Response to Comments on Preliminary Minor General Permit 2
for Portable Oil and Gas Operations

Prepared by Aaron Simpson and Alan Schuler on August 1, 2018

Permit Number: Minor General Permit 2

Public Comment Closing Date: April 16, 2018

This document provides the Alaska Department of Environmental Conservation’s (Department’s) reply to all public comments on the preliminary decision to issue Air Quality Control Minor General Permit 2 (MG-2) for Portable Oil and Gas Operations. The Department provided opportunity for public comment from March 15, 2018 through April 16, 2018.

The Department received comments from: the Alaska Oil and Gas Association (AOGA) and Alaska Support Industry Alliance (ASIA); ConocoPhillips Alaska, Inc. (CPAI); BP Exploration (Alaska) Inc. (BPXA); and Hilcorp Alaska, LLC. (Hilcorp). AOGA-ASIA provided a “high level” summary of their comments, along with an attachment that provided their detailed comments. CPAI and Hilcorp stated that they supported the AOGA-ASIA comments, along with providing additional comments.

All comments are verbatim in this Response to Comment (RTC) document, unless otherwise denoted through the use of {curly brackets}. However, the Department has renumbered the comments using the following alpha-numeric format: the first letter of the Commenter’s name followed by a sequential number for each comment from that Commenter. For example, the Department designated the third comment provided by AOGA-ASIA as “A-3” and the third comment from BPXA as “B-3.” The Department’s responses are shown in Times New Roman italic font.

**AOGA-ASIA’s High Level Comments**

**A-1: Notification Form**

The Notification Form should be broken into two separate forms: 1) one-time (initial) notification that MG2 will be used; and 2) annual notifications that will satisfy draft permit Condition 13.

The one-time (initial) notification form is the form the permittee submits when deciding to use the MG2 permit and is required only once during the life of the permit. Pages 1 – 4 and 6 of the form are appropriate for this Initial Notification. A new form for annual notifications that will satisfy draft permit condition 13 should be developed that contains only the Dates of Operation on page 3 of the draft permit Notification Form, the elements on page 4 of the draft permit Notification Form, and the appropriate permittee identification and signature blocks. Creating these two separate forms will facilitate compliance with draft permit condition 13.

The Notification Form in the draft permit also contains a Form 9 at page 5. We do not believe this form will serve any permit administration purpose and we would suggest it be removed. In addition, the information the form requires will be difficult to obtain on a routine basis since drill rig equipment is not under the control of the permittee. As equipment on rigs ages, it is replaced (with like kind or newer technology) often without the knowledge of the permittee because it is not owned by the permittee. We believe the information required by Form 9 is best obtained by periodic on-site inspections by the Department.

*Response: The Department split the notification form into two separate ‘forms’: a one-time (initial) application that an applicant submits when deciding to use the MG-2 permit, and an annual notification form that: identifies the owner, application contact, responsible official, drill rig, location of well pad(s), fuel monitoring plan, payment information, equipment to be operated, and a certification page. The Department finds that this information is required to be submitted on an annual basis because it can be subject to change each drilling season. The Department removed the applicability criteria and definition sections from the annual notification form because the Permittee is already required to submit an annual affirmation that the portable oil and gas operation (POGO) is still accurately described by the original application.*

*The Department also removed Form 9 from the initial application and annual notification forms because providing a complete list of all equipment on a well pad or oil and gas unit for an entire year would be difficult to provide so far in advance. Instead it included the emissions unit inventory from the permit with check boxes that can be used to indicate which of EUs 1 through 6 are expected to operate during the calendar year. This will meet the requirement under 18* *AAC* *50.560(c)(3) to identify all of the equipment to be operated under the minor general permit.*

**A-2: Since EU IDs 3-{6}**[[1]](#footnote-2) **are not regulated by the permit they should be removed; adjust PTE at condition 4.4 and Table 1 and Appendix A of the TAR**

In previous discussions with the Department, we made the case that the activities represented by this equipment are best regulated in a stationary source permit, as applicable, for the pad where the activities are occurring. The permittee is responsible for ensuring the appropriate permit for the pad taking into account the potential to emit that includes the activities represented by EU IDs 3-{6}.Removal of these EU IDs would, of course, require adjustment of the potential to emit values in permit condition 4.4a and Table 1 of Appendix A in the TAR. Please note also that the Department has previously issued guidance that VOC emissions from new well flowbacks are not part of a stationary source's potential to emit (attached).

*Response: The Department did not remove emissions units (EUs) 3 through 6 from the permit for the following reasons:*

1. *Listing these EUs in the permit makes it clear to all parties (the applicant, Department staff, and members of the public) that they are authorized EUs – excluding them could lead to future questions and challenges; and*
2. *The emissions from EUs 5 and 6 are assessable under 18 AAC 50.410 since they are part of a “building, structure, facility, or installation which emits or may emit a regulated [New Source Review] pollutant” – see 18 AAC 50.990(105). The volatile organic compound (VOC) emissions from EU 3 likewise could be assessable – see the following paragraph. The emissions from EU 4 are not assessable, as previously noted in Section 6 of the Technical Analysis Report.*

*The Department acknowledges its September 21, 2005 letter related to VOC emissions from well construction activity (See Appendix A) and confirms that it is not appropriate to limit VOC emissions from well construction activity for the purpose of avoiding classification as a Prevention of Significant Deterioration (PSD) major source or major modification and the subsequent PSD review. The Department added a finding to that effect in Section 6 of the final Technical Analysis Report (TAR). However, the emissions are still assessable.*

**A-3: Technical analysis Report (TAR)**

Page 5, 2nd full paragraph of the TAR should be clarified to state that Attachment 2 applies only to deviations from the annual notification required by condition 13. This is consistent with the very clear administrative goal that only three types of notifications are required under the MG2: 1) Notification of Intent (submitted only once), 2) annual notifications, and 3) notification of deviations from the annual notifications. As worded in the draft, it is not so clear.

