DEPARTMENT OF ENVIRONMENTAL CONSERVATION

AIR QUALITY CONTROL MINOR PERMIT

Permit No.: AQ0923MSS04 Date: **Preliminary – January 12, 2010**
Rescinds Permit AQ0923MSS01, Revision 1

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Minor Permit AQ0923MSS04 to the Permittee listed below.

Permittee:	**Eni US Operating Co. Inc.** 1201 Louisiana Houston, TX 77002 (713) 393-6100
Owner:	Same as Permittee
Operator:	Same as Permittee
Stationary Source:	**Nikaitchuq Development**
Location:	UTM Zone 6; Northing 7,825,307.5 m; Easting 393,344.0 m (NAD83)
Physical Address:	200 feet southeast of Kuparuk River Unit Seawater Treatment Plant
Permit Contact:	Don Graika or Patrick Conway don.graika@enipetroleum.com, Patrick.Conway@enipetroleum.com (907) 670-8501
Project	**Permit Revision**

This project is classified under 18 AAC 50.502(c)(3)(A) since the increase in sulfur dioxide (SO_2) potential to emit (PTE) exceeds 15 tons per year and the stationary source's existing SO_2 PTE exceeds the amount specified under 18 AAC 50.502(c)(1). This project is further classified under 18 AAC 50.508(6) to revise or rescind terms and conditions of a Title I permit issued under 18 AAC 50. This permit satisfies the obligation of the Permittee to obtain a minor permit under these provisions. As required by AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this minor permit. This permit authorizes the Permittee to operate under the terms and conditions of this permit, and as described in the original permit application and subsequent application supplements listed in Section 6 except as otherwise specified in this permit.

The Permittee may operate under this permit upon issuance.

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John F. Kuterbach
Manager, Air Permits Program

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Abbreviations/Acronyms

AAC ....Alaska Administrative Code
ADEC ....Alaska Department of Environmental Conservation
AS..................................Alaska Statutes
ASTM............................American Society of Testing and Materials
C.F.R. ....Code of Federal Regulations
EPA ....Environmental Protection Agency
HHV ....Higher heating value
NA ....Not Applicable
NAICS ....North American Industry Classification System
PS ....Performance specification
PSD................................Prevention of Significant Deterioration
PTE................................Potential to Emit
RM.................................Reference Method
SIC.................................Standard Industrial Classification
SN..................................Serial Number
TBD...............................To Be Determined

Units and Measures

bbl.................................barrels
bhp.................................brake horsepower[1]
gr./dscf...........................grains per dry standard cubic feet (1 pound = 7,000 grains)
dscf ....dry standard cubic foot
gph.................................gallons per hour
kW ....kiloWatts
kW-e ....kilowatts electric[2]
MMBtu ....million British Thermal Units[3]
MW-e ....megawatts electric
ppm................................parts per million
ppmv..............................parts per million by volume
tph..................................tons per hour
tpy..................................tons per year
wt%................................weight percent

Pollutants

CO ....Carbon Monoxide
HAPS.............................Hazardous Air Pollutants
H_2S ....Hydrogen Sulfide
NO_X ....Oxides of Nitrogen
NO_2................................Nitrogen Dioxide
NO ....Nitric Oxide
PM-10............................Particulate Matter with an aerodynamic diameter less than 10 microns
SO_2 ....Sulfur Dioxide
VOC ....Volatile Organic Compound

[1] For engines: approximately 7,000 Btu-fuel per brake horsepower-hour is required for an average diesel internal combustion engine.
[2] "electric" refers to the rated generator electrical output rather than the engine/turbine rated output
[3] For purposes of this permit, all boiler and heater ratings are in heat input.

Section 1 Emission Unit Inventory

1. **Authorization.** The Permittee is authorized to install and operate the emission units listed in Table 1 in accordance with the terms and conditions of this permit and the minor permit application. For purposes of this permit, the emission units listed in Table 1 are collectively referred as "Permanent Emission Units."

Table 1 – Permanent Emission Units [a]

Emission Unit ID	Unit Description	Make/Model	Fuel Type	Rating/size	Installation Date
Combustion Units					
1	Gas Turbine [a]	Solar Taurus 70	Gas	7.5 MW-e	TBD
2	Gas Turbine [a]	Solar Taurus 70	Gas	7.5 MW-e	TBD
3	Reciprocating Engine, Blackstart Generator	TBD	Diesel	2,011 bhp	TBD
4	Process Safety Flare (with two tips)	Unknown	Gas	[b]	TBD
Storage Tanks					
5	Off-Spec Crude Oil Tank #1[c]	TBD	NA	750 bbl	TBD
6	Off-Spec Crude Oil Tank #2[c]	TBD	NA	750 bbl	TBD
7	Diesel Storage Tank	TBD	NA	750 bbl	TBD
8	Methanol Tank	TBD	NA	50 bbl	TBD
32	Gas Turbine [a]	Solar Taurus 70	Gas	7.5 MW-e	TBD
33	Gas Turbine [a]	Solar Taurus 70	Gas	7.5 MW-e	TBD
34	Process Tank	TBD	NA	750 bbl	TBD
35	Process Tank	TBD	NA	750 bbl	TBD
36	Process Tank	TBD	NA	750 bbl	TBD
37	Process Tank	TBD	NA	750 bbl	TBD
38	Process Tank	TBD	NA	750 bbl	TBD
39	Process Tank	TBD	NA	750 bbl	TBD
40	Process Tank	TBD	NA	750 bbl	TBD
41	Process Tank	TBD	NA	750 bbl	TBD
42	Storage Tank	TBD	NA	750 bbl	TBD
43	Storage Tank	TBD	NA	750 bbl	TBD
44	Storage Tank	TBD	NA	750 bbl	TBD

45	Storage Tank	TBD	NA	750 bbl	TBD
46	Storage Tank	TBD	NA	750 bbl	TBD
47	Reciprocating Engine, Emergency Generator	TBD	Diesel	2,011 bhp	TBD
48	Incinerator	TBD	NA	200 lb/hr	TBD
49	Reciprocating Engine, Drilling Camp Generator	TBD	Diesel	730 bhp	TBD
50	Reciprocating Engine, Drilling Camp Generator	TBD	Diesel	730 bhp	TBD
51	Storage Tank	TBD	NA	750 bbl	TBD
52	Storage Tank	TBD	NA	750 bbl	TBD
53	Storage Tank	TBD	NA	750 bbl	TBD
54	Process Tank	TBD	NA	750 bbl	TBD
55	Process Tank	TBD	NA	750 bbl	TBD
56	Process Tank	TBD	NA	750 bbl	TBD
57	Process Tank	TBD	NA	750 bbl	TBD
58	Process Tank	TBD	NA	750 bbl	TBD
59	Process Tank	TBD	NA	750 bbl	TBD
60	Process Tank	TBD	NA	750 bbl	TBD
61	Process Tank	TBD	NA	750 bbl	TBD
62	Process Tank	TBD	NA	750 bbl	TBD
63	Process Tank	TBD	NA	750 bbl	TBD
66	Reciprocating Engine, Drilling Mud Pump	TBD	Diesel	500 bhp	TBD
67	Reciprocating Engine, Cement Pump	TBD	Diesel	950 bhp	TBD
68	Reciprocating Engine, Grind and Inject Pump	TBD	Diesel	1,100 bhp	TBD
69	Boiler	Weil-McLain	Diesel	0.75 MMBtu/hr	TBD
70	Boiler	Weil-McLain	Diesel	0.75 MMBtu/hr	TBD
71	Boiler	Weil-McLain	Diesel	0.75 MMBtu/hr	TBD
72	Reciprocating Engine, Grind and Inject Power	TBD	Diesel	2,682 bhp	TBD
73	Reciprocating Engine, Grind and Inject Power	TBD	Diesel	2,682 bhp	TBD

Table 1 Footnotes:

[a] The Permittee may install Waste Heat Recovery Units (WHRU) on the Gas Turbines (Emission Units 1, 2, 32 and 33) to provide process and space heat. The WHRUs may *not* include supplemental burners.

[b] The process safety flare is rated at:

0.25 MMscf/day (pilot and purge operation)
15 MMscf/day (low pressure emergency operation)
50 MMscf/day (high pressure emergency operation)

[c] The Permittee may not use Units 5 and 6 (Off-Spec Crude Oil Tank #1 and #2) for routine flow-through of sales-quality crude oil.

1.1 Except as noted elsewhere in this permit, the information in Table 1 is for identification purposes only. The specific unit descriptions do not restrict the Permittee from replacing an emission unit identified in Table 1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement emission unit, including any applicable minor or construction permit requirements.

2. The Permittee is authorized to operate a Drilling Rig in accordance with the terms and conditions of this permit and the minor permit application.

2.1 For purposes of this permit, the emission units represented as Emission Units 9 through 18, 74, and 75 in Table 2 are collectively referred as the "Drilling Rig."

2.2 The actual Drilling Rig operated under this permit may be similar or smaller than the Drilling Rig represented in Table 2. In all situations, the cumulative boiler/heater rating shall not exceed 19.3 MMBtu/hr and the cumulative engine rating shall not exceed 5,330 bhp.

Table 2 – Example Drilling Rig Emission Units [a]

Emission Unit ID	Unit Description	Make/Model	Rating/size
Drilling Rig (Nabors 245E) [b]			
9	Rig Boiler	Cleaver Brooks CB100-100	4.2 MMBtu/hr
10	Rig Boiler	Cleaver Brooks CB100-100	4.2 MMBtu/hr
11	Air Heater	Tioga 1DF-21B0	4.2 MMBtu/hr
12	Air Heater	Tioga 1DF-21B0	4.2 MMBtu/hr
13	Air Heater	Tioga 1DF-11C0	2.5 MMBtu/hr
14	Rig Engine	Caterpillar D399	1,125 bhp
15	Rig Engine	Caterpillar D399	1,125 bhp
16	Rig Engine	Caterpillar D399	1,125 bhp
17	Rig Engine	Caterpillar D399	1,125 bhp
18	Generator Motor	Caterpillar D353	230 bhp
74	Reciprocating Engine	TBD	300 bhp
75	Reciprocating Engine	TBD	300 bhp

Table 2 Footnotes:
[a] All of the fuel burning units listed in Table 2 are diesel-fired.
[b] While the Permittee anticipates use of the Nabors 245E rig, the actual Drilling rig may be similar or smaller than the Nabors 245E (i.e., the selected Drilling Rig may have fewer and/or smaller emission units).

