1001 Pennsylvania Avenue, NW, Washington, DC 20004-2595 ▪ p202 624-2500 ▪ f202 628-5116

crowell moring

DUANE A. SILER
(202) 624-2885
DSiler@crowell.com

April 14, 2010

BY HAND DELIVERY

U.S. Environmental Protection Agency
Eurika Durr, Clerk of the Board
Environmental Appeals Board
1341 G Street, N.W., Suite 500
Washington, D.C. 20005

Re: Request for Expedited Resolution of Anticipated Petitions for Review of Shell Outer Continental Shelf Air Permit Number R10OCS/PSD-AK-2010-01 (Beaufort Sea)

Dear Ms. Durr:

By this letter, Shell Offshore Inc. ("SOI") respectfully requests that the Environmental Appeals Board ("EAB" or "the Board") expedite its consideration and resolution of any petitions for review that may be filed challenging the Outer Continental Shelf ("OCS") Prevention of Significant Deterioration ("PSD") major source air permit issued to SOI for exploration activities in the Beaufort Sea, R10OCS/PSD-AK-2010-01 ("Beaufort Air Permit"). EPA Region 10 issued the Beaufort Air Permit on April 9, 2010, subject to administrative appeals to this Board. *See* Attachment A hereto. The period within which to file petitions for review of the permit with this Board will close on May 12, 2010. Extensive comments were filed in opposition to the proposed permit, and SOI anticipates that the Board will receive petitions to review the Beaufort Air Permit.

The reasons why the Board should expedite its evaluation of challenges to the Beaufort Air Permit are substantially the same as the reasons why, as explained in Shell's letter to you dated April 2. 2010, the Board should expedite its review of the Chukchi Air Permit, issued to Shell Gulf of Mexico, Inc. ("SGOMI") on March 31, 2010.[1] As with that permit, the Beaufort Air Permit is required for exploration work that is scheduled to begin in July 2010 and which can be conducted only during a few summer/early fall months. We will not burden you or the Board by repeating those reasons, but respectfully refer you and the Board to our earlier letter. In this letter we incorporate our prior letter by reference and provide additional information that is unique to SOI's exploration project in the Beaufort Sea.

[1] In this letter we sometimes refer to SOI and SGOMI jointly as "Shell."

Having now obtained two PSD air permits, Shell plans to initiate drilling in either the Chukchi or Beaufort at the earliest date permitted, with the location dependent on weather, ice conditions, logistics, and other contingencies. It is possible that Shell would be able only to operate in one of the seas during the 2010 season. As explained in our letter dated April 2, 2010, any delay in Shell's 2010 Arctic drilling season beyond early July will cost Shell, on average, about $2.5 million dollars per day for a full 120-day season.

For this reason, SOI respectfully requests that the Board expedite its review of the anticipated petitions against the Beaufort Air Permit, while concurrently expediting any review of the Chukchi Air Permit. SOI will formally move for leave to intervene in any such petitions against the Beaufort Air Permit and for an order establishing an expedited briefing schedule that would allow the Board to fully consider and issue a decision on the petitions for review prior to the commencement of the 2010 drilling season. Specifically, SOI will ask the Board to follow with this permit, as with the Chukchi Air Permit, a process similar to the expedited review of SOI's Arctic OCS air permit undertaken in 2007, with accelerated briefing, hearing and resolution of the expected petitions for review of the Beaufort permit.

EPA has expressly recognized in connection with the Chukchi Air Permit the need for prompt resolution of permit challenges.[2] The need for timely EAB action is equally compelling in regard to the Beaufort Air Permit, as confirmed by the President's March 31, 2010 expression of support for oil and gas development in the Arctic OCS generally[3] and the Administration's explicit statement that: "The Administration strategy supports exploratory drilling in the Chukchi and Beaufort Seas in the Arctic Ocean, which could begin as early as this summer, to develop critical information."[4]

The Beaufort Air Permit authorizes SOI to conduct oil and gas exploratory operations on its lease-holdings in the Beaufort Sea using the drill ship, *Frontier Discoverer*, the same drillship that SGOMI will seek to use to explore in the Chukchi Sea. Because the *Frontier Discoverer* can operate only in relatively ice-free waters with the protection of ice management vessels, Shell's drilling season is limited to the open water season, which varies from year to year, but which generally begins in July and ends in October. Under Shell's

---

[2] *See* Letter from Gina McCarthy to Peter E. Slaiby (Jan. 29, 2010) at 1 ("Region 10 has already expressed to you their commitment to work within whatever expedited schedule the EAB may establish, and we will convey our view to EAB of the significance of this permit and the importance of expeditious processing relative to the company's ability to conduct exploratory drilling this season at the appropriate time.") (Attachment B hereto). The Agency will, of course, determine for itself how to appropriately manifest its recognition of SOI's need for prompt resolution when and if a request for review occurs and, as outlined herein, SOI formally requests expedited scheduling of any such request.

[3] Remarks by the President on Energy Security at Andrews Air Force Base, 3/31/10, available at: http://www.whitehouse.gov/the-press-office/remarks-president-energy-security-andrews-air-force-base-3312010

[4] Department of Interior Press Release: Secretary Salazar Announces Comprehensive Strategy for Offshore Oil and Gas Development and Exploration (March 31, 2010) (emphasis added), available at: http://www.doi.gov/news/pressreleases/2010_03_31_release.cfm (visited 4/1/10).

MMS-approved exploration plans, this drilling season is substantially shorter than the open water season. Any period of administrative review of the Beaufort Air Permit that continues for any period of time into the drilling season will deprive SOI of valuable time to drill in that sea and, if prolonged, could even foreclose SOI's 2010 drilling season.

Permitting History

Our April 2, 2010 letter details Shell's efforts over the past four years to obtain an air permit for exploratory operations on Shell's lease-holdings on the OCS in the Chukchi and Beaufort Seas, including SOI's initial permit for exploration in the Beaufort utilizing the drillship *Kulluk*. *See In re Shell Offshore Inc., Kulluk Drilling Unit and Frontier Discoverer Drilling Unit*, OCS Appeal Nos. 07-01 and 07-02, slip op. at 5, 69 (EAB, Sept. 14, 2007); *In re Shell Offshore Inc., Kulluk Drilling Unit*, OCS Appeal Nos. 08-01, 08-02, and 08-03 (EAB, April 30, 2009). Ultimately, SOI withdrew the minor source permit application and, on Region 10's advice, applied for a PSD major source permit for the Beaufort Sea.[5] SOI submitted its revised application materials on January 18, 2010. Region 10 issued a completeness determination on February 11, 2010 and a draft permit on February 17, 2010. On April 9, 2010. Region 10 issued the final Beaufort Air Permit.

Harm to Shell As a Result of Delay

Under the Beaufort Air Permit, SOI may begin operations on July 1, when the Chukchi Sea is generally open, and must complete operations by December 31 each year. But, as a practical matter, for the 2010 drilling season Shell would be bound by the requirements of its 2010 MMS-approved Exploration Plan, which allows drilling to begin on or about July 10, 2010, requires cessation of drilling operations from the commencement of the Alaska Native whaling season on August 25, 2010, until the hunt is completed, and then mandates that resumed operations end no later than October 31, 2010. Thus, SOI's 2010 Beaufort drilling season consists of a maximum of about 80-95 days, even shorter than the approximate 120-day Chukchi drilling season.

As a general rule, Arctic conditions and applicable regulations restrict Shell's drilling operations to a narrow window of open water during the summer/early fall. As noted above, for the Beaufort, the drilling season is further restricted because SOI is not permitted by MMS to drill when the Villages of Nuiqsuit and Kaktovik conduct their annual whale hunt. *See* Supplemental Declaration of Peter E. Slaiby (April 12, 2010) ("Slaiby Beaufort

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[5] As noted in our prior letter, in the same time frame as SOI applied for the PSD permit, Shell submitted new Exploration Plans to the Minerals Management Service for the Chukchi Sea and for the Beaufort Sea. MMS approved them, and challenges to each are pending in the Ninth Circuit. The Court of Appeals has ordered expedited briefing of these appeals and has scheduled oral argument on the merits for May 6, 2010. *Native Village of Point Hope, et al. v. Salazar, et al.*, Nos. 09-73942, 09-73944, 10-70166, and 10-70368, orders dated January 15, 2010 and March 2, 2010. Unlike in the previous litigation over the earlier Exploration Plans, because of the Ninth Circuit's expedited schedule for decision, challengers have not sought a stay of or preliminary injunction against the EPs for the 2010 drilling season, and have stated that they do not intend to do so if the Court provides for disposition of the case before exploration activities begin in July 2010.

Declaration") at ¶ 5 (Attachment C hereto). A delay in the Board's review of any challenges to SOI's permit during the short drilling season could thus work a disproportionate and unique hardship on SOI. For that reason, SOI respectfully requests that the Board give the Beaufort Air Permit, along with the Chukchi Air Permit, even higher priority for resolution of challenges than EAB customarily accords to PSD permits.

Shell needs both air permits at the outset of the season because, due to ice conditions and weather, Shell may not be able to explore in one or the other sea. Shell cannot confidently predict which sea will be sufficiently ice-free by July to allow drilling. For this reason, as well as other contingencies, Shell needs the flexibility afforded by both permits in order to increase the chances of drilling and completing one or more wells in one or the other sea during the short 2010 drilling season. *Id.* at ¶ 4.

Without presuming to pre-judge the merits of any potential request for review, SOI believes that EPA and SOI will demonstrate that the Beaufort Air Permit is environmentally protective, fully compliant with the Clean Air Act, and procedurally sound, and that EAB will affirm the permit. In that event, each and every day of delay after July 10, 2010 in resolving any requests for review will prejudice Shell.

Because of the long preparation time and specialized resources required to carry out these exploration activities, Shell has been required to make significant financial commitments for the 2010 season, and must continue to do so in order to preserve its ability to drill this year. This is in addition to Shell's investment over the last four years of over three billion dollars and countless other resources to obtain OCS leases in the Chukchi and Beaufort seas and to develop and permit a safe, environmentally responsible Arctic drilling program. *See* Declaration of Peter E. Slaiby (April 2, 2010) ("Slaiby Chukchi Declaration") at ¶ 10 (Attachment D hereto). These new commitments are necessary in order to obtain and mobilize the necessary vessels, personnel, support services, fuel, supplies and other goods and services necessary for the planned operations. *Id.* Between January 1 and May 31, 2010, Shell will have incurred irrevocable obligations for virtually all the goods and services needed for drilling in one or both seas in the 2010 season at a sunk cost in excess of $300 million. *Id.*

Thus by the time Shell can begin drilling under the Beaufort EP, Shell's summer drilling season will, in effect, be fully funded. Every day without an air permit after that date would reduce the approximately 120 full days available to complete all operations planned for 2010. The out-of-pocket cost alone to Shell of delay after July 10 is on the order of an average of $2.5 million per day for the full season. Slaiby Chukchi Declaration at ¶ 12. Every day that is lost will likely have to be replicated, and paid for again, in a future season. And because Shell's objective is to drill two wells in the Arctic OCS in 2010, a delay that prevents completion of a second well (and consequent delay in the acquisition of data from a second completed well) would reduce the utility of the drilling season far more than just a certain number of lost operating days. *Id.* at ¶ 13. Moreover, there is a risk that Shell may not even be able to make up such delays in subsequent seasons. As more fully explained in Mr. Slaiby's April 2, 2010 Declaration, Shell's leases have limited time-horizons. Thus, the loss of operating days in a season represents the loss of a material portion of the lease term and threatens the entirety of Shell's significant financial investment in the leases. *Id.* at ¶¶ 14-15.

For all of these reasons, SOI finds itself in an unavoidable situation where delay in consideration of any anticipated petitions for review of the final Beaufort Air Permit would work a disproportionate and irreparable harm justifying expedition of the EAB appeal process in these unique circumstances.

As discussed in our April 2 letter, EAB's expedited review of the *Kulluk* air permit in July 2007 provides a model for proceedings on the Beaufort Air Permit (and on the Chukchi Air Permit). SOI respectfully again asks the Board for similar expedition in order to preserve the already-brief 2010 drilling season.

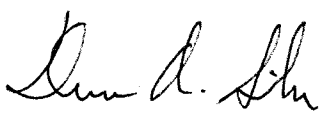
Shell is diligently pursuing, and believes it will timely obtain, all other approvals it will need for the 2010 drilling season in the Beaufort Sea. Slaiby Chukchi Declaration at ¶ 16. Under the circumstances, a delay at the EAB could cost Shell irreplaceable days for potential drilling in 2010, or if prolonged, could preclude Shell from drilling at all this summer. Thus, SOI respectfully requests that the Board treat any petitions for review of the Beaufort Air Permit as an emergency and once again accord them highest priority among PSD appeals.

In addition to requesting an urgent priority for these appeals, SOI will seek an expedited briefing schedule under which SOI and EPA would be required to respond to all petitions for review within 15 days, and under which both petitioners and respondents would be limited to a single opening brief. EAB's procedures allow the Board to decide a petition for review and responses thereto, without any subsequent briefing by the parties. Under the circumstances, Shell believes that any petitioner should be able to provide the Board with complete petitions that will need no supplementation in the form of a reply brief, also obviating the need for a sur-reply.

For the reasons discussed above, and in order to promote the Administration's goal of developing as soon as possible the "critical information" needed to assess the potential for oil and gas production on already-leased areas on the Arctic OCS, SOI respectfully requests that the Board make preparations to expedite any petitions for review of the Beaufort Air Permit by (i) immediately notifying SOI of any such petition to allow SOI to immediately request permission to participate, (ii) upon the filing of any request for review, setting an expedited briefing schedule for SOI and Region 10 to respond to the petition(s) within 15 days and (iii) once again setting a hearing and issuing a decision as quickly as possible.

SOI appreciates the Board's consideration in this urgent matter and would be happy to provide the Board any further information or filings that would be of assistance prior to the anticipated receipt of petitions for review.

Sincerely,



Duane A. Siler
Counsel for Shell Offshore Inc.

Enclosures: Attachments A, B, C and D

Attachment A

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

OUTER CONTINENTAL SHELF
PREVENTION OF SIGNIFICANT DETERIORATION
PERMIT TO CONSTRUCT

Permit Number: R10OCS/PSD-AK-2010-01 Issuance Date: April 9, 2010

In accordance with the provisions of Clean Air Act Section 328 and Code of Federal Regulations (C.F.R.) Title 40, Part 55, and the provisions of Part C to Title I of the Clean Air Act and 40 C.F.R. § 52.21,

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

is authorized to construct and operate the Frontier Discoverer drillship and its air emission units and to conduct other air pollutant emitting activities in accordance with the permit conditions listed in this permit, and only at the following lease blocks from the Beaufort Sea lease sales 195 and 202:

BF 195:	6657	6658	6659	6707	6708	6709	6712	6713	6751	6752	6757	6758	6764	6773	6774	6801
	6802	6814	6815	6822	6823	6824	6851	6873	6874							
BF 202:	6259	6308	6309	6310	6359	6406	6407	6409	6410	6457	6459	6460	6461	6508	6510	6511
	6512	6558	6559	6560	6561	6562	6609	6610	6611	6612	6660	6662				

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 and citizens under the Clean Air Act.

/S/

Richard Albright
Director, Office of Air, Waste and Toxics

April 9, 2010
Date

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ABBREVIATIONS AND ACRONYMS

AAC .....Alaska Administrative Code
ADEC.....Alaska Department of Environmental Conservation
BACT.....Best Available Control Technology
CAA .....Clean Air Act
CCV .....Closed Crankcase Ventilation
CDPF.....Catalyzed Diesel Particulate Filter
C.F.R .....Code of Federal Regulations
COA .....Corresponding Onshore Area
CTM.....Conditional Test Method
EPA.....United States Environmental Protection Agency
FTIR.....Fourier Transform Infrared
HPU.....Hydraulic Power Unit
MLC.....Mud Line Cellar
NA.....Not applicable
NAAQS.....National Ambient Air Quality Standards
OCS.....Outer Continental Shelf
OTM.....Other Test Method
PDF .....Portable Document Format
PSD .....Prevention of Significant Deterioration
PTE .....Potential to Emit
QA/QC .....Quality Assurance/Quality Control
SCR.....Selective Catalytic Reduction

UNITS AND MEASUREMENTS

Btu.....British thermal units
^{o}C.....degree Celsius
dscf.....dry standard cubic foot
^{o}F .....degree Fahrenheit
g.....grams
hp.....brake horsepower
hr .....hour
kW.....kiloWatts (mechanical)
kWe.....kiloWatts electrical
lb .....pounds
MMBtu/hr .....Million British thermal units per hour
ppmv .....parts per million by volume
scf.....standard cubic foot
tpy .....tons per year

POLLUTANTS

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

AUTHORITY

The United States Environmental Protection Agency (EPA) issues this outer continental shelf (OCS)/prevention of significant deterioration (PSD) permit pursuant to Section 328 of the Clean Air Act (CAA), 42 U.S.C. § 7627, and the implementing OCS regulations at 40 C.F.R. Part 55, and pursuant to Part C to Title I of the CAA, 42 U.S.C §§ 7470 to 7492, and the implementing PSD air quality regulations at 40 C.F.R. § 52.21. This action is based upon the application submitted by Shell Offshore Inc. (Shell) on January 18, 2010, supplemental submittals identified in the administrative record for this permit action, and upon the technical analysis performed by EPA.

In addition EPA is issuing this OCS/PSD permit consistent with Article 3 of the State of Alaska Air Quality Control Regulations 18 Alaska Administrative Code (AAC) 50.302 (Construction Permits) and 18 AAC 50.306 (Prevention of Significant Deterioration Permits), the applicable provisions of which have been incorporated into 40 C.F.R. Part 55 Appendix A.

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 C.F.R. Part 55.
2. The permittee will meet all of the applicable requirements of the 40 C.F.R. § 52.21.
3. The permittee will meet all of the applicable requirements of 18 AAC 50.

APPROVAL CONDITIONS

Shell Offshore Inc. (Shell or permittee) is authorized to construct and operate the vessels and emission units listed in Tables 1 through 6, 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.

Table 1: – Frontier Discoverer Emission Units

ID	Description	Make and Model	Rating[a]
FD-1 – 6	Generator Engines	Caterpillar D399 SCAC 1200 rpm	1,325 hp
FD-7	Propulsion Engine	Mitsubishi 6UEC65	7,200 hp
FD-8	Emergency Generator	Caterpillar 3340	131 hp
FD-9 – 11	MLC Compressor Engines	Caterpillar C-15	540 hp
FD-12 – 13	HPU Engines	To be determined	250 hp
FD-14	Port Deck Crane Engine	Caterpillar D343	365 hp
FD-15	Starboard Deck Crane Engine	Caterpillar D343	365 hp
FD-16 – 17	Cementing Unit Engines	Detroit 8V-71N	335 hp
FD-18	Cementing Unit Engine	GM 3-71	147 hp

ID	Description	Make and Model	Rating[a]
FD-19	Logging Winch Engine	Caterpillar C7	250 hp
FD-20	Logging Winch Engine	John Deere PE4020TF270D	35 hp
FD-21 – 22	Heat Boilers	Clayton 200	7.97 MMBtu/hr
FD-23	Incinerator	TeamTec GS500C	276 lb/hr
FD-24 -30	Fuel Tanks	Not applicable (NA)	Various
FD-31	Supply Ship Generator Engine(s)	Generic	584 hp
FD-32	Drilling Mud System	NA	NA
FD-33	Shallow Gas Diverter System	NA	NA
FD-34	Cuttings/Mud Disposal Barge[b]	NA	NA

[a] Permit conditions may limit operation to less than rated capacity.

