision); see also *In re Knauf Fiber Glass GmbH*, 8 E.A.D. 121, 147 (EAB 1999) (stating that the Board's jurisdiction, and thus review power, is limited, extending only to those issues that are directly related to permit conditions that implement the federal PSD program).

As part of its environmental justice analysis, Region 10 generally considered Shell's impact on local communities while engaging in subsistence activities in areas where such activities are regularly conducted. For example, Region 10 noted that subsistence foods are an important component of the Iñupiat diet, that the residents reported traveling long distances off shore for hunting and other subsistence activities, and that subsistence plays an important cultural role in the communities. Region 10 also noted the location of the

Shell lease blocks relative to the subsistence areas. See Statement of Basis, Figure 5.1, at 56 (Subsistence Use Areas Mapped over Exploration Sites).

There are other regulatory programs in place to address the commenters' concerns. Kulluk EAB Decision, slip op. at 68-69, fn. 66. For example, BOEMRE did consider the effect and impacts of Shell's exploration activities on subsistence activities and the Iñupiat culture and way of life; risk of oil spills and their potential impacts to area fish and wildlife resources; disturbance to bowhead whale migration patterns; and harassment and potential harm of wildlife from noise, discharges, and vessel operations. See Finding of No Significant Impact, dated August 3, 2011, for Shell Offshore Inc., 2012 Revised Camden Bay Exploration Plan. http://alaska.boemre.gov/ref/EIS%20EA/2012_Shell_CamdenEP_EA/2012FONSI.pdf; Letter from Jeffrey Walker, BOEMRE, to Susan Childs, Shell, re: 2012 Revised Camden Bay Exploration Plan, dated August 4, 2011. http://alaska.boemre.gov/ref/ProjectHistory/2012Shell_BF/2011_0804_soi.pdf

Finally, as explained in the Statement of Basis and this Response to Comments, Region 10's analysis indicates that this project, as regulated by the final permit, will not cause or contribute to a violation of any currently applicable NAAQS. Since NAAQS are established to protect public health and welfare, the project is not expected to have an adverse impact upon public health or welfare.

With respect to consideration of endangered species, see Section 5.1 of the Statement of Basis and Category KK of the Response to Comments. With respect to Region 10 oversight of Shell's compliance with permit requirements, see Category O of the Response to Comments.

The comments made regarding the draft ConocoPhillips permit are not relevant to this permit proceeding for the Shell Kulluk permit.

EE. CATEGORY – HEALTH IMPACTS AND GENERAL AIR QUALITY CONCERNS

Comment EE.1: Commenters state that some of the leases on which Shell would be allowed to drill are less than 25 miles from the Alaskan coast and that the environmental and human health impacts have not been sufficiently studied or communicated to potential communities that are downwind of exploration ships and the areas where a drilling rig would be stationed. The commenters contend that 500 meters as an outer perimeter for human health considerations for air quality standards is not sufficient and legally questionable under the Clean Air Act. The commenters also assert that a 25 mile radius for a major air pollution permit from exploration ships and drilling rig do not take into considerations of impacts to other communities that were not as consulted or informed of potential impacts to furred and feathered, or finned creatures that could be impacted by airborne particulates farther downwind "Kulluk's potential operations and will establish precedents that affect the Arctic's people and Environment. (Water Advocacy and Big Village)

Response: As explained, in response to comment BB.1.a, as part of Region 10's evaluation of Shell's permit applications, Region 10 considered the NAAQS. These national air quality standards are set at a level designed to protect public health protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly, with an adequate margin of safety. For example, in setting the new 1-hour NAAQS for NO_2 and a new 1-hour SO_2 NAAQS, EPA understood that exposure to NO_2 and SO_2 concentrations above the standard has been linked to respiratory illnesses that lead to emergency room visits and hospital admissions, particularly in at-risk populations such as children, the elderly, and people with respiratory disease. In issuing the new 1-hour NO_2 and SO_2 NAAQS, EPA noted in particular that the prevalence and severity of asthma are higher among certain ethnic or racial groups such as Alaskan Natives. In these promulgations EPA specifically considered the exposure of sensitive subpopulations, including Alaskan Natives. 75 Fed. Reg. 6,482 (February 9, 2010); 75 Fed. Reg. 35,527 (June 22, 2010). See also Technical Support Document at Statement of Basis at 33-36 and Environmental Justice Analysis.

Region 10 determined through detailed modeling and careful analysis that Shell's operations as allowed under the permit will not exceed the national standards. In fact, the emissions are expected to be well below the standards in the North Slope communities on the Beaufort Sea and to be less than the NAAQS in the areas where the communities regularly conduct subsistence activities. Maximum modeled impacts from Shell's operations in the communities of Nuiqsut, Deadhorse and Kaktovik are well below the significant impact levels for the NAAQS pollutants. See Statement of Basis, Table 12, at 35. Considering existing air quality in these communities, the total impacts in these communities (from Kulluk operations and background concentrations) is less than 50% of the NAAQS for NO2 and PM2.5, and much less for all other NAAQS pollutants. Since this project will not cause or contribute to a NAAQS violation and since NAAQS are established to protect public health, the project is not expected to have an adverse impact upon public health. The commenters have provided no information to show that the impact in other onshore communities would be greater than the communities considered in this permitting action.

With respect to concerns regarding the 500 meter safety zone, please see responses to comments in Category P.

FF. CATEGORY – MODELING ICEBREAKER ACTIVITY

Comment FF.1: Commenters reference Shell's assumption that it will break ice for 38% of the time that it is authorized to operate under the Draft Permit and note that Shell used the same assumption in its application for the 2011 Discoverer Permits. Commenters question why Shell used the same assumption when the drilling vessels are different and conditions in the Beaufort and Chukchi Seas are different, and ask that Region 10 explain why Shell used the same assumption of ice breaking time for both permits. (NSB, p. 33)

Response: The Draft Permit limits Shell's operations to a 120-day period between July and November. This period coincides with expected open water conditions but as Shell noted in its application, the frequency and intensity of ice conditions is unpredictable. In submitting its application, Shell relied on multi-year data from 2003-2005 collected at the Sivulliq drill site that showed a 15% frequency of ice at the drill site and 23% frequency of ice within 30 miles of the drill site. Shell summed these numbers to obtain a probability of ice management of 38% and used this assumption to estimate the maximum expected emissions for purposes of determining appropriate synthetic minor limits. See response to comments H.1.b, FF.2 and FF.3. Considering the year-to-year variability of ice conditions, Shell's use of multi-year data is appropriate and Region 10 does not consider the use of the same dataset for both the Draft Permit and the 2011 Discoverer Permits to be unreasonable.

In regards to their air quality modeling analysis, Shell assumed the open water period coincides with the availability of data from the buoys they deployed in the Beaufort Sea in 2009 and 2010 to model open water and ice conditions. Permit Application Supplement at 97. Shell also conservatively assumed that the ice management vessels are continuously operating at maximum load during the entire 120-day period (see Section 3.3.2 of the Technical Support Document). The question regarding ice duration is therefore moot in regards to modeled emissions.

Comment FF.2: Commenters reference Shell's permit application which states:

> For emission estimation purposes the ice management fleet is assumed to be operating at maximum (nameplate rates) rate for 38 percent of the 120-day OCS period. For modeling purposes, the ice management vessels are assumed to be operating at maximum emission rate whenever the meteorology indicates that ice is present and assumed to be beyond the 25-mile radius when the data indicates open water.

Commenters state that there is no mention of icebreaker activity assumptions in the Statement of Basis or Air Quality Impact Analysis and that the amount of time the icebreaker fleet was assumed to be operating in the modeling analysis is unclear. Commenters question how the modeling analysis compares to the 38% figure used for estimating emissions and request that Region 10 make clear that the modeled activity represents the worst case operating scenario.

