DEPARTMENT OF ENVIRONMENTAL CONSERVATION

AIR QUALITY CONTROL MINOR GENERAL PERMIT

PORTABLE OIL AND GAS OPERATIONS

**Minor General Permit** **2**  Final Date: DATE

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues this minor general permit to be used for the construction, operation, or relocation of a Portable Oil and Gas Operation (POGO), as described in 18 AAC 50.990(124). This minor general permit satisfies the obligation of the Permittee to obtain a minor permit under 18 AAC 50 and AS 46.14.120(g). As required by AS 46.14.120(c) the Permittee shall comply with the terms and conditions of this permit.

Technical support for permit conditions can be found in the Technical Analysis Report. This permit authorizes the Permittee to operate any emissions unit that meets the requirements listed in this permit. The owner must comply with the applicable requirements at the location where the emissions units operate.

This minor general permit does not expire and is valid until the Department terminates, modifies, reopens, or revokes and reissues the permit. The letter of authorization is in effect until withdrawn, modified, revoked and reissued, or if the source no longer qualifies for this permit. The use of sample forms provided with this permit are not a reporting requirement, however, any independently developed form must contain all the reporting requirements listed within this permit.

**Permittee:** [Portable Oil and Gas Operation]

[Address]

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James R. Plosay, Manager
Air Permits Program

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1. Emissions Unit Inventory

**Emissions Unit (EU) Authorization.** The Permittee is authorized to install or relocate, and operate a POGO in accordance with the terms and conditions of this permit. The POGO may consist of one or more drill rigs, along with miscellaneous support equipment. The possible EUs authorized under this permit are listed in Table 1. Unless otherwise noted elsewhere in this permit, the information in Table 1 is for identification purposes only. The specific EU descriptions do not restrict the Permittee from replacing an EU identified in Table 1.

**Table 1: EU Inventory**

| EU  | EU Name | EU Description | Total Rating/Size |
| --- | --- | --- | --- |
| 1 | Drill Rig Reciprocating Engines | Diesel-fired Nonroad Engines | Varies |
| 2 | Drill Rig Heaters and Boilers | Diesel-fired Heaters and Boilers | Varies |
| 3 | Well Venting/Flow Backs | N/A | 90 tons VOC (25 new wells) |
| 4 | Miscellaneous POGO Reciprocating Engines Not On Drill Rig | Diesel-fired Nonroad Engines | Varies |
| 5 | Miscellaneous POGO Heaters and Boilers Not On Drill Rig | Diesel-fired Heaters and Boilers | Varies  |
| 6 | POGO Portable Flares | Fuel Gas | Varies |

Note: The Permittee is also authorized to concurrently conduct well servicing activities, as defined in 18 AAC 50.990(125), and operate nonroad engines associated with construction activities, in accordance with the terms and conditions of this permit.

1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement EU, including any applicable minor or construction permit requirements**.**
2. **Verification of Equipment Specifications and Maintenance of Equipment.** The Permittee shall install and maintain the equipment listed in Table 1 according to the manufacturer’s or operator’s maintenance procedures. Keep a copy of the manufacturer’s or operator’s maintenance procedure onsite and make records available to the Department personnel upon request. The records may be kept in electronic format.
3. Emission and Compliance Fees
4. **Administration Fees.** The Permittee shall pay to the Department all assessed permit administration fees. Administration fee rates are set out in 18 AAC 50.400-499.
5. **Assessable Emissions**. The Permittee shall pay to the Department annual emission fees based on the POGO’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. Notwithstanding 18 AAC 50.410(a) – (d), for the POGO projected annual rate of emissions under a general minor permit under 18 AAC 50.560, the emission fee is allocated to the emission control permit receipts accounts under AS 46.14.265, and the Permittee shall pay the emission fee:
	1. At the time of application or notification for operation that will occur during that state fiscal year.
	2. For operation under a single application or notification during subsequent state fiscal years, after annual emission fee billing under 18 AAC 50.420 for each subsequent state fiscal year.
	3. For each individual POGO for which the owner or operator submits a new application or notification for operation under the general minor permit, at the following rates:
		1. $1,414 for operation at one or more ice pads during a winter drilling season;
		2. $4,241 for operation during a state fiscal year at one or more sites not including a seasonal ice pad.
	4. For subsequent state fiscal years, the Department will assess fees[[1]](#footnote-2) per ton of each air pollutant that the POGO emits or has the potential to emit in quantities 10 tons per year or greater. The quantity for which fees will be assessed is the lesser of:
		1. each individual POGO’s assessable potential to emit of 252 tpy; or
		2. each individual POGO’s projected annual rate of emissions that will occur from July 1st to the following June 30th, 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:
			1. an enforceable test method described in 18 AAC 50.220;
			2. material balance calculations;
			3. emission factors from EPA’s publication AP-42, Vol. I, adopted by reference in 18 AAC 50.035; or
			4. other methods and calculations approved by the Department, including appropriate vendor-provided emissions factors when sufficient documentation is provided**.**
6. **Assessable Emission Estimates.** Emission fees will be assessed as follows:
	1. No later than March 31 of each year, the Permittee may submit an estimate of the POGO’s assessable emissions via the Department’s Air Online Services (AOS) System at <http://dec.alaska.gov/applications/air/airtoolsweb> using the Permittee Portal option and filling out the Emission Fee Estimate Form. Alternatively, the report may be submitted by:
		1. Email under a cover letter using dec.aq.airreports@alaska.gov; or
		2. Hard copy to the following address: ADEC, Air Permits Program, ATTN: Assessable Emissions Estimate, 555 Cordova Street, Anchorage, Alaska 99501.
	2. ThePermittee shall include with the assessable emission report all of the assumptions and calculations used to estimate the assessable emissions in sufficient detail so the Department can verify the estimates.
	3. If no estimate is submitted 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 4.4a.
7. **Annual Compliance Fee.** For a POGO not classified as needing a Title V permit, the Permittee shall pay an annual compliance fee as set out in 18 AAC 50.400(d), to be paid for each period from July 1st through the following June 30th.
8. Applicability Criteria
9. This minor general permit applies to a POGO that:
	1. contains fuel-burning equipment;
	2. is not located in a non-attainment area;
	3. does not concurrently operate under an MG-1 permit at a given well pad or drill site;
	4. operates at a given well pad or drill site identified by the application or relocation notification;
	5. does not operate on a platform[[2]](#footnote-3) surrounded by open water;
	6. operates north of 69 degrees, 30 minutes North latitude; and
	7. maintains the nonroad engine status of EUs 1 and 4 as defined in 40 C.F.R. 89.2.
10. State Emission Standards
11. **Visible Emissions for Industrial Processes and Fuel-Burning Equipment.**  The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from all fuel-burning equipment[[3]](#footnote-4) listed in Table 1, to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.
	1. For each heater or boiler operated as EU 2, verify compliance with Condition 8 by performing one of the following:
		1. Certified Manufacturer Guarantee. Obtain a certified manufacturer guarantee prior to operating the heater or boiler under this permit, that the given heater or boiler will comply with the visible emission standard; or
		2. Annual Method 9 Observation. Conduct visible emission observations following 40 C.F.R. 60, Appendix A-4, Method 9, for 18 minutes to obtain 72 consecutive 15-second opacity observations, at least once in each calendar year that the heater or boiler, as applicable, operates for at least seven consecutive days under the terms and conditions of this permit.
	2. When using Condition 8.1a to verify compliance of a heater or boiler operated as EU 2, attach a copy of the guarantee obtained under Condition 8.1a to the operating report required by Condition 18 that covers the initial period of operation of the heater or boiler under this permit.
	3. Attach a copy of the observation records developed under Condition 8.1b (using the form in Attachment 1) to the operating report required under Condition 18, for the period that covers the dates the observations were conducted.
	4. For each flare operated as EU 6 observe one daylight flare event[[4]](#footnote-5) annually, on a calendar year basis. If there is no qualifying flare event within the calendar year, then the Permittee shall observe the next qualifying daylight flare event for that flare when it is operated onsite.
		1. Observe the flare exhaust following 40 C.F.R. 60, Appendix A-4, Method 9, for 18 minutes to obtain 72 consecutive 15-second opacity observations during flare events.
		2. Record the following information for observed events:
			1. the flare’s EU number;
			2. results of the Method-9 observations;
			3. reason(s) for flaring;
			4. date, beginning and ending time of event; and
			5. volume of gas flared.
		3. Monitoring of a flare event may be postponed for safety or weather reasons, or because a qualified observer is not available. If a flare event has not yet been observed during a calendar year and monitoring of a flare event is postponed for any of the reasons described in this condition, the Permittee shall include in the next operating report required by Condition 18 an explanation of the reason the flare event was not monitored. If no flare events occurred during the reporting period, then no monitoring or reporting is required.
		4. Include copies of the records required by Condition 8.4b in the first operating report submitted under Condition 18 for the period covered by the report.
	5. Report as a permit deviation under Condition 17 if any of Conditions 8.1 through 8.4 are not met.
	6. If the results of Method 9 observations completed under Condition 8 exceed the standard in Condition 8, report as excess emissions in accordance with Condition 17, take corrective actions, and conduct follow-up Method 9 observations as soon as possible after completing corrective actions until the standard in Condition 8 is met.
12. **Particulate Matter for Industrial Processes and Fuel-Burning Equipment.** The Permittee shall not cause or allow particulate matter emitted from all fuel-burning equipment listed in Table 1, to exceed 0.05 grains per dry standard cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.
	1. For each heater/boiler operated as EU 2, conduct a particulate matter source test according to the requirements set out in Section 8 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.
13. **Sulfur Compound Emissions for Industrial Processes and Fuel-Burning Equipment.** The Permittee shall not cause or allow sulfur compound emissions, expressed as SO2, from each fuel-burning equipment listed in Table 1 to exceed 500 parts per million averaged over three hours. Monitor, record, and report in accordance with Condition 12.2.
14. Ambient Air Quality Protection Requirements
15. To protect the 1-hour and annual nitrogen dioxide (NO2); 24-hour particulate matter with an aerodynamic diameter of 10 microns or less (PM-10); 24-hour and annual particulate matter with an aerodynamic diameter of 2.5 microns or less (PM-2.5); 1-hour, 3-hour, 24-hour, and annual sulfur dioxide (SO2), and 1-hour and 8-hour carbon monoxide (CO) Alaska Ambient Air Quality Standards (AAAQS), the Permittee shall:
	1. Construct and maintain vertical, uncapped exhaust stacks on all nonroad engines operated as EU 1 and all heaters/boilers operated as EU 2. This condition does not preclude the use of flapper-style rain covers, or other similar designs, that do not hinder the vertical momentum of the exhaust plume.
		1. Confirm in each operating report required under Condition 18 that the exhaust stack for each nonroad engine operated as EU 1, and each heater/boiler operated as EU 2, complies with Condition 11.1; or state that no unit was operated as EU 1 or 2 during the reporting period.
		2. Report as described in Condition 17, if a requirement under Condition 11.1 was not met.
	2. Prohibit the hydraulic fracturing (fracing) of unconventional resources[[5]](#footnote-6) while engaged in POGO activities at a given well pad. Report as described in Condition 17 if fracing of unconventional resources occurs.
	3. Limit the combined daily diesel fuel consumption for all nonroad engines operated as EU 1 and all heaters/boilers operated as EU 2 on a given well pad or drill site, as specified in Table 2. The Permittee may exceed the applicable limits in Table 2 by up to 25 percent on any six or fewer days in any thirty consecutive days. The not to exceed values (excursion limits) for each daily fuel limit identified in Table 2 are as follows:

 14,700 x 1.25 = 18,375 gallons per day;

 11,400 x 1.25 = 14,250 gallons per day; and

 10,700 x 1.25 = 13,375 gallons per day.

**Table 2 – EUs 1 and 2 Daily Fuel Consumption Limits (gallons per day)**

| Fuel Consumption Operational Scenarios | Routine Drilling Isolated(RDi)[[6]](#footnote-7) | Routine Drilling Collocated(RDc)[[7]](#footnote-8) | **Developmental Drilling Isolated(DDi)[[8]](#footnote-9)** | **Developmental Drilling Collocated(DDc)[[9]](#footnote-10)** |
| --- | --- | --- | --- | --- |
| POGO Without Concurrent Hydraulic Fracturing of a Conventional Resource | 14,700 | 11,400 | 14,700 | 10,700 |
| POGO With Concurrent Hydraulic Fracturing of a Conventional Resource | 11,400 | 11,400 | 10,700 | 10,700 |

Table Notes:

Daily fuel consumption thresholds apply to the drill rig only and do not apply to other emissions units that may be a part of the POGO or operating on the well pad, such as stationary well pad equipment, portable power generators, or well servicing equipment (as defined in 18 AAC 50.990(125)) – these activities are represented by the background values added to the modeled impacts.

* 1. Record and report in each operating report required under Condition 18, the following information:
		1. Drill rig identification;
		2. Pad identification
		3. Pad category (collocated[[10]](#footnote-11) or isolated);
		4. Dates occupied by the rig(s) at each pad;
		5. Drilling category(s) (routine or developmental);
		6. Start and end dates when any nonroad engine operated as EU 1 operate concurrently with fracing; and
		7. Start and end dates when any heater/boiler operated as EU 2, operate concurrently with fracing during the reporting period.
	2. For each nonroad engine operated as EU 1 and each heater/boiler operated as EU  2, determine the maximum possible fuel consumption for that engine/heater/boiler as described in Condition 11.5a, or measure the actual daily fuel consumption for that engine/heater/boiler as described in Condition 11.5b. The Permittee may use Condition 11.5a for some units and Condition 11.5b for the other units, as long as the combined total daily fuel consumption for EUs 1 and 2 is either determined or measured. Make this determination for each well pad/drill site identified in the initial application, the subsequent annual notification submitted under Condition 20, or the most recent relocation notification submitted through Attachment 3, as applicable.
		1. Determine the maximum possible fuel consumption for a unit as follows:
			1. Determine the maximum hourly fuel consumption in gal/hr for the given unit from either vendor data, or a back-calculation from the rated capacity using standard engineering techniques and thermal efficiencies. Keep a copy of your determination and all supporting data, assumptions, and/or calculations, as required under Condition 16; and
			2. Calculate the maximum daily fuel consumption for the unit by multiplying the maximum hourly fuel consumption determined under Condition
			11.5a(i) by 24. Record the result, in units of gal/day.
		2. Monitor and record the actual fuel consumption for a unit or a group of units as follows:
			1. Monitor the fuel consumption using one of the following methods:
				1. Install, maintain, and operate totaling fuel flow meters that are accurate to within ± 5 percent;
				2. Tank strapping;
				3. Delivery truck fuel dispensing meters;
				4. Runtime (hours) and full load fuel consumption rate in gal/hr provided by the manufacturer or back-calculation from the rated capacity using standard engineering techniques and thermal efficiencies; or
				5. Methods similar to those described in the Sample Fuel Consumption Monitoring Plan[[11]](#footnote-12) in Attachment 4.
			2. Record the daily fuel consumption in gal/day using one or more of the following methods:
				1. Fuel flow meters – record the total amount of diesel fuel fired during the calendar day;
				2. Tank strapping:

At a consistent time each day, record the diesel fuel height in the tank and the time of the reading.

For each fuel delivery

Initial diesel fuel height;

Final diesel fuel height;

Tank identification; and

Method of volume calculation (chart, site glass, mathematical equation, etc.).

Maintain a copy of the manufacturer height to volume calculation chart on site for each tank;

* + - * 1. Delivery truck fuel dispensing meters – record the diesel fuel dispensed to the units subject to Condition 11.5b during each calendar day;
				2. Runtime and full load assumption:

Use a non-resettable hour meter to determine the runtime of the unit;

For each day the unit operates, record at a consistent time each day, the daily hours of operation; and

Calculate and record the daily fuel usage of the unit using the hours of operation recorded in Condition 11.5b(ii)(D)(2) and the manufacturer’s full load fuel consumption rate or back-calculation from the rated capacity using standard engineering techniques and thermal efficiencies.

* + - * 1. Methods similar to those described in the Sample Fuel Consumption Monitoring Plan12 in Attachment 4.
		1. Record the total daily fuel consumption, in gal/day, as described below:
			1. If solely using Condition 11.5a for determining the daily fuel consumption for all nonroad engines operated as EU 1 and all heaters/boilers operated as EU 2 during the reporting period, sum the maximum possible daily fuel consumptions determined under Condition 11.5a(ii) for each unit. Record the total maximum fuel consumption in gal/day.
			2. If using Condition 11.5b for determining the actual daily fuel consumption for one or more nonroad engines operated as EU 1 or one or more heaters/boilers operated as EU 2 during the reporting period, do the following at the end of each calendar day for the previous day:
				1. Sum the total fuel consumed during the day by all units that are being tracked under Condition 11.5b;
				2. If applicable, add the maximum possible daily fuel consumption determined under Condition 11.5a for the remaining units, to the sum determined under Condition 11.5c(ii)(A);
				3. Record, in gal/day, the value determined under Condition 11.5c(ii)(A), and if applicable, the value determined under Condition 11.5c(ii)(B).
		2. Report in each operating report required under Condition 18 one of the following for each well pad/drill site identified in the initial application, the subsequent annual notification submitted under Condition 20, or the most recent relocation notification submitted through Attachment 3, as applicable:
			1. The maximum possible combined daily fuel consumption, in gal/day, of all nonroad engines operated as EU 1 and all heaters/boilers operated as EU 2 during the reporting period, as determined under Condition 11.5c(i);
			2. The largest actual combined daily fuel consumption for the reporting period, in gal/day, of all nonroad engines operated as EU 1 and all heaters/boilers operated as EU 2, as determined under Condition 11.5c(ii);
			3. In the event that records of the total daily fuel consumption are kept according to Condition 11.5c(i) and according to Condition 11.5c(ii), report the sum total of the maximum combined daily fuel consumption (gal/day) determined under Condition 11.5c(i) and the actual combined daily fuel consumption (gal/day) determined under Condition 11.5c(ii) for all nonroad engines operated as EU 1 and all heaters/boilers operated as EU 2 during the reporting period; or
			4. That no POGO activity occurred at the given well pad/drill site during the reporting period.
		3. Report in each operating report required under Condition 18 the start and end dates that EU 1 and/or EU 2 operated concurrently with fracing.
		4. Report as described in Condition 17, anytime the daily combined fuel consumption limits for EUs 1 and 2 listed in Table 2 are exceeded (except as provided under the excursion limits listed in Condition 11.3), or if Condition 11 or its sub-conditions are not met.
		5. Upon request by the Department, demonstrate how the fuel consumption has been tracked/ estimated for all nonroad engines identified as EU 1 and/or all heaters and boilers identified as EU 2. These records may include but are not limited to: recorded data from fuel tracking devices or procedures, calculations used to estimate fuel consumption based on operating time, review of fuel tracking standards, and/or inspection of the fueling operation and volume tracking.
1. **SO2 Ambient Air Quality Protection.** To protect the 1-hour, 3-hour, 24-hour, and annual SO2 AAAQS, the Permittee shall:
	1. Combust only diesel fuel that meets the specifications of ultra low sulfur diesel (ULSD) (i.e., less than 0.0015 percent sulfur by weight) in each nonroad engine operated as EU 1.