Importantly, the TAR at page 9, item 8 should clearly state that once the MG2 is secured, requests to remove POGO-related language from previously issued and existing permits and for revocation of POGO­specific minor source specific and Title V (TV) permits qualify as administrative revisions. We believe such requests qualify as administrative revisions since the substantive and technical work associated with the revisions will have all been completed and undergone public comment by the time any such requests are received by the Department.

Finally, please clarify in the TAR that the 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.

*Response: The Department revised the 1st paragraph on page 5 of the TAR to clarify that the form in Attachment 2 (now Attachment 3) is for relocations differing from the locations proposed in the initial application or the annual notification required by Condition 20 using Attachment 2.*

*The Department included additional information in Section 8 of the TAR to clarify how it expects the permit administration of an MG-2 permit to work in conjunction with existing minor source specific and Title V permits. It included the following paragraphs:*

*“For Permittees that have applied to renew or establish standalone Title V permits that address POGO activities and the Title V permits do not have any underlying Title I permit conditions, the Permittee may notify the Department that the renewal or initial Title V permit applications are withdrawn. Upon receipt and acknowledgment by the Department of this notice, the Permittee may immediately transition POGO-related activities governed by these application shields to instead comply with the provisions of the MG-2 permit. The Department reminds Permittees that a MG-2 permit must be effective prior to discontinuing these types of Title V permits/applications in order for POGO activities conducted under these permits/applications to continue without interruption.*

*Requests to remove POGO-related language from existing Title V permits that incorporate POGO activity provisions from an underlying Title I permit 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). In order to meet these requirements for Title V permits that are not standalone POGO permits, any POGO-related limit in an underlying Title I permit that contradicts a term or condition of the MG-2 permit, or that a Permittee seeks to revise, must be revised or rescinded prior to administratively revising the Title V permit.*

*Some Permittees conduct POGO activities under a Title I permit that does not have a corresponding Title V permit for the activity. Any POGO-related limit in such a permit that contradicts a term or condition of the MG-2 permit, or that a Permittee seeks to revise, must be revised or rescinded prior to transitioning to use of the MG-2 permit instead of the existing Title I permit.*

*In situations where a Permittee has elected to transition from conducting POGO-related activities under an existing Title I permit to a MG-2 permit, the Permittee may contact the Department to determine, on a case specific basis, if any condition of the permit must be revised or rescinded prior to implementing ongoing POGO activities under the MG-2 permit. In all cases where the Permittee desires to transition from an existing permit to the MG-2, the Permittee may contact the Department to work through the case specific details of their situations.”*

*The Department also included a statement in Section 6 of the TAR that 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.*

**AOGA-ASIA’s Detailed Comments**

On March 15, 2018, the Alaska Department of Environmental Conservation (ADEC or "Department") released its draft Air Quality Control Minor General Permit MG-2 ("MG-2"). The Alaska Support Industry Alliance and the Alaska Oil and Gas Association are submitting the following comments for the Notice of Intent to Operate, Permit, and the Technical Analysis Report that accompanies the MG-2 draft permit.

Text to be inserted into a permit condition is shown with underline formatting while text to be deleted is shown with ~~strikeout formatting~~. Occasionally, **bold font** is used in these comments to help spotlight edits that might otherwise be difficult to identify.

**Comments on Notice of Intent (NOI)**

**A-4**: Page 1: It is unclear what information is required by "Name of Prospect(s)." We suggest asking for "Oil and Gas Unit(s)" instead of prospect. Units are defined as noted within the Technical Analysis Report (TAR) on page 6 of 9.

*Response: The Department revised Page 1 of the Initial Application and Annual Notification Form (now included as Attachment 2) to clarify the information being requested is the name of the Oil and Gas Unit(s) or Well Pad(s).*

**A-5**: Page 1: The Department should expand the area for "Drilling Rig Identification" to allow for the listing of multiple drilling rigs. Currently the NOI appears to have limited space available to note multiple rigs.

*Response: The Department expanded the area for Drilling Rig(s) Identification to allow for a listing of multiple drilling rigs.*

**A-6**: Page 4: Revise Check box language as follows:

"Check here if a list of ~~all~~ drill rig equipment to be utilized as EU 1 or EU 2 to be operated under the ~~general~~ minor general permit is attached. Include make, model, and rated capacity with Form 9 or an equivalent summary."

*Basis:* The list of equipment should be limited to the equipment that will be utilized as Emission Units (EU) 1 (Drill Rig Reciprocating Engines) or 2 (Drill Rig Heaters and Boilers). These are the EUs that have express fuel use limitations within the permit.

*Response: The Department revised the check box language to clarify that the list of equipment that should be included per 18* *AAC* *50.560(c) can be met by checking boxes on the emission unit inventory table now provided in the initial application and annual notification in Attachment 2.*

**A-7**: Page 4: Revise Map requirements as follows:

"Attach a map showing the location(s) of your ~~stationary source~~ well sites to be drilled, and including roads, buildings, and water bodies~~, topography, and adjacent activities.~~"

*Basis:* Stationary Source should not be used to describe the activities within this permit as this permit is for Portable Oil and Gas Operations (POGOs). It is assumed the intent of the maps is to show the locations to be drilled, the proposed language above expressly states this intent.

The scope of this permit is expressly for the North Slope, and as demonstrated in the modeling conducted for this permit, the topography is known and therefore does not need to be disclosed again to the Department in a map.

The term "adjacent activities" is vague and therefore should be removed. The definition of this term could differ between Department personnel who receive NOI applications, which could result in permitting delays. Adjacent activities have also been well characterized and modeled within the background of the modeling for this permit and therefore do not need to be disclosed again within the maps submitted with this NOI.

*Response: The Department revised the map requirements to clarify that the locations identified on the map should be well sites to be drilled rather than a stationary source. The Department acknowledges that the topography is known for the North Slope and therefore does not need to be disclosed in a map. It also agrees that the term ‘adjacent activities’ is adequately characterized in the MG-2 permit and should be addressed with regard to the daily fuel consumption monitoring regime, not by the map associated with the notification form. See Footnote 10 of the permit for additional information.*

**A-8**: Remove **Form 9** from the permit or, at minimum, revise it as follows:

"~~Facility~~ Unit Name:"

"List in the table below the POGO equipment that is subject to the Permit ~~including equipment installed or removed during the reporting period~~."