Response: The modeling assumptions regarding icebreaker activity are described Section D.3.2 (page 9) of the Technical Support Document. The assumptions regarding open water periods are described in Section E.2 (page 28) of the Technical Support Document. Shell did not use the 38 % assumption in its modeling analysis. They instead defined the open water period as the time a buoy could be (and was) deployed in the Beaufort Sea (August 5 – October 13, 2009; and August 14 – October 10, 2010). However, the distinction between open water and ice conditions only affected which dispersion model/meteorological data set they used (AERMOD for ice conditions or AERMOD-COARE for open water conditions).

It is true that in its initial air quality analysis, Shell assumed that the ice management vessels would be beyond a 25-mile radius from the Kulluk during open water periods. Region 10 questioned this assumption and in response Shell revised its analysis by assuming that both ice management vessels would operate at maximum loads during the open water periods. Shell therefore modeled both ice breakers as if the vessels were managing ice continuously throughout the 120-day operational period. As described in the Technical Support Document (p.9), Region 10 believes that this approach is conservative because Shell does not intend to operate the primary ice management vessel within the 25-mile radius during open water periods, and should not need to operate the anchor handler under full load conditions during this period.

Comment FF.3: Commenters express concern that ice management activities may be underestimated in Shell's analyses. The commenters explain that heavier ice conditions result in heavier engine load factors and higher emissions, and reference that the 38% frequency of ice within 30 miles of the Kulluk is based on data from 2003-2005. The commenters cite to Shell's application to the US Coast Guard for safety zone designation in which the company stated that:

> Ice conditions during 2006 were such that the areas of drilling interest were ice covered the majority of the period between July and October. If ice conditions are similar during 2007, then each drill rig will be constantly ice managed within its anchor array.

The commenters also reference the permit application in which Shell stated that "[t]he frequency and intensity of ice conditions is unpredictable and could range from no ice to ice sufficiently dense that the ice management vessels have insufficient capacity to push it out of the way". Commenters contend that Region 10 must use an unbiased source of data which is something other than the applicant's estimate of ice conditions. Commenters also state that if estimates are based on a scientific analysis of ice flow data from 2003-2005 then that analysis should be made available for review and more recent data should be incorporated into the analysis, if possible. Commenters suggest that icebreaker emissions could be estimated and modeled to account for the maximum potential operation scenario, and any percentage less than the worst possible case would need to be specified as an enforceable permit conditions *(e.g.,* the permit could include an enforceable provision limiting the icebreaker operations to no more than 38% of the time).

Response: Region 10 agrees that the frequency and intensity of ice conditions in the Arctic is unpredictable. To provide operational flexibility to account for, among other things, unpredictability in ice frequency and intensity, the Region established source-wide emission limits and operational restrictions. Shell is required to comply with these limits and restrictions and has accepted the risk that, if ice conditions are worse than assumed, Shell may be required to curtail its drilling season or otherwise curtail operations to ensure compliance with the permit terms and conditions. For this reason, the Region disagrees with commenters suggestion that an enforceable provision limiting icebreaker operations to 38% of the operational period should be included in the Permit. There is no need to specifically state that Shell can only operate the icebreakers for 38% of the time as the emissions from the ice breakers are counted against the source-wide limits and restrictions. Similarly, Region 10 does not believe it is necessary to obtain ice data from another source or to require that Shell use data that is more recent than the 2003-2005 dataset.

GG. CATEGORY – ANNUAL MODELING ANALYSIS

Comment GG.1: Commenters state that one of the basic principles of the Clean Air Act is that EPA may not issue a permit unless it can "assure" that allowable emissions will not result in a violation of any applicable requirement, including NAAQS, citing to 42 U.S.C. §§ 7661c(e) and 7661c(a); 40 CFR §§ 71.2, 71.6(a)(1), 71.6(e)(1). Consistent with this basic principle, the commenters continue, Region 10 has interpreted Title V as requiring that an operating permit applicant demonstrate compliance with NAAQS in the same manner as the PSD program requires, citing to the Statement of Basis (at 26-27). Commenters therefore assert that, to receive a Title V permit, Shell must show that emission increases allowed by the permit will not result in a violation of NAAQS, but that the modeling of Shell's proposed operations is both complex and wholly uncertain because Shell has not identified many of the emission units it will use. The commenters contend that Region 10 acknowledges that Shell's failure to identify many emission units means that it has not actually demonstrated allowable increases will not violate NAAQS, citing to the Statement of Basis (at 36), where Region 10 stated "different configurations of emission units as well as their stack characteristics (height, diameter, location relative to structures) can change the modeled impact even if emissions are the same." The commenters state that Region 10 attempts to overcome this uncertainty and comply with the law by "[r]equiring subsequent modeling analyses to be conducted. . . to establish that any future configuration" will not cause a violation of standards, making Shell's present modeling a preliminary and purely hypothetical exercise that Region 10 intends to revisit once Shell identifies the equipment it intends to use. The commenters assert that this approach does not comply with the requirement that Shell demonstrate, before it is issued a permit, that its emissions will not cause a violation of applicable standards. The commenters further state that allowing Shell to provide its final modeling after Region 10 issues the permit violates the public's right to comment on the complete draft permit, including the modeling demonstration, citing to 40 CFR § 71.11. The commenters conclude that Region 10 must withdraw the permit and require Shell to make this showing based upon the actual equipment that Shell intends to use in its exploratory drilling operations.

Response: Region 10 continues to believe that the limitations on emissions and operations, along with the associated monitoring, recordkeeping, and reporting requirements, together ensure that the Kulluk and Associated Fleet would not, at any authorized location or with any authorized changes in equipment, cause or contribute to a violation of the NAAQS when operating in compliance with the terms and conditions of the permit.

As discussed in the Statement of Basis (at Section 2.6.2), Section 504(e) of the CAA, 40 CFR 71.6(e), and the comparable Title V COA regulations authorize Region 10 to issue Shell a single permit authorizing emissions from similar operations at multiple temporary locations, provided that the permit includes conditions that will assure compliance with all applicable requirements at all locations. [19] As also discussed, the NAAQS are an "applicable requirement" for Title V temporary sources. CAA § 504(e); 40 CFR §§71.2 (definition of applicable requirement) and 71.6(e). Thus, this permit must include terms and conditions that assure compliance with the NAAQS at all authorized locations.

With respect to the locations at which operation is authorized under this permit, the modeling that has already been conducted demonstrates that the NAAQS will be protected with the modeled equipment configuration at all locations that constitute ambient air lease holdings.

With respect to potential changes in equipment referred to by the commenters, Region 10 acknowledges that the specific equipment to be installed on the Kulluk and the specific Associated Fleet vessels and emission units on those vessels are not specified in the permit or known at this time. EPA's Part 71 regulations were revised in 2009 to clarify the availability of just this kind of flexibility in Title V operating permits. See Operating Permit Programs, Flexible Air Permitting Rules; Final Rule, 74 Fed. Reg. 51,418 (October 6, 2009). Use of the Flexible Air Permitting Rules is particularly appropriate in the case of Title V permits for Title V temporary sources under CAA § 504(e) and 40 CFR § 71.6(e). Congress specifically recognized that the operations of such Title V temporary sources would be "similar" and did not require that they be "identical." See CAA § 504(e)

The applicable requirement at issue is the NAAQS as it applies to a Title V temporary source. In addition to the emission limits, operational restrictions, and monitoring, recordkeeping, and reporting requirements, the permit includes an "approved replicable methodology" or "ARM" to provide a reasonable assurance that the NAAQS will continue to be protected with any actual changes of vessels or equipment. Kulluk Final Permit, Condition C.4. An ARM is defined as Title V permit terms that

(1) Specify a protocol which is consistent with and implements an applicable requirement, or requirement of [Part 71], such that the protocol is based on sound scientific and/or mathematical principles and provides reproducible results using the same inputs; and

(2) Require the results of that protocol to be recorded and used for assuring compliance with such applicable requirement, any other requirement

[19] As discussed in the Statement of Basis (at 4) and the Technical Support Document (at 5-6), this permit also serves as a minor source permit under the COA regulations that govern operation in the Inner OCS. ADEC's minor source rules, which are approved as part of the COA regulations applicable to this permitting action, specifically authorize the issuance of a single permit that is valid for multiple locations. See 18 AAC 50.502(d)). The rules do not require the permittee to update its ambient assessment prior to moving to a location previously authorized under the permit.