[b] Permit conditions prohibits cuttings/mud disposal barge from emitting any air pollutants.

Table 2: – Icebreaker #1

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

[a] Permit conditions may limit operation to less than rated capacity.

Table 3: – Icebreaker #2

ID	Description	Make and Model	Rating[a]
Tor Viking			
TV-1 - 2	Main Propulsion Engines	Caterpillar MaK 8M32	5,046 hp
TV-3 - 4	Main Propulsion Engines	Caterpillar MaK 6M32	3,784 hp
TV-5 – 6	Non-propulsion Generator Engines	Caterpillar 3412	1,168 hp
TV-7	Heat Boiler	NA	1.37 MMBtu/hr
TV-8	Incinerator	NA	151 lb/hr
Hull 247[b]			
	Main Engines	NA	24 MW[c]
	Heat Boiler	NA	4 MMBtu/hr
	Incinerator	NA	151 lb/hr

[a] Permit conditions may limit operation to less than rated capacity.

[b] Hull 247 is the shipbuilder's (Edison Chouest) designation for a vessel to be built under contract to Shell. The final name for the vessel may be different than this temporary designation.

[c] This represents an aggregate rating of all engines on board Hull 247.

Table 4: – Supply Ship/Barge and Tug

Description	Make and Model	Maximum Aggregate Rating[a]
Propulsion Engines and Non-Propulsion Generator Engine(s) Excluding Emergency Engine	Various	7,784 hp
Propulsion Engines Only	Various	7,200 hp
Emergency Engine(s)	Various	200 kW

[a] Permit conditions may limit operation to less than rated capacity.

Table 5: – Oil Spill Response Fleet

ID	Description	Make and Model	Rating[a]
Offshore Management Ship - Point Barrow Tug			
PBT-1 – 2	Propulsion Engines	Caterpillar 3512	1050 hp
PBT-3 – 4	Non-propulsion Generator Engines	Caterpillar 3304	150 hp
Skimmer - Arctic Endeavor Barge			
AEB-1 –4	Non-propulsion Generator Engines	Various	556 hp
Oil Spill Response Ship – Nanuq			
N-1 - 2	Propulsion Engines	Caterpillar 3608	2,710 kW
N-3 – 4	Non-propulsion Electrical Generators	Caterpillar 3508	1,285 hp
N-5	Emergency Generator	John Deere	166 kW
N-6	Incinerator	ASC/CP100	125 lbs/hr
Oil Spill Response Work Boat - Kvichak 34-foot No. 1			
K-1 – 2	Propulsion Engines	Cummins QSB	300 hp
K-3	Generator Engines	Various	12 hp
Oil Spill Response Work Boat - Kvichak 34-foot No. 2			
K-4 – 5	Propulsion Engines	Cummins QSB	300 hp
K-6	Generator Engines	Various	12 hp
Oil Spill Response Skimmer - Rozema 47-foot			
R-1 –2	Propulsion Engines	Various	700 hp
R-3	Generator Engines	N/A	9 hp

[a] Permit conditions may limit operation to less than rated capacity.

Table 6: – Cuttings/Muds Disposal Barge and Tug

ID	Description	Make and Model	Rating
Cuttings/Mud Disposal Barge[a]			
	Non-propulsion Engine(s)	Not Specified	Not Specified
Tug[b]			
	Propulsion Engine(s)	Not Specified	Not Specified
	Non-propulsion Engine(s)	Not Specified	Not Specified

[a] The barge itself has no air quality implications since it has no generators or other fuel-burning equipment.
[b] The tug may have emission units that have not been included in the emission inventory and have not been evaluated.

Effective Date. This permit becomes effective 30 days after the service of notice of the final permit decision, unless review of the permit decision is requested pursuant to 40 C.F.R. § 124.19.

OCS Source. Permit conditions contained in Sections B through R, except for those conditions addressing notification, reporting and testing, apply only during the time that the Frontier Discoverer drillship (Discoverer) is an OCS Source. Permit conditions in Sections A and S as well as permit conditions contained in Sections B through Q addressing notification, reporting and testing apply at all times as specified.

For the purpose of this permit, the Discoverer is an "OCS Source" between the time the Discoverer is declared by the Discoverer's on-site company representative to be secure and stable in a position to commence exploratory activity at the drill site until the Discoverer's on-site company representative declares that, due to retrieval of anchors or disconnection of its anchors, it is no longer sufficiently stable to conduct exploratory activity at the drill site, as documented by the records maintained pursuant to Condition B.2.2.

Lease Identification. This major source permit authorizes the mobilization and operation of the Discoverer drillship and its associated fleet at various drill sites in the Beaufort Sea OCS off the North Slope of Alaska in connection with an exploratory oil and gas drilling program (exploration drilling program). The proposed permit will allow Shell to operate the Frontier Discoverer drillship and associated fleet for a multi-year exploration drilling program within Shell's current lease blocks in lease sales 195 and 202 on the Beaufort Sea OCS. The group of lease blocks authorized under this permit is located within 25 miles and beyond 25 miles from Alaska's seaward boundary. In some instances, lease blocks are both within and beyond 25 miles from Alaska's seaward boundary. For purpose of the Statement of Basis and the proposed permit, the portion of the OCS which is 25 or more miles from the State's seaward boundary is referred to as the "Outer OCS". The portion of the OCS that is within 25 miles of the State's seaward boundary is referred to as the "Inner OCS".

The leases can be divided into the three following groups:

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

When the Discoverer drillship and/or its associated fleet is within the Beaufort Sea Inner OCS, the applicable corresponding onshore area (COA) regulations apply. The provisions in this permit that apply only to operations within 25 miles of the state seaward boundary are identified as "COA Regulations". A reference to any Alaska Administrative Code (AAC) provisions in this permit refers to the ACC provisions incorporated into 40 C.F.R. Part 55 (See 75 FR 3387 and 75 FR 3392).

COA REGULATIONS: PERMIT DOCUMENTATION

Date	Document Details
January 18, 2010	Shell Offshore Inc. Outer Continental Shelf Pre-Construction Air Permit Application – Frontier Discoverer Beaufort Sea Exploration Drilling Program

A. GENERALLY APPLICABLE REQUIREMENTS

1. **Construction and Operation.** 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. For purposes of this permit, Icebreaker #1, Icebreaker #2, the Supply Ship/Tug and Barge, the Point Barrow Tug, Arctic Endeavor Barge, Nanuq, Kvichaks Nos. 1-2, Rozema Skimmer, and Cuttings/Mud Disposal Barge and Tug shall collectively be referred to as the "Associated Fleet."

2. **Overlapping Requirements.** When two or more provisions apply to the same emission unit or activity the permittee must comply with both.

3. **Compliance Required.** The permittee shall comply with all applicable requirements of 40 C.F.R. § 52.21, Part 55, 18 AAC 50, and this permit. Failure to do so shall be considered a violation of Sections 111(e) and 165 of the CAA. All enforcement provisions of the CAA, including but not limited to Sections 113, 114, 120, 167, 303, and 304, apply to the permittee.

4. **Compliance with Other Requirements.** This permit does not relieve the permittee of the responsibility to comply fully with applicable provisions of any other requirements under federal law.

5. **Terms to Make Permit Enforceable.** It is not a defense in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with a permit term or condition.

6. **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.

7. **Expiration of Approval to Construct.** As provided in 40 C.F.R. § 52.21(f)(4), this approval shall become invalid 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 construction is not completed within a reasonable time. EPA may extend the 18-month period upon a satisfactory showing that an extension is justified.

8. **Permit Revision, Termination and Reissuance.** This permit may be revised, terminated, or revoked and reissued by EPA for cause. Cause exists to revise, terminate, or revoke and reissue this permit under the following circumstances:

   8.1. This permit contains a material mistake;

   8.2. Materially inaccurate statements were made in establishing the terms or conditions of this permit;

   8.3. The permittee fails to comply with any material condition of this permit; or

   8.4. This permit must be revised, terminated, or revoked and reissued to assure compliance with CAA requirements.

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.

9. **Credible Evidence.** For the purpose of 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.

10. **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:

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

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

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

10.4. 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.

11. **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:

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

11.2. The date(s) analyses were performed;

11.3. The company or entity that performed the analyses;

11.4. The analytical techniques or methods used;

11.5. The results of such analyses;

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

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

11.8. The location 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.

12. **Agency Notifications.** Unless otherwise specified in this permit, any documents required to be submitted under this permit, including reports, test data, monitoring data, notifications, and applications for renewals and permit modifications shall be submitted to:

    OCS/PSD Air Quality Permits

    U.S. EPA - Region 10, AWT-107

    1200 Sixth Avenue, Suite 900

    Seattle, WA 98101

    Facsimile no. 206-553-0110

13. **Certification.** Any document required to be submitted under this permit shall be certified by a responsible official, as that term is defined in 40 C.F.R. § 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.

14. **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.

15. **Property Rights.** This permit does not convey any property rights of any sort, or any exclusive privilege.

16. **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.

17. **Excess Emission and Permit Deviation Reports.** Except as provided in Condition A.18, the permittee shall report all emissions or operations that exceed or deviate from the requirements of this permit as follows:

    17.1. As soon as possible after the event commences or is identified, report via fax or email:

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

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

    17.2. Within three business days after the event commenced or was identified, report via fax or email 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 other exceedance of a throughput limit.

17.3. Report all other permit deviations.

17.3.1. Within 30 days of the end of the month in which the deviation occurs, except as provided in Condition A.17.3.2.

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

17.4. When reporting excess emissions, 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.

17.5. When reporting a permit deviation, 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.

17.6. 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. **Operating Reports**. During the life of this permit[1], the permittee shall submit an original and two copies of an Operating Report by March 31 for the preceding calendar year.

18.1. The Operating Report must include all information required to be in Operating Reports by other conditions of this permit.

18.2. If excess emissions or permit deviations that occurred during the reporting period are not reported under Condition A.17, either:

18.2.1. The permittee shall identify:

18.2.1.1. The date of the deviation;

18.2.1.2. The equipment involved;

18.2.1.3. The permit condition affected;

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

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

18.2.2. When excess emissions or permit deviations have already been reported under Condition A.17, the permittee shall cite the date or dates of those reports.

[1] "Life of this permit" is defined as the permit effective dates, including any periods of reporting obligations that extend beyond the permit effective dates. 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.

18.3. The Operating Report must include 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:

18.3.1. The date of the emissions;

18.3.2. The equipment involved;

18.3.3. The permit condition affected; and

18.3.4. The monitoring result which triggered the additional monitoring.

19. **COA Regulations: 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 – 50.405.

20. **COA Regulations: 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:

20.1. The OCS source's (including the Associated Fleet) assessable potential to emit of 2,053 tpy; or

20.2. 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:

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

20.2.2. Material balance calculations;

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

20.2.4. Other methods and calculations approved by the EPA.

21. **COA Regulations: Assessable Emissions Estimates**. Emission fees will be assessed as follows:

21.1. 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.12, 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

21.2. 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.20.1.

22. **COA Regulations: Annual Compliance Certification.** Each year by March 31 for the preceding calendar year and for reporting periods following the effective date of this permit, the permittee shall compile and submit to the EPA one original and one copy of an annual compliance certification report as follows.

22.1. For each permit term and condition set forth in the permit including terms and conditions for monitoring, reporting, and recordkeeping:

22.1.1. Certify the compliance status over the preceding calendar year consistent with the monitoring required by this permit;

22.1.2. State whether compliance is intermittent or continuous;

22.1.3. Briefly describe each method used to determine the compliance status; and

22.1.4. Notarize the responsible official's signature.

23. **COA Regulations: General Source Test Requirements.**

23.1. **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.

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

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

23.2.2. 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.

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

23.3.1. 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 C.F.R. 60.

23.3.2. 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 C.F.R. 61.

23.3.3. 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 C.F.R. 63.

23.3.4. 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.

23.3.5. 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 C.F.R. 60, Appendix A.

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

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

23.4. **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).

23.5. **Test Exemption.** The permittee is not required to comply with Conditions B.20.2, when the exhaust is observed for visible emissions.

23.6. **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's appropriate division director or designee.

23.7. **Particulate Matter Calculation.** In source testing for compliance with the PM standards in Condition B.12, the three-hour average is determined using the average of three one-hour test runs.

B. SOURCE-WIDE REQUIREMENTS

1. **Drill Site Notification.** At least 10 days prior to the Discoverer becoming an OCS Source, the permittee shall notify EPA via facsimile 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 within the Beaufort Sea lease sales 195 or 202 where the drill site is located;

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

   1.4. Confirmation that emissions from the source would impact no Class I area. The confirmation shall include a description of the legal and factual basis for this determination; and

   1.5. Confirmation that emissions from the source would impact no area where an applicable increment was known to be violated. The confirmation shall include a description of the legal and factual basis for this determination.

2. **Duration of Exploration Operations.** The permittee shall only conduct exploration drilling operations in the Beaufort Sea between July 1 and December 31 each year (referred to hereafter as the "drilling season").

   2.1. During any rolling 12-month period, the permittee shall not operate the Discoverer as an OCS Source in excess of 168 calendar days. Each partial day shall be counted as a calendar day.

   2.2. For each drill site at which the Discoverer operates, the permittee shall record the following:

      2.2.1. The location of each drill site, using a modern global positioning system to determine the location. Location shall be recorded by providing coordinates in the following formats:

         2.2.1.1. Latitude and longitude, and

         2.2.1.2. Universal Transverse Mercator grid system.

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

      2.2.3. The date and hour that the Discoverer became an OCS Source at that drill site;

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

   2.3. Any time spent drilling a relief well shall be included in the time recorded in Conditions B.2.1.

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

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

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

4. **Best Available Control Technology (BACT) for Sulfur Dioxide (SO_2) Emissions from Discoverer Emission Units.** The permittee shall not combust any liquid fuel with sulfur content greater than 0.0015 percent by weight, as determined by Condition B.4.1, in any emission unit on the Discoverer (except for Unit FD-7).

   4.1. Representative fuel samples shall be obtained using one of the methods in 40 C.F.R. § 80.330(b). The sulfur content of the fuel shall be determined using ASTM D 5453-08b.

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

      4.2.1. Prior to mobilizing the Discoverer for the first time at the beginning of a drilling season, determine the sulfur content in each fuel oil storage tank on the Discoverer. The permittee shall obtain a representative sample of the fuel and analyze the sample for sulfur content using the procedures in Condition B.4.1.

      4.2.2. Thereafter, determine and record the sulfur content upon receiving each fuel shipment, as follows:

         4.2.2.1. Obtain a representative sample of the fuel delivered and analyze the sample for sulfur content using the procedures in Condition B.4.1.; or

         4.2.2.2. Obtain a single certification of sulfur content for each shipment of fuel from the fuel supplier based on an analysis of the fuel, providing that the certification indicates that the sulfur content has been determined by the ASTM method listed in Condition B.4.1.

   4.3. 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 any emission unit on the Discoverer (except Unit FD-7)

5. **Sulfuric Acid Mist Owner Requested Limit for Associated Fleet.** The permittee shall not combust any liquid fuel with sulfur content greater than 0.0015 percent by weight, as determined by Condition B.5.1, in any emission unit on any vessel in the Associated Fleet.

   5.1. Representative fuel samples shall be obtained using one of the methods in 40 C.F.R. § 80.330(b). The sulfur content of the fuel shall be determined using ASTM D 5453-08b.

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

5.2.1. Prior to mobilizing the Discoverer for the first time at the beginning of a drilling season, determine the sulfur content in each fuel oil storage tank on the vessels comprising the Associated Fleet. The permittee shall obtain a representative sample of the fuel and analyze the sample for sulfur content using the procedures in Condition B.5.1.

5.2.2. Thereafter, determine and record the sulfur content upon receiving each fuel shipment, as follows:

5.2.2.1. Obtain a representative sample of the fuel delivered and analyze the sample for sulfur content using the procedures in Condition B.5.1; or

5.2.2.2. Obtain a single certification of sulfur content for each shipment of fuel from the fuel supplier based on an analysis of the fuel, providing that the certification indicates that the sulfur content has been determined by the ASTM method listed in Condition B.5.1.

5.3. 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 any emission unit on any vessel in the Associated Fleet.

6. **COA Regulations: Marine Vessel Visible Emission Standards.** At all times while the Discoverer is an OCS Source, visible emissions, excluding condensed water vapor, may not reduce visibility through the exhaust effluent of the Associated Fleet within 25 miles of the Discoverer, by more than 20 percent except as follows:

6.1. While at berth or at anchor, visibility may be reduced by up to 100 percent for periods aggregating no more than:

6.1.1. Three minutes in any one hour; and

6.1.2. An additional three minutes during initial startup of a vessel; for purposes of this subparagraph, "initial startup" includes the period during which a vessel is testing equipment in preparation to casting off or weighing anchor.

6.2. During the hour immediately after weighing anchor or casting off, visibility may be reduced under one, but not both, of the following options:

6.2.1. Visibility may be reduced by up to 40 percent for that entire hour; or

6.2.2. Visibility may be reduced by up to 100 percent for periods aggregating no more than nine minutes during that hour.

6.3. During the hour immediately before the completion of all maneuvers to anchor or make fast to the shore, visibility may be reduced under one, but not both, of the following options:

6.3.1. Visibility may be reduced by up to 40 percent for that entire hour; or

6.3.2. Visibility may be reduced by up to 100 percent for periods aggregating no more than nine minutes during that hour.

6.4. At any time not covered by Conditions B.6.1 through B.6.3 of this section, visibility may be reduced by up to 100 percent for periods aggregating no more than three minutes in any one hour.

6.5. Observe, record, and report the visible emissions, excluding condensed water vapor, using the visible emission monitoring, recordkeeping, and reporting Conditions B.9 through B.11.

7. **BACT for Particulate Matter Emissions (PM, PM_{10}, and $PM_{2.5}$) from Discoverer Diesel IC Engine Crankcase Ventilation.** Except for the MLC Diesel Compressor Engines (FD-9 –11) and the Caterpillar C7 Logging Winch Engine (FD-19), each diesel IC engine on the Discoverer shall be equipped with a closed crankcase ventilation (CCV) system.

8. **COA Regulations: Industrial Process and Fuel-Burning Equipment Visible Emissions Standard.** The permittee shall comply with the following.

8.1. Do not cause or allow visible emissions, excluding condensed water vapor, emitted from Units FD-1 through 22, and FD-31 listed in Table 1 to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.

8.2. For Units FD-1 through 22, and FD-31, monitor, record, and report in accordance with Condition B.9.1 – B.11.

8.3. For Units FD-1 through 22, and FD-31, as long as they do not exceed the limits in Condition B.8, monitoring shall consist of an annual compliance certification (as provided in Condition A.22.1) with the opacity standard.

9. **COA Regulations: Visible Emissions Monitoring, Recordkeeping, and Reporting.**

9.1. Visible Emissions Monitoring. In addition to the requirements for Units FD-1 through 31 specified in Sections C through R below, the permittee shall observe the exhaust of emission Units FD-1 through 22, and FD-31 listed in Table 1 for visible emissions using either the Method 9 Plan under Condition B.9.2 or the Smoke/No-Smoke Plan under Condition B.9.3. The permittee may change visible-emissions plans for an emission unit at any time unless prohibited from doing so by Condition B.9.4.

9.2. Method 9 Plan. For all 18-minute observations in this plan, observe exhaust, following 40 C.F.R. 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.

9.2.1. First Method 9 Observation. Observe exhaust for 18 minutes within six months after the issue date of this permit. For any emission unit, observe exhaust for 18 minutes within 14 calendar days after changing from the Smoke/No-Smoke Plan of Condition B.9.3. For any emission units replaced during the term of this permit, observe exhaust for 18 minutes within 30 days of startup.