Monitor, record, and report as follows:

* + 1. Obtain and keep certified receipts from the fuel suppliers that confirms that all diesel fuel combusted in the units listed in Condition 12.1 meets the specifications of ULSD.
		2. Report in each operating report required by Condition 18, for the period covered by that report, a statement indicating whether all fuel combusted in the units listed in Condition 12.1 during the reporting period was ULSD.
		3. Report as described in Condition 17 if any fuel combusted in the units listed in Condition 12.1 exceeds the sulfur content limit required by Condition 12.1.
	1. Combust only diesel fuel that contains a sulfur content of 0.15 percent by weight or less in the heaters/boilers identified as EU 2.

Monitor, record, and report as follows:

* + 1. For diesel fuel delivered from a North Slope topping plant, obtain from the topping plant the results of a monthly fuel sulfur analysis.
		2. For fuel delivered by third-party suppliers, obtain and keep certified receipts from fuel suppliers to document the sulfur content of the delivered fuel.
		3. Include in the operating report required by Condition 18, for the period covered by that report, a copy of all records obtained under Conditions 12.2a and 12.2b.
		4. Report as required under Condition 17 if any fuel combusted in EU 2 exceeds the fuel sulfur content limit required by Condition 12.2.
1. Recordkeeping, Reporting, and Certification Requirements
2. **Certification.** The Permittee shall certify all reports, or other documents 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 emissions 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.
	1. The Department may accept an electronic signature on an electronic application or other electronic record required by the Department if
		1. A certifying authority registered under AS 09.25.510 verifies that the electronic signature is authentic; and
		2. The person providing the electronic signature has made an agreement with the certifying authority described in Condition 13.1a that the person accepts or agrees to be bound by an electronic record executed or adopted with that signature.
3. **Submittals.** Unless otherwise directed by the Department or this permit, the Permittee shall submit reports, compliance certifications, and/or other submittals required by this permit, via the Department’s Air Online Services (AOS) System at <http://dec.alaska.gov/applications/air/airtoolsweb> using the Permittee Portal option.
	1. Alternatively, the documents may be certified in accordance with Condition 13, and submitted either by:
		1. Email under a cover letter using dec.aq.airreports@alaska.gov; or
		2. Hard copy to the following address: ADEC, Air Permits Program ATTN: Compliance Technician, 610 University Ave., Fairbanks, AK 99709-3643.
4. **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, 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.
5. **Recordkeeping Requirements.** The Permittee shall keep all records required by this permit for at least five years after the date of collection, including:
	1. copies of all reports and certifications submitted pursuant to this section of the permit.
	2. records of all monitoring required by this permit, and information about the monitoring including (if applicable):
		1. calibration and maintenance records, original strip chart or computer-based recordings for continuous monitoring instrumentation;
		2. sampling dates and times of sampling or measurements;
		3. the operating conditions that existed at the time of sampling or measurement;
		4. the date analyses were performed;
		5. the location where samples were taken;
		6. the company or entity that performed the sampling and analyses;
		7. the analytical techniques or methods used in the analyses; and
		8. the results of the analyses.
6. **Excess Emissions and Permit Deviation Reports.**
	1. The Permittee shall report all emissions or operations that exceed or deviate from the requirements of this permit as follows:
		1. In accordance with 18 AAC 50.240(c), as soon as possible after the event commenced or is discovered, report
			1. emissions that present a potential threat to human health or safety; and
			2. excess emissions that the Permittee believes to be unavoidable;
		2. 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 caused emissions in excess of a technology based emissions standard;
		3. report all other excess emissions and permit deviations
			1. within 30 days of the end of the month in which emissions or deviation occurs, except as provided in Conditions 17.1c(ii) and 17.1c(iii);
			2. 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 17.1c(i); and
			3. for failure to monitor, as required in other applicable conditions of this permit.
	2. 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 <http://dec.alaska.gov/applications/air/airtoolsweb>, or if the Permittee prefers, the form contained in Attachment 5. The Permittee must provide all information called for by the form that is used.
	3. If requested by the Department, the Permittee shall provide a more detailed written report as requested to follow up an excess emissions report.
7. **Operating Reports.** Submit to the Department an operating report by August 15 for the period January 1 through June 30 of the current year and by February 15 for the period July 1 through December 31 of the previous year. The report shall be submitted under a cover letter certified in accordance with Condition 13.
	1. The operating report must include all information required to be in operating reports by other conditions of this permit, for the period covered by the report.
	2. When excess emissions or permit deviations that occurred during the reporting period are not reported under Condition 18.1, the Permittee shall identify
		1. the date of the deviation;
		2. the equipment involved;
		3. the permit condition affected;
		4. a description of the excess emissions or permit deviation; and
		5. any corrective action or preventative measures taken and the date of such actions; or
	3. When excess emissions or permit deviations have already been reported under Condition 17 the Permittee shall cite the date or dates of those reports.
8. **Annual Affirmation of Qualification.** The Permittee shall submit to the Department by March 31 of each year, an affirmation certified according to Condition 13 of whether the POGOs operating under the MG-2 Permit still qualify for this permit and that Title V permitting will not been triggered by the POGO activities.
9. **Annual Notification.** The Permittee shall submit to the Department by December 31st of each year, their MG-2 POGO plans for the following calendar year. The Permittee shall do so by completing and submitting the Form in Attachment 2. The Permittee may submit one annual notification per Unit.[[12]](#footnote-13)
10. **Relocation Notification.** The Permittee shall notify the Department if there is a revision to the well pads/drill sites identified in the initial application or annual notification submitted under Condition 20 as soon as possible, prior to operating at the new well pad/drill site. Use the form in Attachment 3 to make this notification.
11. Standard Permit Conditions
12. 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
	1. an enforcement action; or
	2. permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280.
13. 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.
14. 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.
15. 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.
16. The permit does not convey any property rights of any sort, nor any exclusive privilege.
17. 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
	1. enter upon the premises where an emissions unit subject to this permit is located or where records required by the permit are kept;
	2. have access to and copy any records required by this permit;
	3. inspect any stationary source, equipment, practices, or operations regulated by or referenced in the permit; and
	4. sample or monitor substances or parameters to assure compliance with the permit or other applicable requirements.
18. General Source Test Requirements
19. **Requested Source Tests.** In addition to any source testing explicitly required by this permit, the Permittee shall conduct source testing as requested by the Department to determine compliance with applicable permit requirements.
20. **Operating Conditions.** Unless otherwise specified by an applicable requirement or test method, the Permittee shall conduct source testing
	1. at a point or points that characterize the actual discharge into the ambient air; and
	2. at the maximum rated burning or operating capacity of the source or another rate determined by the Department to characterize the actual discharge into the ambient air.
21. **Reference Test Methods.** The Permittee shall use the following references for test methods when conducting source testing for compliance with this permit:
	1. Source testing for the reduction in visibility through the exhaust effluent must be conducted in accordance with the procedures set out in 40 C.F.R. 60, Appendix A, Reference Method 9. The Permittee may use the form in Attachment 1 of this permit to record data.
	2. Source testing for emissions of total particulate matter, 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.
	3. Source testing for emissions of PM-10 must be conducted in accordance with the procedures specified in 40 C.F.R. 51, Appendix M, Methods 201 or 201A and 202.
	4. Source testing for emissions of any contaminant may be determined using an alternative method approved by the Department in accordance with 40 C.F.R. 63 Appendix A, Method 301.
22. **Test Deadline Extension.**  The Permittee may request an extension to a source test deadline established by the Department. The Permittee may delay a source test beyond the original deadline only if the extension is approved in writing by the Department’s appropriate division director or designee.
23. **Test Plans.** Before conducting any source tests, the Permittee shall submit a plan to the Department. The plan must include the methods and procedures to be used for sampling, testing, and quality assurance, and must specify how the emissions unit will operate during the test and how the Permittee will document that operation. The Permittee shall submit a complete test plan at least 30 days before the scheduled date of any test unless the Department agrees in writing to some other time period. Retesting may be done without resubmitting the plan.
24. **Test Notification.** At least 10 days before conducting a source test, the Permittee shall give the Department written notice of the date and time the source test will begin.
25. **Test Reports.** Within 60 days after completing a source test, the Permittee shall submit one certified copy of the results in the format set out in the *Source Test Report Outline*, adopted by reference in 18 AAC 50.030. The Permittee shall certify the results as set out in Condition 13. If requested in writing by the Department, the Permittee must provide preliminary results in a shorter period of time specified by the Department.