> implicated by implementation of the ARM, or requirement of [Part 71], including where an ARM is used for determining applicability of a specific requirement to a particular change.

CFR § 71.2 (definition of ARM). Under the flexible permitting provisions, Title V permits can include ARMs provided that no ARM shall contravene any terms needed to comply with any otherwise applicable requirement or requirement of Part 71 or circumvent any applicable requirement that would apply as a result of implementing the ARM. 40 CFR § 71.6(a)(1).

In promulgating the flexible permitting provisions, EPA discussed pilot projects under which permitting authorities determined that replicable procedures could be used to ensure that future changes at a source would meet ambient air quality requirements:

> The plantwide VOC emissions caps used in the pilots were determined to be adequate for purposes of safeguarding the ozone NAAQS, but for other pollutants (e.g., air toxics) states sometimes required a replicable modeling procedure to screen the impacts of individual emissions increases relative to acceptable ambient levels. In the case of one pilot, an ambient dispersion model, complete with implementation assumptions, was included in the permit to evaluate any new air toxic pollutants of concern, or increases in existing toxic pollutants. Failure of a particular change to meet the screening levels triggered a case-by-case review of that change by the permitting authority."

74 Fed. Reg. 51,424.

In this case, Region 10 believes that the permit condition establishing the modeling procedure in the event of equipment changes is a protocol based on sound scientific/mathematical principles. The condition requires reproducible results using the same inputs and requires the results of the protocol to be used for assuring compliance with the NAAQS. Only changes in equipment that are shown to comply with the NAAQS after complying with the modeling condition are allowed to be made under the permit condition. Requiring subsequent modeling analyses to be conducted in an identical manner, reflecting only specific equipment or configuration changes, to establish that any future configuration satisfying this requirement would protect the NAAQS, is using a protocol based on sound scientific principles to provide reproducible results with the same inputs. Thus, Region 10 disagrees with the commenter that the demonstration must be made with the actual equipment that Shell intends to use in future years, provided the permit terms and conditions assure compliance with all applicable requirements (here, the NAAQS as applied to a Title V temporary source) in light of such potential changes in equipment.

Although the commenter asserts that Shell must demonstrate compliance with the NAAQS before a permit can be issued, the commenter does not reference the actual requirements of the Part 71 rules related to compliance demonstrations (plans) in permit applications (specifically 40 CFR § 71.5(c)(8)).[20] Under these requirements, applicants for Part 71 permits are not required to demonstrate that they will comply with applicable requirements but rather only provide a description of the compliance status of the source with respect to all applicable requirements.[21] For requirements that would apply to future changes at the source (such as alternative operating scenarios (AOS) or preapproved changes), the applicant would only need to provide a statement that they will continue to comply with the applicable requirements.

Region 10 also disagrees with the commenter's contention that allowing Shell to submit additional modeling after Region 10 issues the permit if Shell changes any equipment violates the public's right to comment on the complete draft permit, including the modeling demonstration. As explained in the preamble to the proposed Flexible Air Permits rule (72 Fed. Reg. 52,206, 52,208, September 12, 2007), a key purpose of a flexible air permit is to provide flexibility for certain changes after the permit is issued without further review, including further public notice and comment, under permit terms that assure compliance with applicable requirements. The public is given the opportunity to comment on permit terms that provide for such operational flexibility at a source, including terms implementing "alternative operating scenarios" and "approved replicable methodologies," during the initial permit issuance rather than when the source avails itself of the flexibility provided by the terms. This opportunity to review and comment on the draft ARM (including the conditions under which the ARM can be used and whether the draft permit terms meet the Part 71 requirements for an ARM) satisfies the public participation requirements of 40 CFR § 71.11.

With respect to the operations of the Kulluk in the Inner OCS, the ADEC "minor source" rules, which are approved as part of the COA regulations applicable to this permitting action, would not require a permit for equipment changes unless the increased emissions

[20] As discussed in footnote 21 below, although Region 10 has relied on the PSD requirements for a NAAQS modeling demonstration as a guide for the showing here that the NAAQS will be protected when the sources is operating in compliance with the permit terms and conditions, the commenter's reference to 40 CFR § 52.21(k) is not directly applicable to issuance of this permit since this source is not subject to PSD.

[21] The application requirements of Title V and Part 71 do not expressly require the submission of the modeling demonstration that Shell has submitted in support of this permit action. However, 40 CFR § 71.5(c) requires that the application include information sufficient to determine applicable requirements and to implement and enforce such requirements. In order for the permit issued by Region 10 to contain terms and conditions necessary to assure compliance with the unique applicable requirements at issue in this permit (*i.e.*, the NAAQS as directly applicable requirements for this Title V temporary source), Region 10 requested from Shell information on the air quality impacts of emissions from the Kulluk and Associated Fleet for Shell's anticipated operational scenarios. References in documents prepared by EPA in the administrative record to "required compliance demonstration," "NAAQS demonstration," "a Title V temporary source demonstrating compliance with the NAAQS," or similar terms should not be interpreted to alter the Title V and Part 71 permit application requirements, but refer instead to the modeling analysis and other information determined to be necessary by Region 10 in these specific circumstances under the Part 71 rules to support issuance of this permit. As discussed in the Technical Support Document (at 5), Shell was required to submit a demonstration that its proposed potential emissions will not violate the NAAQS for NO_2, SO_2, and PM_{10}.

(if any) exceed 10 tons per year of NOx, SO_2 or PM-10. See 18 AAC 50.502(c)(3).[22] The rules therefore allow some degree of operational flexibility, as long as the permittee stays within the terms and conditions of their permit. Region 10 reiterates, however, that, as provided in Kulluk Final Permit Condition B.16,[23] nothing in the permit relieves Shell of complying with the ADEC minor source rules for changes that would qualify as modifications under those rules.

HH. CATEGORY – OTHER PERMIT TERMS AND CONDITIONS

Comment HH.1: Commenters request that the Region include as a permit condition that the "approval to construct shall become invalid if construction is not commenced within 18 months after receipt of approval" or "if construction is discontinued for a period of 18 months or more."

Response: This preconstruction requirement is already set forth in Permit Condition A.6.5.

Comment HH.2: Commenters request the Region 10 include in the permit a provision that discusses when the permit will be reopened for cause.

Response: The permit states that it will be reopened for cause and that cause exists under any of the circumstances described in 40 CFR § 71.7(f). Permit Condition A.7.1. That section of Part 71 provides that cause exists when:

> (i) Additional applicable requirements under the Act become applicable to a major part 71 source with a remaining permit term of 3 or more years. Such a reopening shall be completed not later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions have been extended pursuant to paragraph (c)(3) of this section.
>
> (ii) Additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program. Upon approval by the Administrator, excess emissions offset plans shall be deemed to be incorporated into the permit.
>
> (iii) The permitting authority (or EPA, in the case of a program delegated pursuant to §71.10) determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.

[22] The terms of this permit, however, would not allow such an increase in emissions without a permit revision.
[23] This condition was Condition B.15.7 in the Kulluk Draft Permit.