9.2.2. 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.

9.2.3. Annual Method 9 Observations. After observing emissions for three consecutive operating months under Condition B.9.2.1, 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.

9.2.4. 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.9.2.3 for annual monitoring are met.

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

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

9.3.2. 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.

9.3.3. Smoke Observed. If smoke is observed, either begin the Method 9 Plan of Condition B.9.2 or perform the corrective action required under Condition B.9.4.

9.4. 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.9.3, then the permittee shall either follow the Method 9 plan of Condition B.9.2 or:

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

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

9.4.3. After completing the actions required under Condition B.9.4.1,

9.4.3.1. Take Smoke/No Smoke observations in accordance with Condition B.9.3.

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

9.4.3.1.2. Continue as described in Condition B.9.3.2; or

9.4.3.2. If the actions taken under Condition B.9.4.1 do not eliminate the smoke, or if subsequent smoke is observed under the schedule of Condition B.9.4.3.1.1, 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.9.3.1.

10. **COA Regulations: Visible Emissions Recordkeeping.** The permittee shall keep records as follows.

10.1. If using the Method 9 Plan of Condition B.9.2,

10.1.1. The observer shall record:

10.1.1.1. 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;

10.1.1.2. 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;

10.1.1.3. 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;

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

10.1.1.5. 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.

10.1.2. 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;

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

10.2. If using the Smoke/No Smoke Plan of Condition 9.3, record the following information in a written log for each observation and submit copies of the recorded information upon request of the EPA:

10.2.1. The date and time of the observation;

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

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

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

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

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

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

11. **COA Regulations: Visible Emissions Reporting.** The permittee shall report visible emissions as follows.

11.1. Include in each Operating Report under Condition A.18:

11.1.1. Which visible-emissions plan of Condition B.9.1 was used for each emission unit; if more than one plan was used, give the time periods covered by each plan;

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

11.1.2.1. 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

11.1.2.2. A summary to include:

11.1.2.2.1. Number of days observations were made;

11.1.2.2.2. Highest six-minute average observed; and

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

11.1.3. 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

11.1.4. A summary of any monitoring or record keeping required under Conditions B.9.1 and B.9.4.3.2 that was not done.

11.2. Report under Condition A.17:

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

11.2.2. If any monitoring under Condition B.9.1 was not performed when required, report within three days of the date the monitoring was required.

12. **COA Regulations: Industrial Process and Fuel-Burning Equipment Particulate Matter Standard.** The permittee shall not cause or allow PM emitted from Units FD-1 through 22, and FD-31 listed in Table 1 to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.

12.1. For Units FD-1 through 22, and FD-31 listed in Table 1, monitor, record and report in accordance with Conditions B.13 – B.14.

12.2. For Units FD-1 through 22, and FD-31, as long as they do not exceed the limits in Condition B.12, monitoring shall consist of an annual compliance certification (as provided in Condition A.22.1) with the PM standard.

12.3. 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.

13. **COA Regulations: Particulate Matter Monitoring, Recordkeeping and Reporting.** PM Monitoring for Diesel Engines. The permittee shall conduct source tests on diesel engines Units FD-1 through 20, and FD-31 to determine the concentration of (PM) in the exhaust of a source in accordance with Condition B.13.

13.1. Within six months of exceeding the criteria of Conditions B.13.2.1 or B.13.2.2, either:

13.1.1. Conduct a PM source test according to requirements set out in Condition B.20, or

13.1.2. Make repairs so that emissions no longer exceed the criteria of Condition B.13.2; to show that emissions are below those criteria, observe emissions as described in Condition B.9.2 under load conditions comparable to those when the criteria were exceeded.

13.2. Conduct the test according to Condition B.13.1 if:

13.2.1. 18 consecutive minutes of Method 9 observations result in an 18-minute average opacity greater than 20 percent; or

13.2.2. 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.

13.3. 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.

13.4. The automatic PM source test requirements in Conditions B.13.1 and B.13.2 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.

14. **COA Regulations: Particulate Matter Record Keeping 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 FD-1 through 20 and FD-31 from Table 1 in the permit. Report the stack diameter(s) in the next Operating Report under Condition A.18.

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

14.1.1. Report under Condition A.17:

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

14.1.1.2. If one of the criteria of Condition B.13.2 was exceeded and the permittee did not comply with either Condition B.13.1.1 or B.13.1.2, this must be reported by the day following the day compliance with Condition B.13.1 was required;

14.2. Report observations in excess of the threshold of Condition B.13.2.2 within 30 days of the end of the month in which the observations occur.

14.3. In each OCS source Operating Report under Condition A.18, include:

14.3.1. The dates, EU ID(s), and results when an observed 18-minute average was greater than an applicable threshold in Condition B.13.2;

14.3.2. A summary of the results of any PM testing under Condition B.13; and

14.3.3. Copies of any visible emissions observation results (opacity observations) greater than the thresholds of Condition B.13.2, if they were not already submitted.

15. **COA Regulations: Particulate Matter Monitoring for Liquid-Fired Boilers and Heaters.** The permittee shall conduct source tests on Units FD-21 through 22 to determine the concentration of PM in the exhaust of Units FD-21 through 22 as follows.

15.1. Conduct a PM source test according to the requirements set out in Condition B.20 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.

15.2. 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.

15.3. The PM source test requirement in Condition B.15 is waived for an emission unit if:

15.3.1. 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

15.3.2. 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.9.2.4 no longer occur.

16. **COA Regulations: Particulate Matter Recordkeeping.** The permittee shall keep records of the results of any PM testing and visible emissions observations conducted under Condition B.15. The permittee shall report as follows.

16.1. In each OCS source Operating Report required by Condition A.18, include:

16.1.1. The dates, emission units, and results when an 18-minute opacity observation was greater than the applicable threshold criterion in Condition B.9.2.4; and

16.1.2. A summary of the results of any PM testing and visible emissions observations conducted under Condition B.15.

16.2. Report as excess emissions, in accordance with Condition A.17, any time the results of a source test for PM exceeds the PM emission limit stated in Condition B.12.

17. **COA Regulations: 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 FD-1 through 22, and FD-31 listed in Table 1 to exceed 500 parts per million (ppm) averaged over three hours.

17.1. For Units FD-1 through 22, and FD-31, monitor, record and report in accordance with Conditions B.18 through B.19.

18. **COA Regulations: Sulfur Compound Monitoring, Recordkeeping and Reporting Liquid Fuel-fired Sources.** Sulfur Compound Emissions – Monitoring and Recordkeeping.

18.1. If a load of fuel contains greater than 0.0015 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 C.F.R. 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 0.0015 percent sulfur by weight, calculate the three-hour exhaust concentration of SO_2 using the following equations:

$A = 31{,}200 \times [\mathbf{wt\%S_{fuel}}] = 31{,}200 \times \_\_\_\_\_ = \_\_\_\_\_$

$B = 0.148 \times [\mathbf{wt\%S_{fuel}}] = 0.148 \times \_\_\_\_\_ = \_\_\_\_\_$

$C = 0.396 \times [\mathbf{wt\%C_{fuel}}] = 0.396 \times \_\_\_\_\_ = \_\_\_\_\_$

$D = 0.933 \times [\mathbf{wt\%H_{fuel}}] = 0.933 \times \_\_\_\_\_ = \_\_\_\_\_$

$E = B + C + D = \_\_\_\_\_ + \_\_\_\_\_ + \_\_\_\_\_ = \_\_\_\_\_$

$F = 20.9 - [\mathbf{vol\%dryO_{2,\ exhaust}}] = 20.9 - \_\_\_\_\_ = \_\_\_\_\_$

$G = [\mathbf{vol\%dryO_{2,\ exhaust}}] \div F = \_\_\_\_\_ \div \_\_\_\_\_ = \_\_\_\_\_$

$H = 1 + G = 1 + \_\_\_\_\_ = \_\_\_\_\_$

$I = E \times H = \_\_\_\_\_ \times \_\_\_\_\_ = \_\_\_\_\_$

SO_2 concentration $= A \div I = \_\_\_\_\_ \div \_\_\_\_\_ = \_\_\_\_\_$ 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 B.4.2.2. 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.

19. **COA Regulations: Sulfur Compound Emissions – Reporting.** The permittee shall report as follows.

19.1. If SO_2, emissions are calculated under Condition B.18.1 to exceed 500 ppm, the permittee shall report under Condition A.17. When reporting under this Condition B.19.1 include the calculation under Condition B.18.1.

19.2. The permittee shall include in the report required by Condition A.18 a list of the fuel grades received at the OCS Source during the reporting period:

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

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

20. **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.

20.1. 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.

20.2. The permittee shall submit to EPA a complete stack test plan within 60 days after receiving a request under Condition A.23.1 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 source test plan shall include and address the following elements:

20.2.1. Purpose and scope of testing;

20.2.2. Source description, including a description of the operating scenarios and mode of operation during testing and including fuel sampling and analysis procedures;

20.2.3. Schedule/dates of testing;

20.2.4. 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;

20.2.5. 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;

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

20.2.7. Analysis procedures and laboratory identification;

20.2.8. Quality assurance plan;

20.2.9. Calibration procedures and frequency;

20.2.10. Sample recovery and field documentation;

20.2.11. Chain of custody procedures;

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

20.2.13. Data processing and reporting;

20.2.14. Description of data handling and QC procedures; and

20.2.15. Report content and timing.

20.3. Unless 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 percent but no more than 100 percent of maximum during all tests.

20.4. 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.

20.5. 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.

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

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

20.6.2. 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.

20.7. 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:

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

20.7.2. EPA Test Methods 201, 201A and 202 are set forth in 40 C.F.R. Part 51, Subpart M;

20.7.3. Conditional Test Method 027 (CTM-027), "Procedure for Collection and Analysis of Ammonia in Stationary Sources," is set forth at http://www.epa.gov/ttn/emc/ctm.html;

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

20.7.5. Other Test Method 27 (OTM 27), "Determination of PM_{10} and $PM_{2.5}$ Emissions from Stationary Sources (Constant Sampling Rate Procedure)," is set forth at http://www.epa.gov/ttn/emc/prelim.html;

20.7.6. Other Test Method 28 (OTM 28), "Dry Impinger Method for Determining Condensable Particulate Emissions from Stationary Sources," is set forth at http://www.epa.gov/ttn/emc/prelim.html; and

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

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

20.9. 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 B.20.6 above.

20.10. 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.

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

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

20.12.1. 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:

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

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

20.12.2. If requested by EPA, the demonstration referred to in Condition B.20.12.1 must use Method 301 in 40 C.F.R. Part 63, Appendix A, to validate the alternative test method or deviation.

20.12.3. EPA must approve the request in writing.

20.12.4. 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.

20.13. 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.

20.14. 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.

21. **Prohibited Activities.** The permittee shall not:

21.1. Flow test wells;

21.2. Flare gas;

21.3. Store liquid hydrocarbons recovered during well testing;

21.4. Refuel any vessel (excluding the Discoverer, the Kvichak workboats, and Rozema Skimmer) within 25 miles of the Discoverer while the Discoverer is an OCS Source, or

21.5. Allow any vessel associated with this project, and that is not authorized by Tables 1 through 5 of this permit, to approach within 25 miles of the Discoverer, while the Discoverer is an OCS Source.

22. **Monthly Emissions Calculations.** By the tenth of each month, the permittee shall, using monitoring data collected pursuant to the requirements of this permit, calculate and record the monthly emissions of CO, NO_X, $PM_{2.5}$, PM_{10}, SO_2 and VOC for the preceding month.

23. **Rolling 12-Month Emissions Calculations.** By the tenth of each month, the permittee shall calculate and record the rolling 12-month emissions of CO, NO_X, $PM_{2.5}$, PM_{10}, SO_2 and VOC by using the monthly emissions calculated for the previous 12 months pursuant to Condition B.22.

24. **Good Operating and Maintenance Requirements.** At all times, including periods of startup, shutdown, 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. 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 keep records of any maintenance that would have a significant effect on emissions (the records may be kept in electronic format) and keep a copy of either the manufacturer's or the operator's maintenance procedures.

25. **COA Regulations: Good Air Pollution Control Practice.** The permittee shall do the following for Units FD-1 through 23 and FD-31:

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

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

26. **COA Regulations: 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.

26.1. If emissions present a potential threat to human health or safety, the permittee shall report any such emissions according to Condition A.17.

26.2. 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.26.

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

26.3.1. 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.26; or

26.3.2. The EPA notifies the permittee that it has found a violation of Condition B.26.

26.4. The permittee shall keep records of:

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

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

26.4.3. A summary of any investigation, including reasons the permittee does or does not believe the emissions have caused a violation of Condition B.26; and

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

26.5. With each OCS Operating Report under Condition A.18, the permittee shall include a brief summary report which must include:

26.5.1. The number of complaints received;

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

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

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

26.6. 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.

C. DISCOVERER GENERATOR ENGINES (FD-1 – 6)

1. **Operation of Selective Catalytic Reduction (SCR) Unit.** At all times that any of Units FD-1 – 6 are in operation, the exhaust from each emission unit shall be directed to an operating SCR emission unit.

2. **Operation of Oxidation Catalyst.** At all times that any of Units FD-1 – 6 are in operation, the exhaust from each emission unit shall be directed to an operating oxidation catalyst.

3. **BACT Limits.** Emissions from each generator engine (Units FD-1 – 6) shall not exceed the emission limits specified for each of the pollutants below.

3.1. **Nitrogen oxides (NO_X):** 0.50 grams (g) per kilowatt-hour (kW-hr)

3.1.1. For compliance with Condition C.3.1, measurement of NO_X shall be determined using EPA Method 7E.

3.2. **Ammonia (NH_3):** 5 parts per million by volume (ppmv) at actual stack gas conditions

3.2.1. For compliance with Condition C.3.2, measurement of NH_3 shall be determined using EPA Conditional Test Method 027 or 038.

3.3. **Particulate Matter:** 0.127 g/kW-hr

3.3.1. For compliance with Condition C.3.3, measurement of PM shall be determined using EPA Method 5.

3.4. **Particulate Matter with an aerodynamic diameter less than 10 microns (PM_{10}):** 0.127 g/kW-hr

3.4.1. For compliance with Condition C.3.4, measurement of PM_{10} shall be determined using EPA Method 201/201A and Other Test Method (OTM) 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

3.5. **Particulate Matter with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$):** 0.127 g/kW-hr.

3.5.1. For compliance with Condition C.3.5, measurement of $PM_{2.5}$ shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

3.6. **Visible Emissions:** Visible emissions, excluding condensed water vapor, shall not reduce visibility through the exhaust effluent more than 20 percent averaged over any six consecutive minutes.

3.6.1. For compliance with Condition C.3.6, measurement of visible emissions shall be determined using EPA Method 9.

3.7. **Carbon Monoxide (CO):** 0.1790 g/kW-hr

3.7.1. For compliance with Condition C.3.7, measurement of CO shall be determined using EPA Method 10.

3.8. **Volatile Organic Compounds (VOC):** 0.0230 g/kW-hr

3.8.1. For compliance with Condition C.3.8, measurement of VOC shall be determined using EPA Method 25A.

4. **Potential to Emit (PTE) Emission Limits.** Emissions from all six generator engines in aggregate (Units FD-1 – 6) shall not exceed the emission limits specified for each of the pollutants below.

4.1. **Nitrogen oxides (NO_X):** 9.000 tons/rolling 12-month period

4.1.1. For compliance with Condition C.4.1, measurement of NO_X shall be determined using EPA Method 7E.

4.2. **Particulate Matter with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$):** 28.80 lbs/day

4.2.1. For compliance with Condition C.4.2, measurement of PM_{10} shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

4.3. **Particulate Matter with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$):** 28.80 lbs/day

4.3.1. For compliance with Condition C.4.3, measurement of $PM_{2.5}$ shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

5. **Electrical Power Output Limit.** The permittee shall not operate Units FD-1 – 6 such that aggregate electrical power from the attached generators is in excess of 3,872 kWe for any hour that these emission units are operated.

6. **Stack Test Requirements.** The permittee shall stack test all of Units FD-1 – 6 as follows:

6.1. At the start of the first drilling season that the Discoverer operates under this permit in the Beaufort Sea, all six of Units FD-1 – 6 shall have been stack tested under the requirements of this section.

6.2. Each stack test shall be conducted at three different loads: 50 percent, 75 percent and 100 percent.

6.3. Each stack test run shall test for emissions of CO, NO_X, $PM_{2.5}$, PM_{10}, VOC, ammonia and visible emissions.

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

6.4.1. Quantity of fuel used (in gallons);

6.4.2. Density of the fuel used (in lbs/gallon);

6.4.3. Heat content of the fuel used (in Btu/gallon); and

6.4.4. Electrical power produced (in kWe-hr).

6.5. For each engine, each load, and each pollutant, the permittee shall determine emission factors in the following units: g/kW-hr, g/kWe-hr, lbs/kW-hr, lbs/kWe-hr and lbs/gallon.

7. **Monitoring, Recordkeeping and Reporting:** The permittee shall:

7.1. Equip each of the generator engines (Units FD-1 – 6) on board the Discoverer with a electrical output monitoring device:

7.1.1. Each electrical output monitoring device shall measure the electrical output of the generator attached to each engine with an accuracy equal to or better than 2 percent of the engine's maximum output (in kWe);

7.1.2. Each electrical output monitoring device shall measure the electrical output of the generator attached to each engine at least once every 10 minutes;

7.1.3. Each electrical output monitoring device shall be equipped to record each reading taken as well as provide and record average loads for each hour.

7.2. Maintain the accuracy of each electrical output monitoring device in accordance with manufacturer's recommendations.

7.3. Monitor and record the power output, in kWe, resulting from the operation of each of Units FD-1 – 6 at least once every 10 minutes.

7.4. Monitor and record the following operational parameters for each SCR, at least once every 10 minutes:

7.4.1. The operational status of urea pump;

7.4.2. The stack temperature upstream of the catalyst in either Celsius (^{o}C), or Fahrenheit (^{o}F); and

7.4.3. The load level of all engines exhausting to the SCR system.

7.5. Monitor and record the hourly NO_X emissions from the exhaust of each engine, at least once per hour.

7.6. Each month, calculate and record NO_X emissions in g/kW-hr from each engine for each hour during the month, using the emission factors collected under Condition C.6.5 and power output data collected under Condition C.7.3, and converted to kW (mechanical).

7.7. Each day, calculate and record for the previous calendar day, the emissions of NO_X, $PM_{2.5}$ and PM_{10} in pounds per day from each engine by using the emission factors for each tested engine collected under Condition C.6.5 and electrical load data collected under Condition C.7.3, to determine emissions from that source. Emissions shall be calculated for each ten-minute load reading for each engine.

7.8. For the purposes of Conditions C.7.6 and C.7.7, if a specific emission unit has not been tested yet, the permittee shall use the highest emission factor for the corresponding load from the test results for any of the generator engines that have already been tested.

7.9. For the purposes of Condition C.7.7, if a specific load reading is missing, the permittee shall calculate the emissions for that missing load reading by using the emission factor and load combination that results in the highest emissions rate for that emissions unit. If the engine in question has not been tested yet, the permittee shall use the emission factor as provided for in Condition C.7.8.

7.10. For the purpose of Condition C.7.7, if either the urea pump is not operating or if the catalyst inlet temperature, measured in Condition C.7.4.2, is less than 250°C, calculate emissions of NO_X for the affected time period by using an uncontrolled emission factor obtained by applying a 95 percent NO_X reduction efficiency to the emission factor determined pursuant to Condition C.6.5.

D. DISCOVERER PROPULSION ENGINE (FD-7)

1. The permittee shall not operate Unit FD-7 for any reason when operating the Discoverer as an OCS Source.

2. The permittee shall report to EPA via facsimile or email, any deviation from Condition D.1 within 3 business days of identification.