3. The Permittee is also authorized to periodically operate intermittent well servicing equipment in accordance with the terms and conditions of this permit and the minor permit application.[4] The intermittent well servicing equipment includes the emission units listed in Table 3.

3.1 For purposes of this permit, the emission units represented as Emission Units 26 through 31 in Table 3 are collectively known as the "Workover Rig."

[4] In all cases, intermittent well servicing equipment must be portable, and must only be operated on a periodic and temporary basis, in a manner analogous with the non-road engine rule, adopted by reference in 18 AAC 50.100.

3.2 The actual Workover Rigs operated under this permit may be similar or smaller than the Workover Rig represented in Table 3. In all situations, the cumulative boiler/heater rating may not exceed 9.6 MMBtu/hr and the cumulative engine rating may not exceed 4,350 bhp.

Table 3 – Partial List of Intermittent Well Servicing Equipment [a]

Emission Unit ID	Unit Description	Rating/size
19	500 Ton Crane	650 bhp
20	300 Ton Crane	575 bhp
23	Hot Oiler Boiler/Heater	6.0 MMBtu/hr
24	Boiler/Heater	9.5 MMBtu/hr
25	Vibration Hammer Engine	625 bhp
Workover Rig (Nordic Rig #3) [b]		
26	Workover Rig Engine #1	1,450 bhp
27	Workover Rig Engine #2	1,450 bhp
28	Workover Rig Engine #3	1,450 bhp
29	Workover Rig Boiler #1	2.7 MMBtu/hr
30	Workover Rig Boiler #2	2.7 MMBtu/hr
31	Workover Rig Heater	4.2 MMBtu/hr

Table 3 Footnotes:

[a] Except as noted elsewhere in this permit, the information in this table is for identification purposes only. All of the fuel burning units listed in Table 3 are diesel-fired.

[b] While the Permittee based their application on the Nordic Rig #3, the actual Workover Rigs may be similar or smaller than the Nordic Rig #3 (i.e., the selected Workover Rigs may have fewer and/or smaller emission units).

4. Label each emission unit listed in Table 1 with the Emission Unit ID within 30 days of installing the emission unit. Place the ID in a conspicuous location on or adjacent to the unit.

5. For each combustion unit listed in Table 1, submit to the Department's Fairbanks Office the following information within 30 days of installing the emission unit:

5.1 actual installation date;

5.2 serial number, model number; and

5.3 vendor specification sheet.

6. For Emission Units 1, 2, 32, and 33:

6.1 submit to the Department's Fairbanks Office the emission and fuel control settings (as provided by the vendor) within 30 days of installing each emission unit. If subsequent changes to the emission and fuel control settings are later deemed necessary, provide the revised settings and the reason for the revision in the operating report submitted under Condition 31 for that operating period.

6.2 construct the stacks with:

a. sampling ports that comport with 40 CFR 60, Appendix A, Method 1, Section 2.1, and stack or duct *free of cyclonic flow* at the port location during the applicable test methods and procedures,

b. safe access to sampling ports, and

c. utilities for emission sampling and testing equipment.

7. For Emission Units 3, 47, 49, 50, 66 through 68, 72 and 73 submit to the Department's Fairbanks Office the emission and fuel control settngs (as provided by the vendor) within 30 days of installing the emission unit. Include for Department approval NO_X and CO emission factors representing the maximum capacity of each emission unit to emit these pollutants in accordance with Conditions 13.1b and 14.1b. If subsequent changes to the emission and fuel control settings are later deemed necessary, provide the revised settings and the reason for the revision in the operating report submitted under Condition 31 for that operating period.

8. Prior to the start of production well drilling or upon subsequent revisions to the emission unit inventory of the selected Drilling Rig, submit to the Department's Fairbanks Office:

8.1 the name of the selected Drilling Rig (e.g., Nabors 245E);

8.2 an emission unit inventory listing each combustion unit in the Drilling Rig, along with the make/model and rating of each combustion unit;

8.3 the cumulative capacity of the Drilling Rig engines;

8.4 the cumulative capacity of the Drilling Rig boilers/heaters; and

8.5 a statement as to whether the selected Drilling Rig complies with Condition 2.2.

Section 2 State Emission Standards

9. **Industrial Process and Fuel-Burning Equipment Visible Emissions.** Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from Emission Units 1 through 4, 32, 33, 47, 49, 50, and 66 through 73, listed in Table 1, Emission Units 9 through 13 listed in Table 2, and Emission Units 23, 24 and 29 through 31 listed in Table 3 to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.

9.1 Verify the initial compliance of Emission Units 3, 4, 47, 49, 50, 66 through 68, 72 and 73, by either

a. obtaining a certified manufacturer guarantee that the emission unit will comply with the visible emission standard; or

b. conducting a Method 9 visible emission source test within 90 days of unit installation.

9.2 For each emission unit listed in Condition 9.1, attach a copy of the guarantee obtained under Condition 9.1a, or a copy of the survellance records developed under Conditions 9.1b, as applicable, to the operating report submitted under Condition 31 for the period that covers the 90^{th} day after unit installation.

9.3 Conduct all visible emission source tests in a manner consistent with Condition 32.

10. **Incinerator Visible Emissions.** The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, through the exhaust of Emission Unit 48 listed in Table 1 to reduce visibility by more than 20 percent averaged over any six consecutive minutes.

11. **Industrial Process and Fuel-Burning Equipment Particulate Matter.** The Permittee shall not cause or allow particulate matter emitted from Emission Units 1 through 4, 32, 33, 47, 49, 50, and 66 through 73, listed in Table 1, Emission Units 9 through 13 listed in Table 2, and Emission Units 23, 24 and 29 through 31 listed in Table 3 to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.

12. **Sulfur Compound Emissions.** The Permittee shall not cause or allow sulfur compound emissions, expressed as SO_2, from Emission Units 1 through 4, 32, 33, 47, 49, 50, and 66 through 73, listed in Table 1, Emission Units 9 through 13 listed in Table 2, and Emission Units 23, 24 and 29 through 31 listed in Table 3 to exceed 500 ppm averaged over three hours.

Section 3 Requirements to Avoid PSD Classification

13. **CO Limits:**

13.1 To avoid classification as a PSD major stationary source, the Permittee shall limit the CO emissions from Emission Units 1 through 4, 9 through 13, 23, 24, 29 through 31, 32, 33, 47, 49, 50, and 66 through 73 to no greater than 225 tons per 12 month rolling period.[5] Monitor and record as follows:

a. For Emission Units 1, 2, 32 and 33 (CO Group A):

(i) Capture the *sixty second average load* (in percent of full-load) and the *sixty second average inlet air temperature* (in degrees Fahrenheit) for each unit during all periods of operation. Record for each calendar day, the minimum *sixty second average load* (in percent of full-load) and the minimum *sixty second average inlet air temperature* (in degrees Fahrenheit). Data capture and recording may be electronic.

(ii) Except as noted below, round the *sixty second average load* up to the next highest load and round the *sixty second average inlet air temperature* down to the next lowest inlet air temperature presented in Table 8 of Appendix A. Consider all *sixty second average loads* between 40% (inclusive) and 50% (exclusive), as 40% loads. Data rounding may be electronic.

(iii) Using the method described in Condition 13.1a(iv), determine the pounds of CO emitted during the sixty-second period for the given *sixty second average load* and *sixty second average inlet air temperature*, as rounded under Condition 13.1a(ii). For each hour, sum the sixty-second emissions to determine the hourly CO emissions (in pounds). Record the hourly CO emissions. Data selection and recording may be electronic.

(iv) When calculating the CO emissions under Condition 13.1a(iii), the Permittee must use either the lb/min CO values listed in Table 8 of Appendix A, or Department-approved substitute lb/min values derived from a Department-approved source test. Use one of the following

[5] During the initial 12 months of operation, the Permittee shall treat the cumulative operation to date as a substitute for the 12-month rolling period.

approaches if a parameter measured under Condition 13.1a is missing or suspect. Note which approach is used (if applicable) in the operating report submitted under Condition 31.

(A) If the *sixty second average load* is unknown or suspect, use the largest lb/min CO emissions in Table 8 (or the substitute worst-case lb/min value) for the given inlet air temperature.

(B) If the *sixty second average inlet air temperature* is unknown or suspect,

(1) use the largest lb/min CO emissions in Table 8 (or the substitute worst-case lb/min value) for the given load, or

(2) obtain the ambient temperature measured by the National Weather Service (NWS) at the Deadhorse Airport for each hour of missing inlet air temperature and use the NWS temperature in lieu of the inlet air temperature when calculating the pounds of CO under Condition 13.1a(iii).

(C) If the *sixty second average load* and the *sixty second average inlet air temperature* are both unknown or suspect, use 17.03 pounds (or the Department-approved substitute maximum lb/min value).

(v) By the 15th of each calendar month, calculate and record the *monthly CO emissions* (in pounds) for each unit by summing the CO emissions calculated in Condition 13.1a(iii) during the previous month. Calculation and recording may be electronic.

(vi) By the 15th of each calendar month, calculate and record the *cumulative monthly CO emissions* (in pounds) for CO Group A by summing all *monthly CO emissions* calculated in Condition 13.1a(v) for the previous calendar month. Calculation and recording may be electronic.

(vii) By the 15th of each calendar month, calculate and record the *Group A twelve month rolling CO emissions* (in tons) by summing the *cumulative monthly CO emissions* during the previous twelve months and dividing the sum by 2,000 (lb/ton). Calculation and recording may be electronic.

b. For Emission Units 3, 47, 49, 50, 66 through 68, 72, and 73 (CO Group B):

(i) Before initial start-up of each unit install a dedicated engine hour meter.

(ii) Calculate and record the *monthly CO emissions* (in pounds) of each unit using one of the following two methods. The same method does not need to be used for all units. Identify the method selected for each unit in the operating report submitted under Condition 31.