> (iv) The permitting authority (or EPA, in the case of a program delegated pursuant to §71.10) determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

40 CFR § 71.7(f). Through the cross-reference to 40 CFR § 71.7(f), the Kulluk Permit does include provisions that discuss when cause exists to reopen the permit.

Comment HH.3: Commenters request that Shell demonstrate compliance with the new 8-hour Ozone NAAQS within six months of the new standard being announced.

Response: As discussed in response to comment X.2, the proposal to revise the 8-hour ozone NAAQS has not been finalized and indeed EPA has stated that it does not intend to take final action on that proposal at this time. Part 71 has provisions that address when a permit must be reopened to add newly promulgated requirements. See 40 CFR § 71.7

Comment HH.4: Shell commented that its permit application requested aggregate limits for the three deck crane engines. Shell states that aggregate limits are essential for the cranes because the proposed activity requires the flexibility to operate up to two cranes simultaneously and it's impossible to know in advance which cranes will operate at any given time. Given the intermittent nature of crane operation and operational limits that will keep the crane engines from operating at maximum rated power, Shell believed that this approach supported aggregate limits that would ensure NAAQS protection.

Shell recognizes, however, that Region 10 set draft permit limits based specifically on the emission rates used in the modeling analysis (Statement of Basis, p. 40). Shell notes that because the crane modeling in the application divided total 24-hour emissions by three, Region 10 assigned a portion of the aggregate to each crane, resulting in per-crane-engine limits for NO_x, $PM_{2.5}$, and PM_{10}. Furthermore, the dispersion analysis in the permit application evaluated daily average NOx emission rates when evaluating compliance with the short-term NOx ambient air quality standard; maximum one-hour emissions would be higher than daily average hourly emissions.

Specifically, Shell requests that Condition D.6.4 in the Draft Permit be revised to include the following language:

6.4 Deck Crane Engines (Units K-4A – 4C)

6.4.1 During Drilling Activity, aggregate emissions from all deck crane engines combined shall not exceed the emission limits specified for each of the pollutants below.
D.6.4.1.1 NO_x: 12.0 lb/hr
D.6.4.1.2 $PM_{2.5}$: 3.4 lb/day
D.6.4.1.3 PM_{10}: 3.4 lb/day

6.4.2 During all times other than Drilling Activity, aggregate emissions from all deck crane engines combined shall not exceed the emission limits specified for each of the pollutants below.

D.6.4.2.1 NO_x: 12.0 lb/hr

D.6.4.2.2 $PM_{2.5}$: 5.7 lb/day

D.6.4.2.3 PM_{10}: 5.7 lb/day

Shell providing additional modeling runs to support this requested permit change. Shell characterized the dispersion modeling runs as using the same model and modeling procedures that Shell used in its permit application, and involving no altered assumptions or any other changes to source characterizations other than as explained below.

Shell re-evaluated the ambient air quality implications of crane emissions by increasing the hourly emissions and assuming that all crane emissions came from a single crane. Specifically, there are three modeling scenarios:

> Scenario 1 considers all three crane engine emissions come from crane engine stack A, with emissions from crane engines B and C set to zero.
>
> Scenario 2 considers all three crane engine emissions come from crane engine stack B, with emissions from crane engines A and C set to zero.
>
> Scenario 3 considers all three crane engine emissions come from crane engine stack C, with emissions from crane engines A and B set to zero.

Shell notes that changing these variables involves no changes to the underlying model, modeling procedures, or assumptions that were subject to public review. The model already contains inputs for the crane engine stacks; the three separate crane locations are already imbedded in the emission sequences used to determine the probabilistic design day. Shell states that the modeling runs supporting this comment simply changed the numerical values associated with those inputs. Anyone running the model would get the same results.

Shell explains that this demonstration focuses on compliance with the 1-hour NO_2 and 24-hour $PM_{2.5}$ NAAQS, which are the most constraining ambient standards for the Kulluk project. As shown in the application, PM_{10} concentrations are well below the NAAQS and any changes to these concentrations would be proportional to the changes in $PM_{2.5}$ concentrations. Therefore, an explicit analysis is not performed for PM_{10}.

Shell states that the modeling approach taken to support this comment provides hourly data, spatial specificity, and a conservative approach that ensures NAAQS compliance while allowing for aggregate limits for the cranes. In its application, Shell demonstrated that the proposed crane emissions contributions to maximum concentrations on the "design days" are very small, showing that the highest-impacting crane engine would contribute approximately 1.2% of the Kulluk concentrations for 1-hour NO_2, and 0.5% for 24-hour $PM_{2.5}$.

By modeling total emissions from all three cranes as coming from a single crane location, Shell contends that the modeling runs provided in support of this comment present an even more conservative approach. This approach shows the maximum possible concentrations from the requested aggregate crane emission rates, because spreading emissions among multiple sources results in lower concentrations than simulating those same emissions from a single location. This is reflected in the modeling results, which are summarized in the table below. Shell explains that with these conservative assumptions, the total 1-hour NO_2 and 24-hour $PM_{2.5}$ concentrations are only slightly increased from the permit application values, and in all cases project concentrations remain below the NAAQS.

1-hour NO_2 & 24-hour $PM_{2.5}$ Concentrations – Comparing Application Results and Revised Crane Engine Scenario Results

NAAQS	Total Concentrations (µg/m^3) (includes background)			NAAQS (µg/m^3)
	Application	Revised Crane Engine Scenarios	Increase from Application	
1-hour NO_2	151.49	162.17	10.68	188
24-hour $PM_{2.5}$	34.01	34.05	0.04	35

In summary, Shell states that the modeling runs provided with this comment support replacing the per-crane limits with aggregate emission limits for the three crane engines. They demonstrate that even if all of the aggregated emissions came from a single crane – which represents the maximum possible impact of the requested limits – the NAAQS would be protected. Shell contends that spreading the aggregate allowable emissions among the three cranes, regardless of the distribution, will result in concentrations that are at-worst equal to, but likely lower than, the concentrations calculated based on all of the emissions coming from a single crane. Shell states that imposing aggregate emission limits will, therefore, ensure that the NAAQS are protected while giving the project necessary operational flexibility.

Response: The air quality impact analysis for 1-hour NO_2 and 24-hour $PM_{2.5}$ provided by Shell during the public comment period supports the permittee's request to adjust the numerical emission limits in Condition D.6.4.1 and D.6.4.2 to reflect aggregate limits for all emission units in that category instead of emission limits on a per unit basis. Accordingly, the numerical limits have been amended as requested.

For $PM_{2.5}$, the analysis provides the basis for revising the permit to move forward with emission limits that apply to all three deck crane engines combined, not separately as the draft permit proposed. For $PM_{2.5}$, the new analysis assumes no emissions increases. The analysis assumes that the same total emissions are generated. But this time, all emissions are assumed to be exhausted through a single stack rather than three stacks that are spread across three locations on the Kulluk deck. The new $PM_{2.5}$ analysis shows an increase of 0.12 percent to the maximum concentration previously predicted. The new resultant ambient concentration of 34.05 µg/m^3 (which includes background) remains less than the

24-hr $PM_{2.5}$ NAAQS of 35µg/m^3. Because NAAQS remain protected, Region 10 has revised the emission limits to reflect the emission rates modeled.

For the revised NO_2 analysis, Shell again modeled emissions as if exhausted from a single stack. This time, however, Shell increased the combined emission rate from 3.6 lb/hr to 12 lb/hr for Well Drilling Activity and from 6 lb/hr to 12 lb/hr for all other activities. Whereas the 12 lb/hr emission rate is based upon an hourly fuel combustion capacity value of 26 gallons per hour, the "3.6 lb/hr" and "6 lb/hr" emission rate values reflect average daily fuel consumption for different activity levels expressed as an hourly value for modeling purposes.[24] The new NO_2 analysis shows an increase of 7 percent to the maximum concentration previously predicted. The new resultant ambient concentration of 162.17 µg/m^3 (which includes background) remains less than the 1-hr NO_2 NAAQS of 188µg/m^3. Because NAAQS remain protected, Region 10 has revised the emission limits to reflect the emission rates modeled.