E. DISCOVERER EMERGENCY GENERATOR (FD-8)

1. The permittee shall operate Unit FD-8 for no more than:

   1.1. 120 minutes during any one day; and

   1.2. 48 hours during any rolling 12-month period.

2. For each instance in which Unit FD-8 is operated while the Discoverer is an OCS Source, the permittee shall record the duration of the episode and the reason for operating.

3. The permittee shall report to EPA via facsimile or email, any deviation from Condition E.1 within 3 business days of identification.

F. MUD LINE CELLAR COMPRESSOR ENGINES (FD-9 – 11)

1. **Operation of Oxidation Catalyst.** At all times that any of Units FD-9 – 11 are in operation, the exhaust from each emission unit shall be directed to an operating oxidation catalyst.

2. **BACT Limits.** Emissions from each MLC compressor engine (Units FD-9 – 11) shall not exceed the emission limits specified for each of the pollutants below.

2.1. **NO_X and non-methane hydrocarbons (NMHC), in aggregate:** 4.0 g/kW-hr

2.1.1. For compliance with Condition F.2.1, measurement of NO_X shall be determined using EPA Method 7E.

2.1.2. For compliance with Condition F.2.1, measurement of NMHC shall be determined using EPA Method 25A.

2.2. **PM:** 0.10 g/kW-hr

2.2.1. For compliance with Condition F.2.2, measurement of PM shall be determined using EPA Method 5.

2.3. **PM_{10}:** 0.10 g/kW-hr

2.3.1. For compliance with Condition F.2.3, measurement of PM_{10} shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

2.4. **$PM_{2.5}$:** 0.10 g/kW-hr

2.4.1. For compliance with Condition F.2.4, measurement of $PM_{2.5}$ shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

2.5. **Visible Emissions:** Visible emissions, excluding condensed water vapor, shall not reduce visibility through the exhaust effluent more than 20 percent averaged over any six consecutive minutes.

2.5.1. For compliance with Condition F.2.5, measurement of visible emissions shall be determined using EPA Method 9.

2.6. **CO**: 1.86 g/kW-hr

2.6.1. For compliance with Condition F.2.6, measurement of CO shall be determined using EPA Method 10.

3. **PTE Annual Emission Limits.** Emissions from all three MLC compressor engines (Units FD-9 – 11) in aggregate shall not exceed the emission limits specified for each of the pollutants below.

3.1. **NO_X:** 5.37 tons/rolling 12-month period

3.1.1. For compliance with Condition F.3.1, measurement of NO_X shall be determined using EPA Method 7E.

4. **PTE Daily Emission Limits.** Emissions from each MLC compressor engine (Units FD-9 – 11) shall not exceed the emission limits specified for each of the pollutants below.

4.1. **PM_{10}:** 2.4 lbs/day

4.1.1. For compliance with Condition F.4.1, measurement of PM_{10} shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

4.2. **$PM_{2.5}$:** 2.4 lbs/day

4.2.1. For compliance with Condition F.4.2, measurement of $PM_{2.5}$ shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

5. **Fuel Usage Limit.** The permittee shall not use in excess of 81,346 gallons of fuel in all three of Units FD-9 – 11 in aggregate during any rolling 12-month period.

6. **Stack Test Requirements.** The permittee shall stack test all of Units FD-9 – 11 as follows:

6.1. At the start of the first drilling season that the Discoverer operates under this permit in the Beaufort Sea, all three of Units FD-9 – 11 shall have been stack tested under the requirements of this section.

6.2. Each stack test shall be conducted for the following pollutants, and at the different loads specified:

6.2.1.	CO	at one load between 50 and 70 percent load;
6.2.2.	NO_X	at two loads – between 50 and 70 percent and between 80 and 100 percent loads;
6.2.3.	NMHC	at one load between 50 and 70 percent load;
6.2.4.	$PM_{2.5}$	at two loads – between 50 and 70 percent and between 80 and 100 percent loads;
6.2.5.	PM_{10}	at two loads – between 50 and 70 percent and between 80 and 100 percent loads; and
6.2.6.	Visible emissions	at one load between 50 and 70 percent load.

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

6.3.1. Quantity of fuel used (in gallons);

6.3.2. Density of the fuel used (in lbs/gallon);

6.3.3. Heat content of the fuel used (in Btu/gallon); and

6.3.4. Mechanical power output (in kW).

6.4. For each engine, each load range, and each pollutant, the permittee shall determine emission factors in the following units: g/kW-hr, lbs/kW-hr and lbs/gallon.

7. **Monitoring, Recordkeeping and Reporting:** The permittee shall:

7.1. Equip each of Units FD-9 – 11 with a diesel fuel flow meter, or install a single fuel meter for all of Units FD-9 -11:

7.1.1. Each fuel flow meter shall be located so that there is no potential for fuel inflows or outflows between it and the engine(s) being served by the meter;

7.1.2. Each fuel flow meter shall be totalizing and nonresettable; and

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

7.2. No less than 60 days before initial deployment of the Discoverer to the Beaufort Sea for the first drilling season, collect information from the manufacturer of each fuel flow meter so as to determine its accuracy. Submit this information to EPA no less than 30 days prior to operation within the Beaufort Sea.

7.3. Maintain the accuracy of each fuel flow meter in accordance with manufacturer's recommendations.

7.4. Monitor and record fuel usage for each engine on a daily basis.

7.5. Each day, calculate and record for the previous calendar day, the emissions of NO_X, $PM_{2.5}$ and PM_{10} using the highest emission factor collected under Condition F.6.4 and fuel usage data collected under Condition F.7.4.

G. HYDRAULIC POWER UNIT (HPU) ENGINES (FD-12 – 13)

1. **Operation of Catalyzed Diesel Particulate Filter (CDPF).** At all times that any of Units FD-12 – 13 are in operation, the exhaust from each emission unit shall be directed to an operating CleanAIR Systems CDPF, Part No. FDA300.

1.1. Each CDPF shall be equipped with an operating HiBACK monitor and alarm unit, that records exhaust pressure and temperature.

1.2. During each day that each of Units FD-12 – 13 is operated, the exhaust temperature shall be above 300°C, or 572 °F for at least 30 percent of the time.

2. **BACT Limits.** Emissions from each HPU engine (Units FD-12 – 13) shall not exceed the emission limits specified for each of the pollutants below.

2.1. **NO_X and NMHC, in aggregate:** 4.0 g/kW-hr

2.1.1. For compliance with Condition G.2.1, measurement of NO_X shall be determined using EPA Method 7E.

2.2. **PM:** 0.030 g/kW-hr

2.2.1. For compliance with Condition G.2.2, measurement of PM shall be determined using EPA Method 5.

2.3. **PM_{10}:** 0.030 g/kW-hr

2.3.1. For compliance with Condition G.2.3, measurement of PM_{10} shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

2.4. **$PM_{2.5}$:** 0.030 g/kW-hr

2.4.1. For compliance with Condition G.2.4, measurement of $PM_{2.5}$ shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

2.5. **Visible Emissions:** Visible emissions, excluding condensed water vapor, shall not reduce visibility through the exhaust effluent more than 20 percent averaged over any six consecutive minutes.

2.5.1. For compliance with Condition G.2.5, measurement of visible emissions shall be determined using EPA Method 9.

2.6. **CO:** 0.70 g/kW-hr.

2.6.1. For compliance with Condition G.2.6, measurement of CO shall be determined using EPA Method 10.

3. **BACT Good Combustion Practices for NO_X.** The permittee shall:

3.1. Ensure that a full-time equipment maintenance specialist shall be on board at all times during operation as an OCS Source;

3.2. 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;

3.3. Have the maintenance specialist inspect, at least once each week, each of Units FD-12 – 13 for proper operation and maintenance consistent with the manufacturer's recommendations;

3.4. Ensure that the operation and maintenance manual provided by the manufacturer for each of Units FD-12 – 13 shall be kept on board the Discoverer at all times;

3.5. Follow the manufacturer's recommended operation and maintenance procedures for each of Units FD-12 – 13;

3.6. Maintain, on board the Discoverer, a log detailing when reporting, inspections and maintenance are conducted pursuant to Conditions G.3.2, G.3.3 and G.3.5, respectively; and

3.7. No less than 30 days prior to each deployment of the Discoverer to the Beaufort Sea, the permittee shall provide notice to the EPA on how the permittee shall comply with the requirements of Conditions G.3.1 and G.3.2 for the upcoming drilling season.

4. **PTE Annual Emission Limits.** Emissions from both HPU engines (Units FD-12 – 13) in aggregate shall not exceed the emission limits specified for each of the pollutants below.

4.1. **NO_X:** 8.18 tons/rolling 12-month period

4.1.1. For compliance with Condition G.4.1, measurement of NO_X shall be determined using EPA Method 7E.

5. **PTE Daily Emission Limits.** Emissions from each HPU engine (Units FD-12 – 13) shall not exceed the emission limits specified for each of the pollutants below.

5.1. **PM_{10}:** 2.50 lbs/day

5.1.1. For compliance with Condition G.5.1, measurement of PM_{10} shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

5.2. **$PM_{2.5}$:** 2.50 lbs/day

5.2.1. For compliance with Condition G.5.2, measurement of $PM_{2.5}$ shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

6. **Annual Fuel Usage Limit.** The permittee shall not use in excess of 44,338 gallons of fuel in both of Units FD-12 – 13 in aggregate during any rolling 12-month period.

7. **Daily Fuel Usage Limits/Alternative Operating Scenarios.** Units FD-12, FD-13 and FD-23 shall be operated under one of three operating scenarios: Base Operating Scenario, Alternative Operating Scenario #1 or Alternative Operating Scenario #2. The permittee shall not use fuel in excess of the following limits while operating under the operating scenarios:

7.1. Under Base Operating Scenario, the permittee shall not operate either of Units FD-12 – 13;

7.2. Under Alternative Operating Scenario #1, the permittee shall not use in excess of 352 gallons of fuel in both of Units FD-12 – 13 in aggregate during any calendar day;

7.3. Under Alternative Operating Scenario #2, the permittee shall not use in excess of 704 gallons of fuel in both of Units FD-12 – 13 in aggregate during any calendar day; and

7.4. For each calendar day that the permittee intends to operate under either of Alternative Operating Scenarios #1 or 2, the permittee shall record in a log, at the beginning of the calendar day, which scenario it will be operating under for the day. In the absence of a log entry, the permittee shall comply with the requirements applicable to the Base Operating Scenario.

8. **Stack Test Requirements.** The permittee shall stack test both of Units FD-12 – 13 as follows:

8.1. At the start of the first drilling season that the Discoverer operates under this permit in the Beaufort Sea, both of Units FD-12 – 13 shall have been stack tested under the requirements of this section.

8.2. Each stack test shall be conducted for the following pollutants, and at the different loads specified:

8.2.1.	CO	at one load between 50 and 70 percent load;
8.2.2.	NO_X	at two loads – between 50 and 70 percent and between 80 and 100 percent loads;
8.2.3.	$PM_{2.5}$	at two loads – between 50 and 70 percent and between 80 and 100 percent loads;
8.2.4.	PM_{10}	at two loads – between 50 and 70 percent and between 80 and 100 percent loads;
8.2.5.	VOC	at one load between 50 and 70 percent load; and
8.2.6.	Visible emissions	at one load between 50 and 70 percent load.

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

8.3.1. Quantity of fuel used (in gallons);

8.3.2. Density of the fuel used (in lbs/gallon);

8.3.3. Heat content of the fuel used (in Btu/gallon); and

8.3.4. Mechanical power output (in kW).

8.4. For each engine, each load range, and each pollutant, the permittee shall determine emission factors in the following units: g/kW-hr, lbs/kW-hr and lbs/gallon.

9. **Monitoring, Recordkeeping and Reporting:** The permittee shall:

9.1. Equip each of Units FD-12 – 13 with a diesel fuel flow meter, or install a single fuel meter for both of Units FD-12 - 13:

9.1.1. Each fuel flow meter shall be located so that there is no potential for fuel inflows or outflows between it and the engine(s) being served by the meter;

9.1.2. Each fuel flow meter shall be totalizing and nonresettable; and

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

9.2. No less than 60 days before initial deployment of the Discoverer to the Beaufort Sea for the first drilling season, collect information from the manufacturer of each fuel flow meter so as to determine its accuracy. Submit this information to EPA no less than 30 days prior to operation within the Beaufort Sea.

9.3. Maintain the accuracy of each fuel flow meter in accordance with manufacturer's recommendations.

9.4. Monitor and record fuel usage for each engine on a daily basis.

9.5. Monitor the exhaust temperature of each engine by use of the HiBACK monitor and alarm unit, whenever the engine is in operation.

9.6. Each day, calculate and record for the previous calendar day, the percent of operational time for each engine that the exhaust temperature was above 300°C (572°F).

9.7. Each day, calculate and record for the previous calendar day, the emissions of NO_X, $PM_{2.5}$ and PM_{10} using the highest emission factor collected under Condition G.8.4 and fuel usage data collected under Condition G.9.4.

H. DECK CRANES (FD-14 – 15)

1. **Operation of Catalyzed Diesel Particulate Filter (CDPF).** At all times that any of Units FD-14 – 15 in operation, the exhaust from each emission unit shall be directed to an operating CleanAIR Systems CDPF, Part No. 07040401AF.

1.1. Each CDPF shall be equipped with an operating HiBACK monitor and alarm unit, that records exhaust pressure and temperature.

1.2. During each day that each of Units FD-14 -15 is operated, the exhaust temperature shall be above 300°C, or 572°F, for at least 30 percent of the time.

2. **BACT Limits.** Emissions from each deck crane engine (Units FD-14 – 15) shall not exceed the emission limits specified for each of the pollutants below.

2.1. **NO_X:** 10.327 g/kW-hr

2.1.1. For compliance with Condition H.2.1, measurement of NO_X shall be determined using EPA Method 7E.

2.2. **PM:** 0.0715 g/kW-hr

2.2.1. For compliance with Condition H.2.2, measurement of PM shall be determined using EPA Method 5.

2.3. **PM_{10}:** 0.0715 g/kW-hr.

2.3.1. For compliance with Condition H.2.3, measurement of PM_{10} shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

2.4. **$PM_{2.5}$:** 0.0715 g/kW-hr.

2.4.1. For compliance with Condition H.2.4, measurement of $PM_{2.5}$ shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

2.5. **Visible Emissions:** Visible emissions, excluding condensed water vapor, shall not reduce visibility through the exhaust effluent more than 20 percent averaged over any six consecutive minutes.

2.5.1. For compliance with Condition H.2.5, measurement of visible emissions shall be determined using EPA Method 9.

2.6. **CO:** 0.220 g/kW-hr.

2.6.1. For compliance with Condition H.2.6, measurement of CO shall be determined using EPA Method 10.

2.7. **VOC:** 0.0640 g/kW-hr.

2.7.1. For compliance with Condition H.2.7, measurement of VOC shall be determined using EPA Method 25A.

3. **BACT Good Combustion Practices for NO_X.** The permittee shall:

3.1. Ensure that a full-time equipment maintenance specialist shall be on board at all times during operation as an OCS Source;

3.2. 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;

3.3. Have the maintenance specialist inspect, at least once each week, each of Units FD-14 – 15 for proper operation and maintenance consistent with the manufacturer's recommendations;

3.4. Ensure that the operation and maintenance manual provided by the manufacturer for each of Units FD-14 – 15 shall be kept on board the Discoverer at all times;

3.5. Follow the manufacturer's recommended operation and maintenance procedures for each of Units FD-14 – 15;

3.6. Maintain, on board the Discoverer, a log detailing when reporting, inspections and maintenance are conducted pursuant to Conditions H.3.2, H.3.3, and H.3.5, respectively; and

3.7. No less than 30 days prior to initial deployment of the Discoverer to the Beaufort Sea, the permittee shall provide notice to the EPA on how the permittee shall comply with the requirements of Conditions H.3.1, and H.3.2 for the upcoming drilling season.

4. **PTE Annual Emission Limits.** Emissions from both deck crane engines (Units FD-14 – 15) in aggregate shall not exceed the emission limits specified for each of the pollutants below.

4.1. **NO_X:** 9.50 tons/rolling 12-month period

4.1.1. For compliance with Condition H.4.1, measurement of NO_X shall be determined using EPA Method 7E.

5. **PTE Daily Emission Limits.** Emissions from each deck crane engine (Units FD-14 – 15) shall not exceed the emission limits specified for each of the pollutants below.

5.1. **PM_{10}:** 0.96 lbs/day

5.1.1. For compliance with Condition H.5.1, measurement of PM_{10} shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

5.2. **$PM_{2.5}$:** 0.96 lbs/day

5.2.1. For compliance with Condition H.5.2, measurement of $PM_{2.5}$ shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

6. **Fuel Usage Limit.** The permittee shall not use in excess of 63,661 gallons of fuel in both of Units FD-14 – 15 in aggregate during any rolling 12-month period.

7. **Stack Test Requirements.** The permittee shall stack test both of Units FD-14 – 15 as follows:

7.1. At the start of the first drilling season that the Discoverer operates under this permit in the Beaufort Sea, both of Units FD-14 – 15 shall have been stack tested under the requirements of this section.

7.2. Each stack test shall be conducted for the following pollutants, and at the different loads specified:

7.1.1	CO	at one load between 60 and 80 percent load;
7.1.2	NO_X	at two loads – between 60 and 80 percent and between 80 and 100 percent loads;
7.1.3	$PM_{2.5}$	at two loads – between 60 and 80 percent and between 80 and 100 percent loads;
7.1.4	PM_{10}	at two loads – between 60 and 80 percent and between 80 and 100 percent loads;
7.1.5	VOC	at one load between 60 and 80 percent load; and
7.1.6	Visible emissions	at one load between 60 and 80 percent load.

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

7.3.1. Quantity of fuel used (in gallons);

7.3.2. Density of the fuel used (in lbs/gallon);

7.3.3. Heat content of the fuel used (in Btu/gallon); and

7.3.4. Mechanical power output (in kW).

7.4. For each engine, each load range, and each pollutant, the permittee shall determine emission factors in the following units: g/kW-hr, lbs/kW-hr and lbs/gallon.

8. **Monitoring, Recordkeeping and Reporting:** The permittee shall:

8.1 Equip each of Units FD-14 -15 with a diesel fuel flow meter or install a single fuel meter for both of Units FD-14 - 15:

8.1.1 Each fuel flow meter shall be located so that there is no potential for fuel inflows or outflows between it and the engine(s) being served by the meter;

8.1.2 Each fuel flow meter shall be totalizing and nonresettable; and

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

8.2 No less than 60 days before initial deployment of the Discoverer to the Beaufort Sea for the first drilling season, collect information from the manufacturer of each fuel flow meter so as to determine its accuracy. Submit this information to EPA no less than 30 days prior to operation within the Beaufort Sea.

8.3 Maintain the accuracy of each fuel flow meter in accordance with manufacturer's recommendations.

8.4 Monitor and record fuel usage for each engine on a daily basis.

8.5 Monitor and record the exhaust temperature of each engine by use of the HiBACK monitor and alarm unit, while the engine is in operation.

8.6 Each day, calculate and record for the previous calendar day, the percent of operational time for each engine that the exhaust temperature was above 300°C (572°F).

8.7 Each day, calculate and record for the previous calendar day, the emissions of NO_X, $PM_{2.5}$ and PM_{10} using the highest emission factor collected under Condition H.7.4 and fuel usage data collected under Condition H.8.4.