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| **EU** | **Equipment Description** | **Make */* Model** | **Rated Capacity****hp/kW or tph** | **~~Date~~****~~Installed~~** | **~~Date~~****~~Removed~~** | **~~Operated~~****~~Yes/No~~** |

*Basis:*  Replace “Facility" with "Unit", as the MG-2 is regulating POGOs, there is not a facility that will be designated, however there will be locations specified for drill rig operations.

The date which equipment was installed or removed and operated is not relevant to this permit and, given the equipment is periodically replaced with like kind or newer technology, will be difficult to obtain. Because there is a fuel use limit for EUs 1 and 2, as long as the equipment remains in the internal combustion engine or heater/boiler category, it does not matter which equipment is actually used.

*Response: The Department removed Form 9 from the initial application and annual notification forms because providing a complete list of all equipment on a well pad for an entire year would be difficult to provide so far in advance. Instead it included the emissions unit inventory from the permit with check boxes that can be used to indicate which of EUs 1 through 6 are expected to operate during the calendar year. This will meet the requirement under 18 AAC 50.560(c)(3) to identify all of the equipment to be operated under the minor general permit.*

**Comments on the Permit**

**A-9**: Table 1: EU 3 (Well Venting/Flow Backs), EU 4 (Miscellaneous POGO Reciprocating Engines Not on Drill Rig), EU 5 (Miscellaneous Heaters and Boilers Not on Drill Rig), and EU ID 6 (POGO Portable Flares) should be removed from the EU Inventory. Condition 4.4a, the POGO's assessable potential to emit, should be commensurately adjusted.

*Basis*: There are no permit requirements which are affiliated with any of these three EUs and, as previously discussed with the Department. Rather, these EUs are associated with the stationary source at which they operate. Having these units in the EU Inventory table only creates confusion for the permittee as it unnecessarily notes units which are not governed by this permit. These units were accounted for within the modeling for this permit and are appropriately described within the TAR. They should not be noted within the permit itself.

*Response: The Department did not remove EUs 3 through 6 from the permit, for the reasons previously discussed in the Department’s response to Comment A-2.*

**A-10**: Condition 4.4b should be revised as follows:

“...based on actual annual emissions emitted during the most recent calendar year or another 12month period ...”

*Basis:* Typographical error.

*Response: The Department revised Condition 4.4b to hyphenate 12-month period.*

**A-11**: Revise Condition 8.1b and c as follows:

“~~b. Conducting a visible emissions observation following 4 0 C.F.R. 60, Appendix A 4 , Method 4 , for 18 minutes to obtain 72 consecutive 15 second opacity observations, within 90 days after the POGO becomes fully operational and within 12 consecutive months of the previous Method 9 observation; or~~

~~c. Including documentation with the first operating report required by Condition 20 that is submitted after the POGO becomes fully operational to show that a Method 9 observation was competed on each heater and boiler operating as EU 2 within 12 months prior to the POGO becoming fully operational and that results of those observations show compliance with the standard in Condition 8.~~

b. Annual Method 9 Observation: Conducting annual 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 a calendar year for emission unit operating at least 7 consecutive days at a site governed by this permit, regard less of physical location of the POGO within the Permittee's operated area.”

*Basis:* As written, Conditions 8.lb and c are confusing. It appears the Department's intent is to have visible emissions (VEs) conducted annually. Rather than specify “initial” versus “continuous” VEs, it would be simpler to conduct VEs on a calendar year basis and have the permit directly say that.

There should also be an allowance for not conducting a VE for short term use of equipment under the Permittee's authorization of this permit. If a rig spends less than seven consecutive days under the control of this permit, a VE should not be required. This is currently allowed under CPAI's Transportable Drilling Rigs Title V permit (AQ0909TVP01).

*Response: The Department received multiple proposals as to how Conditions 8.1b and 8.1c could be clarified (see Comment B-10). The Department agrees that clarification is warranted and that a VE reading should not be required for short-term usage of a boiler or heater (i.e., less than seven consecutive days). The Department therefore replaced Conditions 8.1b and 8.1c with a single sub-condition that requires an annual visible emissions observation for each heater and boiler that operates as EU 2 for more than seven consecutive days. The Department did not include the “site” and “physical location” language since those aspects are already addressed by the terms and conditions of MG-2. The Department also made minor editorial revisions to Condition 8 in order to enhance the overall readability.*

**A-12**: Revise Condition 8.3 as follows:

“8.3 ~~When using Condition 8.lb or 8.lc to verify initial compliance of a heater or boiler operated as EU 2, submit a copy of the observation records developed under Condition 8.1b or 8.1c (use the form in Attachment l), as applicable, to the first operating report submitted under Condition 20 for the period that covers the 30~~~~th~~ ~~day after the unit becomes fully operational.~~ Attach a copy of the observation records developed under Condition 8.lb (using the form in Attachment 1), ~~if applicable,~~ to the operating report that covers the period when the observations were completed.”

*Basis:* Should the language proposed in Comment 3) on the permit be adopted, the language in Condition 8.3 would need to be revised. This proposed language simplifies the reporting requirements for the VE observations.

*Response: The Department received multiple proposals as to how Condition 8.3 should be clarified as a follow-up to the proposed revisions to Conditions 8.1b and 8.1c (see Comment B-11). The Department agrees that revisions are warranted due to the changes made to Conditions 8.1b and 8.1c. The Department revised Condition 8.3 by removing the reference to Condition 8.1c (since it no longer exists) and clarifying that the Method 9 observation forms should be attached to operating reports for the reporting period during which the observations are conducted.*

**A-13**: Delete Footnote 4.

*Basis:* Should the language proposed in Comment 3) on the permit be adopted, Footnote 4 becomes obsolete. There would no longer be a need to define “fully operational” for the heaters and boilers because there is no longer a separation of "initial" VEs from “continuous” VEs. Also, deleting this footnote would eliminate confusion for requiring permittees to conduct VEs every time a drilling rig moves to a new pad. The way these conditions in conjunction with this footnote currently read, it could be construed the permittee is required to conduct a VE within 90 days of moving to a new well pad. This could mean that potentially 12 or more VEs could be conducted on the same EUs in a single year. We do not believe this is the Department’s intent with these conditions.