Region 10 also revised the text of the permit, but not as requested. Region 10 used the same sentence structure as used in Permit Condition D.6.2.1 for the MLC HPU Engines. Region 10 took this approach because Shell modeled the deck crane engines in an analogous manner to the MLC HPU engines. In both cases, emissions from identical emission units were conservatively assumed to be generated at a single location on the Kulluk deck. Demonstrating compliance with the NAAQS using this conservative assumption provides for additional flexibility in the corresponding permit condition.

While the change to Permit Conditions D.6.4.1 and D.6.4.2 does increase the amount of NO_X the deck crane engines can emit during any given hour, this revision does not increase the overall PTE of the OCS source which remains at 240 tpy.

Comment HH.5: The Alaska Department of Natural Resources provided the following specific comments on the Draft Permit and Statement of Basis:

<u>Kulluk Draft Permit</u>

1. Page 20, Item 26.3.4 refers to a form in Appendix B for recording visibility, but there was no Appendix B provided with the document.
2. Page 23, Item 3.1.1.4 refers to a form in Appendix B for recording visibility, but there was no Appendix B provided with the document.

<u>Kulluk Statement of Basis</u>

1. Page 20, final paragraph, sentence four references the Discoverer drill rig. This reference should be changed to the Kulluk drill rig.
2. Page 34, Condition B.15 – the text refers to 18 AC 50.110. The correct citation should read 18 AAC 50.110.

[24] Max 1-hr: (26 gal/hr) x (0.462 lb NO_X/gal) = 12lb/hr
Average Well Drilling Activity: (184 gal / 24 hr) x (0.462 lb NO_X/gal) = 3.6 lb/hr
Average Cementing/Logging Activity: (307 gal / 24 hr) x (0.462 lb NO_X/gal) = 6 lb/hr
See Permit Application, Appendix G pages 4 and 6.

3. Page 39, Condition D.4.9 – prohibits Shell from operating the Kulluk in the Beaufort Sea within the same drilling season as the Noble Discoverer drilling vessel. This condition appears as Condition D.4.8 on page 38 of the permit. Consideration should be given to adding a caveat on this condition that in the unlikely event of a well blowout emergency this condition should not preclude the use of a second drilling vessel to drill a relief well.
4. Page 53, Section 5.3 Coastal Zone Management – it should be noted that the Alaska Coastal Management Program described in this section ceased to exist as of July 1, 2011.
5. Page 55, Footnote 20, line 2 – The reference refers to Alaska's Notrth Slope. It should refer to Alaska's North Slope.

Response: Region 10 erroneously omitted the Visible Emissions Field Data Sheet as Appendix B of the proposed permit. In the final permit, the Visible Emissions Field Data Sheet is presented as Appendix B.

With respect to the comments regarding errors in the Statement of Basis, Region 10 acknowledges the errors the commenter points out. Region 10 inadvertently referenced the Discoverer drill rig rather than the Kulluk drill rig on page 20; incorrectly cited 18 AAC 50.110 on page 34; and misspelled the word "North" on page 55.

With respect to the comment regarding the termination of Alaska's Coastal Zone Management Program, see response to Category JJ earlier in this document.

Lastly, the commenter asks Region 10 to consider including a caveat to Condition D.4.8 to ensure that this condition does not prohibit the use of a second vessel to drill a relief well in the event of an emergency blowout. Condition D.4.8 prohibits Shell from operating the Kulluk in the Beaufort Sea in the same drilling season as the Discoverer because Shell's application did not consider the air quality impacts or the aggregation aspects (*i.e.*, what constitutes the "stationary source") of operating both vessels in the same sea during the same drilling season. See response to comment E.1. As a general matter, Clean Air Act stationary source permitting programs are not intended to address emergency activities, such as those that may be necessary to respond to a blowout. See generally *Shell Gulf of Mexico, Inc. and Shell Offshore, Inc.*, Frontier Discoverer Drilling Units, OCS Appeal Nos. 10-01 through 10-04, Order on Four Additional Issues, dated March 14 2011, at 26-38. To the extent Shell determines that safety considerations associated with an emergency blowout require operation of both the Discoverer and the Kulluk in the Beaufort Sea in violation of Permit Condition D.4.8, Region 10 will evaluate any such situation in accordance with EPA's excess emissions policy.[25]

[25] See e.g., Memorandum from Kathleen M. Bennett to Assistant Administrator for Air, Noise and Radiation Regional Administrators, Regions I-X, Re: Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions, dated September 28, 1982; Memorandum from John B. Rasnic, Director, Stationary Source Compliance Division Office of Air Quality Planning and Standards to Linda M. Murphy, Director, Air, Pesticides and Toxics Management Division Region 1, Re: Automatic or Blanket Exemptions for Excess Emissions During Startup, and Shutdowns Under PSD, dated January 28, 1993; Memorandum from Eric Schaeffer, Director, Office of Regulatory Enforcement, to Addressees, Re:

Comment HH.6: Shell recommended the following changes to the Draft Permit to correct what it characterized as unintended errors:

- Page 6, Table 2 in "Source Description." The bottom right cell of the table (the "600 hp" Approximate Aggregate Rating for OSRV WB-1A-1Z) should also refer to footnote "h."
- Page 33, Table D.2.1, footnote p. This footnote is for the $PM_{2.5}$ column in the table, so should refer to "$PM_{2.5}$ emission factors," not "PM_{10} emission factors."
- Page 34, Table D.2.2. The column headings for N_2O and CH_4 are swapped. The 0.0009 lb/gal emission factor for engines is for methane (CH_4), not N_2O (see 7/20/11 EPA memo, "Derivation of Emission Factors in Tables D.2.1 and D.2.2 of Draft Permit to Shell for Operation of Kulluk in Beaufort Sea").
- Page 40, Condition D.6.3.1. To be consistent with the language in Condition 6.4.1, delete the word "Combined," the "s" from the word "engines," and the phrase "operating at a single location", and add the word "each" before "MLC" so it reads: "Emissions from each MLC air compressor engine shall not exceed …"

Response: With respect to the last cell in Table 2 of the proposed permit, Region 10 acknowledges that we inadvertently referenced footnote "g" rather than footnote "h." In the final permit, the last cell of Table 2 references footnote "h." With respect to the text within footnote "p," Region 10 inadvertently references "PM_{10}" rather than "$PM_{2.5}$." In the final permit, footnote "p" makes reference to "$PM_{2.5}$." Finally, Region 10 acknowledges inadvertently misidentifying N_2O and CH_4 emission factors in Table D.2.2. The final permit's Table D.2.2 correctly identifies N_2O and CH_4 emission factors.

With respect to the comment regarding Permit Condition D.6.3.1, commenter requests Region 10 to consider amending the text. Region 10 is revising Permit Condition D.6.3.1 and is creating Permit Condition D.6.3.2 to provide clarity with respect to the emission limits applicable to MLC Air Compressors engines necessary for NAAQS protection.

The Draft Permit's Condition D.6.3.1 stated,

6.3.1 Combined emissions from MLC air compressor engines operating at a single location shall not exceed the emission limits specified for each of the pollutants below.

6.3.1.1	NO_X:	14.8 lb/hr
6.3.1.2	$PM_{2.5}$:	7.4 lb/day
6.3.1.3	PM_{10}:	7.4 lb/day

Guidance on the Appropriate 6/12/08 Meyer Memo; Memorandum from Steven A. Herman, Assistant Administrator for Enforcement and Compliance Assurance; Robert Perciasepe, Assistant administrator for Air and Radiation to Regional Administrators, Regions I-X, Re: State Implementation Plans: Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown, dated September 20, 1999.