(A) Full Load Assumption Method

(1) For each calendar month, monitor and record the *total monthly hours of operation* of the unit.

(2) By the 15th of each calendar month, calculate the *monthly CO emissions* (in pounds) for the previous month by multiplying the *total monthly hours of operation* of each unit by a Department approved emission factor in units of pounds of CO per hour. If the *total monthly hours of operation* is unknown or suspect, use the total hours for that month.

(B) Hourly Load Tracking Method

(1) Install a dedicated electrical load meter on the unit.

(2) Monitor the *average electrical power* produced (in kilowatts) for each hour of operation of each unit. Record the number of hours each unit operated at that level, along with the *average electrical power*. The hours may be rounded up to the nearest whole integer, and recorded in sequential ranges of produced power. Data capture and recording may be electronic.

(3) By the 15th of each calendar month, determine the *monthly CO emissions* (in pounds) for each unit for the previous month by summing the CO emissions associated with each recorded level of power production. Calculate the CO emissions associated with each level by multiplying: the *average electrical power* (in kilowatts); the hours operated at that level during the previous month; and the Department approved CO emission factor in units of lb/kw-hr.

(iii) By the 15th of each calendar month, calculate and record the *cumulative monthly CO emissions* (in pounds) for CO Group B by summing the *monthly CO emissions* for Emission Units 3, 47, 49, 50, 66 through 68, 72, and 73 during the previous calendar month.

(iv) By the 15th of each calendar month, calculate and record the *Group B twelve month rolling CO emissions* (in tons) by summing the *cumulative monthly CO emissions* calculated in Condition 13.1b(iii) during the previous twelve months and dividing the sum by 2,000 (lb/ton).

c. For Emission Unit 4 (CO Group C):

(i) Monitor and record the volume of flared gas (in standard cubic feet) on a monthly basis.

(ii) By the 15th of each calendar month, calculate and record the *monthly CO emissions* (in pounds) by multiplying the *volume of flared gas* by 0.00047 (4.7×10^{-4}) lb/scf.

(iii) By the 15th of each calendar month, calculate and record the *Group C twelve month rolling CO emissions* (in tons) by summing the *cumulative monthly CO emissions* during the previous twelve months and dividing the sum by 2,000 (lb/ton).

d. For Emission Units 9 through 13, 23, 24, 29 through 31, and 69 through 71 (CO Group D):

(i) Determine and record the *monthly hours of operation* for each unit using one of the following two methods. The same method does not need to be used for all units.

Identify the method selected for each unit in the operating report submitted under Condition 31.

(A) Daily Operation Method

(1) For each calendar day, monitor and record whether the unit was operated.

(2) By the 15th of each calendar month, calculate the *monthly hours of operation* during the previous month by multiplying the days operated by 24 hours per day.

(B) Hourly Operation Method

(1) Monitor and record each startup and shutdown time.

(2) By the 15th of each calendar month, review the startup and shutdown times and determine the *monthly hours of operation*. Round portions of an hour up to the next whole hour or quarter hour fraction.

(ii) By the 15th of each calendar month, calculate and record the *monthly CO emissions* (in pounds) of each unit during the previous month by multiplying the unit's rating (in MMBtu/hr) by 0.043 lb/MMBtu and the *monthly hours of operation* determined under Condition 13.1d(i) for that month.

(iii) By the 15th of each calendar month, calculate and record the *cumulative monthly CO emissions* (in pounds) for CO Group D by summing the *monthly CO emissions* for Emission Units 9 through 13, 23, 24, 29 through 31, and 69 through 71 during the previous calendar month.

(iv) By the 15th of each calendar month, calculate and record the *Group D twelve month rolling CO emissions* (in tons) by summing the *cumulative monthly CO emissions* calculated in Condition 13.1d(iii) during the previous twelve months and dividing the sum by 2,000 (lb/ton).

e. By the 15th of each calendar month, calculate and record the *Total Twelve Month Rolling CO Emissions* (in tons) by adding the *Group A twelve month rolling CO emissions*, the *Group B twelve month* *rolling CO emissions,* the *Group C twelve month rolling CO emissions*, and *the Group D twelve month rolling CO emissions*.

13.2 Report, as described in Condition 30, if the *Total Twelve Month Rolling CO Emissions* (as calculated under Condition 13.1e) exceeds 225 tons per 12 month rolling period.

13.3 In each operating report submitted under Condition 31, report

a. For each month of the reporting period

(i) The range of inlet air temperatures recorded for each turbine (Emission Units 1, 2, 32, and 33) during the month, and

(ii) Any periods where the monitoring equipment / electronic algorithm required under Condition 13.1, was malfunctioning or inoperable (specify the malfunctioning/inoperable item with each period),

b. The *cumulative monthly CO* emissions for CO Group A, as calculated in Condition 13.1a(vi), for each month of the reporting period,

c. The *Group A twelve month rolling CO emissions*, as calculated in Condition 13.1a(vii), and

d. The *Total Twelve Month Rolling CO Emissions*, as calculated under Condition 13.1e, for each twelve month period covered by the operating report.

14. **NOx Limits:**

14.1 To avoid classification as a PSD major stationary source, the Permittee shall limit the NOx emissions from Emission Units 1 through 4, 9 through 13, 23, 24, 29 through 31, 32, 33, 47, 49, 50, and 66 through 73 to no greater than 225 tons per 12 month rolling period.[6] Monitor and record as follows:

a. For Emission Units 1, 2, 32 and 33 (NOx Group A):

(i) Using the method described in Condition 14.1a(ii), determine the pounds of NOx emitted during the sixty-second period for the given *sixty second average load* and

[6] During the initial 12 months of operation, the Permittee shall treat the cumulative operation to date as a substitute for the 12-month rolling period.

sixty second average inlet air temperature, as rounded under Condition 13.1a(ii). For each hour, sum the sixty-second emissions to determine the hourly NOx emissions (in pounds). Record the hourly NOx emissions. Data selection and recording may be electronic.

(ii) When calculating the NOx emissions under Condition 14.1a(i), the Permittee must use either the lb/min NOx values listed in Table 8 of Appendix A, or Department-approved substitute lb/min values derived from a Department-approved source test. Use one of the following approaches if a parameter measured under Condition 13.1a(i) is missing or suspect. Note which approach is used (if applicable) in the operating report submitted under Condition 31.

(A) If the *sixty second average load* is unknown or suspect, use the largest lb/min NOx emissions in Table 8 (or the substitute worst-case lb/min value) for the given inlet air temperature.

(B) If the *sixty second average inlet air temperature* is unknown or suspect,

(1) use the largest lb/min NOx emissions in Table 8 (or the substitute worst-case lb/min value) for the given load, or

(2) use the NWS temperature obtained under Condition 13.1a(iv)(B)(2) in lieu of the inlet air temperature when calculating the pounds of NOx under Condition 14.1a(i).

(C) If the *sixty second average load* and the *sixty second average inlet air temperature* are both unknown or suspect, use 0.78 pounds (or the Department-approved substitute value maximum lb/min value).

(iii) By the 15th of each calendar month, calculate and record the *monthly NOx emissions* (in pounds) for each unit by summing the NOx emissions calculated in Condition 14.1a(i) during the previous month. Calculation and recording may be electronic.

(iv) By the 15th of each calendar month, calculate and record the *cumulative monthly NOx emissions* (in pounds) for NOx

Group A by summing all *monthly NOx emissions* calculated in Condition 14.1a(iv) for the previous calendar month. Calculation and recording may be electronic.

(v) By the 15th of each calendar month, calculate and record the *Group A twelve month rolling NOx emissions* (in tons) by summing the *cumulative monthly NOx emissions* during the previous twelve months and dividing the sum by 2,000 (lb/ton). Calculation and recording may be electronic.

b. For Emission Units 3, 47. 49, 50, 66 through 68, 72 and 73 (NOx Group B):

(i) Calculate and record the monthly NOx emissions (in pounds) of each unit using one of the following two methods. The same method does not need to be used for all units. Identify the method selected for each unit in the operating report submitted under Condition 31.

(A) Full Load Assumption Method:

(1) For each calendar month, monitor and record the *total monthly hours of operation* of each unit (if not previously monitored and recorded under Condition 13.1b(ii)(A)(1)).

(2) By the 15th of each calendar month, calculate and record the *monthly NOx emissions* (in pounds) for the previous month by multiplying the *total monthly hours of operation*, of each unit as recorded under Condition 13.1b(ii)(A)(1), by a Department approved emission factor in units of NOx per hour. If the *total monthly hours of operation* is unknown or suspect, use the total hours for that month.

(3) Hourly Load Tracking Method

(4) Comply with Condition 13.1b(ii)(B)(1).

(5) Comply with Condition 13.1b(ii)(B)(2).

(ii) By the 15th of each calendar month, determine the *monthly NOx emissions* (in pounds) for each unit for the previous month by summing the NOx emissions associated with each recorded level of power production. Calculate the

NOx emissions associated with each level by multiplying: the *average electrical power* (in kilowatts); the hours operated at that level during the previous month; and the Department approved NOx emission factor in units of lb/kw-hr.By the 15th of each calendar month, calculate and record the *cumulative monthly* NOx *emissions* (in pounds) for NOx Group B by summing the *monthly* NOx *emissions* for Emission Units 3, 47, 49, 50, 66 through 68, 72, and 73 during the previous calendar month.

(iii) By the 15th of each calendar month, calculate and *record the Group B twelve month rolling NOx emissions* (in tons) by summing the *cumulative monthly NOx emissions* calculated in Condition 14.1b(ii) during the previous twelve months and dividing the sum by 2,000 (lb/ton).

c. For Emission Unit 4 (NOx Group C):

(i) By the 15th of ea*ch calendar month, calcu*late and record the *monthly NOx emissions* (in pounds) by multiplying the *volume of flared gas*, as recorded under Condition 13.1c(i), by 0.0000867 (8.67×10^{-5}) lb/scf.