*Response: The Department deleted Footnote 4, but not for the reasons provided by the Commenter. The Department originally used Footnote 4 to define the phrase “fully operational,” which was used on Conditions 8.1a, 8.1b, 8.2, and 8.3. The Department has subsequently developed alternative wording in response to multiple comments regarding these conditions. The Department deleted the “fully operational” phrase from Conditions 8.1b and 8.3 as part of its response to the Comments A-11 and A-12. The Department deleted the phrase from Conditions 8.1a and 8.2 as part of its response to Comment B-9.*

**A-14**: Revise Condition 11.2 as follows:

“11.2 Prohibit the hydraulic fracturing (fracing) of unconventional resources6 while ~~operating~~ engaged in POGO activities at a given well pad...”

*Basis:* Using “engaged in POGO activities” rather than “operating” gives more clarity to the type of operation that is limited if fracing of unconventional resources might occur on the same pad.

*Response: The Department revised Condition 11.2 to clarify the type of operation that is limited if fracing of unconventional resources might occur on the same well pad (i.e., engaged in POGO activities).*

**A-15**: Revise Table 2 as follows:

“POGO With Concurrent Hydraulic Fracturing of a ~~Convenational~~ Conventional Resource”

*Basis:* Typographical error.

*Response: The Department corrected the typographical error in Table 2.*

**A-16**: Revise Condition 11.4 as follows:

“11.4 Record and report ~~In~~ in each operating report required under Condition 20, ~~the Permittee shall record~~ the drill rig identification ...”

*Basis:* There is no permit condition which explicitly requires the permittee to record the information requested to be in the operating report in Condition 11.4. Modifying the beginning sentence of this condition clarifies that recordkeeping and reporting of this information is required.

*Response: The Department received multiple requests to clarify Condition 11.4 (see Comment B-16). The Department revised Condition 11.4 to explicitly require the Permittee to record and report the information needed to demonstrate compliance with the fuel consumption limits in Table 2. It also revised the format of Condition 11.4 from a narrative to a list, in order to better describe the information that must be reported under this condition.*

**A-17**: Revise Condition 11.5b(i)(D) as follows:

“(D) 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”

*Basis:* This condition should include a provision like that found in draft condition 11.5a(i) for back calculation of fuel consumption. In the event the manufacturer does not provide full load consumption rates, the ability to back calculate the fuel consumption rate should be allowed.

*Response: The Department revised Condition 11.5(b)(i)(D) to include a provision for using a back-calculation from the rated capacity using standard engineering techniques and thermal efficiencies to calculate and record runtime hours and maximum fuel consumption rates.*

**A-18**: Revise Condition 11.5b(ii) as follows:

“Record the daily fuel consumption in gal/day using one or more of the following methods:

…

(D)(3) 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.”

*Basis:* Fuel use summations should be allowed to employ multiple methods of tracking, adding the language “or more” allows for this flexibility.

Should the language proposed in Comment 9 for the permit be accepted, “or back calculation” would need to be added to this condition.

*Response: The Department revised Condition 11.5(b)(ii)(D)(3) to include a provision for using a back-calculation from the rated capacity using standard engineering techniques and thermal efficiencies to calculate and record runtime hours and maximum daily fuel consumption totals.*

**A-19**: Revise Condition 11.5c(ii) as follows:

“(ii) 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 day~~:”

*Basis:* Drill rig operation is a 24-hour per day operation, where periods are measured by rig tower shifts. Fuel use is tabulated daily for the previous day, total daily fuel use will not be known until the next day.

*Response: The Department revised Condition 11.5(c)(ii) to allow the daily fuel consumption to be determined by the end of each calendar day for the previous day to allow for a 24-hour operating day as described by the Commenter.*

**A-20**: Revise Condition 14 as follows:

“14. The Permittee shall notify the Department if there is a revision to the well pads/drill sites identified in the notification submitted under Condition 13 ~~at least 10 days~~ as soon as practicable prior to operating at the new well pad/drill site. Use the form in Attachment 2 to make this notification.”

*Basis:* 10 days may not always be feasible for notification if a pad has changed from the original drill plan. Other factors can change the drill plans, for example: A bird nest was discovered on a well house only a few days before the rig move to that well. The rig schedule was changed to a different drill site to avoid disturbance of the bird nest per other environmental regulations. Another advance notification (aside from the annual notification) made 10 days prior to the change would not have been possible in this circumstance. To prevent high idling costs, well site changes need to be able to be made on short notice without delay to the drilling schedule.

*Response: The Department revised Condition 14 (now Condition 21) to require the relocation notification to be submitted to the Department ‘as soon as possible’ prior to operating at the new well pad/drill site to allow for additional flexibility in the event of an unexpected rig move. The term ‘as soon as practicable’ was not used because the Department finds it would be difficult to evaluate based on respective thoughts and intentions. ‘As soon as possible’ is intended to mean a test of feasibility and physical possibility, but in any event to occur prior to operating at the new site.*

**A-21**: Revise Condition 20 as follows:

“20. Operating Reports. Submit to the Department an operating report by August ~~1~~ 15for the period January 1 through June 30 of the current year and by February ~~1~~ 15for the period July 1 through December 31 of the previous year...”

*Basis:* We request a 45-day reporting period. Giving 45 days allows enough time to adequately QA/QC the reports before they go out to ADEC, particularly if these reports are compiled by a shared shift position. The Department appears to be concerned that an extra 15 days is too long to go without knowing if there is a violation. However, the permit already has timelines within it that require compliance by a certain date. In most cases, if there is a noncompliance, the permittee would know about it and submit permit deviations as appropriate in accordance with the timelines in the permit. The Department would know about the noncompliance with the permit before the FOR is received.