Although not made clear in the Draft Permit, Region 10 intended to limit emissions from two groups of engines operating at two separate locations through this one permit term. As the application clearly illustrates, one group was modeled as if located on the Port side of the Kulluk while the other was modeled as if located on the Starboard side. The two groups were modeled simultaneously, and each group's emissions were modeled as exhausting through a single stack distinct from the other group's stack.

The Port engines were modeled with the following emission rates: NO_X - 14.8 lb/hr, $PM_{2.5}$ - 7.4 lb/day and PM_{10} - 7.4 lb/day. The Starboard engines were modeled with the following emission rates: NO_X - 14.8 lb/hr, $PM_{2.5}$ - 7.4 lb/day and PM_{10} - 7.4 lb/day. See Technical Support Document Tables 3 and 4.

Region 10 recognizes that the Draft Permit language can be improved to better reflect emission rates that were modeled for the MLC Air Compressor Engines. The following two Permit Conditions, which do not represent an increase in allowable emissions, are being inserted into the permit to clarify Draft Permit Condition D.6.3.1.

6.3.1 Combined emissions from Port MLC air compressor engines shall not exceed the emission limits specified for each of the pollutants below.

6.3.1.1	NO_X:	14.8 lb/hr
6.3.1.2	$PM_{2.5}$:	7.4 lb/day
6.3.1.3	PM_{10}:	7.4 lb/day

6.3.2 Combined emissions from Starboard MLC air compressor engines shall not exceed the emission limits specified for each of the pollutants below.

6.3.2.1	NO_X:	14.8 lb/hr
6.3.2.2	$PM_{2.5}$:	7.4 lb/day
6.3.2.3	PM_{10}:	7.4 lb/day

II. CATEGORY – GOVERNMENT-TO-GOVERNMENT CONSULATION

Comment II.1: Commenters questioned whether Region 10 had properly engaged in government-to-government consultation. One commenter referenced the trust relationship between federal and tribal governments and stated that the federal government has a fiduciary responsibility to Indian tribes to protect their lands and resources. The commenter stated that the federal government must recognize tribal governments as separate sovereign nations. The commenter read from a document that was described as Department of Interior order number 3225 concerning the Endangered Species Act and subsistence uses in Alaska. In reading from this document the commenter stated that the Department of Interior will ensure government-to-government consultation with Alaska natives, and the Department of Commerce will comply with relevant orders and policies in consulting with Alaska natives. The commenter also read from what was described as a court case concerning the question of whether the Alaska Native Claims Settlement Act can lawfully extinguish aboriginal title or rights in Alaska. The commenter also cited to a Supreme Court case, City of Sherrill v. Oneida Indian Nation of New York, 544 U.S. 197 and stated that the Alaska Native Claims Settlement Act was unconstitutional and an act of genocide and fraud upon the indigenous people of Alaska.

Response: Region 10 recognizes that the federal government has a unique legal relationship with tribal governments which involves, among other things, providing for meaningful and timely consultation. Executive Order 13175, issued on November 9, 2000 and entitled "Consultation and Coordination with Indian Tribal Governments," requires federal agencies to have an accountable process to ensure meaningful and timely input by tribal officials in the development of policies that have tribal implications. 65 Fed. Reg. 67,249; EPA Policy on Consultation and Coordination with Indian Tribes, May 4, 2011. To ensure meaningful and timely consultation, Region 10 has established a tribal consultation framework and developed a communications protocol to provide for meaningful involvement of North Slope communities in decision making.

Given the geographic proximity between the Kulluk's proposed operations and off-shore areas where subsistence activities occur, Region 10 determined that tribal consultation was warranted. In letters dated June 6, 2011, Region 10 invited the Inupiat Community of the Arctic Slope, Native Village of Kaktovik, and Native Village of Nuiqsut to engage in government-to-government consultation. The Region also held informational meetings in Barrow and Kaktovik on June 15-17, 2011 to discuss OCS permitting actions, including the Draft Permit. These meetings were open to the public and all North Slope entities (city governments, tribal governments, the North Slope Borough, and the Alaska Eskimo Whaling Commission) received invitations to attend these early informational meetings. The Region believes its actions have ensured meaningful and timely consultation with tribal governments.

Comments regarding the Alaska Native Claims Settlement Act are outside the scope of this proceeding.

JJ. CATEGORY – COASTAL ZONE MANAGEMENT

Comment JJ.1: Commenters reference the fact that Alaska's Coastal Management Program (ACMP) expired by operation of statute on June 30, 2011. One commenter stated that it is premature for Region 10 to issue the Draft Permit without a coastal management program.

Response: Region 10 is aware that the ACMP expired on June 30, 2011 by operation of Alaska Statutes 44.66.020 and 44.66.030. Because a federally approved coastal zone management program must be administered by a state agency, the National Oceanic and Atmospheric Administration (NOAA) withdrew the ACMP from the National Coastal Management Program established under the Coastal Zone Management Act. 76 Fed. Reg. 39,857 (July 7, 2011). As a result, the Coastal Zone Management Act consistency provisions at 16 U.S.C. § 1456(c)(3) and 15 CFR Part 930 no longer apply in Alaska and consistency certifications are no longer required. However, prior to the expiration of the ACMP, Region 10 conducted a review of the projects required to undergo ACMP consistency review and determined that a consistency review for the Draft Permit was not required under the ACMP. Accordingly, Region 10 does not believe that a decision on the Draft Permit would be premature in the absence of a coastal management program.

KK. CATEGORY – ENDANAGERED SPECIES ACT

Comment KK.1: At the public hearing in Barrow, one commenter questioned whether he should be concerned about the Draft Permit with respect to the Coastal Zone Management Act and Endangered Species Act (ESA).

Response: Although the Alaska Coastal Management Program is no longer in effect, the Region determined that a consistency review would not have been required under the former program. See response to comment JJ.1. Section 7 of the ESA requires federal agencies, in consultation with the National Marine Fisheries Service and 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. The BOEMRE is the lead agency for ESA Section 7 compliance with respect to Shell’s oil exploration activities and has consulted with the Services regarding Shell’s activities in the Beaufort Sea. In fulfilling its ESA obligations for this permitting action, Region 10 reviewed the ESA consultation documents prepared by BOEMRE and the biological opinions issued by the Services. A discussion of Region 10’s ESA process is provided in the Statement of Basis (pp.50-51).

II. SUMMARY OF CHANGES TO THE PERMIT

The following table lists the changes made to the Draft Permit and provides a brief summary of the rationale for the changes (as compared to July 22, 2011 Revised Draft Permit).

Permit Condition or Location	Description	Explanation or Response to Comments Discussion
Page 1	Added actual issuance date.	
Page 1	Added actual date permit is to become effective.	
Page 1	Added actual date Title V permit is to expire.	
Page 5	Added acronym for continuous monitoring	

Permit Condition or Location	Description	Explanation or Response to Comments Discussion
	system	
Table 2	Corrected two typos. In row “OSRV Work Boats (OSRV WB)”, correct reference is to footnote “g” rather than footnote “f”. In last cell of table, correct reference is to footnote “h” rather than footnote “g”.	Corrected typo. See also RTC Comment HH.6.
A.18	Revised to make minor changes to reflect most recent COA requirements for excess emissions and permit deviation reports.	OCS permits on the Inner OCS must include COA requirements. See 40 CFR 55.14. The draft permit did not include the most current COA language. See 18 AAC 50.346(b)(2), Standard Permit Condition III Excess Emissions and Permit Deviation Reports.
B.2.2.1	Replaced language that required visible emissions observations to be conducted within 6 months of permit issuance. Revised permit condition states, “Within 30 days of the Kulluk becoming an OCS source or within 30 days of startup of an emission unit, whichever is later, observe exhaust for 18 minutes.”	In response to concerns raised by Shell in a telephone conversation on October 13, 2011, between Doug Hardesty, EPA, and Pauline Ruddy, Shell, Region 10 is deviating from standard operating permit language to account for the fact that this is both a Title V permit and a construction permit. Equipment may not be installed, much less operating, within 6 months of permit issuance. The Kulluk is prohibited from becoming an OCS source until July 1, 2012. New language provides flexibility to permittee to conduct observations within a reasonable time after startup.