(ii) By the 15th of ea*ch calendar month, calculate and record th*e *Group C twelve month rolling NOx emissions (in tons) by* summing the *cumulative monthly NOx emissions* during the previous twelve months and dividing the sum by 2,000 (lb/ton).

d. For Emission Units 9 through 13, 23, 24, 29 through 31, and 69 through 71 (NOx Group D):

(i) By the 15th of each calendar month, calculate and record the *monthly NOx emissions* (in pounds) of each unit by multiplying the unit's rating (in MMBtu/hr) by 0.17 lb/MMBtu and the *monthly hours of operation* determined in Condition 13.1d(i).

(ii) By the 15th of each calendar month, calculate and record the *cumulative monthly NOx emissions* (in pounds) for NOx Group D by summing the *monthly NOx emissions* calculated in Condition 14.1d(i) for Emission Units 9 through 13, 23, 24, 29 through 31, and 69 through 71 during the previous calendar month.

e. By the 15th of each calendar month, calculate and record the *Group D twelve month rolling NOx emissions* (in tons) by summing the *cumulative monthly NOx emissions* calculated in Condition 14.1d(ii) during the previous twelve months and dividing the sum by 2,000 (lb/ton).

f. By the 15th of each calendar month, calculate and record the *Total Twelve Month Rolling NOx Emissions* (in tons) by adding the *Group A twelve month rolling NOx emissions*, the *Group B twelve month rolling NOx emissions*, the *Group C twelve month rolling NOx emissions*, and *the Group D twelve month rolling NOx emissions*.

14.2 Report, as described in Condition 30, if the *Total Twelve Month Rolling NOx Emissions* (as calculated under Condition 14.1f) exceeds 225 tons per 12 month rolling period.

14.3 In each operating report submitted under Condition 31, report

a. the *cumulative monthly NOx* emissions for NOx Group A, as calculated in Condition 14.1a(iv), for each month of the reporting period,

b. the *Group A twelve month rolling NOx emissions*, as calculated in Condition 14.1a(v), and

c. the *Total Twelve Month Rolling NOx Emissions*, as calculated under Condition 14.1f, for each twelve month period covered by the operating report.

15. **Verification of Turbine Emission Factors**: Conduct a winter performance test on one of Emission Units 1, 2, 32 or 33 to verify the CO and NOx emission factors in Table 8. Use the performance test procedures described in Condition 32. For purposes of this condition, winter is defined as the period between December 1st and April 1st.

15.1 Conduct the winter performance test within the first year of starting either Unit 1 or 2 (whichever unit starts first).

15.2 Except as noted in Condition 15.3, conduct the tests at the following turbine load[7] and inlet temperature conditions:

a. Inlet temperature greater than $0^{o}F$, and 80% to 90% load;

b. Inlet temperature greater than $0^{o}F$, and load less than 50%;

[7] Percent load is defined as the actual output divided by the maximum output that could be produced by the turbine under the given operation conditions (e.g., inlet air temperature), times 100 (to convert from a fractional to percent format).

c. Inlet temperature less than 0^oF, and 80% to 90% load; and

d. Inlet temperature less than 0^oF, and load less than 50%.

15.3 If the weather conditions do not allow for an inlet temperature of less than 0^oF, substitute the following for Conditions 15.2c and 15.2d: Inlet temperature greater than 0^oF, and 60 to 70% load.

15.4 In the source test report submitted under Condition 32.4, compare the average CO concentrations (in parts per million by volume or ppmv) to the CO ppmv values listed Table 8 and the average NOx concentrations (in ppmv) to the NOx ppmv values listed in Table 8, for each load and inlet temperature condition tested under Condition 15.2. Propose for Department approval under Condition 33, revised lb/min emission factors for the entire table if the ppmv source test results exceed the ppmv values listed in Table 8. All testing and reporting must be consistent with the following requirements.

a. Use Method 19 of 40 CFR 60, or an alternative approach approved by the Department, for converting all ppmv values into lb/min values. Describe all assumptions (including the assumed standard conditions) and provide example calculations.

b. Express all NOx concentrations as NO_2.

c. For each individual test and test condition average, report the

(i) turbine inlet temperature,

(ii) the concurrent NWS temperature recorded at Deadhorse,

(iii) the produced eletrical power and percent load,

(iv) the NOx and CO concentrations in ppmv,

(v) the percent excess oxygen in the exhaust,

(vi) the exhaust volume flow rate and exhaust temperature,

(vii) the gas producer speed,

(viii) the equivalent NOx and CO mass emission rate (in lb/min),

(ix) whether inlet preheating was used, and

(x) whether the turbine was operating in or out of SoLoNOx mode.

d. Measure and report the heat content from a representative fuel sample.

e. Note in the source test report whether the turbine was operating under the same emission and fuel control settings provided in Condition 6.1. If not, provide the emission and fuel control settings used during the performance tests.

Section 4 Ambient Air Quality Protection Requirements

16. **General Ambient Air Quality Provisions.** Comply with the following provisions to protect the NO_2, SO_2 and PM-10 air quality standards:

16.1 **Air Quality Boundary:** Establish and maintain the ambient boundaries using the procedures described in Condition 17.

16.2 **Stack Configuration:**

a. For all fuel burning units authorized under Conditions 1, 2, and 3, construct and maintain each exhaust stack with uncapped, vertical outlets – flapper valves, or similar, are allowed for these units as long as they do not hinder the vertical momentum of the exhaust plume. Intermittent well servicing equipment rated at less than 400 bhp or 2.8 MMBtu/hr (as applicable), are exempt from this condition.

b. Construct and maintain the exhaust stack for each unit listed in Table 4 with a release height (above grade) that meets or exceeds the indicated height.

Table 4 – Minimum Stack Height Requirements

Emission Unit ID	Unit Description	Minimum Release Height Above Grade (m)
1, 2, 32 and 33	Gas Turbines	28.0
3and 47	Generators	10.7
9 – 12, 49 and 50	Drilling Rig heaters and boilers rated at or above 2.8 MMBtu/hr and Drilling Camp Generators	12.8
14 – 17	Drilling Rig engines rated at or above 400 bhp	14.8
26 – 28	Workover Rig engines rated at or above 400 bhp	11.6
31	Workover Rig heaters and boilers rated at or above 2.8 MMBtu/hr	9.1
66 – 68	Pump Engines	8.2
72 and 73	Grind and Inject Power Engines	9.8

c. Provide as-built drawings and/or photographs of each exhaust stack subject to Conditions 16.2b in the first operating report submitted under Condition 31.

16.3 **On-Site Housing:** If providing on-site housing follow the procedures described in Condition 18.

17. **Public Access Control Plan.** Establish and maintain the ambient air boundaries as follows:

17.1 Comply with the provisions contained in the October 21, 2009 "Nikaitchuq Project Public Access Control Plan" (as provided in Appendix B), or a subsequent written version approved by the Department that contains at least the following elements:

a. a scaled map that clearly shows the ambient air boundaries, coast line, spill response boat ramp, Kuparuk Seawater Treatment Plant, Oliktok Road, and warning sign locations;

b. ambient boundaries that are consistent with the land owner's authorization to preclude public access from the area within the boundaries;

c. defined methods of establishing and maintaining the boundary, such as surveillance and posting of strategically located warning signs (provide size, wording, and inspection/repair schedule);

d. the date of the Public Access Control Plan; and

e. the procedure for approaching unauthorized people who have crossed the ambient air boundary.

17.2 Post and maintain all warning signs described in the Public Access Control Plan as follows:

a. post all signs as stated in the Public Access Control Plan;

b. use a font, font size and contrast coloring that makes all lettering easy to read;

c. inspect and repair the signs according to the schedule described in the Public Access Control Plan; and

d. keep all signs free of nearby visibile obstructions (including wind-blown snow).

18. Comply with the provisions contained in the November 3, 2009 "Eni Local Policy" (as provided in Appendix C), or a subsequent written version approved by the Department that contains at least the following elements:

18.1 a statement specifying that the worker housing area is for offical businees/worker use only; and

18.2 a statement specifying that the on-site workers are on 24 hour call.

19. **Annual Average NO_2 and SO_2Ambient Air Quality Protection:** Protect the Annual Average NO_2 and SO_2 ambient air quality standards by:

19.1 Limiting the operation of Emission Units 3, 20, 25, 47, 49, 50, 66 through 68, 72, and 73 to the limits listed in Table 5

a. Installing a dedicated engine hour meter on each emission unit listed in Table **5**.

b. For each calendar month, monitor and record the total hours of operation during the month of each emission unit listed in Table 5.

c. By the 15th of each calendar month, calculate and record the cumulative hours of operation during the previous twelve months for each emission unit listed in Table 5. During the intial twelve months of operation, use the operating period to date as a substitute for the twelve month period.

d. Report the hours recorded under Conditions 19.1b and 19.1c with the operating report required under Condition 31.

Table 5 – Annual Operating Limits

Emission Unit ID	Unit Description	Operating Limit (hours/year)
3 and 47	Generators	500 *each*
20	Manitowoc Crane	4,380
25	Vibration Hammer	252
49 and 50	Generators	1,895 *each*
66	Pump Engine	2,767
67	Pump Engine	1,456
68	Pump Engine	1,258
72 and 73	Grind and Inject Engines	6,214 *combined*

19.2 Limiting the operation of Emission Units 23 and 24 to the limits listed in Table 6

a. Monitor and record the startup and shutdown times of each emission unit listed in Table 6..

b. For each calendar month, determine the monthly hours of operation of each emission unit listed in Table 6 by reviewing the startup and shutdown times.

c. By the 15th of each calendar month, calculate and record the cumulative hours of operation during the previous twelve months for each emission unit listed in Table 6. During the intial twelve months of operation, use the operating period to date as a substitute for the twelve month period.

d. Report the hours recorded under Conditions 19.2b and 19.2c with the operating report required under Condition 31.

Table 6 – Annual Operating Limits

Emission Unit ID	Unit Description	Operating Limit (hours/year)
23	Heater	816
24	Heater	2,000

19.3 Limiting the operation of the Workover Rig to 55 days per consecutive twelve month period

a. For each calendar month in which the Workover Rig is on site, monitor and record the total days of operation during the month – days of operation includes movement between wellheads, but does not include transportation to and from the Nikaitchuq onshore and offshore pads.

b. By the 15th of each calendar month, calculate and record the cumulative days of operation during the previous twelve months. During the intial twelve months of operation, use the operating period to date as a substitute for the twelve month period.

c. Report the days recorded under Conditions 19.3a and 19.3b in the operating report required under Condition 31, for each month covered by the reporting period.