I. CEMENTING UNIT AND LOGGING WINCH ENGINES (FD-16 – 20)

1. **Operation of Catalyzed Diesel Particulate Filter (CDPF).** At all times that any of the cementing unit and logging winch engines (Units FD-16 – 20) are in operation, the exhaust from each emission unit shall be directed to operating CleanAIR Systems CDPF, Part No. FDA300 for Units FD-16 and 17, Part No. FDA225 for Unit FD-18, and as specified by CleanAIR Systems for Units FD-19 – 20.

1.1. Each CDPF shall be equipped with an operating HiBACK monitor and alarm unit, that records exhaust pressure and temperature.

1.2. During each day that each of Units FD-16 – 20 is operated, the exhaust temperature shall be above 300°C, or 572°F, for at least 30 percent of the time.

2. **BACT Limits.** Emissions from each of Units FD-16 – 20 shall not exceed the emission limits specified for each of the pollutants below.

2.1. **NO_X:**

FD-16	13.155 g/kW-hr
FD-17	13.155 g/kW-hr
FD-18	15.717 g/kW-hr
FD-19	4.0 g/kW-hr
FD-20	7.50 g/kW-hr

2.1.1. For compliance with Condition I.2.1, measurement of NO_X shall be determined using EPA Method 7E.

2.2. **PM:**

FD-16	0.253 g/kW-hr
FD-17	0.253 g/kW-hr
FD-18	0.386 g/kW-hr
FD-19	0.03 g/kW-hr
FD-20	0.090 g/kW-hr

2.2.1. For compliance with Condition I.2.2, measurement of PM shall be determined using EPA Method 5.

2.3. **PM_{10}:**

FD-16	0.253	g/kW-hr
FD-17	0.253	g/kW-hr
FD-18	0.386	g/kW-hr
FD-19	0.03	g/kW-hr
FD-20	0.090	g/kW-hr

2.3.1. For compliance with Condition I.2.3, measurement of PM_{10} shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

2.4. **$PM_{2.5}$:**

FD-16	0.253	g/kW-hr
FD-17	0.253	g/kW-hr
FD-18	0.386	g/kW-hr
FD-19	0.03	g/kW-hr
FD-20	0.090	g/kW-hr

2.4.1. For compliance with Condition I.2.4, measurement of $PM_{2.5}$ shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

2.5. **Visible Emissions:** Visible emissions, excluding condensed water vapor, shall not reduce visibility through the exhaust effluent more than 20 percent averaged over any six consecutive minutes.

2.5.1. For compliance with Condition I.2.5, measurement of visible emissions shall be determined using EPA Method 9.

2.6. **CO:**

FD-16	0.40	g/kW-hr
FD-17	0.40	g/kW-hr
FD-18	0.880	g/kW-hr
FD-19	0.70	g/kW-hr
FD-20	0.550	g/kW-hr

2.6.1. For compliance with Condition I.2.6, measurement of CO shall be determined using EPA Method 10.

2.7. **VOC:**

FD-16	0.20	g/kW-hr
FD-17	0.20	g/kW-hr
FD-18	0.270	g/kW-hr
FD-19	4.0	g/kW-hr
FD-20	0.750	g/kW-hr

2.7.1. For compliance with Condition I.2.7, measurement of VOC shall be determined using EPA Method 25A.

3. **BACT Good Combustion Practices for NO_X.** The permittee shall:

3.1. Ensure that a full-time equipment maintenance specialist shall be on board at all times during operation as an OCS Source;

3.2. 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;

3.3. Have the maintenance specialist inspect, at least once each week, each of Units FD-16 – 20 for proper operation and maintenance consistent with the manufacturer's recommendations;

3.4. Ensure that the operation and maintenance manual provided by the manufacturer for each of Units FD-16 – 20 shall be kept on board the Discoverer at all times;

3.5. Follow the manufacturer's recommended operation and maintenance procedures for each of Units FD-16 – 20;

3.6. Maintain, on board the Discoverer, a log detailing when reporting, inspections and maintenance are conducted pursuant to Conditions I.3.2, I.3.3 and I.3.5, respectively; and

3.7. No less than 30 days prior to initial deployment of the Discoverer to the Beaufort Sea, the permittee shall provide notice to the EPA on how the permittee shall comply with the requirements of Conditions I.3.1 and I.3.2 for the upcoming drilling season.

4. **PTE Annual Emission Limits.** Emissions from all cementing unit and logging winch engines (Units FD-16 – 20) in aggregate shall not exceed the emission limits specified for each of the pollutants below:

4.1. **NO_X:** 11.84 tons/rolling 12-month period

4.1.1. For compliance with Condition I.4.1, measurement of NO_X shall be determined using EPA Method 7E.

5. **PTE Daily Emission Limits.** Emissions from all cementing unit and logging winch engines (Units FD-16 – 20) in aggregate shall not exceed the emission limits specified for each of the pollutants below:

5.1. **PM_{10}:** 3.46 lbs/day

5.1.1. For compliance with Condition I.5.1, measurement of PM_{10} shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

5.2. **$PM_{2.5}$:** 3.46 lbs/day

5.2.1. For compliance with Condition I.5.2, measurement of $PM_{2.5}$ shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

6. **Fuel Usage Limit.** The permittee shall not use in excess of:

6.1. 53,760 gallons of fuel in all Units FD-16 – 20 in aggregate during any rolling 12-month period; and

6.2. 320 gallons of fuel in all Units FD-16 – 20 in aggregate during any calendar day.

7. **Stack Test Requirements.** The permittee shall stack test all of Units FD-16 – 20 as follows:

7.1. At the start of the first drilling season that the Discoverer operates under this permit in the Beaufort Sea, all of Units FD-16 – 20 shall have been stack tested under the requirements of this section.

7.2. Each stack test shall be conducted for the following pollutants, and at the different loads specified:

7.2.1.	CO	at one load between 50 and 70 percent load;
7.2.2.	NO_X	at two loads – between 50 and 70 percent and between 80 and 100 percent loads;
7.2.3.	$PM_{2.5}$	at two loads – between 50 and 70 percent and between 80 and 100 percent loads;
7.2.4.	PM_{10}	at two loads – between 50 and 70 percent and between 80 and 100 percent loads;
7.2.5.	VOC	at one load between 50 and 70 percent load; and
7.2.6.	Visible emissions	at one load between 50 and 70 percent load.

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

7.3.1. Quantity of fuel used (in gallons);

7.3.2. Density of the fuel used (in lbs/gallon);

7.3.3. Heat content of the fuel used (in Btu/gallon); and

7.3.4. Mechanical power output (in kW).

7.4. For each engine, each load range, and each pollutant, the permittee shall determine emission factors in the following units: g/kW-hr, lbs/kW-hr and lbs/gallon.

8. **Monitoring, Recordkeeping and Reporting:** The permittee shall:

8.1. Equip each of Units FD-16 – 20 with a diesel fuel flow meter or install a single fuel meter for all of Units FD-16 - 20:

8.1.1. Each fuel flow meter shall be located so that there is no potential for fuel inflows or outflows between it and the engine(s) being served by the meter;

8.1.2. Each fuel flow meter shall be totalizing and nonresettable; and

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

8.2. No less than 60 days before initial deployment of the Discoverer to the Beaufort Sea for the first drilling season, collect information from the manufacturer of each fuel flow meter so as to determine its accuracy. Submit this information to EPA no less than 30 days prior to operation within the Beaufort Sea.

8.3. Maintain the accuracy of each fuel flow meter in accordance with manufacturer's recommendations.

8.4. Monitor and record fuel usage for each engine on a daily basis.

8.5. Monitor and record the exhaust temperature of each of engines FD-16 – 20 by use of the HiBACK monitor and alarm unit, while the engine is in operation.

8.6. Each day, for each of engines FD-16 – 20, calculate and record for the previous calendar day, the percent of operational time for each engine that the exhaust temperature was above 300°C (572°F).

8.7. Each day, calculate and record for the previous calendar day, the emissions of NO_X, $PM_{2.5}$ and PM_{10} using the highest emission factor collected under Condition I.7.4 and fuel usage data collected under Condition I.8.4.

J. HEAT BOILERS (FD-21 – 22)

1. **BACT Limits.** Emissions from each of the heat boilers (Units FD-21 – 22) shall not exceed the emission limits specified for each of the pollutants below.

1.1. **NO_X:** 0.20 lbs/MMBtu

1.1.1. For compliance with Condition J.1.1, measurement of NO_X shall be determined using EPA Method 7E.

1.2. **PM:** 0.0235 lbs/MMBtu

1.2.1. For compliance with Condition J.1.2, measurement of PM shall be determined using EPA Method 5.

1.3. **PM_{10}:** 0.0235 lbs/MMBtu

1.3.1. For compliance with Condition J.1.3, measurement of PM_{10} shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

1.4. **$PM_{2.5}$:** 0.0235 lbs/MMBtu

1.4.1. For compliance with Condition J.1.4, measurement of $PM_{2.5}$ shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

1.5. **Visible Emissions:** Visible emissions, excluding condensed water vapor, shall not reduce visibility through the exhaust effluent more than 20 percent averaged over any six consecutive minutes.

1.5.1. For compliance with Condition J.1.5, measurement of visible emissions shall be determined using EPA Method 9.

1.6. **CO:** 0.0770 lbs/MMBtu

1.6.1. For compliance with Condition J.1.6, measurement of CO shall be determined using EPA Method 10.

1.7. **VOC:** 0.00140 lbs/MMBtu

1.7.1. For compliance with Condition J.1.7, measurement of VOC shall be determined using EPA Method 25A.

2. **BACT Good Combustion Practices for NO_X, PM, $PM_{2.5}$, PM_{10}, CO, and VOC.** The permittee shall:

   2.1. Ensure that a full-time equipment maintenance specialist shall be on board at all times during operation as an OCS Source;

   2.2. 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;

   2.3. Have the maintenance specialist inspect, at least once each week, each of Units FD-21 – 22 for proper operation and maintenance consistent with the manufacturer's recommendations;

   2.4. Ensure that the operation and maintenance manual provided by the manufacturer for each of Units FD-21 – 22 shall be kept on board the Discoverer at all times;

   2.5. Follow the manufacturer's recommended operation and maintenance procedures for each of Units FD-21 – 22;

   2.6. Maintain, on board the Discoverer, a log detailing when reporting, inspections and maintenance are conducted pursuant to Conditions J.2.2, J.2.3 and J.2.5, respectively; and

   2.7. No less than 30 days prior to initial deployment of the Discoverer to the Beaufort Sea, the permittee shall provide notice to the EPA on how the permittee shall comply with the requirements of Conditions J.2.1 and J.2.2 for the upcoming drilling season.

3. **PTE Annual Emission Limits.** Emissions from all heat boilers (Units FD-21 – 22) in aggregate shall not exceed the emission limits specified for each of the pollutants below.

   3.1. **NO_X:** 6.46 tons/rolling 12-month period

      3.1.1. For compliance with Condition J.3.1, measurement of NO_X shall be determined using EPA Method 7E.

4. **PTE Daily Emission Limits.** Emissions from each heat boiler (Units FD-21 – 22) shall not exceed the emission limits specified for each of the pollutants below.

   4.1. **PM_{10}:** 4.50 lbs/day

      4.1.1. For compliance with Condition J.4.1, measurement of PM_{10} shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

4.2. **$PM_{2.5}$:** 4.50 lbs/day

4.2.1. For compliance with Condition J.4.2, measurement of $PM_{2.5}$ shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

5. **Stack Test Requirements.** The permittee shall stack test both of Units FD-21 – 22 as follows:

5.1. At the start of the first drilling season that the Discoverer operates under this permit in the Beaufort Sea, both of Units FD-21 – 22 shall have been stack tested under the requirements of this section.

5.2. Each stack test shall be conducted for the following pollutants, and at the different loads specified:

5.2.1.	CO	at 100 percent load;
5.2.2.	NO_X	at 50 percent and 100 percent loads;
5.2.3.	$PM_{2.5}$	at 50 percent and 100 percent loads;
5.2.4.	PM_{10}	at 50 percent and 100 percent loads;
5.2.5.	VOC	at 100 percent load; and
5.2.6.	Visible emissions	at 100 percent load.

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

5.3.1. Quantity of fuel used (in gallons);

5.3.2. Density of the fuel used (in lbs/gallon); and

5.3.3. Heat content of the fuel used (in Btu/gallon).

5.4. For each boiler, each load range and each pollutant, the permittee shall determine emission factors in the following units: lbs/MMBtu and lbs/gallon.

6. **Monitoring, Recordkeeping and Reporting:** The permittee shall:

6.1. Equip each of Units FD-21 – 22 with a diesel fuel flow meter or install a single fuel meter for both of Units FD-21 – 22:

6.1.1. Each fuel flow meter shall be located so that there is no potential for fuel inflows or outflows between it and the boiler(s) being served by the meter;

6.1.2. Each fuel flow meter shall be totalizing and nonresettable; and

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

6.2. No less than 60 days before initial deployment of the Discoverer to the Beaufort Sea for the first drilling season, collect information from the manufacturer of each fuel flow meter so as to determine its accuracy. Submit this information to EPA no less than 30 days prior to operation within the Beaufort Sea.

6.3. Maintain the accuracy of each fuel flow meter in accordance with manufacturer's recommendations.

6.4. Monitor and record fuel usage for each boiler on a daily basis.

6.5. Each day, calculate and record for the previous calendar day, the emissions of NO_X, $PM_{2.5}$ and PM_{10} using the highest emission factor collected under Condition J.5.4 and fuel usage data collected under Condition J.6.4.

K. WASTE INCINERATOR (FD-23)

1. **BACT Limits.** Emissions from the incinerator (Unit FD-23) shall not exceed the emission limits specified for each of the pollutants below.

1.1. **NO_X:** 5.0 lbs/ton of waste incinerated

1.1.1. For compliance with Condition K.1.1, measurement of NO_X shall be determined using EPA Method 7E.

1.2. **PM:** 8.20 lbs/ ton of waste incinerated

1.2.1. For compliance with Condition K.1.2, measurement of PM shall be determined using EPA Method 5.

1.3. **PM_{10}:** 8.20 lbs/ton of waste incinerated

1.3.1. For compliance with Condition K.1.3, measurement of PM_{10} shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

1.4. **$PM_{2.5}$:** 7.00 lbs/ton of waste incinerated

1.4.1. For compliance with Condition K.1.4, measurement of $PM_{2.5}$ shall be determined using OTM 27 and OTM 28, provided, however, that if proposed changes to Method 201/201A in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 1/201A shall be used in lieu of OTM 27 and if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

1.5. **CO:** 31.0 lbs/ton of waste incinerated

1.5.1. For compliance with Condition K.1.5, measurement of CO shall be determined using EPA Method 10.

1.6. **VOC:** 3.0 lbs/ton of waste incinerated

1.6.1. For compliance with Condition K.1.6, measurement of VOC shall be determined using EPA Method 25A.

2. **BACT Good Combustion Practices for NO_X, PM, $PM_{2.5}$, PM_{10}, CO, and VOC.** The permittee shall:

2.1. Ensure that a full-time equipment maintenance specialist shall be on board at all times during operation as an OCS Source;

2.2. 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 hour of identification;

2.3. Have the maintenance specialist inspect, at least once each week, Unit FD-23 for proper operation and maintenance consistent with the manufacturer's recommendations;

2.4. Ensure that the operation and maintenance manual provided by the manufacturer for Unit FD-23 shall be kept on board the Discoverer at all times;

2.5. Follow the manufacturer's recommended operation and maintenance procedures for Unit FD-23;

2.6. Maintain, on board the Discoverer, a log detailing when reporting, inspections and maintenance are conducted pursuant to Conditions K.2.2, K.2.3 and K.2.5, respectively; and

2.7. No less than 30 days prior to initial deployment of the Discoverer to the Beaufort Sea, the permittee shall provide notice to the EPA on how the permittee shall comply with the requirements of Conditions K.2.1 and K.2.2 for the upcoming drilling season.

3. **PTE Annual Emission Limits.** Emissions from the incinerator (Unit FD-23) shall not exceed the emission limits specified for each of the pollutants below.

3.1. **NO_X:** 0.06 tons/rolling 12-month period

3.1.1. For compliance with Condition K.3.1, measurement of NO_X shall be determined using EPA Method 7E.

4. **PTE Daily Emission Limits.** Emissions from the incinerator (Unit FD-23) shall not exceed the emission limits specified for each of the pollutants below.

4.1. **PM_{10}:** 5.33 lbs/day

4.1.1. For compliance with Condition K.4.1, measurement of PM_{10} shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

4.2. **$PM_{2.5}$:** 4.55 lbs/day

4.2.1. For compliance with Condition K.4.2, measurement of $PM_{2.5}$ shall be determined using OTM 27 and OTM 28, provided, however, that if proposed changes to Method 201/201A in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 1/201A shall be used in lieu of OTM 27 and if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

5. **PTE Throughput-Based Emission Limits.** Emissions from the incinerator (Unit FD-23) shall not exceed the emission limits specified for each of the pollutants below.

5.1. **PM_{10}:** 8.20 lbs/ton of waste incinerated

5.1.1. For compliance with Condition K.5.1, measurement of PM_{10} shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

5.2. **$PM_{2.5}$:** 7.00 lbs/ton of waste incinerated

5.2.1. For compliance with Condition K.5.2, measurement of $PM_{2.5}$ shall be determined using OTM 27 and OTM 28, provided, however, that if proposed changes to Method 201/201A in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 1/201A shall be used in lieu of OTM 27 and if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

5.3. **SO_2:** 2.50 lbs/ton of waste incinerated

5.3.1. For compliance with Condition K.5.3, measurement of SO_2 shall be determined using EPA Method 6C.

6. **Annual Waste Throughput Limit.** The permittee shall not incinerate in excess of 50,400 lbs of all types of waste in Unit FD-23 during any rolling 12-month period.

7. **Daily Fuel Usage Limits/Alternative Operating Scenarios.** Units FD-12, FD-13 and FD-23 shall be operated under one of three operating scenarios: Base Operating Scenario, Alternative Operating Scenario #1 or Alternative Operating Scenario #2. The permittee shall not incinerate waste in excess of the following limits while operating under the operating scenarios:

7.1. Under Base Operating Scenario, the permittee shall not incinerate in excess of 1300 lbs of waste during any calendar day;

7.2. Under Alternative Operating Scenario #1, the permittee shall not incinerate in excess of 800 lbs of waste during any calendar day;

7.3. Under Alternative Operating Scenario #2, the permittee shall not incinerate in excess of 300 lbs of waste during any calendar day; and

7.4. For each calendar day that the permittee intends to operate under either of Alternative Operating Scenarios #1 or 2, the permittee shall record as specified in Condition G.7.4.

8. **Waste Segregation Work Practice.** The permittee shall develop and implement a written waste segregation work practice plan to ensure that non-combustible items containing heavy metals that could be volatilized and emitted from the incinerator as PM are not introduced into the incinerator. The plan shall be submitted to EPA Region 10 at least 30 days prior to initial deployment of the Discoverer to the Beaufort Sea.

9. **Stack Test Requirements.** Prior to each of the first three drilling seasons that the Discoverer operates under this permit in the Beaufort Sea, the permittee shall stack test the incinerator (Unit FD-23) as follows.

9.1. Each stack test shall be conducted at full rated capacity.

9.2. For the first drilling season, each stack test run shall test for emissions of CO, NO_X, $PM_{2.5}$, PM_{10}, SO_2 and VOC.

9.3. For subsequent drilling seasons, each stack test run shall test for emissions of NO_X, $PM_{2.5}$, PM_{10} and SO_2.