Permit Condition or Location	Description	Explanation or Response to Comments Discussion
B.14.1	Added "Perform regular maintenance considering the manufacturer's or the operator's maintenance procedures."	Revised to include a subparagraph in a COA requirement that was erroneously omitted. See 18 AAC 50.346(b)(5), Standard Permit Condition VI Good Air Pollution Practices.
B.16	Re-numbered Condition B.15.7 as Condition B.16. Entitled B.16, "COA Obligations for Modifications Subject to 18 AAC Article 5 Minor Permits."	Clarifying change.
B.17	Created condition to require permittee to provide emissions information consistent with COA requirement born out of the State's emissions reporting obligations in 40 CFR Part 51.	OCS permits on the Inner OCS must include COA requirements. See 40 CFR 55.14. Region 10 erroneous omitted this standard condition from the draft permit. See 18 AAC 50.346(b)(8), Standard Permit Condition XV Emission Inventory Reporting.
C.3.3	Added language clarifying that permittee is to report capacity of boilers and heaters in units of "MMBtu per hour" and "gallons per hour."	Clarifying change.
Table D.2.1 – Row for Units K-5A – 5Z. Table D.2.2 – Rows for Units IB1-2A – 2Z and IB2-2A – 2Z.	Revised CO emission factor to 0.007 lb/gal.	See RTC Comment I.3.a-c. See also October 21, 2011 EPA memo. New value reflects worst-case emissions test results for boiler on the Discoverer.
Table D.2.1 – Row for Unit K-6. Table D.2.2 – Row for OSRV WB-1A – 1Z	Revised NO_X and $PM_{10/2.5}$ emission factors to 0.399 lb/gal and 0.038 lb/gal, respectively.	See RTC Comment I.3.a. See also October 21, 2011 EPA memo. New values reflect 90th percentile

Permit Condition or Location	**Description**	**Explanation or Response to Comments Discussion**
		emissions test result values for engines with output greater than 600 hp on Discoverer and Associated Fleet.
Table D.2.1 – Last Cell	Revised CH_4 emission factor to 1596 lb/month.	See RTC Comment I.3.d. New value assumes that what was projected to be emitted during an entire drilling season is emitted in just one month.
Table D.2.1 – Footnote p	Changed "PM_{10}" to "$PM_{2.5}$"	Corrected typo.
Table D.2.2	Under column "Emission Unit ID," replace "OSRV WB 1 – 4" with "OSRV WB-1A – 1Z."	Corrected typo.
Table D.2.2	Exchange emission factor values in columns "N_2O" and "CH_4."	Corrected typo. See also RTC Comment HH.6.
D.3.4	Added phrase "within a drilling season" to the end of condition.	Clarifying change. Revised language is consistent with language in Condition D.3.3.
D.3.10	Added requirement to calculate and record information on the number of days the Kulluk operates as an OCS source, the number of hours of drilling activity, and the number of hours of MLC activity.	Requires recordkeeping to provide a reasonable assurance of compliance with Conditions D.3.2, D.3.3, and D.3.4 and are generally responsive to concerns expressed in comments within Category I.1, J.1, K and M.1 that the permit include sufficient monitoring to assure compliance with limits.
D.4.1.2, D.4.1.3, D.4.2.2, D.4.2.3, D.4.4.3, D.4.4.4, D.6.14.2, D.6.15.2, D.6.15.3	Corrected a series of typos in which cross references failed to identify correctly the permit condition being referenced.	Corrected typos. Each cross reference failed to identify the letter (D.4.4.1, for example) in the designation of the referenced permit conditions.

Permit Condition or Location	**Description**	**Explanation or Response to Comments Discussion**
D.4.1.4, D.4.2.4, D.4.4.5, D.6.14.3, D.6.15.4	Deleted conditions requiring Shell to calculate heater and boiler emissions assuming operation at maximum capacity.	In response to concerns raised by Shell in a telephone conversation on October 13, 2011, between Doug Hardesty, EPA, and Pauline Ruddy, Shell, Region 10 is revising these conditions to make the emission calculation requirement for heaters and boilers consistent with emission calculation requirement for regularly operated engines.
D.4.5	Corrected a typo that erroneously referenced Condition F.2.3 rather than Condition F.2.4.	Corrected typo.
D.4.6	Revised total fuel combustion allowance to 7,004,428 gallons.	See RTC Comment I.3.d. New fuel allowance reflects increased projection of mud degassing PTE.
D.4.9	Created condition prohibiting permittee from purchasing any liquid fuel other than ULSD. Condition requires permittee to keep records to show compliance.	See RTC Comment G.1. Permittee originally requested operating limit that restricts diesel fuel purchases to ULSD. Proposed permit inadvertently omitted this owner-requested limit. Final permit includes operating limit.

Permit Condition or Location	Description	Explanation or Response to Comments Discussion
D.5.5	Make reference to "drilling season" rather than "rolling 12-month period." Clarify that an activity occurring during parts of two days is considered two events regardless of whether the activity lasts longer than 24 hours.	Clarifying change. The changes recognize that compliance with the NAAQS is based upon air quality observations that occur within blocks of time that align with the calendar. The specific 24-hour period is the day, and the specific 12-month period is the calendar year. That portion of the calendar year in which permittee is authorized to operate is the drilling season.
D.6.3.1, D.6.3.2	Revised Condition 6.3.1 and created Condition 6.3.2 to clarify that one set of emission limits apply to "Port" emission units and the other apply to "Starboard" emission units.	See RTC Comment HH.6. The change limits Shell to installing MLC Air Compressor Engines to two distinct locations and makes it more clear what emission limits apply at those locations. Change in no way represents an increase in allowable emissions from draft permit.
D.6.4.1, D.6.4.2	Revised deck crane engines' emission limitations.	See RTC Comment HH.4. Emissions from all engines now aggregated to determine compliance with new limits. Change represents an increase to hourly NO_X allowable emissions, but no increase to allowable $PM_{2.5}$ emissions. Change results from new modeling provided by Shell.
D.6.10.1.2	Revised the $PM_{2.5}$ emission limit from 73.9 lb/day to 74.4 lb/day.	Corrected typo.

Permit Condition or Location	Description	Explanation or Response to Comments Discussion
D.6.14	Revised permit condition to require that units K-5A – 5Z and K-8 demonstrate compliance with 1-hour NO_X limit by multiplying appropriate emission factor by hourly operation rate.	To demonstrate compliance with 1-hour NO_X limit, hourly emissions must be calculated for these emission units. In the proposed permit, Region 10 inadvertently exempted permittee from making this hourly demonstration for the Kulluk incinerator (K-8). The change to the permit corrects this error. In response to concerns raised by Shell in a telephone conversation on October 13, 2011, between Doug Hardesty, EPA, and Pauline Ruddy, Shell, Region 10 is also revising this condition with respect to Kulluk heaters and boilers (K-5A – 5Z). In the proposed permit, Region 10 had erroneously thought the permittee was accepting of calculating boiler emissions assuming operation at maximum hourly capacity in exchange for not monitoring operating rate. In the final permit, permittee is required to collect hourly operating data for heaters and boilers and to use the data to calculate emissions.
D.6.15.3	Revised permit condition to delete the following language, "multiplied by the appropriate emission factor (lb/ton) specified in Tables D.2.1 – D.2.2 times 24."	Clarifying change. The deleted language is not necessary given the language in D.6.15. Revised permit condition is now consistent with D.6.15.2.