*Response: The Department revised Condition 20 (now Condition 18) to allow for a 45-day reporting period for the facility operating reports because of the unique nature of the MG-2 where there can be multiple drill rigs operating at multiple well pads. An additional 15 days will ensure adequate time to compile multiple reports from potentially multiple rig operators and ensure adequate quality assurance and quality control. The Department acknowledges that an MG-2 permit holder could use multiple sub-contractors to conduct the portable oil and gas operations within the operating area of their MG-2 permit which is a key factor in granting this request.*

**A-22**: Revise Condition 20.2 as follows:

“20.2 When excess emissions or permit deviations that occurred or were discovered during the reporting period are not reported under Condition 20.1,...”

*Basis:* We recognize that Condition 20.2 is a standard permit condition, however adding a discovery clause avoids other unnecessary paperwork permit deviations. If a permit deviation occurred in one month, but was not discovered until 6 months later, then it is impossible to comply with this condition as it is written, therefore another permit deviation must be noted. The discovery clause should be added to this condition to allow for common sense regulation.

*Response: The Department did not revise Condition 20.2 (now Condition 18.2) to include the proposed clause ‘or were discovered’ because it would undermine the need for complying with the permit conditions. Permittees are responsible for maintaining continual compliance with the terms and conditions of their permit. Part of maintaining continual compliance is to establish robust procedures for identifying permit deviations and excess emissions. Those procedures should be able to detect noncompliance early enough to be able to report it the following month. Therefore, the scenario that the Commenter described should be more theoretical/rare, rather than a periodic occurrence that needs to be addressed within the permit. The Department considers the length and severity of an infraction when dealing with a compliance issue. Therefore, Permittees should have a desire to minimize the duration of a permit infraction, including infractions of the reporting requirement. Providing an exception clause reduces the apparent need for continual compliance, which undermines a basic goal of the permit program.*

**A-23**: Revise Condition 21 to state, **“Annual Affirmation of Qualification.** The Permittee shall submit to the Department by March 31 of each year an affirmation certified according to condition 15 of whether the POGO still qualifies for this permit and that Title V permitting has not been triggered by the POGO activities.”

*Basis:* The TAR states on page 8, that the requirement to have an annual affirmation “applies to stationary sources not subject to Title V permitting.” Since this is specific to Title V avoidance, this affirmation should reflect that sentiment. This change will also make the heading to Condition 21 match the heading used for this condition on page 8 of the TAR.

*Response: The Department received multiple, but identical, requests regarding Condition 21 (see Comment B-20). The Department revised Condition 21 (now Condition 19) to clarify the intent for the annual affirmation of qualification (i.e., whether the POGO still qualifies for an MG-2 permit, and that Title V permitting has not been triggered by the POGO activities).*

**A-24**: Revise Attachment 2 as follows:

“Submit to the Department at ~~least l 0 days~~ *as soon as practicable* before deviating from the annual notification and moving the POGO to a new pad.”

*Basis:* Please see the basis for Comment {A-20}.

*Response: The Department revised Attachment 2 to require the notification to be submitted to the Department ‘as soon as possible’ prior to operating at the new well pad/drill site to allow for additional flexibility in the event of an unexpected rig move. The term ‘as soon as practicable’ was not used because the Department finds it would be difficult to evaluate based on respective thoughts and intentions. ‘As soon as possible’ is intended to mean a test of feasibility and physical possibility, but in any event to occur prior to operating at the new site.*

**A-25**: Revise Attachment 2 by deleting the requirement to list the “Drill Rig Identification to be relocated.”

*Basis:* This form field is redundant with “Rig Name(s),” and is therefore unnecessary.

*Response: The Department deleted the requirement to list the “Drill Rig Identification to be relocated” since it is redundant with the form field “Rig Name(s).”*

**A-26**: Revise Attachment 2 to delete the certification statement by the Responsible Official.

*Basis:* Current rig move notifications are not required to be certified by a Responsible Official. This should remain consistent with the current requirement. Also, if the rig schedule changes on short notice, it may be impracticable to obtain a Responsible Official's signature for the notification to ADEC.

*Response: The Department deleted the certification statement by the Responsible Official from the Relocation Notification (Attachment 3) to remove the potentially time consuming step that could delay the submittal of the relocation notification form. So long as the notification is submitted before deviating from the annual notification and moving a POGO to a new pad, Department staff can evaluate the location and request additional information from a responsible official if warranted.*

**A-27**: Revise Attachment 2 as follows:

*“Send completed report to: Compliance Technician, ADEC Air Permits Program, 610 University Avenue, Fairbanks, AK 99709-3643, or e-mail to dec.AQ.Airrepo**rts@alaska.gov*.*”*

*Basis:* Including the e-mail option will allow for the Department to become aware of the change in the rig schedule much faster than sending the notification via mail.

*Response: The Department added the email option to Attachment 2, as requested. The Department also included the option to submit relocation reports 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.*

**Comments on the TAR**

**A-28**: Revise Number 4 paragraph 5 (page 5 of 9) as follows:

“18 AAC 50.560(g) provides a process for relocating a portable stationary source. Condition 14 requires the Permittee to notify the Department of POGO relocations differing from the original NOI by submitting a completed relocation notification described in Attachment 2

*Basis:* Adding this language gives clarity on when a notification is required for a rig move and is consistent with the permit language.

*Response: The Department received multiple, but identical, requests to add the suggested clarification to the 18 AAC 50.560(g) discussion (see Comment C-31). The Department revised the discussion by stating the Permittee must notify the Department of POGO relocations that differ from the Initial Application or Annual Notification Form by submitting a completed relocation notification located in Attachment 3.*

**A-29**: Please add the same footnote for the definition of “unconventional resource” from the permit to the TAR for Section 7 referencing Section 5 Condition 11-14 of the permit.

*Response: The Department added the footnote definition of “unconventional resource” to the TAR in order to clarify what the Department means by this term.*

**A-30**: Appendix A, Table 2: EU IDs 3, 4, 5, and 6 should be deleted from this Table.

*Basis:* These emission units are not subject to permit applicability but, rather, are associated with the stationary source at which they operate. Please see {Comment A-9}. Please see the CPAI comment letter for more detail on this request.