20. **Annual, 24-hr, and 3-hr Average SO_2 Ambient Air Quality Protection:** Protect the Annual, 24-hr and 3-hr Average SO_2 ambient air quality standards as follows:

20.1 For Emission Units 1, 2, 4, 32 and 33, burn only natural gas with a hydrogen sulfide content that does not exceed 250 ppmv (on an instantaneous basis at standard conditions).

a. Monitor compliance monthly using ASTM D 4810-88, D 4913-89, or Gas Producers Association 2377-86, or an alternative analytical method approved by the Department.

b. Keep records of the monitoring conducted under Condition 20.1a for five years. The records may be kept in electronic format.

c. Report the results of the monitoring conducted under Condition 20.1a during the applicable reporting period, in the operating report submitted under Condition 31.

20.2 Limit the fuel sulfur content of liquid fuel burned to the fuel sulfur limits listed in Table **7**.

Table 7 – Liquid Fuel Sulfur Limits

Emission Unit ID	Unit Description	Fuel Sulfur Limit (weight percent sulfur)
Drilling Rig operating at the onshore pad	Engines, boilers and heaters	0.30
Drilling Rig operating at the offshore pad	Engines, boilers and heaters	0.0015 (Ultra Low Sulfur Diesel fuel or ULSD)
Workover Rig	Engines, boilers and heaters	ULSD
3	Generator	ULSD
19 through 25	Cranes, boilers/heaters, and vibration hammer	ULSD
47, 49 and 50	Generators	ULSD
66 through 68	Pump Engines	ULSD
69 through 73	Engines and boilers	0.30
N/A	Intermittently used oil field service equipment rated at less than 400 hp or 2.8 MMBtu/hr.	ULSD

a. For each shipment of fuel consumed in any emission unit listed in Table **7** required to burn fuel with a maximum sulfur content of 0.0015 percent by weight

(i) if the fuel grade requires a sulfur content less than or equal to 0.0015 percent by weight, keep receipts that specify fuel grade and amount; or

(ii) if the fuel grade does not require a sulfur content less than 0.0015 percent by weight,

(A) test the fuel sulfur content as indicated in Conditon 20.2b, or

(B) obtain test results showing the sulfur content of the fuel from the supplier or refinery; the test results must include a statement signed by the supplier or refinery of what fuel they represent.

b. Fuel testing under Condition 20.2a must follow an appropriate method listed in 18 AAC 50.035 or another method approved in writing by the Department.

c. For any emission units (except Drilling Rig) listed in Table **7** required to burn fuel with a maximum sulfur content of 0.0015 percent by weight.maintain a separate fuel tank(s) for those emission units and clearly label the fuel tank(s) for ULSD fueling only.

d. Clearly label the Drilling Rig fuel tank(s) for ULSD fueling only while operating at the offshore pad.

e. For each shipment of fuel consumed in any emission unit listed in Table **7** required to burn fuel with a maximum sulfur content of 0.30 percent by weight

(i) if the fuel grade requires a sulfur content less than or equal to 0.30 percent by weight, keep receipts that specify fuel grade and amount; or

(ii) if the fuel grade does not require a sulfur content less than 0.30 percent by weight,

(A) test the fuel sulfur content as indicated in conditon 20.2f, or

(B) obtain test results showing the sulfur content of the fuel from the supplier or refinery; the test results must include a statement signed by the supplier or refinery of what fuel they represent.

f. Fuel testing under Condition 20.2e must follow an appropriate method listed in 18 AAC 50.035 or another method approved in writing by the Department.

g. Report under Condition 31 the fuel sulfur content of the fuel consumed in the emission units listed in Table **7**.

h. Report as a permit deviation under Condition 30 if the fuel sulfur content of the fuel consumed in any emission unit listed in Table **7** exceeds the fuel sulfur limit for that emission unit listed in Table **7**.

i. Prior to the Drilling Rig beginning operation at the offshore pad

(i) Drain the Drilling Rig fuel tank(s) and fuel line(s).

(ii) Flush the Drilling Rig fuel tank(s) and fuel line(s) with fuel with a maximum suflur content of 0.0015 weight percent sulfur.

(iii) Include in the reports required in 21.1c the dates the Drilling Rig fuel tank(s) and line(s) were drained and flushed with fuel with a maximum suflur content of 0.0015 weight percent sulfur.

21. **24-hr Average SO_2 and PM-10 Ambient Air Quality Protection:** Protect the 24-hr Average SO_2 and PM-10 ambient air quality standards as follows:

21.1 Except as noted below, do not operate any intermittent well servicing equipment concurrently with the Drilling Rig at the same pad. The exceptions (which may be operated at either pad at any time) include:

a. Emission Units 19, 20, 23; 24 and 25; and

b. Intermittent well servicing equipment with a rating smaller than:

(i) 400 bhp for internal combustion engines, and

(ii) 2.8 MMBtu/hr for boilers and heaters.

c. Report in each operating report required in Condition 31 a summary of drilling operations that were covered by this permit during the reporting period. Such summaries must indicate, for the Drilling Rig and intermittent well service equipment, the location and dates of operation of each activity that occurred or is occurring during the reporting period.

Section 5 Miscellaneous

22. **Assessable Emissions**.

22.1 The Permittee shall pay to the Department annual emission fees based on the stationary source's assessable emissions as determined by the Department under 18 AAC 50.410. The assessable emission fee rate is set out in 18 AAC 50.410. The Department will assess fees per ton of each air pollutant that the stationary source emits or has the potential to emit in quantities greater than 10 tons per year. The quantity for which fees will be assessed is the lesser of:

a. the stationary source's assessable potential to emit of 670 tpy; or

b. the stationary source's 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 Department, when demonstrated by:

(i) an enforceable test method described in 18 AAC 50.220;

(ii) material balance calculations;

(iii) emission factors from EPA's publication AP-42, Vol. I, adopted by reference in 18 AAC 50.035; or

(iv) other methods and calculations approved by the Department**.**

23. **Assessable Emission Estimates.**

23.1 Emission fees will be assessed as follows:

a. no later than March 31 of each year, the Permittee may submit an estimate of the stationary source's assessable emissions to ADEC, Air Permits Program, ATTN: Assessable Emissions Estimate, 410 Willoughby Ave., p.o. Box 111800 Juneau, AK 99811-1800; the submittal must include all of the assumptions and calculations used to estimate the assessable emissions in sufficient detail so the Department can verify the estimates; or

b. 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 forth in Condition 22.1a.

General Record Keeping, Reporting, and Compliance Requirements

24. **Good Air Pollution Control Practice**. Maintain and operate Emission Units 1 through 4 according to the manufacturer recommendations or the operator's operation and maintenance procedures. Keep a copy of either the manufacturer's or the operator's procedures on-site.

25. **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. **Monitoring, Record Keeping, and Reporting for Air Pollution Prohibited.**

26.1 If emissions present a potential threat to human health or safety, the Permittee shall report any such emissions according to Condition 30.

26.2 As soon as practicable after becoming aware of a complaint that is attributable to emissions from the facility, the Permittee shall investigate the complaint to identify emissions that the Permittee believes have caused or are causing a violation of Condition 25.

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:

a. after an investigation because of a complaint or other reason, the Permittee believes that emissions from the facility have caused or are causing a violation of Condition 25; or

b. the Department notifies the Permittee that it has found a violation of Condition 25.

26.4 The Permittee shall keep records of the following:

a. the date, time and nature of all emissions complaints received;

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

c. a summary of any investigation, including reasons the Permittee does or does not believe the emissions have caused a violation of Condition 25; and

d. any corrective actions taken or planned for complaints attributable to emissions from the facility.

26.5 With each operating report under Condition 31, the Permittee shall include a brief summary report which must include the following:

a. the number of complaints received;

b. the number of times the Permittee or the Department found corrective action necessary;

c. the number of times action was taken on a complaint within 24 hours; and

d. the status of corrective actions the Permittee or Department found necessary that were not taken within 24 hours.

26.6 The Permittee shall notify the Department of a complaint that is attributable to emissions from the facility within 24 hours after receiving the complaint, unless the Permittee has initiated corrective action within 24 hours of receiving the complaint.

27. **Certification.** The Permittee shall certify any permit application, report, affirmation, or compliance certification submitted to the Department and required under the permit by including the signature of a responsible official for the permitted stationary source following the statement: *"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."* Excess emission reports must be certified either upon submittal or with an operating report required for the same reporting period. All other reports and other documents must be certified upon submittal.

27.1 The Department may accept an electronic signature on an electronic application or other electronic record required by the Department if

a. a certifying authority registered under AS 09.25.510 verifies that the electronic signature is authentic; and

b. the person providing the electronic signature has made an agreement, with the certifying authority described in Condition 27.1a, that the person accepts or agrees to be bound by an electronic record executed or adopted with that signature.

28. **Submittals.** Unless otherwise directed by the Department or this permit, the Permittee shall send an original and one copy of reports, compliance certifications, and other submittals required by this permit to ADEC, Air Permits Program, 610 University Ave., Fairbanks, AK 99709-3643, ATTN: Compliance Technician. The Permittee may, upon consultation with the Compliance Technician regarding software compatibility, provide electronic copies of data reports, emission source test reports, or other records under a cover letter certified in accordance with Condition 27.

29. **Information Requests.** The Permittee shall furnish to the Department, within a reasonable time, any information the Department 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 to the Department copies of records required to be kept by the permit. The Department may require the Permittee to furnish copies of those records directly to the federal Administrator.

30. **Excess Emissions and Permit Deviation Reports.**

30.1 Except as provided in Condition 25, the Permittee shall report all emissions or operations that exceed or deviate from the requirements of this permit as follows:

a. in accordance with 18 AAC 50.240(c), as soon as possible after the event commenced or is discovered, report:

(i) emissions that present a potential threat to human health or safety; and

(ii) excess emissions that the Permittee believes to be unavoidable.

b. in accordance with 18 AAC 50.235(a), within two working days after the event commenced or was discovered, report an unavoidable emergency, malfunction, or nonroutine repair that causes emissions in excess of a technology based emission standard;

c. report all other excess emissions and permit deviations:

(i) within 30 days of the end of the month in which the emissions or deviation occurs, except as provided in Condition 30.1c(ii); and

(ii) if a continuous or recurring excess emissions is not corrected within 48 hours of discovery, within 72 hours of discovery unless the Department provides written permission to report under Condition 30.1c(i).