Permit Condition or Location	Description	Explanation or Response to Comments Discussion
E.3.2	Revised permit to require all incinerators undergo source testing to determine test-derived emission factors for CO and NO_X.	See RTC Comment I.3.a.

Permit Condition or Location	Description	Explanation or Response to Comments Discussion
F.1.1	Added additional GPS requirement for Shell to monitor the date, time and location of the Associated Fleet when the Kulluk becomes and ceases to be an OCS source and when the Associated Fleet enters or leaves the 25 mile radius area around the Kulluk.	The revised permit condition makes it more clear that all fuel combusted while the Associated Fleet is within 25 miles of the Kulluk must be accounted for if the permit requires Shell to record the time at which each vessel enters or leaves the 25 mile radius area around the Kulluk when the Kulluk is an OCS source, as well as the location of the Associated Fleet at the time the Kulluk becomes and ceases to be an OCS source. These requirements have been added to Condition F.1.1 of the permit and will require the collection of information needed to ensure, in conjunction with other permit requirements, that all of the fuel combusted by the Associated Fleet while regulated by this permit is accounted for and considered when determining compliance. These changes are generally responsive to concerns expressed in comments within Category I.1, J.1, K and M.1 that the permit include sufficient monitoring to assure compliance with limits.

Permit Condition or Location	Description	Explanation or Response to Comments Discussion
F.2.2	Amended condition to require permittee monitor heater and boiler fuel consumption.	In response to concerns raised by Shell in a telephone conversation on October 13, 2011, between Doug Hardesty, EPA, and Pauline Ruddy, Shell, Region 10 is revisiong this condition to make the fuel monitoring requirement for heaters and boilers consistent with fuel monitoring requirement for engines that operate regularly.
F.2.2.1.1	Amended condition to replace “engine” with “emission unit or emission unit group” to recognize that fuel flow meters may be employed to determine fuel consumption rate of an individual combustion unit or a group of combustion units.	Clarified that a fuel flow meter should have no inflows or outflows between it and the associated individual emission unit or emission unit group. Clarifying Condition F.2.2.1.1 is generally responsive to comments within Category I.1, J.1, K and M.1 that the permit include sufficient monitoring to assure compliance with limits.
F.2.2.5	Added requirement to record fuel usage for all emission units.	Added to ensure the annual fuel usage limit has appropriate recordkeeping requirements. Enhancing Condition F.2.2.5 is generally responsive to comments within Category I.1, J.1, K and M.1 that the permit include sufficient monitoring to assure compliance with limits.

Permit Condition or Location	**Description**	**Explanation or Response to Comments Discussion**
F.2.4.2	The revised language in the permit specifies that the permittee is to “determine the sulfur content of each delivery of fuel to the Kulluk and Associated fleet.” In lieu of sampling and analyzing each delivery, the permittee may “Obtain from the fuel supplier certification of the sulfur content of the fuel as purchased, and obtain documentation that each storage tank transporting the fuel between purchase and delivery has not caused the fuel delivered to become higher than 100 ppm sulfur content.”	See RTC Comment G. Changes to language more clearly specify options for determining sulfur content of fuel shipments.
F.2.5	Added language to clarify when monitoring of the incinerator temperature is required.	In response to concerns raised by Shell in a telephone conversation on October 13, 2011, between Doug Hardesty, EPA, and Pauline Ruddy, Shell, Region 10 is revising this condition to more clearly describe the time period during which the permittee is required to monitor incinerator temperature. Temperature monitoring is to begin as soon as waste is introduced to the incinerator.

Permit Condition or Location	Description	Explanation or Response to Comments Discussion
F.2.7	Created condition to require permittee to monitor Kulluk emergency generator operation.	Added to ensure the Kulluk emergency generator operating restrictions have appropriate recordkeeping requirements. Creating Condition F.2.7 is generally responsive to comments within Category I.1, J.1, K and M.1 that the permit include sufficient monitoring to assure compliance with limits.
F.3	Spell out abbreviation for CMS as continuous monitoring system.	Clarifying change.
F.3.2	Added language to clarify when operation of the SCR inlet temperature and urea pump CMS is required.	In response to concerns raised by Shell in a telephone conversation on October 13, 2011, between Doug Hardesty, EPA, and Pauline Ruddy, Shell, Region 10 is revising this condition to clarify the time period during which the permittee is required to operate these two aspects of the SCR CMS.
F.3.7	Correct typos that cross reference incorrect permit conditions.	Clarifying change.
F.4.2	Added language to clarify when monitoring of the exhaust gas inlet temperature to the oxidation catalyst is required.	In response to concerns raised by Shell in a telephone conversation on October 13, 2011, between Doug Hardesty, EPA, and Pauline Ruddy, Shell, Region 10 is revising this condition to clarify the time period during which the permittee is required to monitor temperature.

Permit Condition or Location	**Description**	**Explanation or Response to Comments Discussion**
G.1, G.2, G.3, G.4, G.5	Added descriptive titles.	Clarifying change.
G.1.5, G.1.6.1, G.1.7.1, G.1.7.4, G.1.8.1, G.2.12.2, G.3.3	Correct typos that cross reference incorrect permit conditions.	Clarifying change.
G.1.8, G.1.8.1 and G.1.8.2.	The revised language in the permit specifies that the permittee is to "determine and record the sulfur content, cetane index and aromatic content of each delivery" in accordance with the appropriate sampling and analysis methods. In lieu of sampling and analyzing each delivery, the permittee may "Obtain from the fuel supplier certification of the sulfur content of the fuel as purchased, and obtain documentation that each storage tank transporting the fuel between purchase and delivery has not caused the fuel delivered to become higher than 15 ppm sulfur content."	See RTC Comment G. Original permit language simply requiring "the purchase" of ULSD lacked specificity. The fuel being delivered to storage tanks serving affected sources must meet specification as it is delivered from supply vessel. Requirement applies to all fuel intended to be combusted while Kulluk is an OCS source. Revisions also specify how compliance is to be determined.
G.3.5	Correct a typo that identified the incorrect underlying regulation.	Corrected typo.

Permit Condition or Location	Description	Explanation or Response to Comments Discussion
G.3.5.1, G.3.5.2, G.3.5.3	Replace “or” with “and” with respect to requirement to determine cetane index and aromatic content. Replace “ASTM D 4737 10” with “ASTM D 976-80.” Replace “ASTM 5186-03” with “ASTM D 1319-03”	Changes consistent with changes to G.1.8.1.1 that correctly reference requirement to test for cetane index “and” aromatic content, not cetane index “or” aromatic content. Changes also correct the references to analytical methods for determination of cetane index and aromatic content for diesel fuel as referenced in ASTM D975-11 “Standard Specification for Diesel Fuel Oils.”
G.5.2.2.3	Correct a typo where a cross reference failed to identify the letter in the designation of the referenced permit condition.	Corrected typos.
Attachment A – EPA Notification Form – Excess Emission and Permit Deviation Reporting	Added form to permit.	Region 10 erroneously omitted this form from the draft permit.
Attachment B – Visible Emission Field Data Sheet	Added form to permit.	Region 10 erroneously omitted this form from the draft permit. See RTC at Comment HH.5.
Attachment C – Emission Inventory Reporting Form.	Added form to permit.	Region 10 erroneous omitted this form from the draft permit. OCS permits on the Inner OCS must include COA requirements. See 40 CFR 55.14. See 18 AAC 50.346(b)(9), Standard Permit Condition XVI Emission Inventory Reporting Form. Form is referenced by newly created Condition B.17.