*Response: The Department did not remove EUs 3 through 6 from Table 2 for the reasons previously discussed in its Response to Comment A-2.*

**CPAI’s Comments**

Text to be inserted into a permit condition is shown with underline formatting while text to be deleted is shown with ~~strikeout formatting~~. Occasionally, **bold font** and/or highlighting is used in these comments to help spotlight edits that might otherwise be difficult to identify.

**Comments on Notice of Intent (NOI)**

**C-1: Page 2**: includes a **definition for “Portable Oil & Gas Operation” (POGO)**.  The definition in the MG-2 NOI matches the definition found on page 3 of the MG-1 NOI.  However, it does not match the definition found at 18 AAC 50.990(124), which is the definition referenced on the cover page of the MG-2 permit.  Revise the definition in the MG-2 NOI to match 18 AAC 50.990(124). Shown below are the differences (edits are shown to revise the POGO definition in the MG-2 NOI to match 18 AAC 50.990(124)).

**“’Portable Oil & Gas Operation’** means an operation that moves from site to site to drill or test ~~an~~ 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 & gas operation’ does not include ‘well servicing activities’ as defined in 18 AAC 50.990(125).  For the purposes of this ~~meaning~~ paragraph, ‘test’ means a test that involves the use of a flare.**”**[Note: the text shown in blue above is not included in the definition of POGO found at 18 AAC 50.990(124), but seems appropriate to include in the MG-2 NOI definition of POGO to point the reader to what “well servicing activities” means.]

1. The definition in the NOI should match the definition found in regulation and in the TAR that accompanies the MG-2 permit (see TAR, Section 3, Definitions).

*Response: The Department revised the definition of ‘portable oil and gas operation’ in the initial application form to match the definition found at 18 AAC 50.990(124). It also included the citation for ‘well servicing activities’ (i.e., 18 AAC 50.990(125)) to point the reader to where that definition is found.*

**C-2: Page 3:** Revise the layout presentation to address the following**:**

1. The section numbering begins at “Section 2” on this page. There does not appear to be a “Section 1” in the NOI. Perhaps the section numbering on this page should begin with “Section 1”.
2. Following the “sections” identified on page 3, there are two additional blocks of questions, but they are not identified as “sections”. Perhaps the “Dates of Operation under This Notification” and the “Location Above 69° 30’ North” should be labeled with a section number.
3. Remove Form 9 from the NOI as requested by AOGA in their comments regarding the draft NOI. Otherwise, we believe it makes sense that “Form 9: Equipment Operated Report Form” should be given a number that follows the number of the last section of the NOI or that it be labeled as “Form 1…” since there are no other forms on the NOI.

*Response: The Department revised the initial application to correct the section numbering and removed the sections from the annual notification form altogether. The Department also removed Form 9 from the initial application and annual notification forms because providing a complete list of all equipment on a well pad for an entire year would be difficult to provide so far in advance. Instead it included the emissions unit inventory from the permit with check boxes that can be used to indicate which of EUs 1 through 6 are expected to operate during the calendar year. This will meet the requirement under 18* *AAC* *50.560(c)(3) to identify all of the equipment to be operated under the minor general permit.*

**C-3: Page 4:** Revise check box language as follows:

“Check here if a list of ~~all~~ drill rig equipment to be utilized as EU 1 or EU 2 to be operated under the ~~general~~ minor general permit is attached. Include make, model, and rated capacity ~~with Form 9 or an equivalent summary~~.”

1. 1) The list of equipment should be limited to the equipment that will be utilized as Emission Units (EU) 1 (Drill Rig Reciprocating Engines) or 2 (Drill Rig Heaters and Boilers). These are the EUs that have express fuel use limitations within the permit.

2) The term “minor general permit”, not “general minor permit” is used everywhere else in the MG-2 NOI.

3) The edit shown in blue strikeout font will be appropriate if the Department removes Form 9 from the NOI as requested by AOGA in the comments regarding the draft NOI.

*Response: The Department removed the check box and language related to drill rig equipment identification from the initial application and annual notification forms because providing a complete list of all equipment on a well pad for an entire year would be difficult to provide so far in advance. Instead it included the emissions unit inventory from the permit with check boxes that can be used to indicate which of EUs 1 through 6 are expected to operate during the calendar year.*

**C-4**: Remove **Form 9** from the NOI or, at a minimum, revise Form 9 as follows in addition to the minimum revisions requested by the AOGA NOI comment regarding Form 9:

“~~Facility~~ Drill Rig Name(s):

Location (i.e., DNR/ BLM Unit, if applicable) Name(s):”

1. 1) As the MG-2 permit will regulate POGOs, there is not a “facility” that will be designated; however, it would make sense to identify the drill rig(s) that will be used to perform the POGO activities authorized by the MG-2 permit issued to the Permittee. This also makes sense in that this will identify the rig(s) whose equipment inventory is to be listed on Form 9 and operated at the location(s) identified on Form 9.

2) The form should clarify/ encourage the applicant to include the name of the DNR/BLM unit(s) where the POGO activities will take place in conjunction with the locations specified for drill rig operations.

*Response: The Department removed Form 9 from the initial application and annual notification forms and replaced it with the emission unit inventory from the permit with check boxes that can be used to identify which of EUs 1 through 6 are planned to be operated. The forms were also revised to identify the drill rigs, well pads, and/or DNR/BLM units where POGO activities will take place.*

**C-5**: Revise Page 6, Certification Page, as follows:

“Any permit application, report, affirmation, or compliance certification required by the department…”

1. The text representing 18 AAC 50.205, Certification, should be edited as shown to make it match 18 AAC 50.205.

*Response: The Department revised the Certification Page for consistency with the certification requirements in 18 AAC 50.205.*

**Comments on the Permit**

**C-6**: Edit Section 1, introductory paragraph to Table 1 as follows:

“**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. ~~Except as~~ Unless otherwise noted elsewhere in this permit, the information in Table 1 is for identification purposes only….”

1. Inclusion of the exception in the manner stated in the fourth sentence implies that one exists in the permit.  We request that the Department revise this sentence to acknowledge that there may be an exception to the information in permit Table 1 being used for identification purposes only, but doing so without implying that there is, in fact, an exception in the permit.  (We do not believe there is an exception in the MG-2 permit.)