Attachment 1 – Visible Emissions Form

**VISIBLE EMISSION OBSERVATION FORM**

This form is designed to be used in conjunction with EPA Method 9, “Visual Determination of the Opacity of Emissions from Stationary Sources.” Temporal changes in emission color, plume water droplet content, background color, sky conditions, observer position, etc. should be noted in the comments section adjacent to each minute of readings. Any information not dealt with elsewhere on the form should be noted under additional information. Following are brief descriptions of the type of information that needs to be entered on the form. For a more detailed discussion of each part of the form, refer to “Instructions for Use of Visible Emission Observation Form.”

|  |  |
| --- | --- |
| * Source Name: full company name, parent company or division or subsidiary information, if necessary.
* Address: street (not mailing or home office) address of facility where VE observation is being made.
* Phone (Key Contact): number for appropriate contact.
* Source ID Number: number from NEDS, agency file, etc.
* Process Equipment, Operating Mode: brief description of process equipment (include type of facility) and operating rate, % capacity, and/or mode (e.g. charging, tapping, shutdown).
* Control Equipment, Operating Mode: specify type of control device(s) and % utilization, control efficiency.
* Describe Emission Point: for identification purposes, stack or emission point appearance, location, and geometry; and whether emissions are confined (have a specifically designed outlet) or unconfined (fugitive).
* Height Above Ground Level: stack or emission point height relative to ground level; can use engineering drawings, Abney level, or clineometer.
* Height Relative to Observer: indicate height of emission point relative to the observation point.
* Distance from Observer: distance to emission point; can use rangefinder or map.
* Direction from Observer: direction plume is traveling from observer.
* Describe Emissions and Color: include physical characteristics, plume behavior (e.g., looping, lacy, condensing, fumigating, secondary particle formation, distance plume visible, etc.), and color of emissions (gray, brown, white, red, black, etc.). Note color changes in comments section.
* Visible Water Vapor Present?: check “yes” if visible water vapor is present.
* If Present, is Plume…: check “attached” if water droplet plume forms prior to exiting stack, and “detached” if water droplet plume forms after exiting stack.
* Point in Plume at Which Opacity was Determined: describe physical location in plume where readings were made (e.g., 1 ft above stack exit or 10 ft. after dissipation of water plume).
* Describe Plume Background: object plume is read against, include texture and atmospheric conditions (e.g., hazy).
* Background Color: sky blue, gray-white, new leaf green, etc.
 | * Sky Conditions: indicate cloud cover by percentage or by description (clear, scattered, broken, overcast).
* Wind Speed: record wind speed; can use Beaufort wind scale or hand-held anemometer to estimate.
* Wind Direction From: direction from which wind is blowing; can use compass to estimate to eight points.
* Ambient Temperature: in degrees Fahrenheit or Celsius.
* Wet Bulb Temperature: can be measured using a sling psychrometer
* RH Percent: relative humidity measured using a sling psychrometer; use local US Weather Bureau measurements only if nearby.
* Source Layout Sketch: include wind direction, sun position, associated stacks, roads, and other landmarks to fully identify location of emission point and observer position.
* Draw North Arrow: to determine, point line of sight in direction of emission point, place compass beside circle, and draw in arrow parallel to compass needle.
* Sun’s Location: point line of sight in direction of emission point, move pen upright along sun location line, mark location of sun when pen’s shadow crosses the observer’s position.
* Observation Date: date observations conducted.
* Start Time, End Time: beginning and end times of observation period (e.g., 1635 or 4:35 p.m.).
* Data Set: percent opacity to nearest 5%; enter from left to right starting in left column. Use a second (third, etc.) form, if readings continue beyond 30 minutes. Use dash (-) for readings not made; explain in adjacent comments section.
* Comments: note changing observation conditions, plume characteristics, and/or reasons for missed readings.
* Range of Opacity: note highest and lowest opacity number.
* Observer’s Name: print in full.
* Observer’s Signature, Date: sign and date after performing VE observation.
* Organization: observer’s employer.
* Certified By, Date: name of “smoke school” certifying observer and date of most recent certification.
 |



Attachment 2 – Annual Notification Form

**Alaska Department of Environmental Conservation**

**Division of Air Quality - Air Permit Program**

**Air Quality Control General Permit**

# MINOR GENERAL PERMIT MG-2

**PORTABLE OIL AND GAS OPERATIONS**

**Annual Notification Form for Calendar Year 20****YY**

 **Company Name**

**Oil and Gas Unit(s) or Well Pad(s)**

**Drilling Rig(s) Identification**

|  |
| --- |
| **Location Above 69° 30’ North** |
| What Type of well pad(s) will you operate on?[ ]  Gravel[ ]  Ice |
| Will you operate at multiple pads under this notice?[ ]  Yes[ ]  No |
| [ ]  Check here if a custom fuel consumption monitoring plan is attached, or[ ]  Check here and identify the plan if the department already has a copy:[ ]  Check here if you agree to maintain daily logs that are readily accessible and that are adequate to demonstrate compliance with the applicability criteria and conditions of MG2. [ ]  Check here if appropriate Payment required by MG-2, Condition 4 is attached. |
|  |
| *Provide well sites to be drilled under this notice. Use additional sheets if necessary.* |
| Name of Pad and exact location description: | Latitude: | Longitude: |
|       |       |       |
|       |       |       |
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|       |       |       |
| Attach a map showing the location(s) of your well sites to be drilled, and including roads, buildings, and water bodies. Attach as many maps as necessary to show all locations under this notification.[ ]  Check here if all necessary maps are attached. |

**Equipment to Operate during Calendar Year 20YY**

Permit No.: AQ####MG20##

Select the appropriate check boxes in the table below, identifying the POGO equipment that is planned to operate during calendar year 20YY.

| EU  | Planned Operation | EU Name | EU Description | Total Rating/Size |
| --- | --- | --- | --- | --- |
| 1 | [ ]  Yes[ ]  No | Drill Rig Reciprocating Engines | Diesel-fired Nonroad Engines | Varies |
| 2 | [ ]  Yes[ ]  No | Drill Rig Heaters and Boilers | Diesel-fired Heaters and Boilers | Varies |
| 3 | [ ]  Yes[ ]  No | Well Venting/Flow Backs | N/A | 90 tons VOC (25 new wells) |
| 4 | [ ]  Yes[ ]  No | Miscellaneous POGO Reciprocating Engines Not On Drill Rig | Diesel-fired Nonroad Engines | Varies |
| 5 | [ ]  Yes[ ]  No | Miscellaneous POGO Heaters and Boilers Not On Drill Rig | Diesel-fired Heaters and Boilers | Varies  |
| 6 | [ ]  Yes[ ]  No | POGO Portable Flares | Fuel Gas | Varies |

**CERTIFICATION**

**FOR**

**MINOR PERMITS**

18 AAC 50.205 Certification. Any permit application, report, affirmation, or compliance certification required by the department under a permit program established under AS 46.14 must include the signature of a responsible official for the permitted stationary source.

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.

\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

Signature

\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

Printed Name

\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

Title

Attachment 3 – Relocation Notification

Submit the following information to the Department as soon as possible ***before*** moving the POGO to a well pad/drill site not previously identified in the initial application or annual notification form.

**Facility Information:**

Permittee Name:\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_ Permit: AQ\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_­\_\_\_\_

Rig Name(s):\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

Unit Name (if applicable):\_­\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

Well Pad(s) / Drill Site(s): \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

Operator Name:\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

Contact Person:\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_ Telephone:\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

**Estimated Operating Dates:**

Estimated start-up date: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

Estimated shut-down date: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

**Location Information:**

New Rig Location:

Latitude\_\_\_\_\_\_\_\_\_\_\_\_\_\_ Longitude\_\_\_\_\_\_\_\_\_\_\_\_\_\_(specify to at least four decimal degrees)

**Comments:**\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

Printed Name:\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_ Title:\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_ Date:\_\_\_\_\_\_\_\_\_\_

Signature:\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_ Phone Number:\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

*Submit completed report using the Air Online Services Permittee Portal located at*

[*http://dec.alaska.gov/Applications/Air/airtoolsweb*](http://dec.alaska.gov/Applications/Air/airtoolsweb)*. This requires the Permittee to have a MyAlaska account and the Responsible Official documented with the Department for electronic signature.*

*Or send to: Compliance Technician, ADEC Air Permits Program, 610 University Avenue, Fairbanks, AK 99709-3643 or email to dec.AQ.Airrepo**rts@alaska.gov**.*

Attachment 4 – Sample Fuel Consumption Monitoring Plan

Sample Fuel Consumption Monitoring Plan

# Purpose

To monitor and record daily fuel consumed in rig diesel-fired equipment.

# Scope

This Plan covers drilling rigs’ emissions units powered with diesel fuel. It does not cover fuel consumed by individual vehicles or ancillary equipment.