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

9.4.1. Quantity of fuel used (in gallons);

9.4.2. Density of the fuel used (in lbs/gallon);

9.4.3. Heat content of the fuel used (in Btu/gallon);

9.4.4. Quantity of waste incinerated (tons); and

9.4.5. Type of waste incinerated.

9.5. For each pollutant, the permittee shall determine emission factors in the following units: lbs/ton of waste incinerated.

10. **Monitoring, Recordkeeping and Reporting:** The permittee shall:

10.1. For each batch of waste charged to the incinerator:

10.1.1. Record the date and time that each batch of waste was charged to the incinerator;

10.1.2. Weigh the batch of waste by using a weigh scale used that shall be accurate to within 0.5 lbs; and

10.1.3. Record the weight of each batch of waste charged to the incinerator.

10.2. No less than 60 days before initial deployment of the Discoverer to the Beaufort Sea for the first drilling season, collect information from the manufacturer of the weigh scale to determine its accuracy. Submit this information to EPA no less than 30 days prior to operation within the Beaufort Sea.

10.3. Maintain the accuracy of the weigh scale in accordance with manufacturer's recommendations.

10.4. Monitor and record the exhaust temperature of the incinerator at least every 15 minutes.

10.5. Each day, calculate and record for the previous calendar day, the emissions of NO_X, $PM_{2.5}$ and PM_{10} using the highest emission factor collected under Condition K.9.5 and waste material incinerated throughput collected under Condition K.10.1.

11. **COA Regulations: Incinerator Visible Emissions.** The permittee shall comply with the following.

11.1. Do not cause or allow visible emissions, excluding condensed water vapor, through the exhaust of Unit FD-23, to reduce visibility by more than 20 percent averaged over any six consecutive minutes.

11.2. Observe, record, and report the exhaust of Unit FD-23 using the visible emission monitoring, recordkeeping, and reporting Conditions B.9 through B.11.

L. SUPPLY SHIP GENERATOR ENGINE (FD-31)

1. **Operational Limits**. For events where the supply ship is attached to the Discoverer, the permittee shall:

1.1. Not use in excess of 184.0 gallons of fuel per day in the non-propulsion generators (not including the emergency engine), in aggregate;

1.2. Not use in excess of 1472.0 gallons of fuel during any rolling 12-month period in the non-propulsion generators (not including the emergency engine), in aggregate; and

1.3. Limit the total number of events to 8 per rolling 12-month period.

2. **PTE Annual Emission Limits.** For events where the supply ship is attached to the Discoverer, emissions from operation of the supply ship generator engine (Unit FD-31) shall not exceed the emission limits specified for each of the pollutants below.

2.1. **NO_X:** 0.43 tons/rolling 12-month period

2.1.1. For compliance with Condition L.2.1, measurement of NO_X shall be determined using EPA Method 7E.

3. **PTE Daily Emission Limits.** For events where the supply ship is attached to the Discoverer, emissions from operation of the supply ship generator engine (Unit FD-31) shall not exceed the emission limits specified for each of the pollutants below.

3.1. **PM_{10}:** 7.60 lbs/day

3.1.1. For compliance with Condition L.3.1, measurement of PM_{10} shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

3.2. **$PM_{2.5}$:** 7.60 lbs/day

3.2.1. For compliance with Condition L.3.2, measurement of $PM_{2.5}$ shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

4. **Stack Test Requirements.** Prior to the first supply ship trip of each drilling season to resupply the Discoverer while the Discoverer is operating under this permit in the Beaufort Sea, the permittee shall stack test the supply ship generator engine (Unit FD-31) as follows:

4.1. If the generator from the intended supply ship has already been tested pursuant to Conditions L.4.2 through L.4.5 during the past 5 years, no additional stack testing is required.

4.2. Each stack test shall be conducted at 100 percent load.

4.3. Each stack test run shall test for emissions of NO_X, $PM_{2.5}$ and PM_{10}.

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

4.4.1. Manufacturer and model no. of the engine;

4.4.2. The rated capacity of the engine (in hp);

4.4.3. Quantity of fuel used (in gallons);

4.4.4. Density of the fuel used (in lbs/gallon);

4.4.5. Heat content of the fuel used (in Btu/gallon); and

4.4.6. Electrical power output (in kWe).

4.5. For each engine, each load range, and each pollutant, the permittee shall determine emission factors in the following units: lbs/kWe-hr and lbs/gallon.

5. **Monitoring, Recordkeeping and Reporting:** The permittee shall:

5.1. Equip each of the non-propulsion generator engines (not including the emergency engine) with a diesel fuel flow meter, or install a single fuel meter for all of these engines:

5.1.1. Each fuel flow meter shall be located so that there is no potential for fuel inflows or outflows between it and the engine(s) being served by the meter;

5.1.2. Each fuel flow meter shall be totalizing and nonresettable; and

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

5.2. No less than 60 days before the first deployment to the Beaufort Sea of a vessel as the supply ship, collect information from the manufacturer of each fuel flow meter so as to determine its accuracy. Submit this information to EPA no less than 30 days prior to departure of the supply vessel to the Beaufort Sea.

5.3. Maintain the accuracy of each fuel flow meter in accordance with manufacturer's recommendations.

5.4. Monitor and record fuel usage for the non-propulsion generators while the supply vessel is attached to the Discoverer.

5.5. For each event, record the date and time that the supply ship attaches to the Discoverer.

5.6. For each event, record the date and time that the supply ship detaches from the Discoverer.

5.7. For each event, record the manufacturer, model no. and rated capacity (in hp) of the supply ship generator engine.

5.8. For each event, calculate daily emissions of NO_X, $PM_{2.5}$ and PM_{10} using the highest emission factor collected under Condition L.4.5 and fuel usage data collected under Condition L.5.4

6. **Supply Barge and Tug Alternative.** If a supply barge and tug is used in lieu of the supply ship the permittee shall not operate any emission units on the supply barge when it is attached to the Discoverer. At no time shall the supply barge tug be attached to the Discoverer.

6.1. For each event, record the date and time that the supply barge attaches to the Discoverer.

6.2. For each event, record the date and time that the supply barge detaches from the Discoverer.

M. SHALLOW GAS DIVERTER SYSTEM (FD-33)

1. **Shallow Gas Diversions.** The permittee shall:

1.1. Record the frequency and duration of each shallow gas diversion.

1.2. Report the frequency and duration of each shallow gas diversion no later than March 1st for the time period beginning January 1st and ending December 31st of the preceding year.

N. CUTTINGS/MUD DISPOSAL BARGE (FD-34)

1. **Operational Limits.** The permittee shall not operate any emission units on the cuttings/mud disposal barge when it is attached to the Discoverer. At no time shall the cuttings/mud disposal barge tug be attached to the Discoverer.

1.1. No later than 45 days prior to deployment to the Beaufort Sea each drilling season, the permittee shall provide notification to EPA of the selected cuttings/mud disposal barge. The notification shall include a list of all emission sources on board the barge.

1.2. For each event, record the date and time that the cuttings/mud disposal barge attaches to the Discoverer.

1.3. For each event, record the date and time that the cuttings/mud disposal barge detaches from the Discoverer.

O. ICEBREAKER #1

1. **Aggregate Capacity Limits.** For a given drilling season, the permittee may select any vessel as Icebreaker #1, subject to the following conditions:

1.1. The total capacity of all propulsion engines on Icebreaker #1 shall not exceed 28,400 hp.

1.2. The total capacity of all generator engines on Icebreaker #1 shall not exceed 2,800 hp.

1.3. The total capacity of all boilers on Icebreaker #1 shall not exceed 10 MMBtu/hr.

1.4. The total capacity of all incinerators on Icebreaker #1 shall not exceed 154 lbs/hr.

1.5. Total uncontrolled emissions of $PM_{2.5}$ from all emission sources on board Icebreaker #1 shall not exceed 42.20 lbs/hour.

1.5.1. For compliance with Condition O.1.5, measurement of $PM_{2.5}$ shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

1.5.2. For the purposes of Condition O.1.5, emissions from each emission unit shall be based on operation of that emission unit at 100 percent of rated capacity, except for the propulsion engines, for which emissions shall be based on operation of that emission unit at 80 percent of rated capacity.

1.6. Total uncontrolled emissions of PM_{10} from all emission sources on board Icebreaker #1 shall not exceed 48.0 lbs/hour.

1.6.1. For compliance with Condition O.1.6, measurement of PM_{10} shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

1.6.2. For the purposes of Condition O.1.6, emissions from each emission unit shall be based on operation of that emission unit at 100 percent of rated capacity, except for the propulsion engines, for which emissions shall be based on operation of that emission unit at 80 percent of rated capacity.

1.7. No later than 45 days prior to deployment to the Beaufort Sea each drilling season, the permittee shall provide notification to EPA of the vessel selected as Icebreaker #1. The notification shall include a list of all emission sources on board the vessel as well as manufacturer, model and rated capacity of each such emission source, and the conversion efficiency (mechanical to electrical) of each generator on board.

2. **Capacity Limit on Icebreaker #1 Propulsion Engines.** At all times while the Discoverer is an OCS Source and Icebreaker #1 is within 25 miles of the Discoverer, the permittee shall limit operation of the propulsion engines in Icebreaker #1 to no greater than 80 percent of rated capacity.

3. **PTE Annual Emission Limits.** At all times while the Discoverer is an OCS Source and Icebreaker #1 is within 25 miles of the Discoverer, emissions from all emission sources on Icebreaker #1 in aggregate shall not exceed the emission limits specified for each of the pollutants below.

3.1. **NO_X:** 850.0 tons/rolling 12-month period

3.1.1. For compliance with Condition O.3.1, measurement of NO_X shall be determined using EPA Method 7E.

4. **PTE Daily Emission Limits.** At all times while the Discoverer is an OCS Source and Icebreaker #1 is within 25 miles of the Discoverer, emissions from all emission sources on Icebreaker #1 in aggregate shall not exceed the emission limits specified for each of the pollutants below.

4.1. **PM_{10}:** 1,098.0 lbs/day

4.1.1. For compliance with Condition O.4.1, measurement of PM_{10} shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

4.2. **$PM_{2.5}$:** 966.0 lbs/day

4.2.1. For compliance with Condition O.4.2, measurement of $PM_{2.5}$ shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

5. **Electrical Power Output Limit.** At all times while the Discoverer is an OCS Source and Icebreaker #1 is within 25 miles of the Discoverer, the permittee shall not operate the internal combustion engines in excess of:

5.1. 28,233,704 kWe from all of the generators on board Icebreaker #1 in aggregate during any rolling 12-month period; or

5.2. 420,188 kWe from all of the generators on board Icebreaker #1 in aggregate during any calendar day.

6. **Fuel Usage Limit.** At all times while the Discoverer is an OCS Source and Icebreaker #1 is within 25 miles of the Discoverer, the permittee shall not use fuel in excess of:

   6.1. 302,400 gallons in all heat boilers on board Icebreaker #1 in aggregate during any rolling 12-month period; or

   6.2. 1,800 gallons in all heat boilers on board Icebreaker #1 in aggregate during any calendar day.

7. **Operating Location and Distance from Discoverer.** Except when transferring crew and supplies to and from the Discoverer, or traveling on other non-icebreaking activities, Icebreaker #1 shall operate outside of a cone with its apex 150 meters behind the stern of the Discoverer, plus and minus 20 degrees from the centerline of the Discoverer, and extending 4800 meters beyond the bow of the Discoverer.

   7.1. For the purpose of Condition O.7, the permittee shall use a global positioning system or laser range finder capable of accuracy to within 10 meters; and

   7.2. For each event when Icebreaker #1 enters the cone described in Condition O.7, the permittee shall record the following information:

      7.2.1. The time and date that Icebreaker #1 entered the cone;

      7.2.2. The location coordinates where Icebreaker #1 entered the cone;

      7.2.3. The time and date that Icebreaker #1 exited the cone;

      7.2.4. The location coordinates where Icebreaker #1 exited the cone;

      7.2.5. The purpose of Icebreaker #1 entering the cone; and

      7.2.6. The operating load of each engine during transit through the cone.

8. **Attachment to Discoverer.** At no time shall Icebreaker #1 be attached to the Discoverer.

9. **Volume Source Limit for Icebreaker #1.** The permittee shall ensure that the volume source release height of Icebreaker #1 is no less than 25.22 meters.

   9.1. For the purposes of Condition O.9 the volume source release height shall be determined by:

      9.1.1. The permittee shall obtain the vessel source dimensions and emission source parameters;

      9.1.2. The permittee shall determine the volume source release height based on plume rise and by using the following information:

         9.1.2.1. The SCREEN3 model as set forth in 40 C.F.R. Part 51, Appendix W;

         9.1.2.2. An hourly meteorological condition of "D stability," as that term is used in 40 C.F.R. Part 51, Appendix W;

         9.1.2.3. A wind speed of 20 meters per second; and

         9.1.2.4. The vessel dimensions and emission source parameters required under Condition O.9.1.1.

9.1.3. If EPA promulgates a different screening model in place of SCREEN3 in 40 C.F.R. Part 51, Appendix W, the permittee shall use that newly promulgated screening model to determine the volume source release height.

10. **Stack Test Requirements.** Prior to each of the first two drilling seasons that a vessel is used as Icebreaker #1, and while the Discoverer is operating under this permit in the Beaufort Sea, the permittee shall stack test each propulsion engine, non-propulsion generator engine, boiler and incinerator on Icebreaker #1 as follows:

10.1. Each stack test on the propulsion engines shall be conducted at three different loads: 30 percent, 60 percent and 80 percent.

10.2. Each stack test on the non-propulsion generator engines shall be conducted at two different load ranges: 50 - 60 percent and 90 - 100 percent.

10.3. Each stack test on the boilers shall be conducted at full loads.

10.4. Each stack test on the incinerator shall be conducted at full load.

10.5. Each stack test run shall test for emissions of NO_X, $PM_{2.5}$ and PM_{10}.

10.6. During each test run for the propulsion engines, generator engines, and boilers, the permittee shall monitor and record the following information:

10.6.1. Quantity of fuel used (in gallons);

10.6.2. Density of the fuel used (in lbs/gallon);

10.6.3. Heat content of the fuel used (in Btu/gallon); and

10.6.4. For the engines, electrical power output (in kWe).

10.7. During each test run for the incinerator, the permittee shall monitor and record the quantity of waste material incinerated (in lbs).

10.8. For each engine, each load range, and each pollutant, the permittee shall determine emission factors in the following units: lbs/kWe-hr and lbs/gallon.

10.9. For each boiler, and each pollutant, the permittee shall determine emission factors in the following units: lbs/MMBtu and lbs/gallon.

10.10. For each incinerator, and each pollutant, the permittee shall determine emission factors in the following units: lbs/ton of waste combusted.

11. **Monitoring, Recordkeeping and Reporting.** The permittee shall:

11.1. Equip each of the propulsion engines and generator engines on board Icebreaker #1 with an electrical output monitoring device:

11.1.1. Each electrical output monitoring device shall measure the electrical output of the generator attached to each engine with an accuracy equal to or better than 2 percent of the engine's maximum output (in kWe);

11.1.2. Each electrical output monitoring device shall measure the electrical output of the generator attached to each engine at least once every 10 minutes;

11.1.3. Each electrical output monitoring device shall be equipped to record each reading taken as well as provide and record average loads for each hour.

11.2. Maintain the accuracy of each electrical output monitoring device in accordance with manufacturer's recommendations.

11.3. Monitor and record the electrical load for each engine at least once every ten minutes, and record the average hourly load for each hour.

11.4. Equip each of the boilers on board Icebreaker #1 with a diesel fuel flow meter or install a single fuel meter for all of the boilers:

11.4.1. Each fuel flow meter shall be located so that there is no potential for fuel inflows or outflows between it and the boiler(s) being served by the meter;

11.4.2. Each fuel flow meter shall be totalizing and nonresettable; and

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

11.5. No less than 60 days before initial deployment of the Discoverer to the Beaufort Sea for the first drilling season, collect information from the manufacturer of each fuel flow meter so as to determine its accuracy. Submit this information to EPA no less than 30 days prior to operation within the Beaufort Sea.

11.6. Maintain the accuracy of each fuel flow meter in accordance with manufacturer's recommendations.

11.7. Monitor and record fuel usage for each boiler.

11.8. At least 45 days before deployment to the Discoverer each drilling season, the permittee shall notify the EPA of the volume source release height of Icebreaker #1.

11.9. Once each hour, and using a global positioning system or laser range finder capable of accuracy to within 10 meters, measure and record the date, time and location of Icebreaker #1.

11.10. Once each hour, monitor and record the date, time, direction the bow of the Discoverer is pointed, and wind direction at the Discoverer.

11.11. Record any instance that Icebreaker #1 attaches to the Discoverer.

11.12. Each day, calculate and record for the previous calendar day, the emissions of NO_X, $PM_{2.5}$ and PM_{10} in pounds per day from the boilers and incinerator by using the highest emission factor for each tested boiler or incinerator collected under Conditions O.10.9 and O.10.10 and fuel usage data collected under Condition O.11.7, to determine emissions from that source. For the purposes of this condition, the permittee shall assume that the incinerator has been operated continuously at the maximum operating rate, and shall use the highest emission factor collected under Condition O.10.10.

11.13. Each day, calculate and record for the previous calendar day, the emissions of NO_X, $PM_{2.5}$ and PM_{10} in pounds per day from each engine by using the emission factors for each tested engine collected under Condition O.10.8 and electrical load data collected under Condition O.11.3, to determine emissions from that source. Emissions shall be calculated for each ten-minute load reading for each engine.

11.14. For the purposes of Conditions O.11.12 and O.11.3, if a specific emission unit has not been tested yet, the permittee shall use the highest emission factor for the corresponding load from the test results for any equivalent emission unit in equivalent service that has already been tested.

11.15. For the purposes of Conditions O.11.12 and O.11.3, if a specific load reading is missing, the permittee shall calculate the emissions for that missing load reading by using the emission factor and load combination that results in the highest emissions rate for that emissions unit. If the engine in question has not been tested yet, the permittee shall use the emission factor as provided for in Condition O.11.14.

P. ICEBREAKER #2

1. **Icebreaker #2 Vessel Alternatives.** For a given drilling season, the permittee may use either the Tor Viking or Hull 247 as Icebreaker #2, subject to the conditions in Section O of this permit. Hull 247 is a temporary vessel name assigned by the shipbuilder, Edison Chouest. This permit is intended to apply to this vessel even when renamed with its permanent name.

1.1. The total capacity of all propulsion engines on Icebreaker #2 shall not exceed 17,660 hp for the Tor Viking and 24,000 kW for Hull 247.

1.2. The total capacity of all non-propulsion generator engines on Icebreaker #2 shall not exceed 2,336 hp for the Tor Viking and 0 hp for Hull 247 shall not have electrical generation capacity in addition to the engines specified in Condition P.1.1.

1.3. The total capacity of all boilers on Icebreaker #2 shall not exceed 1.37 MMBtu/hr for the Tor Viking and 4.00 MMBtu/hr for Hull 247.

1.4. The total capacity of all incinerators on Icebreaker #2 shall not exceed 151.23 lbs/hr.

1.5. Total uncontrolled emissions of $PM_{2.5}$ from all emission sources on board Icebreaker #2 shall not exceed 11.4 lbs/hour.

1.5.1. For compliance with Condition P.1.5, measurement of $PM_{2.5}$ shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

1.5.2. For the purposes of Condition P.1.5, emissions from each emission unit shall be based on operation of that emission unit at 100 percent of rated capacity, except for the propulsion engines, for which emissions shall be based on operation of that emission unit at 80 percent of rated capacity.

1.6. Total uncontrolled emissions of PM_{10} from all emission sources on board Icebreaker #2 shall not exceed 11.7 lbs/hour.