*Response: The Department revised the introductory paragraph as requested, since the revised language more accurately reflects the subsequent permit conditions.*

**C-7**: Edit **Condition 4.4** as follows to make the language match 18 AAC 50.410:

“4.4 …or has the potential to emit in quantities ~~greater than~~ 10 tons per year or greater.”

*Response: The Department revised Condition* *4.4 for consistency with the language in 18* *AAC* *50.410.*

**C-8**: Revise **Condition 4.4b(iv)** as follows to make the language match the current version of ADEC’s Standard Permit Condition (SPC) I, Condition 1.2d:

“(iv) other methods and calculations approved by the Department, including appropriate vendor-provided emissions factors when sufficient documentation is provided.”

*Response: The Department revised Condition* *4.4b(iv) as requested in order to match the language in SPC* *I (revised May 18, 2016).*

**C-9**: Revise **Condition 5.1** as follows to update the address where ADEC would like assessable emissions estimates to be submitted (according to the January 2018 public notice draft proposed revisions to SPC I):

“5.1 …ADEC, Air Permits Program, ATTN: Assessable Emissions Estimate, ~~410 Willoughby Ave., PO Box 111800, Juneau, AK 99811-1800~~ 555 Cordova Street, Anchorage, Alaska 99501.”

*Response: The Department updated the address in Condition 5.1 with the address it proposed in the January 2018 revision to SPC* *I. The Department also included the website for its Air Online Services system to allow for reporting assessable emissions via the Permittee Portal as well as the email address for submitting the estimates electronically via email.*

**C-10**: Revise **Condition 5.2** as follows to make the language match the current version of ADEC’s SPC I, Condition 2.2:

“5.2 if no estimate is ~~received~~ submitted on or before March 31**~~st~~** of each year…”

*Response: The Department revised Condition* *5.2 as requested in order to match the language in SPC* *I (revised May 18, 2016).*

**C-11**: Revise the **heading to Condition 8** as follows to add clarity (by matching the presentation used in the heading to Condition 9) and to correct a typographical error:

“8. **Visible Emissions for Industrial Processes and Fuel-Burning Equipment ~~Visible Emissions~~**….”

*Response: The Department revised the heading to Condition* *8 as requested in order to improve clarity and to correct the typographical error.*

**C-12**: If EU 6 is removed from the permit as requested by AOGA in their comments regarding the draft MG-2 permit, **Condition 8.4** should also be deleted. Otherwise, at a minimum, revise **Condition 8.4** as follows to add clarity:

“8.4 For each flare operated as EU 6, while it is onsite, observe one daylight flare event5 annually, on a calendar year basis. If there is no qualifying flare event within the ~~12-month period~~ calendar year, then the Permittee shall observe the next qualifying daylight flare event for that flare when it is operated onsite.”

*Response: The Department did not delete Condition* *8.4 since it kept EU* *6 in the Emissions Unit Authorization. (See the Department’s response to Comment A-2 as to why it kept EU 6 in the EU Inventory). The Department did revise Condition 8.4 to clarify that observing the flare using Method 9 should occur on a calendar year basis and to specify that the observations should only occur if a qualifying flare event occurs during that calendar year.*

**C-13**: If EU 6 is not deleted from the MG-2 permit as noted in our permit Comment #0, revise **Condition 8.4a** as follows:

“a. ~~Monitor~~ Observe the flare exhaust following 40 C.F.R. 60, Appendix A-4, Method 9 ~~for visible emissions~~ for 18 minutes to obtain 72 consecutive 15-second opacity observations during flare events ~~using Method 9~~.”

1. Formalize the language of Condition 8.4a to be like that used by the Department in draft permit Condition 8.1b. Condition 8.4a should stand on its own and provide more formal instructions to the Permittee on what is required.

*Response: The Department revised Condition 8.4a to provide more formal instructions to the Permittee on what is required by using ‘Method 9’.*

**C-14**: If EU 6 is not deleted from the MG-2 permit as noted in our permit Comment #0, revise **Condition 8.4c** as follows:

“c. 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 20 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.”

1. 1)Reporting of a postponed observation of a qualifying flare event should only be required if the requirement in Condition 8.4 for a once-per-calendar year observation has not yet been fulfilled for the year.

2)  Add the last sentence to clarify that monitoring and reporting under Condition 8.4 are not required if there were no qualifying flare events during the reporting period.

*Response: The Department revised Condition 8.4c to clarify that reporting of a postponed observation of a qualifying flare event should only be required if the once-per-calendar year observation has not yet been fulfilled for the year. The Department also included the last sentence indicating that if no flare events occurred during the reporting period, then no monitoring or reporting is required.*

**C-15: Condition 8.4d**: We do not understand the purpose of submitting records with the operating report “for the period that covers the 30th day after the observation was conducted”.  If EU 6 is not deleted from the MG-2 permit as noted in our permit Comment #0, we suggest revising this condition as follows to simplify and clarify the reporting requirement:

**“**d. Include copies of the records required by Condition 8.4b in the first operating report submitted under Condition 20 for the period covered by the report ~~that covers the 30~~~~th~~ ~~day after the observation was conducted~~.**”**

*Response: The Department revised Condition 8.4d to clarify that the records required by Condition 8.4b should be reported for observed events that occurred during a given reporting period.*

**C-16**: Revise the **heading to** **Condition 9** as shown to correct a typographical error and split **Condition 9** into two conditions as follows:

“9. **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.

9.1 For each heater/boiler operated as EU 2, conduct a particulate matter source test according to the requirements set out in Section 8 …”

1. The second sentence of Condition 9 should be segregated from its first sentence, which states the particulate matter standard that applies to fuel burning equipment, to become new Condition 9.1, which states the monitoring that is to be done to demonstrate compliance with this standard if Method 9 observations of fuel burning equipment fail, after corrective maintenance, to meet the visible emissions standard stated in Condition 8.