# Roles and Responsibilities

| Role | Responsibilities |
| --- | --- |
| Toolpusher | **Daily**Ensure all diesel-fired equipment has one of the following methods in place to track daily fuel usage;1. Metering;
2. Tank strapping; or
3. Operational hours tracking

**Fuel Delivery Tracking**Ensure all fuel usage is tracked on the “daily fuel usage report”Ensure this plan is understood and carried out by operating personnel.Be knowledgeable of current permit requirements pertaining to fuel consumption monitoring and recording.Assign competent personnel to record consumed fuel of stipulated diesel fired equipment.Ensure correct and consistent fuel consumption monitoring and recording.Keep fuel use logs on location.Submit reports as requested to the Company Representative Review recording process with assigned personnel periodically.Use Management of Change process for all design, usage or process modifications involving diesel fired equipment. |
| Assigned Personnel | Be knowledgeable of current permit requirements pertaining to fuel consumption monitoring and recording.Be knowledgeable and competent to perform task of recording daily operational hours and consumed fuel of all diesel fired equipment.Keep accurate records.Immediately report any failure of measurement devices. |
| HSE Manager | Develop and Maintain Fuel Consumption ProcedureAssist in monitoring and communicating fuel usage to OperatorsRespond to questions and concerns from Field Personnel |
| HSE Administrative Assistant | Receive Daily Fuel Use LogsMaintain Fuel Use LogsPrepare quarterly a table of daily fuel use by rig and transmit this to Company Environmental Coordinator |

# Procedure/Requirements

1. Assigned Personnel shall monitor daily drill rig fuel use in all rig engines, heaters, and boilers using the methods below and will provide the HSE Administrative Assistant the daily fuel usage reports at the end of each month.
2. Fuel usage monitoring and recordkeeping (if using equipment fuel flow meters)
	* 1. Record on daily fuel usage report the equipment fuel flow meter reading and the time reading was taken.
		2. Calculate and record on the daily fuel usage report daily fuel use by subtracting previous day’s meter reading from today’s.
3. Fuel usage monitoring and recordkeeping (if strapping)
	* 1. For each tank being strapped, record on daily fuel usage report the fuel height and time of daily reading.
		2. On days where fuel is delivered into the tank, record the height on the daily fuel log before the delivery and after the delivery with a note that these additional heights are recorded due to a fuel delivery. The fuel consumption for that day may be determined using the pre-delivery height reading or by taking and recording one at the end of the day. Thus, for the following day use the post-delivery height reading or the end of the day height reading as appropriate.
		3. Document the method of volume calculation from height in inches to gallons (conversion chart, site glass, calculation), keep the conversion chart on location.
4. Fuel usage monitoring and recordkeeping where daily deliveries are made to rig tank(s)
	* 1. If the deliveries are metered, record metered volume on daily fuel usage report. This is the amount assumed to be consumed by rig equipment.
		2. If the deliveries are not metered, record initial and final fuel height readings in the receiving tank(s) and use this to calculate the volume delivered. Record this on the daily fuel usage report as the amount assumed to be consumed.
		3. Generally, tanks should be filled to a similar level each day.
5. Fuel usage monitoring and recordkeeping (no metering or strapping)
	* 1. Ensure affected equipment has a non-resettable hour meter installed
		2. Using Excel, for each piece of equipment on the rig, create a table with columns labeled Date, Time, Equipment Maximum Fuel Consumption Rate Per Hour, Hours Operated, Fuel Consumed (maximum fuel consumption rate per hour x hours operated). Each row on the table will be a separate calendar day. Use separate tabs for each piece of equipment; label the tabs with the equipment ID
		3. Create a summary tab that contains a table with rows representing each day. Label the first column Date and the second column Total Rig Fuel Consumed. Set up each cell in the second column to sum the daily Fuel Consumed from each individual equipment tab.
6. HSE Administrative Assistant will transmit to Company Environmental Coordinator within one week of the end of each calendar quarter a table of daily rig fuel consumption over that calendar quarter.

­­

Attachment 5 – ADEC Notification Form

Excess Emissions and Permit Deviation Reporting

State of Alaska Department of Environmental Conservation

Division of Air Quality

|  |  |  |
| --- | --- | --- |
|   |  |  |
| **Stationary Source Name** |  | **Air Quality Permit No.** |
|  |  |  |
| **Company Name** |  | **Date** |

**When did you discover the Excess Emissions/Permit Deviation?**

|  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Date: |  | / |  | / |  | Time: |  | : |  |

**When did the event/deviation?**

|  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Begin Date: |  | / |  | / |  | Time: |  | : |  | (Use 24-hr clock.) |
| End Date |  | / |  | / |  | Time: |  | : |  | (Use 24-hr 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 unit(s) Involved:

Identify the emission units involved in the event, using the same identification number and name as in the permit. Identify each emission standard potentially exceeded during the event and the exceedance.

|  |  |  |
| --- | --- | --- |
| EU ID | Emission Unit Name | Permit Condition Exceeded/Limit/Potential Exceedance |
|       |       |       |

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

[ ] Opacity     % [ ] Venting     (gas/scf) [ ] Control Equipment Down

[ ] Fugitive Emissions [ ] Emission Limit Exceeded [ ] Record Keeping Failure

[ ] Marine Vessel Opacity [ ] 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) (check boxes correspond with sections in 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 Unit

[ ] Stationary Source-Wide

[ ] Other Section:     (title of section and section # of your permit)

(b) Emission unit(s) 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.

|  |  |  |
| --- | --- | --- |
| EU 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. Department’s Air Online Services using the Permittee Portal option: <http://dec.alaska.gov/applications/air/airtoolsweb>

Or

1. Email to: DEC.AQ.Airreports@alaska.gov

Or

1. Fax to: 907-451-2187

Or

1. Mail to: ADEC

Air Permits Program

610 University Avenue

Fairbanks, AK 99709-3643Or

 Or

1. Phone notifications: 907-451-5173

*Phone notifications require written follow up report*.

*If submitted online, report must be submitted by an authorized E-Signer for the stationary source.*

Technical Analysis Report

**for**

Minor General Permit 2

**Issued to**

**Oil or Gas Drilling Rigs**

**Prepared by Aaron Simpson**

Alaska Department of Environmental Conservation
Air Permits Program

**Final Date: DATE**

1. **INTRODUCTION**

This Technical Analysis Report (TAR) provides the Alaska Department of Environmental Conservation’s (Department’s) basis for issuing minor general permit 2 (MG-2) for North Slope portable oil and gas operations (POGOs) classified under 18 AAC 50.502(c)(2)(A). The Department is issuing MG-2 under the provisions of 18 AAC 50.560.

1. **BACKGROUND DISCUSSION**

The Department developed MG-2 upon the recommendation of the *Workgroup for Global Air Permit Policy Development for Temporary Oil and Gas Drill Rigs* (Workgroup).[[13]](#footnote-14) The Workgroup was organized by the Department and the Alaska Department of Natural Resources (DNR) to discuss air quality concerns and operational limitations for temporary oil and gas drill rig operations at existing oil and gas facilities. The Workgroup consisted of representatives from the following interested parties:

* The Department’s Air Quality Division
* DNR’s Division of Oil and Gas
* Alaska Oil and Gas Association (AOGA)
* Cook Inlet Regional Citizens Advisory Council (CIRCAC)
* Alaska Support Industry Alliance (ASIA)
* North Slope Borough (NSB)

The Workgroup was charged with developing recommendations for improving air permit program policies and procedures. They have been assessing the issue since spring 2013.

The Workgroup established two subcommittees in December 2013, a Technical Subgroup and an Options/Policy Subgroup, to work through the various details of the charge. The Technical Subgroup assessed the monitoring and modeling data available at the time to determine whether it was “sufficiently accurate, representative and complete to reasonably conclude” that drilling activity anywhere in the State is unlikely to cause ambient air concentrations greater than the Alaska Ambient Air Quality Standards (AAAQS) listed in 18 AAC 50.010.[[14]](#footnote-15) They concluded that additional information was needed, which could best be met through air quality modeling.

Since it would be untenable to model the entire State in a single analysis, the Technical Subgroup limited their initial modeling analysis to just North Slope operations. They will likely assess other parts of Alaska in the future, at which point the Workgroup will decide whether they should recommend additional permitting/regulatory changes.

The Technical Subgroup addressed four portable oil and gas operation (POGO) categories, which they designated as:

* Routine infill drilling at an isolated well pad (RDi);
* Routine infill drilling at a collocated well pad (RDc):
* Developmental drilling at an isolated well pad (DDi); and
* Developmental drilling at a collocated well pad (DDc).

They also assumed: the POGO occurs at an onshore location; the POGO emissions units (EUs) are liquid-fired; and that all of the internal combustion units are reciprocating engines.

The Technical Subgroup developed a Technical Report that describes in further detail the air quality modeling approach and assumptions used for the North Slope simulation. The Department sought public comment on the modeling analysis and Technical Report from September 13, 2017 through October 13, 2017. The Department only received editorial comments regarding the Technical Report. The Technical Subgroup finalized the Technical Report on October 17, 2017.[[15]](#footnote-16)

As discussed in the Technical Report, the Technical Subgroup used the U.S. Environmental Protection Agency’s (EPA’s) AERMOD Modeling System (AERMOD) for the North Slope POGO simulation. This is the EPA approved dispersion model for conducting an onshore, near-field simulation. The Technical Report further notes that the modeling analysis is consistent with EPA’s *Guideline on Air Quality Models* (Guideline), as required under 18 AAC 50.215(b).

The Technical Subgroup subsequently decided to also assess POGO activity at island developments within the Beaufort Sea. Emissions from island developments are typically modeled in a different manner than onshore emissions due to the unique dispersion conditions associated with overwater boundary layers. The EPA approved dispersion model for conducting overwater, near-field simulations is the Offshore and Coastal Dispersion (OCD) model. However, the modeling of offshore sources in northern latitudes requires additional consideration since the water bodies seasonally vary from open water to ice cover. OCD is EPA’s preferred model for assessing the ambient impacts during the open water season, but AERMOD is better suited for assessing the winter-time impacts since ice cover leads to similar boundary layer conditions to that of land.