1.6.1. For compliance with Condition P.1.6, measurement of PM_{10} shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

1.6.2. For the purposes of Condition P.1.6, emissions from each emission unit shall be based on operation of that emission unit at 100 percent of rated capacity, except for the propulsion engines, for which emissions shall be based on operation of that emission unit at 80 percent of rated capacity.

1.7. No later than 45 days prior to deployment to the Beaufort Sea each drilling season, the permittee shall provide notification to EPA of the vessel selected as Icebreaker #2. The notification shall include a list of all emission sources on board the vessel as well as manufacturer, model and rated capacity of each emission source.

1.8. At all times that any of the engines on board Icebreaker #2 are in operation, the exhaust from each engine shall be directed to an operating SCR emission unit.

2. **Capacity Limit on Icebreaker #2 Propulsion Engines.** At all times while the Discoverer is an OCS Source and Icebreaker #2 is within 25 miles of the Discoverer, the permittee shall limit operation of the propulsion engines in Icebreaker #2 to 80 percent of rated capacity.

3. **PTE Annual Emission Limits.** At all times while the Discoverer is an OCS Source and Icebreaker #2 is within 25 miles of the Discoverer, emissions from all emission sources on Icebreaker #2 in aggregate shall not exceed the emission limits specified for each of the pollutants below.

3.1. **NO_X:** 71.2 tons/rolling 12-month period

3.1.1. For compliance with Condition P.3.1, measurement of NO_X shall be determined using EPA Method 7E.

4. **PTE Daily Emission Limits.** At all times while the Discoverer is an OCS Source and Icebreaker #2 is within 25 miles of the Discoverer, emissions from all emission sources on Icebreaker #2 in aggregate shall not exceed the emission limits specified for each of the pollutants below:

4.1. **PM_{10}:** 280.5 lbs/day

4.1.1. For compliance with Condition P.4.1, measurement of PM_{10} shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

4.2. **$PM_{2.5}$:** 272.9 lbs/day

4.2.1. For compliance with Condition P.4.2, measurement of $PM_{2.5}$ shall be determined using EPA Method 201/201A and OTM 28, provided, however, that if proposed changes to Method 202 in 56 FR 12970 (March 25, 2009) become final and effective, EPA Method 202 shall be used in lieu of OTM 28.

5. **Electrical Power Output Limit.** At all times while the Discoverer is an OCS Source and Icebreaker #2 is within 25 miles of the Discoverer, the permittee shall not operate the internal combustion engines in excess of:

5.1. 18,058,216 kWe-hr from all of the generators on board the Tor Viking in aggregate during any rolling 12-month period.

5.2. 31,904,074 kWe-hr from all of the generators on board Hull 247 in aggregate during any rolling 12-month period.

5.3. 282,867 kWe-hr from all of the generators on board the Tor Viking in aggregate during any calendar day.

5.4. 423,936 kWe-hr from all of the generators on board Hull 247 in aggregate during any calendar day.

6. **Fuel Usage Limit.** At all times while the Discoverer is an OCS Source and Icebreaker #2 is within 25 miles of the Discoverer, the permittee shall not use fuel in excess of:

6.1. 40,320 gallons in all heat boilers on board the Tor Viking in aggregate during any rolling 12-month period.

6.2. 120,960 gallons in all heat boilers on board Hull 247 in aggregate during any rolling 12-month period.

6.3. 240 gallons in all heat boilers on board the Tor Viking in aggregate during any calendar day.

6.4. 720 gallons in all heat boilers on board Hull 247 in aggregate during any calendar day.

7. **Operating Distance from Discoverer.** Except when transferring crew and supplies to and from the Discoverer, when traveling on other non-icebreaking activities, or as provided for in Conditions O.8 and O.9, Icebreaker #2 shall operate outside of a cone with its apex 150 meters behind the stern of the Discoverer, plus and minus 20 degrees from the centerline of the Discoverer, and extending 1000 meters beyond the bow of the Discoverer.

7.1. For the purpose of Condition P.7, the permittee shall use a global positioning system or laser range finder capable of accuracy to within 10 meters.

7.2. For each event when Icebreaker #2 enters the cone described in Condition O.7, the permittee shall record the following information:

7.2.1. The time and date that Icebreaker #2 entered the cone;

7.2.2. The location coordinates where Icebreaker #2 entered the cone;

7.2.3. The time and date that Icebreaker #2 exited the cone;

7.2.4. The location coordinates where Icebreaker #2 exited the cone;

7.2.5. The purpose of Icebreaker #2 entering the cone; and

7.2.6. The operating load of each engine during transit through the cone.

8. **Anchor Handling Operations.** Notwithstanding Condition P.7, Icebreaker #2 may operate within 1,000 meters of the Discoverer while Icebreaker #2 is being used to either set or retrieve anchors for the Discoverer.

9. **Bow Washing Operations.** Notwithstanding Condition P.7, Icebreaker #2 may operate within 1,000 meters of the Discoverer while Icebreaker #2 is being used to remove ice from the bow of the Discoverer (i.e. bow washing), subject to the following conditions.

9.1. The permittee shall record the date, hour and minute that Icebreaker #2 begins its approach to the Discoverer to remove bow ice.

9.2. The permittee shall record the date, hour and minute that Icebreaker #2 returns to its ice management position at least 1,000 meters from the Discoverer.

10. **Attachment to Discoverer**. At no time shall Icebreaker #2 be attached to the Discoverer.

11. **Volume Source Limit for Icebreaker #2.** The permittee shall ensure that the volume source release height of Icebreaker #2 is no less than 25.22 meters.

11.1. For the purposes of Condition P.11, the volume source release height shall be determined by:

11.1.1. The permittee shall obtain the vessel source dimensions and emission source parameters;

11.1.2. The permittee shall determine the volume source release height based on plume rise and by using the following information:

11.1.2.1. The SCREEN3 model as set forth in 40 C.F.R. Part 51, Appendix W;

11.1.2.2. An hourly meteorological condition of "D stability," as that term is used in 40 C.F.R. Part 51, Appendix W;

11.1.2.3. A wind speed of 20 meters per second; and

11.1.2.4. The vessel dimensions and emission source parameters required under Condition P.11.1.1.

11.1.3. If EPA promulgates a different screening model in place of SCREEN3 in 40 C.F.R. Part 51, Appendix W, the permittee shall use that newly promulgated screening model to determine the volume source release height.

12. **Stack Test Requirements.** Prior to each of the first two drilling seasons that a vessel is used as Icebreaker #2, and while the Discoverer is operating under this permit in the Beaufort Sea, the permittee shall stack test each propulsion engine, non-propulsion generator engine, boiler and incinerator on Icebreaker #2 as follows:

12.1. Each stack test on the propulsion engines shall be conducted at four different loads: 20 percent, 40 percent, 60 percent and 80 percent.

12.2. Each stack test on the non-propulsion generator engines shall be conducted at two different load ranges: 50 - 60 percent and 90 - 100 percent.

12.3. Each stack test on the boilers shall be conducted at full loads.

12.4. Each stack test on the incinerator shall be conducted at full load.

12.5. Each stack test run shall test for emissions of NO_X, $PM_{2.5}$ and PM_{10}.

12.6. During each test run for the propulsion engines, generator engines, and boilers, the permittee shall monitor and record the following information:

12.6.1. Quantity of fuel used (in gallons);

12.6.2. Density of the fuel used (in lbs/gallon);

12.6.3. Heat content of the fuel used (in Btu/gallon); and

12.6.4. For the engines, electrical power output (in kWe).

12.7. During each test run for the incinerator, the permittee shall monitor and record the quantity of waste material incinerated (in lbs).

12.8. For each engine, each load range, and each pollutant, the permittee shall determine emission factors in the following units: lbs/kWe-hr and lbs/gallon.

12.9. For each boiler, and each pollutant, the permittee shall determine emission factors in the following units: lbs/MMBtu and lbs/gallon.

12.10. For each incinerator, and each pollutant, the permittee shall determine emission factors in the following units: lbs/ton of waste combusted.

13. **Monitoring, Recordkeeping and Reporting.** The permittee shall:

13.1. Equip each of the propulsion engines and generator engines on board Icebreaker #2 with an electrical output monitoring device:

13.1.1. Each electrical output monitoring device shall measure the electrical output of the generator attached to each engine with an accuracy equal to or better than 2 percent of the engine's maximum output (in kWe).

13.1.2. Each electrical output monitoring device shall measure the electrical output of the generator attached to each engine at least once every 10 minutes.

13.1.3. Each electrical output monitoring device shall be equipped to record each reading taken as well as provide and record average loads for each hour.

13.2. Maintain the accuracy of each electrical output monitoring device in accordance with manufacturer's recommendations.

13.3. Monitor and record the electrical load for each engine at least once every ten minutes, and record the average hourly load for each hour.

13.4. Equip each of the boilers on board Icebreaker #2 with a diesel fuel flow meter or install a single fuel meter for all of the boilers:

13.4.1. Each fuel flow meter shall be located so that there is no potential for fuel inflows or outflows between it and the boiler(s) being served by the meter;

13.4.2. Each fuel flow meter shall be totalizing and non-resettable; and

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

13.5. No less than 60 days before initial deployment of the Discoverer to the Beaufort Sea for the first drilling season, collect information from the manufacturer of each fuel flow meter so as to determine its accuracy. Submit this information to EPA no less than 30 days prior to operation within the Beaufort Sea.

13.6. Maintain the accuracy of each fuel flow meter in accordance with manufacturer's recommendations.

13.7. Monitor and record fuel usage for each boiler.

13.8. At least 45 days before deployment to the Discoverer each drilling season, the permittee shall notify the EPA of the volume source release height of Icebreaker #2.

13.9. Once each hour, and using a global positioning system or laser range finder capable of accuracy to within 10 meters, measure and record the date, time and location of Icebreaker #2.

13.10. Once each hour, monitor and record the date, time, direction the bow of the Discoverer is pointed, and wind direction at the Discoverer.

13.11. Record any instance that Icebreaker #2 attaches to the Discoverer.

13.12. Each day, calculate and record for the previous calendar day, the emissions of NO_X, $PM_{2.5}$ and PM_{10} in pounds per day from the boilers and incinerator by using the highest emission factor for each tested boiler or incinerator collected under Conditions P.12.9 and P.12.10 and fuel usage data collected under Condition P.13.7, to determine emissions from that source. For the purposes of this condition, the permittee shall assume that the incinerator has been operated continuously at the maximum operating rate, and shall use the highest emission factor collected under Condition P.12.10.

13.13. Each day, calculate and record for the previous calendar day, the emissions of NO_X, $PM_{2.5}$ and PM_{10} in pounds per day from each engine by using the emission factors for each tested engine collected under Conditions P.12.8 and electrical load data collected under Condition P.13.3, to determine emissions from that source. Emissions shall be calculated for each ten-minute load reading for each engine.

13.14. For the purposes of Conditions P.13.12 and P.13.13, if a specific emission unit has not been tested yet, the permittee shall use the highest emission factor for the corresponding load from the test results from an equivalent emission unit in equivalent service that has already been tested.

13.15. For the purposes of Conditions P.13.12 and P.13.13, if a specific load reading is missing, the permittee shall calculate the emissions for that missing load reading by using the emission factor and load combination that results in the highest emissions rate for that emissions unit. If the engine in question has not been tested yet, the permittee shall use the emission factor as provided for in Condition P.13.14.

13.16. Monitor and record at least once every 15 minutes the following parameters associated with each SCR system aboard Icebreaker #2:

13.16.1. Operational status of urea pump; and

13.16.2. Stack temperature upstream of the catalyst.

13.17. For the purpose of Condition P.13.13, if either the urea pump is not operating or if the catalyst inlet temperature, measured in Condition P.13.16.2, is less than 250°C, calculate emissions of NO_X for the affected time period by using an uncontrolled emission factor obtained by applying a 95 percent NO_X-reduction efficiency to the emission factor determined pursuant to Condition P.12.8.

Q. SUPPLY SHIP/BARGE AND TUG

1. **Operational Limits on Supply Ship Engines.** At all times while the Discoverer is an OCS Source and the supply ship is within 25 miles of the Discoverer, the permittee shall:

1.1. Not operate the emergency engine:

1.2. Limit operation of the propulsion engines in the supply ship to no greater than the limit as determined by the equation below.

Operating limit (in percent of full load) = (5760 – (X – 584))/(7784-X)*100

Where X = maximum rating (in hp) of all non-propulsion engines (excluding emergency engine) on board the supply ship.

Propulsion and non propulsion engines combined

2. **Volume Source Limit for Supply Ship.** The permittee shall ensure that the volume source release height of the supply ship is no less than 15.24 meters.

2.1. For the purposes of Condition Q.2, the volume source release height shall be determined by:

2.1.1. The permittee shall obtain the vessel source dimensions and emission source parameters;

2.1.2. The permittee shall determine the volume source release height based on plume rise and by using the following information:

2.1.2.1. The SCREEN3 model as set forth in 40 C.F.R. Part 51, Appendix W;

2.1.2.2. A hourly meteorological condition of "D stability," as that term is defined in 40 C.F.R. Part 51, Appendix W;

2.1.2.3. A wind speed of 20 meters per second; and

2.1.2.4. The vessel dimensions and emission source parameters required under Condition Q.2.1.1.

2.1.3. If EPA promulgates a new screening model in place of SCREEN3 in 40 C.F.R. Part 51, Appendix W, the permittee shall use that newly promulgated screening model to determine the volume source release height.

3. **Monitoring, Recordkeeping and Reporting.** The permittee shall:

3.1. At all times while the Discoverer is an OCS Source and the supply ship is within 25 miles of the Discoverer, monitor the power output of each propulsion engine on the supply ship at least once every 15 minutes.

3.1.1. The monitored power output shall be recorded as a direct readout value as well as a percentage of the rated capacity of each engine.

3.2. At least 45 days before deployment to the Discoverer each drilling season, the permittee shall notify the EPA of the volume source release height.

3.3. For each trip to the Discoverer while the Discoverer is an OCS Source, the permittee shall record the following:

3.3.1. The date and time that the supply ship came within 25 miles of the Discoverer; and

3.3.2. After the delivery to the Discoverer, the date and time that the supply ship was no longer within 25 miles of the Discoverer.

4. **Supply Barge and Tug Alternative.** If a supply barge/tug is used in lieu of the supply ship, the barge and tug shall:

4.1. No later than 45 days prior to deployment to the Beaufort Sea each drilling season, the permittee shall provide notification to EPA of the selected supply barge and tug. The notification shall include a list of all emission sources on board the vessel as well as manufacturer, model and rated capacity of each emission source.

4.2. Operational Limits on Supply Barge and Tug Engines. At all times while the Discoverer is an OCS Source and the supply barge and tug is within 25 miles of the Discoverer, the permittee shall:

4.2.1. Limit operation of all engines to an aggregate of 5760 hp.

4.3. In addition the supply barge and tug will comply with Conditions Q2 and Q3 above.

R. OIL SPILL RESPONSE FLEET

1. **Operation of Catalyzed Diesel Particulate Filter (CDPF).** At all times while the Discoverer is an OCS Source and the Nanuq is within 25 miles of the Discoverer, and any of the Nanuq propulsion engines (Units N-1 – 2) or non-propulsion generator engines (Units N-3 – 4) are in operation, the exhaust from each emission unit shall be directed to operating CleanAIR Systems CDPF, as specified by CleanAIR Systems.

1.1. Each CDPF shall be equipped with an operating HiBACK monitor and alarm unit, that records exhaust pressure and temperature.

1.2. During each day that each of Units N-1 – 4 is operated, the exhaust temperature shall be above 300°C, or 572°F, for at least 30 percent of the time.

2. **PTE Annual NO_X Emission Limits.** At all times while the Discoverer is an OCS Source and the Nanuq is within 25 miles of the Discoverer, emissions of NO_X from operation of the Nanuq propulsion engines (Units N-1 – 2) and Nanuq non-propulsion generator engines (Units N-3 – 4) shall not exceed the emission limits specified below.

2.1. Nanuq propulsion engines (Units N-1 – 2): 118.61 tons/rolling 12-month period

Nanuq generators (Units N-3 – 4): 53.36 tons/rolling 12-month period

2.1.1. For compliance with Condition R.2.1, measurement of NO_X shall be determined using EPA Method 7E.

3. **Fuel Usage Limit.** At all times while the Discoverer is an OCS Source and the Nanuq is within 25 miles of the Discoverer, the permittee shall not use in excess of:

3.1. 504,000 gallons of fuel in the Nanuq propulsion engines (Units N-1 – 2) in aggregate during any rolling 12-month period.

3.2. 134,400 gallons of fuel in the Nanuq non-propulsion generator engines (Units N-3 – 4) in aggregate during any rolling 12-month period.

3.3. 3,000 gallons of fuel in the Nanuq propulsion engines (Units N-1 – 2) in aggregate during any calendar day.

3.4. 800 gallons of fuel in the Nanuq non-propulsion generator engines (Units N-3 – 4) in aggregate during any calendar day.

4. **Operating Distance from Discoverer.** Except for transport of crew and supplies to and from the Discoverer or when responding to an oil spill, the oil spill response fleet shall operate such that the closest point of the fleet to the closest point on the Discoverer shall not be less than 2,000 meters.

4.1. For the purpose of Condition R.4, the permittee shall use a global positioning system or laser range finder capable of accuracy to within 10 meters.

5. **Operating Location.** Except for transport of crew and supplies to and from the Discoverer or when responding to an oil spill, the oil spill response fleet shall operate at a location that is downwind from the Discoverer.

6. **Attachment to Discoverer.** At no time shall the Arctic Endeavor Barge, Point Barrow Tug, Nanuq, Rozema Skimmer or any of the Kvichak work boats be attached to the Discoverer.

7. **Stack Test Requirements.** Prior to each of the first two drilling seasons while the Discoverer is operating under this permit in the Beaufort Sea, the permittee shall stack test at least one of the Nanuq propulsion engines (Units N-1 – 2) and one of the Nanuq non-propulsion generator engines (Units N-3 – 4) as follows:

7.1. At the end of two drilling seasons that the Discoverer operates under this permit in the Beaufort Sea, all of Units N-1 – 4 shall have been stack tested under the requirements of this section.

7.2. Each stack test shall be conducted at four different loads - 25 percent, 50 percent, 75 percent and 100 percent for the propulsion engines and at two loads - 50 percent and 100 percent for the non-propulsion engines.

7.3. Each stack test run shall test for emissions of NO_X.

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

7.4.1. Quantity of fuel used (in gallons);

7.4.2. Density of the fuel used (in lbs/gallon);

7.4.3. Heat content of the fuel used (in Btu/gallon); and

7.4.4. Electrical power output (in kWe).

7.5. For each engine, each load, and each pollutant, the permittee shall determine emission factors in the following units: lbs/kWe-hr and lbs/gallon.

8. **Monitoring, Recordkeeping and Reporting.** The permittee shall:

8.1. Equip each of Units FD-N-1 - 4 with a diesel fuel flow meter or install a single fuel meter for all of Units FD-N-1 - 4:

8.1.1. Each fuel flow meter shall be located so that there is no potential for fuel inflows or outflows between it and the engine(s) being served by the meter;

8.1.2. Each fuel flow meter shall be totalizing and nonresettable; and

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

8.2. No less than 60 days before initial deployment of the Discoverer to the Beaufort Sea for the first drilling season, collect information from the manufacturer of each fuel flow meter so as to determine its accuracy. Submit this information to EPA no less than 30 days prior to operation within the Beaufort Sea.