30.2 When reporting excess emissions or permit deviations, the Permittee must report using either the Department's on-line form, which can be found at http://www.dec.state.ak.us/air/ap/site.htm or https://myalaska.state.ak.us/deca/air/airtoolsweb/, or if the Permittee prefers, the form contained in Appendix D of this permit. The Permittee must provide all information called for by the form that is used.

30.3 If requested by the Department, the Permittee shall provide a more detailed written report as requested to follow up an excess emissions report.**Operating Reports.** During the life of this permit the Permittee shall submit to the Department an original and one copy of an operating report by August 1 for the period January 1 to June 30 of the current year and by February 1 for the period July 1 to December 31 of the previous year.

31.1 The operating report must include all information required to be in operating reports by other conditions of this permit. The Permittee may, upon consultation with the Compliance Technician regarding software compatibility, provide electronic copies of data reports, emission source test reports, or other records under a cover letter certified in accordance with Departmental submission requirements

31.2 If excess emissions or permit deviations that occurred during the reporting period are not reported under Condition 31.1, either

a. The Permittee shall identify

(i) the date of the deviation;

(ii) the equipment involved;

(iii) the permit condition affected;

(iv) a description of the excess emissions or permit deviation; and

(v) any corrective action or preventive measures taken and the date of such actions; or

b. When excess emissions or permit deviations have already been reported under Condition 30 the Permittee shall cite the date or dates of those reports.

32. **Verification (Source) Test Requirements**: The Permittee shall conduct the verification (source) testing required or allowed by this permit as follows:

32.1 Use the applicable test methods set out in 40 CFR Part 60, Appendix A. The Permittee may propose alternative test methods if it can be shown to be of equivalent accuracy, and will ensure compliance with the applicable standards or limits. Alternative test procedures must be approved by the Department prior to the test date.

a. Nitrogen Oxides, NOx, expresses as NO_2 (ppm and lb/hr): Reference Method 7E or Method 20.

b. Carbon Monoxide, CO (ppm and lb/hr): Reference Method 10.

c. Oxygen, O_2 (percent): Reference Method 3 or 3A.

d. Stack Velocity and Volumetric Flow Rate: Reference Methods 1-4.

e. Visible Emissions: Reference Method 9.

32.2 Submit to the Department at least 30 days before the scheduled date of the tests, a complete plan for conducting the source tests. The Permittee need not submit this plan for a visible emissions source test conducted under Condition 9.1b.

32.3 Give the Department written notice of the test dates 10 days before each series.

32.4 Within 60 days after completion of the set of tests, submit the results, to the extent practical, in the format set out in *Source Test Report Outline* in Volume III, Section IV.3, of the State Air Quality Control Plan, adopted by reference in 18 AAC 50.030(8). Include all information required under Condition 15.4, if applicable.

33. **Procedure for Revised Emission Factors**: All requests for revised emission factors must be submitted by the Permittee in writing, and will be considered as a permit modification under AS 46.14.285(a)(3).

33.1 All requests to *increase* emission factors, will be treated as a permit amendment. If approved, the Department will issue a written amendment, but will not reopen the permit for public comment.

33.2 All requests to *decrease* emission factors will be treated as an application to revise or rescind the terms and conditions of a Title I permit under 18 AAC 50.508(6).

Terms to Make Permit Enforceable

34. The Permittee must comply with each permit term and condition. Noncompliance with a permit term or condition constitutes a violation of AS 46.14, 18 AAC 50, and, except for those terms or conditions designated in the permit as not federally enforceable, the Clean Air Act, and is grounds for

34.1 an enforcement action; or

34.2 permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280.

35. 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.

36. Each permit term and condition is independent of the permit as a whole and remains valid regardless of a challenge to any other part of the permit.

37. The permit may be modified, reopened, revoked and reissued, or terminated for cause. 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.

38. The permit does not convey any property rights of any sort, nor any exclusive privilege

39. The Permittee shall allow the Department or an inspector authorized by the Department, upon presentation of credentials and at reasonable times with the consent of the owner or operator to

    39.1 enter upon the premises where an emission unit subject to the permit is located or where records required by the permit are kept;

    39.2 have access to and copy any records required by the permit;

    39.3 inspect any stationary source, equipment, practices, or operations regulated by or referenced in the permit; and

    39.4 sample or monitor substances or parameters to assure compliance with the permit or other applicable requirements.

Section 6 Permit Documentation

May 5, 2006	Permit No. AQ0923MSS01 Technical Analysis Report.
April 9, 2009	Minor permit application submitted by Eni for the Nikaitchuq Development.
October 21, 2009	Minor permit application addendum submitted by Eni for Nikaitchuq Development containing revised Public Access Control Plan and turbine emission factors spreadsheet.
November 6, 2009	Minor permit application addendum submitted by Eni for Nikaitchuq Development containing revised Eni Working Times and Hours Policy document and emission calculations spreadsheet.
December 9, 2009	Minor permit application addendum submitted by Eni for Nikaitchuq Development containing AERMET Stage 3 modeling files.
December 14, 2009	Minor permit application addendum submitted by Eni for Nikaitchuq Development containing BPIP modeling files.
December 18, 2009	Minor permit application addendum submitted by Eni for Nikaitchuq Development containing revised modeling files.

Appendix A – Solar Taurus Emission Factors

Table 8 – Solar Taurus NO_X and CO Emission Factors

10% load				
Ambient Temperature	**NOx (ppm)**	**NOx (lb/min)**	**CO (ppm)**	**CO (lb/min)**
60	54	0.10	9600	11.25
30	54	0.11	9600	11.52
0	54	0.11	9600	11.87
-20	120	0.25	9600	12.03
-60	120	0.26	9600	12.67
20% load				
Ambient Temperature	**NOx (ppm)**	**NOx (lb/min)**	**CO (ppm)**	**CO (lb/min)**
60	58	0.13	9200	12.50
30	58	0.13	9200	12.95
0	58	0.14	9200	13.38
-20	120	0.29	9200	13.70
-60	120	0.31	9200	14.37
30% load				
Ambient Temperature	**NOx (ppm)**	**NOx (lb/min)**	**CO (ppm)**	**CO (lb/min)**
60	62	0.16	8800	13.62
30	62	0.16	8800	14.15
0	62	0.17	8800	14.70
-20	120	0.34	8800	15.03
-60	120	0.35	8800	15.75
40% load				
Ambient Temperature	**NOx (ppm)**	**NOx (lb/min)**	**CO (ppm)**	**CO (lb/min)**
60	66	0.19	8400	14.55
30	66	0.20	8400	15.20
0	66	0.20	8400	15.78
-20	120	0.38	8400	16.22
-60	120	0.40	8400	17.03
50% load				
Ambient Temperature	**NOx (ppm)**	**NOx (lb/min)**	**CO (ppm)**	**CO (lb/min)**
60	15	0.05	25	0.06
30	15	0.05	25	0.06
0	15	0.06	25	0.07
-20	42	0.16	100	0.28

-60	120	0.51	150	0.46
60% load				
Ambient Temperature	**NOx (ppm)**	**NOx (lb/min)**	**CO (ppm)**	**CO (lb/min)**
60	15	0.05	25	0.05
30	15	0.06	25	0.06
0	15	0.06	25	0.06
-20	42	0.18	100	0.26
-60	120	0.56	150	0.43
70% load				
Ambient Temperature	**NOx (ppm)**	**NOx (lb/min)**	**CO (ppm)**	**CO (lb/min)**
60	15	0.06	25	0.06
30	15	0.06	25	0.06
0	15	0.07	25	0.07
-20	42	0.20	100	0.29
-60	120	0.62	150	0.47
80% load				
Ambient Temperature	**NOx (ppm)**	**NOx (lb/min)**	**CO (ppm)**	**CO (lb/min)**
60	15	0.06	25	0.06
30	15	0.07	25	0.07
0	15	0.07	25	0.07
-20	42	0.21	100	0.31
-60	120	0.66	150	0.51
90% load				
Ambient Temperature	**NOx (ppm)**	**NOx (lb/min)**	**CO (ppm)**	**CO (lb/min)**
60	15	0.07	25	0.07
30	15	0.07	25	0.07
0	15	0.08	25	0.08
-20	42	0.23	100	0.33
-60	120	0.72	150	0.54
100% load				
Ambient Temperature	**NOx (ppm)**	**NOx (lb/min)**	**CO (ppm)**	**CO (lb/min)**
60	15	0.07	25	0.07
30	15	0.08	25	0.08
0	15	0.09	25	0.09
-20	42	0.25	100	0.36
-60	120	0.78	150	0.60

Appendix B – Public Access Control Plan (October 21, 2009)

Nikaitchuq Project Public Access Control Plan

ENI US Operating Co. Inc.
October 21, 2009

Purpose

This Public Access Control Plan for the Nikaitchuq Project is designed to protect the general public from health and safety hazards that could occur as a result of heavy industrial work during well drilling, work-over activities, and crude oil production at Nikaitchuq. ENI US Operating Co. Inc. (ENI) has established these reasonable restrictions on general public access to ensure adequate protection of public health and welfare.

ENI is committed to fully and adequately protecting the health and safety of its work force by remaining within the standards for air exposure of the Occupational Safety and Health Administration (OSHA) and, where the general public has access, the National and Alaska Ambient Air Quality Standards (AAQS). The primary purpose of this plan is to delineate the area to be protected and controlled for occupational health and safety from the area that is subject to unrestricted, general public access where the AAQS are applicable. By limiting access to Nikaitchuq to ENI authorized personnel, ENI will reduce the chance that a member of the general public will be injured or otherwise impacted by ENI operations.

This plan ensures that reasonable measures are in place to accomplish reasonable restrictions on public access.