The Technical Subgroup conducted a sensitivity analysis of the potential impacts during open water conditions using OCD and AERMOD. Their findings are discussed in a January 10, 2018 technical memorandum from Isaac Bertschi (SLR International Corporation) to Alan Schuler (Department), which the Department is providing in Appendix B of this TAR. The Technical Subgroup compared the maximum POGO impacts during the typical Beaufort Sea open water season (July through October) for the following averaging periods and pollutants: 1-hour nitrogen dioxide (NO2), period NO2, 1-hour sulfur dioxide (SO2), period SO2, 24-hour particulate matter with an aerodynamic diameter of 2.5 microns or less (PM2.5), and period PM2.5. AERMOD estimated substantially greater impacts than OCD in all cases. The Department therefore concludes that the findings described in the Technical Report also apply to POGO activities at island developments within the Beaufort Sea.

The Department stated in the public notice of the North Slope modeling analysis that it “intends to use the results of the ambient demonstration in a future minor permit decision(s) issued under AS 46.14 and 18 AAC 50.” The MG-2 permit falls under this statement. The modeling analysis demonstrates that operating a North Slope POGO within the constraints described in the report will not cause or contribute to a violation of the following AAAQS:

* SO2: 1-hour, 3-hour, 24-hour, and annual averaging periods.
* Carbon Monoxide (CO): 1-hour and 8-hour averaging periods.
* NO2: 1-hour and annual averaging periods.
* Particulate matter having an aerodynamic diameter of 10 microns or less (PM10): 24-hour averaging period.
* PM2.5: 24-hour and annual averaging periods.

MG-2 includes the constraints described in the Technical Report, except for the onshore constraint. As previously noted, the Technical Report findings also apply to POGOs operating at Beaufort Sea islands. The Department developed the monitoring, recordkeeping, and reporting (MR&R) provisions needed to confirm compliance with the ambient air conditions.

1. **DEFINITIONS**

The term “portable oil and gas operation” is defined in 18 AAC 50.990(124) to mean: “an operation that moves from site to site to drill or test one or more oil or gas wells, and that uses drill rigs, equipment associated with drill rigs and drill operations, well test flares, equipment associated with well test flares, camps, or equipment associated with camps; ‘portable oil and gas operation’ does not include well servicing activities; for the purposes of this paragraph, ‘test’ means a test that involves the use of a flare”.

The term “well servicing activities” is defined in 18 AAC 50.990(125) to mean: “the use of portable equipment for servicing existing oil and gas wells that only stays on site for short and varying periods of time; ‘well servicing activities’ includes the use of [coiled tubing units, well frac units, well slickline units, well hot oil units, and well wireline units]”.

1. **REGULATORY BASIS FOR A MINOR GENERAL PERMIT**

The regulatory provisions for establishing a minor general permit are established in 18 AAC 50.560. Paragraph (a) states the Department “may issue a general minor permit to allow construction and operation of stationary sources or emission units” that require a minor permit, involve the same or similar types of operation, involve the same type of emissions, and are subject to similar air quality control requirements. MG-2 meets this requirement since POGOs are required to obtain a minor permit under 18 AAC 50.502(c)(2)(A), and they involve the same types of operation, emissions, and control requirements.

18 AAC 50.560(c) requires the Department to develop an application or notification form with each minor general permit. 18 AAC 50.560(b) requires the Department to provide notice and opportunity for public comment on the proposed permit and of the proposed application or notification form. The Department therefore provided a public comment period from
March 15, 2018 through April 16, 2018. The Department considered all comments received during this period in its final decision. The Department’s response to these comments are in the Response to Comments document. The minor general permit applications are available on the Department’s general permit web-site at: [http://dec.alaska.gov/air/air-permit/general-permits](http://dec.alaska.gov/air/air-permit/general-permits/).

18 AAC 50.560(d) allows the Department to specify whether the applicant must submit a complete notification form and operate in compliance with the general minor permit, or whether the applicant must also obtain Department approval under 18 AAC 50.560(e) to operate under the general minor permit. The applicant does not need to obtain Department approval under 18 AAC 50.560(e) prior to operating under the MG-2.

18 AAC 50.560(f) describes the required content of a minor general permit. MG-2 complies with these requirements, as further discussed in Section 7 of this TAR.

18 AAC 50.560(g) provides a process for relocating a portable stationary source. Condition 21 requires the Permittee to notify the Department of POGO relocations that differ from the Initial Application or Annual Notification Forms by submitting a completed relocation notification located in Attachment 3.

There are no references to federal regulations because minor permits are not required to include New Source Performance Standards (NSPS) or National Emission Standards for Hazardous Air Pollutants (NESHAP). Equipment subject to federal regulations are still required to comply with any applicable rules.

1. **EMISSIONS SUMMARY AND PERMIT APPLICABLITY**

Table 1 shows the emissions summary and permit applicability from a POGO activity allowed under MG-2. Emission factors and detailed calculations are provided in Appendix A.

Table 1 - Emissions Summary and Permit Applicability, tons per year (tpy)

| Parameter | NOX | CO | VOC | PM-2.5 | PM-10 | SO2 |
| --- | --- | --- | --- | --- | --- | --- |
| Potential to Emit | 40.1 | 56.1 | 3.2 | 20.3 | 20.3 | 42.0 |
| Title V Permit Threshold | 100 | 100 | 100 | 100 | 100 | 100 |
| Title V Permit Required?  | No | No | No | No | No | No |

1. **DEPARTMENT FINDINGS**
2. The ambient analysis conducted by the Technical Subgroup meets the ambient demonstration requirements in 18 AAC 50.540(c)(2)(B) for minor permits classified under 18 AAC 50.502(c)(2)(A). The ambient analysis also demonstrates compliance with the 1-hour NO2 AAAQS.
3. The drill rig engines and portable engines operated as part of the POGO (EUs 1 and 4, respectively) are nonroad engines and therefore not classified as fuel burning equipment per 18 AAC 50.990(39). As such, they are not subject to the state emission standards and emissions from nonroad engines are not included in the potential or assessable emissions total.
4. EUs 1 and 4 must remain nonroad engines in order for the Permittee to continue operating those engines under MG-2 (i.e., EUs 1 and 4 must not remain at the same location[[16]](#footnote-17) for 12 consecutive months or more, per 40 C.F.R. 89.2). For purposes of this paragraph, periods of inactivity between operations count towards the 12 consecutive month limit, unless the POGO is placed into storage mode (also known as ‘stacking’). While a POGO is placed into storage mode, its engines do not lose their nonroad status.
5. The MG-2 permit is structured to allow operators the flexibility to apply it to an entire oil and gas Unit as identified by the Alaska Department of Natural Resources Division of Oil and Gas on state land and by the Bureau of Land Management on federal lands. This allows a Permittee to operate multiple POGOs within a given oil and gas unit boundary. However, the daily fuel limits apply on a per pad basis.
6. Well flow back emissions that occur prior to the wells placed into production should be considered “construction phase emissions” and are not to be included in the calculations to determine if an existing stationary source is subject to Prevention of Significant Deterioration (PSD) review. Consequently, it is not appropriate to limit these emissions for the purpose of avoiding classification as a major source or major modification and the subsequent PSD review. For existing sources that contain VOC avoidance limits for PSD permit applicability, VOC emissions from well flow back events prior to the wells being placed into production should not be counted toward compliance with those limits.
7. **PERMIT CONDITIONS**

18 AAC 50.560(f)(3) requires a minor general permit to include the requirements established under 18 AAC 50.544. These requirements, and how the Department met them in MG-2, are summarized below. This section also discusses the basis for all other conditions as set forth in AS 46.14 and 18 AAC 50.

Cover Page

18 AAC 50.544(a)(1) requires the Department to identify the stationary source, Permittee, and contact information. MG-2 includes place-holders for this information.

Section 1: Emissions Unit Inventory

Permit Table 1 lists emissions units at the source by EU #, EU Name, EU description, and rating/max capacity. Unless otherwise noted in the permit, the information in permit Table 1 is for identification purposes only.

Section 2: Emission Fees

18 AAC 50.544(a)(2) requires the Department to include a requirement to pay fees in accordance with 18 AAC 50.400 – 18 AAC 50.499. MG-2 includes these requirements.

**Section 3: State Emission Standards and MR&R**

The visible and emission limits established in 18 AAC 50.055 apply to all fuel-burning equipment. The Department has therefore incorporated these limits as follows in MG-2 and for well test flares.

**Condition 8: Visible Emissions**

Condition 8 prohibits the Permittee from causing or allowing visible emissions in excess of the applicable standard in 18 AAC 50.055(a)(1).

For activities not subject to Title V permitting or for the provisions of this permit to be included in the operating permit as an administrative amendment or modification, the Department has included monitoring, recordkeeping and reporting requirement to ensure continued compliance with the VE standards. Diesel-fired heaters and boilers have the tendency to exceed the VE standards. As such, the Department has included a requirement to perform Method 9 testing, recordkeeping and reporting requirements to demonstrate continued compliance with the standard.

Condition 9, Particulate Matter (PM)

Condition 9 requires the Permittee to comply with the State PM (also called grain loading) standard in 18 AAC 50.055(b) applicable to fuel-burning equipment. The Permittee shall not cause or allow fuel-burning equipment to violate this standard. The Permittee is required to conduct PM source testing if threshold values for opacity are exceeded.

Condition 10, Sulfur Compound Emissions

Condition 10 requires the Permittee to comply with the sulfur compound emission standard in 18 AAC 50.055(c). Monitoring, recordkeeping, and reporting shall be conducted in accordance with the ambient air quality protection requirements listed in Condition 12.2 to ensure compliance with the sulfur compound emission standard in 18 AAC 50.055(c).