8.3. Maintain the accuracy of each fuel flow meter in accordance with manufacturer's recommendations.

8.4. Monitor and record fuel usage for each propulsion and generator engine (Units N-1 – 4) on a daily basis.

8.5. Once each hour, and using a global positioning system or laser range finder capable of accuracy to within 10 meters, measure and record the location of the Arctic Endeavor Barge, Point Barrow Tug, or Nanuq and the distance from the closest point of the oil spill response fleet to the closest point on the Discoverer.

8.6. Once each hour, monitor and record the wind direction at the Discoverer.

8.7. Record any instance that the Arctic Endeavor Barge, Point Barrow Tug, Nanuq, Rozema Skimmer or Kvichak work boats attach to the Discoverer.

8.8. Each day, calculate and record for the previous calendar day, the emissions of NO_X, using the highest emission factor for each tested engine collected under Condition R.7.5 and fuel usage data collected under Condition R.8.4.

8.9. Monitor and record the exhaust temperature of each engine by use of the HiBACK monitor and alarm unit, while the engine is in operation.

8.10. Each day, calculate and record for the previous calendar day, the percent of operational time for each engine that the exhaust temperature was above 300°C (572°F).

S. POST-CONSTRUCTION AMBIENT AIR QUALITY MONITORING

1. **Ambient Air Quality Monitoring Station.** The permittee shall install, operate and maintain a Federal Reference Method or Federal Equivalent Method ambient air quality monitoring station to measure and record $PM_{2.5}$ concentration data in accordance with EPA, 1984a: Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), EPA-450/4-87-007, May 1987, U.S. Environmental Protection Agency, Research Triangle Park, NC.

1.1. An alternative $PM_{2.5}$ monitoring station may be used in lieu of the required monitoring station provided that approval of the monitoring station is obtained from EPA;

1.2. The permittee shall use a continuous sampler and a manual sampler to measure $PM_{2.5}$. In addition, filters from the manual sampler shall be analyzed as provided for in the EPA-approved ambient air quality and meteorological monitoring plan required pursuant to Condition S.3 to allow for the chemical speciation of $PM_{2.5}$ constituents, including but not limited to sulfates, nitrates, organics, metals, sea salt and crustal matter.

1.3. The monitoring period shall commence within 120 days after the final permit is issued and shall continue for a minimum of 1 year after commencement of initial operation of the Discoverer in the Beaufort Sea as an OCS Source;

1.4. The data recovery shall be as provided for in the EPA-approved ambient air quality and meteorological monitoring plan required pursuant to Condition S.3; and

1.5. The monitoring station shall continue to operate and record data until such time that written approval is obtained from EPA authorizing the termination of its operation.

2. **Meteorological Monitoring Station.** The permittee shall install, operate and maintain a meteorological monitoring station to monitor and record data in accordance with EPA, 1984a: Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), EPA-450/4-87-007, May 1987, U.S. Environmental Protection Agency, Research Triangle Park, NC.

2.1. An alternative meteorological monitoring station may be used in lieu of the required monitoring station provided that approval of the monitoring station is obtained from EPA;

2.2. Data shall include horizontal wind direction and speed, temperature, solar radiation and temperature difference;

2.3. Each quarter's data recovery shall be as provided for in the EPA-approved ambient air quality and meteorological monitoring plan required pursuant to Condition S.3;

2.4. The monitoring period shall commence within 120 days after the final permit is issued and shall continue for a minimum of 1 year after commencement of operation of the OCS Source; and

2.5. The monitoring station shall continue to operate and record data until such time that written approval is obtained from EPA authorizing the termination of its operation.

3. **Ambient Air Quality and Meteorological Monitoring Plan.** At least 60 days prior to the commencement of the data collection, the permittee shall submit to EPA for approval an ambient air quality and meteorological monitoring plan for the post-construction monitoring requirements specified in Conditions S.1 and S.2 in accordance with the requirements of 40 C.F.R. Part 58, Appendix A "Quality Assurance Requirements for SLAMS, SPMs and PSD Air Monitoring." The plan shall include a description of the proposed monitoring site.

4. **Monthly Reporting.** Within 45 days after the end of each calendar month, the permittee shall submit to EPA a printed summary of the $PM_{2.5}$ and meteorological monitoring data collected during the prior calendar month.

5. **Audit Reports.** The permittee shall submit audit reports with 45 days after the following events:

   5.1. Completion of the post-installation equipment audit;

   5.2. Completion of independent performance and system audits;

   5.3. Completion of quarterly audits required for ambient air quality data collection system; and

   5.4. Completion of the semi-annual audits required for the meteorological data collection system.

   Quarterly and semi-annual audit periods shall be based on a calendar year.

6. **Annual Report.** Within 60 days after the end of each calendar year and following completion of the collection of monitoring, the permittee shall submit to EPA annual/final reports in text, tabular, and graphic forms, including data in digitized format. The digitized formats of the measured air quality and meteorological data shall be in ASCII format and AIRS format.

7. **System and Performance Audit Report.** Within 60 days after completion of data collection, the permittee shall also submit the final report for the system and performance audits required prior to monitoring termination.

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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 Compliance Order by Consent, Compliance Order, 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
☐ Control Equipment Failure
☐ Bad fuel/coal/gas
☐ Natural Cause (weather/earthquake/flood)
☐ Scheduled Maintenance/Equipment Adjustments
☐ 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 or source 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 percent ☐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 source 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. R10OCS/PSD-AK-2010-01

Certified Observer: _____

Company & Stationary Source: _____

Location: _____

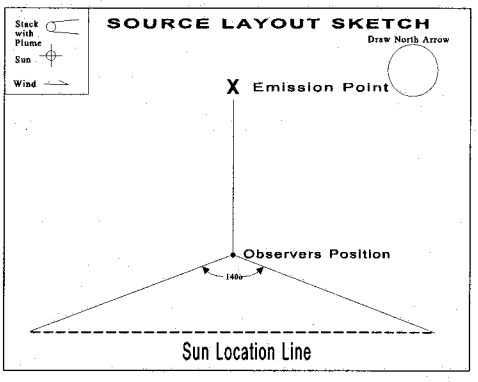
Test No.: _____ Date: _____

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 B

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

JAN 29 2010

OFFICE OF
AIR AND RADIATION

Mr. Peter E. Slaiby
Vice President
Shell Exploration and Production Company
3601 C Street, Suite 1000
Anchorage, Alaska 99503

Dear Mr. Slaiby:

Thank you for your letter of January 4, 2010, and for your participation in the ongoing discussions between the U.S. Environmental Protection Agency (EPA) and your company regarding air permit applications for exploration drilling in the Chukchi and Beaufort Seas. In your letter, you requested that EPA finalize the Chukchi permit within 10 days of the close of the public comment period on February 17, 2010.

EPA understands the significance of these activities and the importance of issuing environmentally protective and legally defensible permits as expeditiously as possible to meet Shell's business needs. Be assured that, although that we cannot commit to a specific date for issuance of the final permit, we commit to do everything reasonably possible to anticipate the issues to which we will need to respond so that issuance of the final permit can occur as expeditiously as possible. EPA will continue to provide support from our Headquarters and other EPA offices as needed to assist our Region 10 office with the review, response to comments, and preparation of the final permit.

Also, in your letter you requested that Region 10 and our Office of Air and Radiation request the Environmental Appeals Board (EAB) to expedite consideration of an appeal of the Chukchi permit, should one be filed. Region 10 has already expressed to you their commitment to work within whatever expedited schedule the EAB may establish, and we will convey our view to the EAB of the significance of this permit and the importance of expeditious processing relative to the company's ability to conduct exploratory drilling this season at the appropriate time.

Your last request in your letter is for a firm date for publication of the draft Beaufort air permit and a clear schedule for finalizing that permit. EPA understands your concern, and work is proceeding well on the permit. Many difficult technical issues have been addressed during the Chukchi permit, which makes the Beaufort permit more

straightforward. We will continue our current level of effort to issue draft and final permits as expeditiously as possible.

Again, thank you for your letter. If you have any further questions, please contact Janet McCabe of my staff at (202) 564-3206.

Sincerely,

Gina McCarthy
Assistant Administrator

cc: Michelle Pirzadeh, Region 10
Janet McCabe, OAR

ATTACHMENT C

Attachment C

ATTACHMENT C

SUPPLEMENTAL DECLARATION OF PETER E. SLAIBY

Peter E. Slaiby declares as follows:

1. My name is Peter E. Slaiby. I have first-hand experience with, and personal knowledge of, the facts and matters discussed in this declaration.

2. This Declaration supplements the Declaration of Peter E. Slaiby dated April 2, 2010 ("Slaiby Chukchi Declaration"). Except as herein supplemented, I affirm and adopt by reference my prior declaration.

3. On April 9, 2010, Region 10 issued a final PSD permit for SOI's planned Beaufort Sea operations.

4. At the outset of Shell's 2010 summer Arctic OCS drilling program in early July, 2010, Shell needs to have both the Beaufort and Chukchi Sea Air Permits in a form that would actually allow for exploration operations on that date because, in the face of uncertain ice conditions and weather, Shell may not be able immediately to explore in one or the other sea. Shell cannot confidently predict which sea will be sufficiently ice-free by July to allow drilling. For this reason, as well as other contingencies, Shell needs the flexibility afforded by having both permits in effect in order to increase the chances of drilling and completing one or more wells in one or the other sea during the short 2010 drilling season.

5. Under the MMS-approved Plan of Exploration ("EP"), SOI is authorized to enter the Arctic OCS waters on July 1, 2010, enabling exploration drilling to begin in the Beaufort Sea on or about July 10, 2010, and to continue operations until October 31, 2010 – an effective potential drilling season of about 110 days. However, the EP also requires SOI to suspend drilling during the Alaska Native whaling season, which begins on August 25 and continues until captains from the Alaska Native Villages of Nuiqsuit and Kaktovik have taken their respective quotas of

whales – usually requiring between 14 and 28 days – yielding an effective drilling season of about 80-95 days. As noted in Paragraph 12 of the Slaiby Chukchi Declaration, between April 1 and May 31, 2010, Shell will commit to new funding well in excess of $300 million to prepare for 2010 Arctic operations. Thus, in April and May 2010, Shell will incur 2010 out-of-pocket costs of, on average, over $2.5 million for each day of a maximum 120-day Arctic drilling season, whether or not Shell is able to drill. This daily cost is even higher for lost days of drilling in the Beaufort Sea due to the much shorter drilling season authorized by MMS. Every day of delay in Shell's ability to begin the drilling season in the Beaufort Sea on July 10, 2010, will result in a lost day of potential operations in a finite drilling season, and the drilling that cannot be accomplished during this period of delay will have to be made up in subsequent seasons, and paid for a second time, at roughly the same $2.5 million per day cost, or higher.

PETER E. SLAIBY

Executed in Anchorage, Alaska on April 14, 2010.

Attachment D

ATTACHMENT D

DECLARATION OF PETER E. SLAIBY

Peter E. Slaiby declares as follows:

1. My name is Peter E. Slaiby. I have first-hand experience with, and personal knowledge of, the facts and matters discussed in this declaration.

2. I am the Vice President, Alaska Exploration & Appraisal, for Shell Energy Resource Company, an affiliate of Shell Gulf of Mexico, Inc. ("SGOMI") and of Shell Offshore Inc. ("SOI"). Both SGOMI and SOI indirectly are wholly-owned subsidiaries of Shell Oil Company ("SOC"). In this declaration, SGOMI and SOI are sometimes collectively referred to as "Shell".

3. I am also a businessman and an Alaska resident with approximately 30 years of experience working in the oil and gas exploration and production industry. I hold a BE degree in Mechanical Engineering from Vanderbilt University and have been employed since 1980 by various affiliates of SOI.

4. In my capacity as Vice President, I direct and supervise the exploration of oil and gas resources on the Alaskan Outer Continental Shelf, including exploration of federal oil and gas leases held by SGOMI in the Chukchi Sea and by SOI in the Beaufort Sea. I have personal knowledge of the matters set forth in this Declaration.

5. On December 11, 2008, SGOMI submitted an application to EPA Region 10 for a permit under Section 328 of the Clean Air Act and EPA's OCS air permitting regulations, 40 C.F.R. Part 55, authorizing emissions from SGOMI's planned exploration drilling activities during 2010 and subsequent years in the Chukchi Sea. On January 18, 2010, SOI submitted a revised application to Region 10 for a permit covering its planned exploration drilling activities in 2010 and subsequent years in the Beaufort Sea. SGOMI and SOI supplemented each

application multiple times at Region 10's request and the applications were determined to be complete on July 19, 2009 and February 11, 2010, respectively. Both applications sought permits authorizing emissions from the drillship *Frontier Discoverer* and from associated vessels, including ice management, supply, and oil spill response vessels.

6. In August, 2009, Region 10 issued for public comment a proposed permit for SGOMI's Chukchi operations. After conducting public meetings and receiving public comment during an extended comment period, Region 10 requested that SGOMI supplement the permit application, which SGOMI did. Region 10 issued a re-proposed permit on January 8, 2010 on which Region 10 received extensive additional comments. In all, the public comment period on the proposed and re-proposed permits totaled approximately 100 days. On March 31, 2010, Region 10 issued a final PSD permit for SGOMI's Chukchi operations.

7. On February 17, Region 10 issued for public comment a proposed PSD permit for SOI's Beaufort operations. Region 10 conducted public meetings and received extensive public comment on the proposed permit prior to the close of the comment period on March 22, 2010. As of the date of this Declaration, Region 10 has not yet issued a final PSD permit for SOI's Beaufort operations.

8. SOI originally applied to Region 10 in early 2007 for two air permits for exploration in the Beaufort Sea utilizing two drillships, the *Kulluk* and the *Frontier Discoverer*. Relying on guidance from Region 10, SOI submitted these original applications in the form of "minor source permits", with extensive owner-requested limits and controls on emissions from each drillship and its associated fleet of ice management, supply, and oil spill response vessels. SOI subsequently determined to proceed only with the *Kulluk* application.

ATTACHMENT D

9. In July 2007, Region 10 issued a minor source permit for the *Kulluk*'s operations in the Beaufort Sea. Petitions for review were filed and the Board granted SOI's request for expedited review. Following accelerated briefing on the petitions for the review and a hearing immediately thereafter, the Board issued a decision remanding the permit for further proceedings to address a single issue – under what circumstances should the *Kulluk*'s potential to emit for purposes of minor source classification reflect "aggregated" emissions at one or more drilling locations. *In re Shell Offshore Inc., Kulluk Drilling Unit and Frontier Discoverer Drilling Unit*, OCS Appeal Nos. 07-01 and 07-02, slip op. at 5, 69 (EAB, Sept. 14, 2007). On remand, Region 10 issued a revised permit addressing the Board's concerns. The revised permit was also appealed to this Board, but that appeal was dismissed at Region 10's request when SOI withdrew its air permit application in order to focus on new applications to the Minerals Management Service ("MMS") for new Exploration Plans for the two seas. *In re Shell Offshore Inc., Kulluk Drilling Unit*, OCS Appeal Nos. 08-01, 08-02, and 08-03 (EAB, Apr. 30, 2009). At that time, Region 10 recommended that Shell apply for PSD major source permits for its Beaufort Sea and Chukchi Sea exploration programs, which Shell did.

10. Shell has made a tremendous effort over the last four years to commence an Arctic OCS exploration program. To meet the high standards expected by Shell, state and local governments, and the public at large, Shell has committed to use highly specialized rigs and support vessels to explore its leases in the Beaufort and Chukchi Seas. To this end, Shell has had to refurbish available Arctic rigs, commission new ice-class spill response and anchor-handling vessels, and commit to multi-year operating contracts before knowing whether exploration will proceed. In addition to the initial lease acquisition costs totaling $2.2 billion, as of March 2010, Shell has invested nearly $870 million to prepare for exploration of its Arctic leases.

These expenditures have included costs to conduct seismic exploration and scientific studies; engagement, refurbishment, and maintenance of offshore drilling and support vessels; broad-based logistics activities; and maintenance of oil spill response capabilities.

11. Shell is planning to conduct a 2010 summer Arctic OCS drilling program. To undertake this program, Shell has made and must continue to make significant advance commitments for new spending, with the largest commitments to be made in April and May, 2010. By May 31, 2010, Shell will have made a series of irrevocable financial commitments necessary for a 2010 drilling season, including mobilizing the *Frontier Discoverer* to the Arctic theater of operations, arranging and staging supplies and fuel, contracting for services, testing equipment, and mobilizing employees. After that date, Shell will have incurred these costs regardless of when, or whether, it is ultimately able to begin drilling operations in 2010. Shell's additional out-of-pocket costs in 2010 to prepare to proceed with exploratory drilling this year, over and above the $870 million discussed above, will substantially exceed $300 million, including charges for new rig modifications, other direct costs associated with a drilling rig and equipment, charges for related support vessels and other logistics, additional costs associated with oil spill response vessels and equipment, and personnel and other overhead costs. In all, mobilization for the 2010 drilling season will involve more than 100 separate contracts, as many as 700 people either employed or contracted, and roughly 800,000 hours, the bulk of which Shell will be committed to by May 31, 2010. With few exceptions, once incurred during preparations to drill in 2010, these costs will be fixed even if Shell's drilling season is truncated or eliminated. These jobs are very important to the economy of Alaska and the communities in which we work, representing a significant opportunity for native Alaskan businesses.

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12. Under the MMS-approved Plan of Exploration, SGOMI is authorized to begin exploration drilling in the Chukchi Sea on July 4, 2010, and to continue operations until October 31, 2010 – an effective potential drilling season of 120 days. As noted, between April 1 and May 31, 2010, Shell will commit to new funding well in excess of $300 million to prepare for 2010 Arctic operations. Thus, in April and May 2010, Shell will incur 2010 out-of-pocket costs of, on average, $2.5 million for each day of the 120-day drilling season, whether or not operations occur that day. Every day of delay in Shell's ability to begin the drilling season on July 4, 2010, will result in a lost day of potential operations in a finite drilling season, and the drilling that cannot be accomplished during this period of delay will have to be made up in subsequent seasons, and paid for a second time, at roughly the same $2.5 million per day cost, or higher.

13. Shell's objective is to drill two wells in 2010. A delay that leaves Shell only enough time to complete one well will mean that Shell will forego in 2010 the additional data that would have been acquired from completing the second well – data that would have a high value in planning drilling locations for 2011. This loss of data could reduce the utility of the drilling season far more than merely the loss of a certain number of operating days.

14. Moreover, there is a risk that Shell may not be able to make up such delays in subsequent seasons. Shell has access to its lease tracts in the Chukchi and Beaufort Seas only during the limited term of the leases. Generally, unless active oil development is underway on those leases at the expiration of their term, the leases will expire. Shell could re-bid on those leases if they were offered again, but there is no guarantee that the leases will be offered, or that Shell would be successful in obtaining them. Bidding could be highly competitive, given that competitors would be aware of Shell's exploration activities, and to prevail, Shell might have to offer new bonus lease payments even higher than Shell's initial payments.

15. Finally, successful exploration is a prerequisite to further oil and gas development projects. Every delay in the exploration of these leases therefore reduces Shell's opportunity to find other viable oil deposits and to bring its leases into production. In short, continued delays in exploration threaten the long-term viability of Shell's Alaskan offshore endeavors.

16. Shell is aggressively pursuing, and believes it will timely obtain all permits and authorizations from federal and state agencies needed in order to commence drilling in the Arctic promptly in July 2010 under the MMS-approved Exploration Plans. Unlike the Chukchi PSD permit (and the anticipated Beaufort PSD permit), which is effectively stayed by an appeal to EAB, each of these permits and authorizations will be fully effective upon issuance by the relevant agency.

I declare under penalty of perjury that the foregoing is true and correct.

PETER E. SLAIBY

Executed in Anchorage, Alaska on April 2, 2010.