General Information

ENI is planning to construct an oil production facility and conduct production well drilling and development from a 600 foot by 600 gravel pad constructed on Oliktok Point (see Figure 1). ENI is also planning to construct a gravel Island approximately 3.5 miles north of the Oliktok Point Processing Facility to drill and install wells. The island will be approximately 630 feet wide and 830 feet long. ENI will restrict access to both the on-shore production facility and the off-shore gravel island to ENI authorized personnel for health and safety and property control reasons. As a result, the ambient air boundary is marked by the edge of the gravel production pad and the off-shore gravel island with signs and reflective boundary markers that will delineate the controlled area. This is consistent with other ambient air boundary selections that have been made for similar facilities and circumstances on the North Slope. To accommodate the required safety zone for the processing facility safety flare, a gravel triangle will be constructed on the south side of the pad that will extend some portions of the on-shore gravel pad up to 170 feet to the south.

Drilling, crude oil production and three-phase fluid processing will be conducted on the on-shore gravel pad. Drilling and crude oil production will occur on the off-shore gravel island. Three phase fluid that is produced from the off-shore gravel island will be shipped via pipeline to the Oliktok Point Processing Facility. Once development drilling and construction is completed on the off-shore gravel island, the island will be unoccupied with the exception of occasional maintenance activities. Operations on the off-shore gravel island will be monitored and controlled from the Oliktok Point Processing Facility. Remote monitoring systems will be installed on the off-shore gravel island to detect the presence of unauthorized personnel on the off-shore gravel island. Public access will be restricted at the edge of the of the gravel pad at both the Oliktok Point Processing Facility and the off-shore gravel island.

The ambient boundary for the Oliktok Point Processing Facility will be marked on the east side by the west edge of the Oliktok road that provides access to the Kuparuk Seawater Treatment Plant (KSTP). The edge of the processing facility gravel pad will mark the north, south, and west ambient boundaries. Ambient air quality receptors were modeled on the Oliktok road and on the processing facility pad boundaries, the modeled concentrations on the Oliktok road and the processing facility pad boundaries show ambient air concentrations below the AAQS. Ambient air quality receptors were also modeled on the toe of the off-shore gravel island facility and the modeled concentrations on the toe of off-shore gravel island were also below the AAQS.

ENI will also establish a second boundary to ensure public safety during flaring by keeping the public a safe distance from the flare at all times. The safe distance from the flare is a semi-circle with a 170 foot radius centered on the extreme southern edge of the pad extension that contains the flare.

The ambient boundary for the off-shore gravel island will be marked along the edge of the off-shore gravel island and the ocean. The top of the off-shore gravel island is approximately 18 feet above sea level.

<u>Public Access Control Measures</u>

The Oliktok Point Processing Facility is located on Oliktok Point, which is a peninsula that is surrounded on three sides by the Beaufort Sea and is located within the Kuparuk River Unit (KRU). The KRU is controlled and operated by Conoco-Philips Alaska Incorporated (CPAI). Access to the KRU is controlled by CPAI. The only access to the Oliktok Point Processing Facility is from the south via the Oliktok Rd. Personnel are not allowed to travel to Oliktok Point without first obtaining permission from CPAI.

Personnel traveling to the KSTP will travel on the Oliktok Rd. passing east of the Oliktok Point Processing Facility. Personnel traveling to the KSTP will not need to cross or access the Oliktok Point Processing Facility in order to access the KSTP. KSTP personnel will not be allowed to enter the Oliktok Point Processing Facility without first obtaining permission from the operator of the Oliktok Point Processing Facility. As a practical matter, few people are likely to visit or traverse the area in which Nikaitchuq development and crude oil production will be located. However, road access by personnel without permission from CPAI to be in the area is possible. As a result several measures will be implemented to reasonably ensure that unauthorized personnel do not access the Oliktok Point Processing Facility. These measures include:

1. Signs;
2. Pad boundary markers;
3. Education and training; and
4. Pad surveillance and exclusion.

The above listed measures will also be used to ensure that unauthorized personnel do not access the off-shore gravel island, although the probability of unauthorized access to the gravel island is even less likely then the Oliktok Processing Facility. Details about the public access control measures are presented below.

Signs

To notify unauthorized personnel that they may not access the Oliktok Point Processing Facility or the gravel pad, bilingual signs (in English and Inupiaq) will be posted at strategic locations, as follows:

- On the northeast, northwest, southeast, and southwest corners of the Oliktok Point Processing Facility and the off-shore gravel pad;
- At designated points of ingress and egress from the Oliktok Point Processing Facility; two ingress and egress points are planned, both on the eastern pad edge from the Oliktok Rd; and
- At the base of the two access ramps to the off-shore gravel island.

The sign specifications are:

- Each sign will be 4 feet by 6 feet and will be supported by sawhorse or pallet post with sandbags.
- Each sign will be written in English and Inupiat.
- Each sign will be inspected regularly and will be repaired or replaced, as necessary.
- Each sign will be free of visible obstructions.
- Each sign will read:

ENI US Operating Co. Inc.
DANGER
UNAUTHORIZED PERSONNEL KEEP OUT
If access is requested,
contact the Oliktok Point Processing Facility Operator
Phone (907) xxx-xxxx

(The Inupiaq translation will be below the English sign restriction)

Pad Boundary Markers

In addition to the warning signs, reflective, boundary markers will be placed along the eastern production pad border between the Oliktok Rd. and the Oliktok Point Processing Facility. Reflective markers will also be placed along the northern edge of the Oliktok Point Processing Facility pad separating it from the adjacent STP pad. In order to distinguish the pad boundary markers from the reflective road edge markers that are used on the North Slope, the Oliktok Point Processing Facility boundary markers will be spaced at approximately fifty percent of the spacing that is normally used for road edge markers on the North Slope.

Education and Training

To work in or access the KRU, all personnel must have completed or be escorted by someone with eight hours of North Slope safety training. One rule that is emphasized in the training for North Slope workers is to be present only in locations where they are authorized to be. North Slope workers that are present at sites where they are not authorized are subject to discipline up to and including termination of employment. Additionally, during their local orientation training ENI workers and ENI contractors that will be working at the Oliktok Point Processing Facility and the gravel island will be made aware of this Public Access Control plan and that if they notice unauthorized personnel at the Oliktok Point Processing Facility or the gravel island that they should notify appropriate personnel that an unauthorized person or persons are in Oliktok Point Processing Facility or the gravel pad.

Pad Boundary Surveillance

Unless prohibited by adverse weather conditions or similar safety related circumstances, the Oliktok Point Processing Facility and the gravel boundary will be formally checked at least twice a day. During these checks of the pad boundary the inspector will check the following items:

1. The presence or indications of the presence, of unauthorized personnel within the Oliktok Point Processing Facility boundary;
2. That the pad boundary warning signs are clear of obstructions such as snow and are still standing. If possible, the inspector will fix sign problems when they are discovered; and
3. That the reflective pad boundary markers that delineate the northern and eastern pad boundaries are in place and are intact. If possible, the inspector will fix problems with the reflective pad boundary markers when they are discovered.

In addition to the formal pad inspections, all ENI personnel and ENI contractors will be responsible for maintaining Oliktok Point Processing Facility and gravel island boundary integrity. When ENI personnel or ENI contractors notice either unauthorized persons within the pad boundary or conditions that compromise the integrity of the pad boundary, they are required to either correct the situation or notify Oliktok Point Processing Facility personnel that have the authority to remedy the situation.

The gravel island will follow the same procedures that will be used for the Oliktok Point Processing Facility when ENI personnel or ENI contractors are present on the gravel island for construction, drilling, or maintenance activities. When the gravel island is unoccupied, the pad boundary will be monitored remotely from the Oliktok Point Processing Facility. If unauthorized personnel are present on the island, when the island is unoccupied, the person would not be exposed to pollutants exceeding the AAQS because with exception of the emergency generator, no emission units will be operating on the island when ENI or ENI contractor personnel are not present on the island.

Pad Boundary Violations

In the event that an unauthorized person enters the Oliktok Point Processing Facility they will be notified by a representative of ENI that they are not allowed within the perimeter of the Nikaitchuq facility without prior approval and will be escorted off the pad by a representative of ENI. The incident will be recorded in the Unauthorized Visitors Logbook and will list the person’s name (if the unauthorized visitor will provide his name), the mode of travel, and the date and time of the incident.

Figure 1. Oliktok Point Processing Facility Ambient Air Boundary.