Section 5: Ambient Air Quality Protection Requirements

Conditions 11 and 12, Ambient Air Quality Protection Requirements

18 AAC 50.544(a)(6) and 18 AAC 50.502(c)(1) require the Department to impose conditions as necessary to protect ambient air quality. The ambient analysis conducted by the Technical Subgroup indicates that restrictions are needed to protect the AAAQS. The Department therefore included these restrictions in MG-2. The restrictions include: daily fuel consumption limits for various POGO categories; limits on the fuel sulfur content; and exhaust stack requirements. MG-2 also prohibits concurrent drilling and fracing of an unconventional resource.[[17]](#footnote-18) The Department added monitoring, recordkeeping, and reporting for each ambient air quality protection requirement. For fuel consumption rates, the Department added flexibility for the applicant to follow four procedures or to propose a site-specific technique to track POGO fuel consumption.

Section 6: General Recordkeeping, Reporting, and Certification Requirements

Condition 13, Certification

18 AAC 50.205 states all reports or compliance certifications required under a permit be signed and certified by a responsible official. This requirement is reiterated as a standard permit condition in 18 AAC 50.345(j), which must be incorporated in all minor permits, per 18 AAC 50.544(a)(5). MG-2 uses the standard language, as required, but it also contains additional wording that allows the Permittee to provide electronic signatures.

Condition 14, Submittals

Condition 14 clarifies where and how the Permittee should send their reports, certifications, and other submittals required by this permit. The Department included this condition from a practical perspective rather than a regulatory obligation.

Condition 15, Information Requests

AS 46.14.020(b) allows the Department to request a wide variety of emissions, design and operational information from the owner and operator of a stationary source. This statutory provision is reiterated as a standard permit condition in 18 AAC 50.345(i), which must be incorporated in all air quality control minor permits, per 18 AAC 50.544(a)(5). The Department used the standard language in MG-2.

Condition 16, Recordkeeping Requirements

The condition restates the regulatory requirements for recordkeeping, and supplements the recordkeeping defined for specific conditions in the permit. The records being kept provide an evidence of compliance with this requirement.

Condition 17, Excess Emission and Permit Deviation Reports

This condition requires the Permittee to comply with the applicable requirement in 18 AAC 50.235(a)(2) and 18 AAC 50.240. Also, the Permittee is required to notify the Department when emissions or operations deviate from the requirements of the permit. The Department mostly used the Standard Condition III language, but with updated web-links.

Condition 18, Operating Reports

The Department mostly used the Standard Operating Permit Condition VII language for the operating report condition in MG-2. However, the Department modified or eliminated the Title V only aspects in order to make the language applicable for a minor permit.

Condition 19, Affirmation of Title V Avoidance

18 AAC 50.544(d) requires the Department to impose a periodic affirmation, in accordance with 18 AAC 50.205, of whether the POGO is still accurately described by the application and minor permit and whether the POGO activities become subject to other permits under
18 AAC 50. The requirement applies to stationary sources not subject to Title V permitting. The Department anticipates that some POGO activities under this minor general permit will not occur as part of a Title V stationary source. Condition 19 incorporates this requirement. The Permittee must provide the affirmation by March 31st of each year.

**Conditions 20 and 21, Annual Notification and Relocation Notification**

18 AAC 50.560(f)(2) requires the Permittee to notify the Department of the physical location of proposed POGO activities before commencing construction or operation under the MG-2.

18 AAC 50.560(f)(4) and (g)(1) require a notification form and procedures for changing locations of portable stationary sources. Condition 20 requires the Permittee to identify annually, which well pads or drill sites they plan to operate at during the following calendar year. Condition 21 requires the Permittee to notify the Department as soon as possible of any changes in the previously identified drilling locations.

Section 7: Standard Permit Conditions

Conditions 22 - 26, Standard Permit Conditions

As previously discussed, 18 AAC 50.544(a)(5) requires each minor permit to contain the standard permit conditions in 18 AAC 50.345, as applicable. 18 AAC 50.345(a) clarifies that subparts (c)(1) and (2), and (d) through (o), may be applicable for a minor permit.

The Department included all of the minor permit-related standard conditions of 18 AAC 50.345 in MG-2. The Department incorporated these standard conditions as follows:

* 18 AAC 50.345(c)(1) and (2) is incorporated as Condition 22 of Section 7 (Standard Permit Conditions);
* 18 AAC 50.345(d) through (h) is incorporated as Conditions 23 through 27, respectively, of Section 7 (Standard Permit Conditions);
* As previously discussed, 18 AAC 50.345(i) is incorporated as Condition 15 and 18 AAC 50.345(j) is incorporated as Condition 13 of Section 6 (Recordkeeping, Reporting, and Certification Requirements); and
* 18 AAC 50.345(k) is incorporated as Condition 28, and 18 AAC 50.345(l) through (o) is incorporated as Conditions 31 through 34, respectively, of Section 8 (General Source Testing Requirements). See the following discussion.

**Section 8: General Source Test Requirements**

AS 46.14.180 states that monitoring requirements must be, “based on test methods, analytical procedures, and statistical conventions approved by the federal administrator or the department or otherwise generally accepted as scientifically competent.” The Department incorporated this requirement as follows:

* Condition 29 requires the Permittee to conduct their source tests under conditions that reflects the actual discharge to ambient air; and
* Condition 30 requires the Permittee to use specific EPA reference methods when conducting a source test.
1. **Permit Administration**

The MG-2 permit could be redundant with the terms and conditions of a Title I or Title V permit. The Permittee may choose to revise their existing stationary source specific permit once the MG-2 permit becomes effective by submitting a permit specific request. Drill sites that are not physically adjacent to or contiguous with Title V major production facilities or production centers are considered isolated well pads for ambient air quality protection purposes. Drill sites that are physically adjacent to or contiguous with Title V major production facilities or production centers are considered collocated well pads for ambient air quality protection purposes. Emissions from these well pads should be reviewed in accordance with the applicable stationary source permit on a case-by-case basis. The MG-2 permit operates outside the scope of this discussion.

Once a Permittee obtains an MG-2 permit, requests to remove POGO-related language from existing Title V permits will qualify as administrative permit amendments if they are permit revisions that meet the requirements in 40 C.F.R. 71.7(d)(1) and the administrative permit amendment procedures in 40 C.F.R. 71.7(d)(3).

However, an underlying Title I permit would need to be revised, prior to administratively revising the Title V permit, if it contradicts or violates a condition in the MG-2 permit. Similarly, Title I permits would need to be revised prior to revising PSD avoidance limits or BACT limits from Title V permits to ensure that the changes are not modifications under any provision of Title I of the Clean Air Act and that the changes do not exceed the emissions allowed under the permit (whether expressed therein as a rate of emissions or in terms of total emissions). The MG-2 permit is applicable to a POGO on a well pad basis or on a unit basis where multiple POGOs can be covered by the permit. This allows a Permittee to operate multiple POGOs within a given oil and gas unit boundary. However, the daily fuel limits apply on a per pad basis.

# Appendix A: Emissions Calculations

Table 2 presents details of the EUs, their characteristics, and emissions. Potential emissions are estimated using maximum annual operation for all fuel-burning equipment as defined in 18 AAC 50.990(39) based on full-time operation.

Table 2 - Emissions Summary, in Tons Per Year (TPY)

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **EU ID** | **Unit ID/Description** | **Maximum Rating or Capacity** | **NOX**  | **CO** | **VOC** | **PM-2.5 / PM-10 / PM** | **SO2** |
| **EF** | **PTE (tpy)** | **EF**  | **PTE (tpy)** | **EF**  | **PTE (tpy)** | **EF**  | **PTE (tpy)** | **PTE (tpy)** |
| 1 | Drill Rig Reciprocating Engines | 15,435 | gal/day | 3.2 | lb/MMBtu | 769.6 | 0.85 | lb/MMBtu | 292.9 | 0.1 | lb/MMBtu | 34.5 | 0.0573 | lb/MMBtu | 3.63 | 0.43 |
| 2 | Drill Rig Heaters and Boilers | 20 | lb/kgal | 17.0 | 5 | lb/kgal | 14.1 | 0.34 | lb/kgal | 1.0 | 3.30 | lb/kgal | 9.30 | 19.90 |
| 3 | Well Venting/Flow Backs | 25 | wells/yr |   |   |   |   |   |   |   |   | 90.4 |   |   |   |   |
| 4 | Miscellaneous POGO Reciprocating Engines Not on Drill Rig | 10,774 | gal/day | 3.2 | lb/MMBtu | 769.6 | 0.85 | lb/MMBtu | 292.9 | 0.1 | lb/MMBtu | 34.5 | 0.0573 | lb/MMBtu | 3.63 | 0.43 |
| 5 | Miscellaneous POGO Boilers and Heaters Not on Drill Rig | 4,661 | gal/day | 20 | lb/kgal | 17.0 | 5 | lb/kgal | 14.1 | 0.34 | lb/kgal | 1.0 | 3.30 | lb/kgal | 9.30 | 19.90 |
| 6 | POGO Portable Flares | 130 | MMscf/yr | 0.068 | lb/MMBtu | 6.1 | 0.31 | lb/MMBtu | 27.9 | 0.66 | lb/MMBtu | 1.2 | 11.02 | lb/hr | 1.72 | 2.19 |
| **Total Potential to Emit for Permit Applicability Determination** | **40.1** |  |  | **56.1** |  |  | **3.2** |  |  | **20.3** | **42.0** |
| **Total Assessable Emissions** |  | **252** |