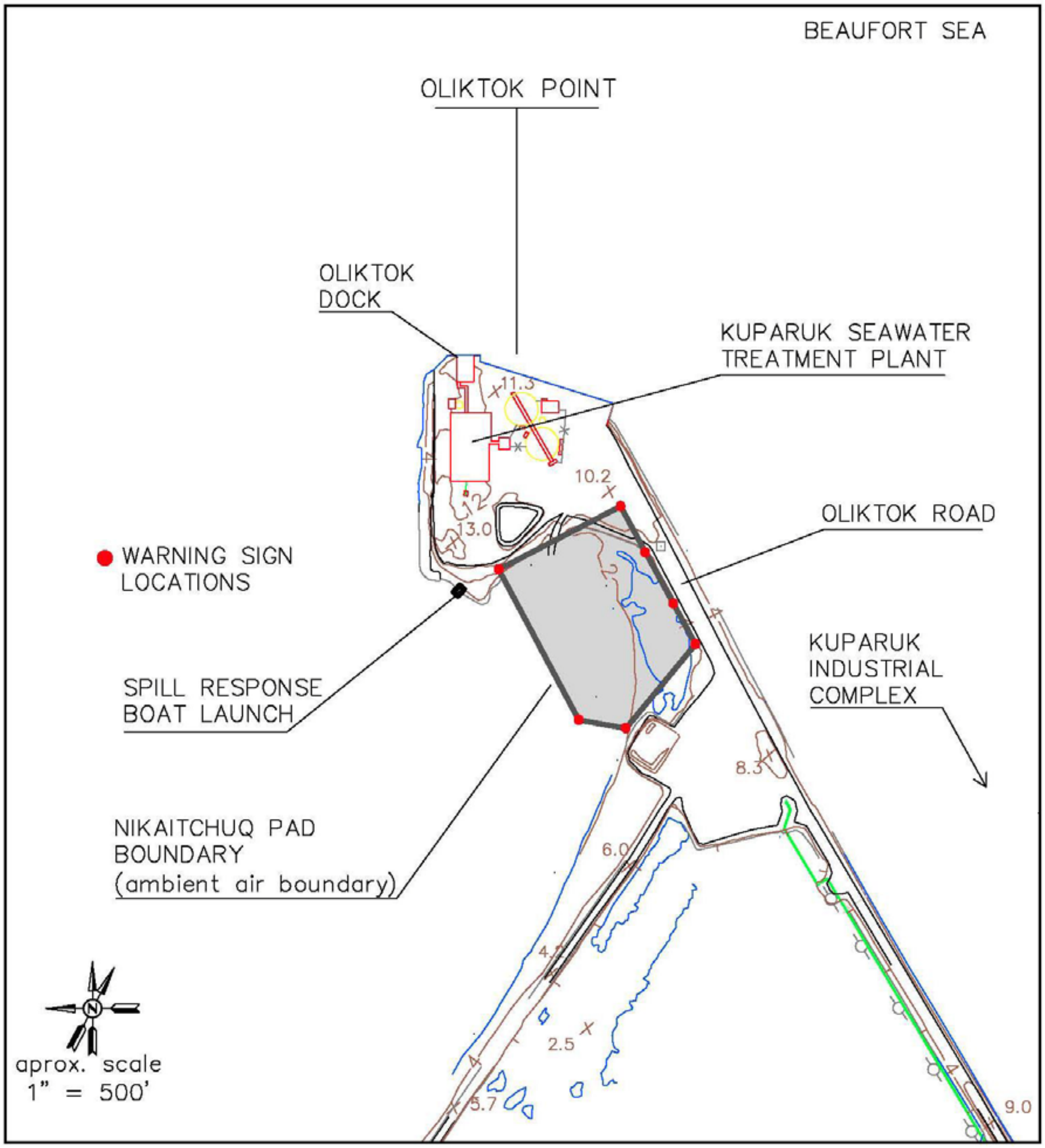
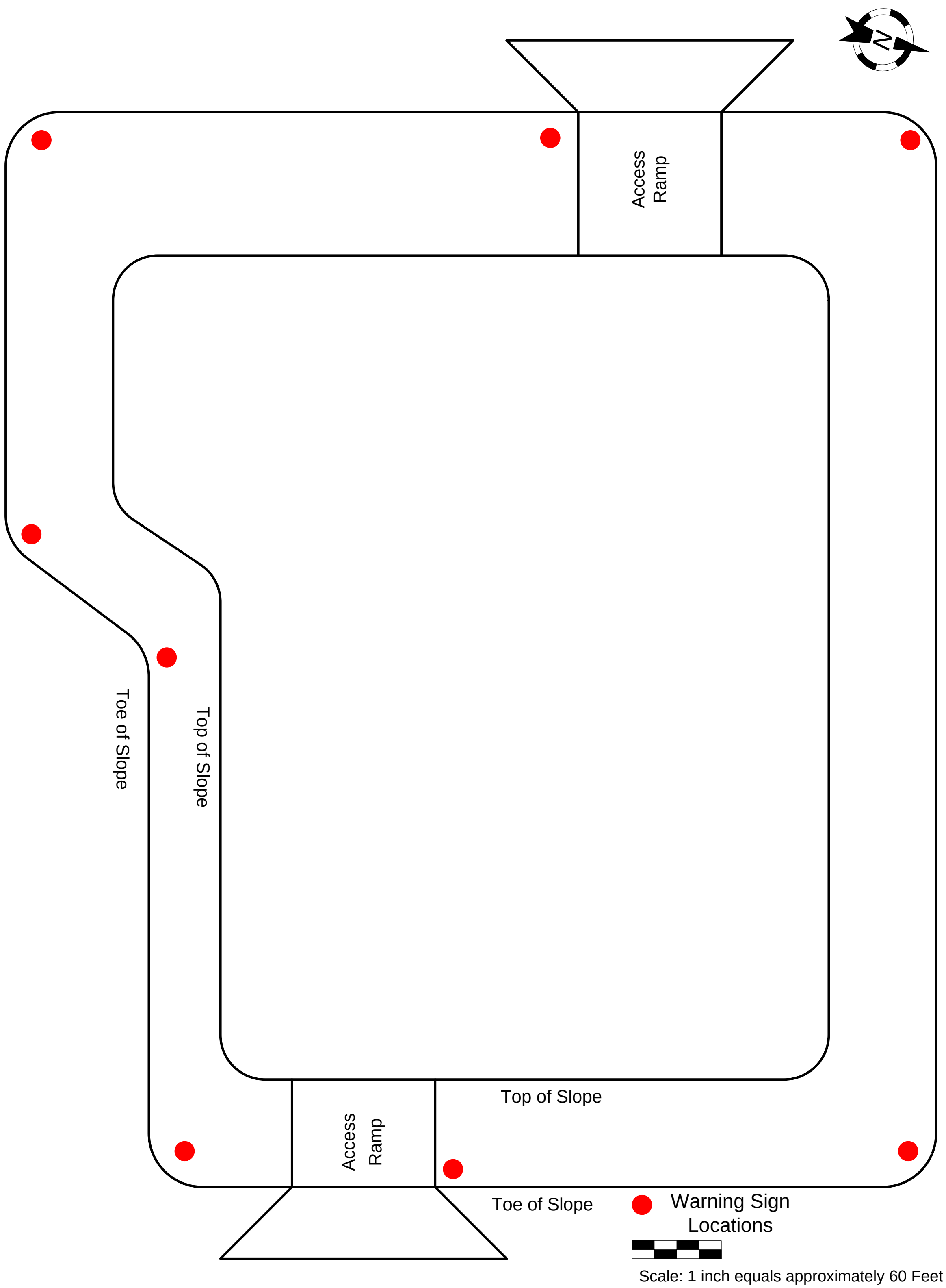


Figure 2. Off-Shore Oliktok Point Gravel Island



Appendix C – Eni Local Policy (November 6, 2009)

ENI LOCAL POLICY
Nikaitchuq Working Times and Hours Policy for Employees and Contractors
November 6, 2009

POLICY NAME: "ENI Working Times and Hours Policy"
POLICY STATEMENT: It is important that all employees and contractor employees know and understand the work schedule that is expected of them. This policy is written with the goal of making clear the days and hours that employees and contractor employees are expected to work at Nikaitchuq.

The work schedule at Nikaitchuq varies depending on the activity that an employee or a contractor is performing. Generally speaking, Nikaitchuq will operate around the clock. Nikaitchuq drilling and construction activities will also be conducted on a 24-hour basis. The normal shift at Nikaitchuq is 12 hours on and 12 hours off. When employees or contractor employees are not working they will reside at a camp provided by ENI Petroleum. Nikaitchuq camp facilities are for ENI Petroleum Employees and Contractor Employees on official business. No visitors that are not on official business may use Nikaitchuq camp facilities.

Camp facilities may either be local to Nikaitchuq or may be removed from the immediate vicinity of Nikaitchuq. Regardless as to the camp location, ENI employees or contractor employees can be required to work shifts in excess of 12 hours or be recalled to work during their off-shift time if emergencies or other special circumstances occur.

Appendix D – ADEC Notification Form

ADEC NOTIFICATION FORM

______________________________ **Stationary Source Name**

______________________________ **Air Quality Permit Number**

______________________________ **Company Name**

When did you discover the Excess Emissions/Permit Deviation?

Date: / / Time: :

When did the event/deviation?

Begin: Date: / / Time: : (please use 24hr clock)
End: Date: / / Time: : (please use 24hr clock)

What was the duration of the event/deviation: : (hrs:min) or days
(total # of hrs, min, or days, if intermittent then include only the duration of the actual emissions/deviation)

Reason for notification: (please check only 1 box and go to the corresponding section)

☐ Excess Emissions - Complete Section 1 and Certify
☐ Deviation from Permit Conditions - Complete Section 2 and Certify
☐ Deviation from COBC, CO, or Settlement Agreement - Complete Section 2 and Certify

Section 1: Excess Emissions

(a) Was the exceedance ☐ Intermittent or ☐ Continuous

(b) Cause of Event (Check one that applies)**:**

☐ Start Up/Shut Down ☐ Natural Cause (weather/earthquake/flood)
☐ Control Equipment Failure ☐ Scheduled Maintenance/Equipment Adjustments
☐ Bad fuel/coal/gas ☐ Upset Condition ☐ Other

(c) Description
Describe briefly what happened and the cause. Include the parameters/operating conditions exceeded, limits, monitoring data and exceedance.

(d) Emission Units Involved:
Identify the emission unit 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	Unit Name	Permit Condition Exceeded/Limit/Potential Exceedance

(e) Type of Incident (please check only one):

☐ Opacity % ☐ Venting (gas/scf) ☐ Control Equipment Down
☐ Fugitive Emissions ☐ Emission Limit Exceeded ☐ Record Keeping Failure

☐Marine Vessel Opacity ☐Failure to monitor/report ☐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 box, corresponding with the section in the permit)
☐Emission Unit Specific
☐General Source Test/Monitoring Requirements
☐Recordkeeping/Reporting/Compliance Certification
☐Standard Conditions Not Included in Permit
☐Generally Applicable Requirements
☐Reporting/Monitoring for Diesel Engines
☐Insignificant Emission Units
☐Stationary Source Wide
☐Other Section: (title of section and section number of your permit)

(b) Emission Unit Involved:
Identify the emission unit 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	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: ______________________

To Submit this Report:

Fax to: 907-451-2187;

Email to: airreports@dec.state.ak.us - *if emailed, the report must be certified within the Operating Report required for the same reporting period per Condition 31;*

Mail to: ADEC, Air Permits Program, 610 University Avenue, Fairbanks, AK 99709-3643;

Phone Notification: 907-451-5173 - p*hone notifications require a written follow-up report within the deadline listed in Condition 31; OR*

Online Submission: *(Website is not yet available)* - *if submitted online, the report must be certified within the Operating Report required for the same reporting period per Condition 31.*