Notes-

a. EUs 1 and 2: Combined daily fuel consumption limit is 15,435 gallons (including 1.25 excursions 20 percent of the time). Assuming the heaters/boilers would consume 30.2% of this limit, which equals 4,661 gal/day. Assumed EU 1 burns the remaining 10,774 gal/day.

b. EUs 4 and 5: PTE based on 15,435 gallons per day (including 1.25 excursions 20 percent of the time). Assuming the heaters/boilers would consume 30.2% of this limit, which equals 4,661 gal/day. Assumed EU 4 burns the remaining 10,774 gal/day.

c. EU 4: Emissions = (10,774 gal/day) \* (365 days/yr) \* (Emission Factors in AP-42, Tables 3.4-1 and 3.4-2). These emissions are not added to the PTE.

d. EU 5: Emissions = (4,661 gal/day) \* (365 days/yr) \* (Emission factors from AP-42, Tables 1.3-1, 1.3-2, and 1.3-7).

e. EU 6: Emissions = (assumed 130 MMscf/yr limit) \* (Emission factors given in AP-42, Chapter 13-5).

f. SO2 emissions for all units estimated by mass balance assuming heat contents in application, 6.76 lb/gal, 15 ppmw S (ULSD) for the engines and 0.15% S by weight (LEPD) for the boilers/heaters, and 200 ppmv H2S, as applicable.

g. HAPs estimated to be 1.6 tpy to confirm the stationary source is not a major source for HAPs.

h. Emissions from New Well Flowbacks: Volume of flowback total oil per well [[18]](#footnote-19) 200 bbls/flowback

 Gas-to-Oil Ratio (GOR) [[19]](#footnote-20) 0.00189 MMscf/bbl

 Lift gas volume [[20]](#footnote-21) 0.06250 MMscf/flowback

 Total Volume of Gas/flowback 0.441 MMscf/flowback

 Total Gas emissions/flowback 12.8 tons/flowback

 Potential number of new wells per year 25 wells

Total flashed gas including CO2, N2, non-VOC, and VOC 320 tons

i. VOC emissions from EU 3 (well flow backs that occur prior to the well being placed into production) should be considered construction phase emissions. Emissions from this activity are similar to bailout emissions for new steam generators which EPA guidance has previously considered to be "construction phase emissions." Construction phase emissions are not be included in the calculations to determine permit applicability. Consequently, it is not appropriate to limit these emissions for the purpose of avoiding classification as a major source or major modification.

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Conversion factors: |  |  |  |  |
| Standard molar volume | 385.3 | scf/lb-mol | 1 ft3 | 28.316 | Liters |
| F-Factor for natural gas | 8,710 | dscf/MMBtu (68 oF) | HHVULSD | 19,500 | Btu/lb |
| F-Factor for diesel | 9,190 | dscf/MMBtu (68 oF) | LHVULSD | 18,400 | Btu/lb |
| Temperature | 60 | oF = 288.71 oK | HHVLEPD | 19,600 | Btu/lb |
| Pressure | 1 | atmosphere | LHVLEPD | 18,500 | Btu/lb |
| 1 lb | 453.592 | grams | Mol. Wt. SO2 | 64.0628 | grams/mol |

# Appendix B:

# AERMOD and OCD Intercomparison Analysisfor Alaska North Slope POGOslocated at gravel islands in the beaufort sea

1. Assess Title V fees if planning to operate POGO contiguous/adjacent on a Title V source. Assess Title I fees if separate. [↑](#footnote-ref-2)
2. The restriction described in Condition 7.5 only applies to platforms. Minor General Permit 2 is applicable to POGOs operating on island developments within the Beaufort Sea. [↑](#footnote-ref-3)
3. “Fuel-burning equipment” does not include equipment operated as a nonroad engine, per 18 AAC 50.990(39). [↑](#footnote-ref-4)
4. For purposes of this permit, a “*flare event*” is flaring of gas at a rate that exceeds the source’s de-minimus pilot, purge, and assist gas rates for a minimum of 18 consecutive minutes. It does not include non-scheduled release operations, i.e. process upsets, emergency flaring, or de-minimis venting of gas incidental to normal operations. [↑](#footnote-ref-5)
5. For the purposes of this permit, *unconventional resources* is differentiated from conventional hydrocarbon resources based on the state of the hydrocarbon, nature of the geologic reservoirs and the types of technologies required to extract the hydrocarbon. Conventional oil and gas deposits have a well-defined areal extent, the reservoirs are porous and permeable, the hydrocarbon is produced easily through a wellbore, and reservoirs generally do not require extensive well stimulation to produce. Unconventional hydrocarbon deposits in general are often lower in resource concentration, dispersed over large areas, and require well stimulation or additional extraction or conversion technology. [↑](#footnote-ref-6)
6. Routine Infill Drilling at an Isolated Well Pad: Drilling that lasts less than 24 consecutive months at a well pad that is not adjacent to, adjoining, or abutting a Title V major production facility. For the purpose of this permit the term production facility includes production centers, gathering centers, flow stations, or equivalent. [↑](#footnote-ref-7)
7. Routine Infill Drilling at a Collocated Well Pad: Drilling that lasts less than 24 consecutive months at a well pad that is adjacent to, adjoining, or abutting a Title V major production facility. [↑](#footnote-ref-8)
8. Developmental Drilling at an Isolated Well Pad: Drilling that lasts 24 or more consecutive months at a well pad that is not adjacent to, adjoining, or abutting a Title V major production facility. [↑](#footnote-ref-9)
9. Developmental Drilling at a Collocated Well Pad: Drilling that lasts 24 or more consecutive months at a well pad that is adjacent to, adjoining, or abutting a Title V major production facility. [↑](#footnote-ref-10)
10. For the purpose of this permit, collocated means that drill rig(s) and/or existing stationary sources are located on one or more contiguous or adjacent properties that are under the control of the same person (or persons under common control) and shall be considered part of a single “building, structure, or facility.” Pollutant emitting activities (SIC Major Group 13) shall be considered adjacent if they are located on the same surface site; or if they are located on surface sites that are located within 1⁄4 mile of one another (measured from the center of the equipment on the surface site) and they share equipment. Shared equipment includes, but is not limited to, produced fluids storage tanks, phase separators, natural gas dehydrators, or emissions control devices. Drill sites that are not physically adjacent to or contiguous with a Title V production facility should be treated as isolated pads for ambient air quality protection purposes. If a well pad or well site is aggregated under an existing Title V permit, but otherwise does not meet the definition of collocated as stated above, that well site or well pad will be considered isolated. [↑](#footnote-ref-11)
11. The Permittee may develop a custom fuel monitoring and recordkeeping plan using the Sample Plan as guidance. This plan shall be submitted with the permit application and is subject to Department review. If the Department determines that the plan does not produce accurate and precise results, the Permittee shall adjust the plan to ensure accuracy and precision. [↑](#footnote-ref-12)
12. Units are identified by the Alaska Department of Natural Resources Division of Oil and Gas on state land and by the Bureau of Land Management on federal lands. [↑](#footnote-ref-13)
13. Additional information regarding the Workgroup may be found on the Department’s website at: <http://dec.alaska.gov/air/air-permit/oil-gas-drill-workgroup> [↑](#footnote-ref-14)
14. [*Meeting Notes Summary – Technical Subgroup of Workgroup for Global Air Permit Policy Development for Temporary Oil and Gas Drill Rigs*](http://dec.alaska.gov/air/ap/docs/OilGasWorkgroup.TechnicalSubgroup.MeetingNotes.1-9-14.pdf) – January 9, 2014 Meeting [↑](#footnote-ref-15)
15. [*Ambient Demonstration for the North Slope Portable Oil and Gas Operation Simulation*](http://dec.alaska.gov/air/ap/docs/North-Slope-POGO-Simulation-Modeling-Report-FINAL-2017-10-17.pdf); October 17, 2107. [↑](#footnote-ref-16)
16. See definition of ‘nonroad engine’ in [40 C.F.R. 89.2](https://www.ecfr.gov/cgi-bin/text-idx?SID=197cbb1a395b5dbcdf6e5794ad57b3d0&mc=true&node=se40.22.89_12&rgn=div8). [↑](#footnote-ref-17)
17. For the purposes of MG-2, *unconventional resources* is differentiated from conventional hydrocarbon resources based on the state of the hydrocarbon, nature of the geologic reservoirs and the types of technologies required to extract the hydrocarbon. Conventional oil and gas deposits have a well-defined areal extent, the reservoirs are porous and permeable, the hydrocarbon is produced easily through a wellbore, and reservoirs generally do not require extensive well stimulation to produce. Unconventional hydrocarbon deposits in general are often lower in resource concentration, dispersed over large areas, and require well stimulation or additional extraction or conversion technology. [↑](#footnote-ref-18)
18. The total volume of oil per flowback for a new well was provided by CPAI Drilling and Wells group. This value represents only the oil and does not include water and other drilling fluids which dominate the total fluids produced during a typical flowback. [↑](#footnote-ref-19)
19. Gas-to-Oil Ratio (GOR) is the average of the GOR for CPF1, CPF2, and CPF3 as provided in Attachment F of the permit application for the Kuparuk River Unit Drill Site 2S, Minor Permit AQ1429MSS01. [↑](#footnote-ref-20)
20. Lift gas volume per flowback is based on a representative flowback which flows gas at 0.25 MMscfd for 6 hours. [↑](#footnote-ref-21)