*Response: The Department revised Condition 9 to correct the typographical error in the heading and to split Condition 9, separating the particulate matter standard from the potential source testing requirement for clarity.*

**C-17**: Revise the heading to Condition 10 and Condition 10 as follows:

“10. **Sulfur Compound Emissions for Industrial Processes and Fuel-Burning Equipment**. The Permittee shall not cause or allow sulfur compound emissions… Monitor, record, and report in accordance with Condition 12.2 ~~Conditions 11 and 12~~.”

1. 1)As done in the headings to draft permit Conditions 8 and 9, the heading to Condition 10 should clarify that the standard presented in the condition applies to industrial processes and fuel-burning equipment.  Most important is the reference to fuel-burning equipment.

2)  The MR&R requirement should reference Condition 12.2, which provides the MR&R to demonstrate compliance with the sulfur standard for fuel burned by heaters and boilers.  The MR&R in Condition 11 does not pertain to fuel sulfur and the rest of Condition 12 pertains to ULSD fuel, which is required to be burned by the nonroad engines (NRE) associated with a rig.  NRE are not “fuel-burning equipment”.

*Response: The Department revised Condition 10 to clarify that the standard presented in the condition applies to industrial processes and fuel-burning equipment and to clarify that the sulfur emissions standard does not apply to nonroad engines so monitoring, recordkeeping, and reporting should be conducted in accordance with Condition 12.2.*

**C-18**: As currently presented in the permit, **Footnotes 7 and 8** address drilling projects that last less than 24 consecutive months and **Footnotes 9 and 10** address drilling projects that last greater than 24 consecutive months. A project that lasts 24 consecutive months is not addressed. One of these two sets of footnotes should be revised to cover a drilling project that lasts 24 consecutive months.

*Response: The Department corrected the oversight noted by the Commenter by revising Footnotes 9 and 10 (now Footnotes 8 and 9) so that they now address drilling projects that last* ***24 or more*** *consecutive months (emphasis added).*

**C-19**: The footnote referenced by Condition 11.5b(ii)(E) should be Footnote 12, not Footnote 11.

*Response: The Department revised Condition* *11.5b(ii)(E) so that it now references the correct footnote (Footnote* *12, which has now changed to Footnote 11).*

**C-20:** Revise **Condition 11.5d(ii)** as follows:

“(i) The maximum possible combined daily fuel consumption…as determined under Condition 11.5c(i);

(ii) The ~~largest maximum~~ actual combined daily fuel consumption for the reporting period…as determined under Condition 11.5c(ii).”

1. The records of fuel consumption obtained under Condition 11.5c(ii) are actual fuel consumption measurements recorded via Condition 11.5b, rather than the estimated maximum fuel consumption estimation records that are obtained under Condition 11.5c(i) via Condition 11.5a. Therefore, the language in Condition 11.5d(ii) should differ from that found in Condition 11.5d(i) and should refer to actual fuel consumption records.

*Response: The Department corrected Condition 11.5d(ii) to identify the ‘largest actual’ combined daily fuel consumption as the reported value rather than ‘largest maximum’ value because the records are obtained from actual fuel consumption measurements recorded in Condition 11.5c(ii).*

**C-21**: Create new **Condition 11.5d(iii)** as follows:

“(ii) …Condition 11.5c(ii); ~~or~~

(iii) 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”

1. Condition 11.5 allows fuel consumption to be determined following the procedures outlined in Condition 11.5a and/or 11.5b.  In the event that both Conditions 11.5a and 11.5b are followed, there should be a subcondition added to Condition 11.5d that requires reporting the sum of fuel consumption determined under Condition 11.5a and recorded under Condition 11.5c(i) combined with fuel consumption determined under Condition 11.5b and recorded under Condition 11.5c(ii).  As drafted, Condition 11.5d requires reporting of “one of the following” values recorded under Condition 11.5c(i) or 11.5c(ii), but does not address the possibility that both types of records might be maintained.

*Response: The Department created a new Condition 11.5d(iii) for the event that both Conditions 11.5a and 11.5b are followed to determine the daily fuel consumption (i.e., a combination of calculating the maximum possible daily fuel consumption for some units and measuring the actual combined daily fuel consumption for the other units).*

**C-22: Conditions 13 and 14:** These conditions are found in permit Section 5, “Ambient Air Quality Protection Requirements”.  They do not appear to be ambient air quality protection requirements since they address notification (i.e., reporting) requirements regarding the well pad/ drill sites where POGO activities are anticipated to occur in the coming year and if there are any changes to the planned locations.  We believe these conditions should instead be included in permit Section 6, “Recordkeeping, Reporting, and Certification Requirements”.

*Response: The Department moved Conditions 13 and 14 (now Conditions 20 and 21) to Section 6 of the permit since these conditions are more accurately described as recordkeeping, reporting, and certification requirements than they are ambient air quality protection requirements.*

**C-23**: Delete Condition 19.1c(iii).

1. This condition is not applicable to the MG-2 permit because there are no unique permit deviation reporting deadlines “in other applicable conditions of this permit”. Therefore, Condition 19.1c(iii) should be deleted, the reference to Condition 19.1c(iii) should be removed from Condition 19.1c(i), and the word “and” should be removed from the end of Condition 19.1c(ii).

*Response: The Department did not delete Condition 19.1c(iii) (now Condition 17.1c(iii)) because it finds that excess emissions and permit deviations should be reported for failing to monitor as required in other applicable conditions of the permit. All enforceable conditions should require excess emissions and permit deviations to be reported, but in the case that monitoring was insufficient to discover them, this sub-condition acts as a catch-all.*

**C-24: Condition 34:** Change this condition to require just one copy of source test reports as the Department has been doing in recent versions of other permits and to coincide with the one copy requirement stated in Condition 15.  It is our understanding that the Department no longer requires two copies of source test reports.

*Response: The Department revised Condition* *34 by replacing the phrase “the Permittee shall submit* ***two copies*** *of the results” with “the Permittee shall submit* ***one certified copy*** *of the result” (emphasis added). This change makes the language consistent with Policy and Procedure* *04.02.110, which states that the Department only requires “one certified (original) document for applications, compliance reports, or data compilations.”*

**C-25**: Correct two typographical errors in the introductory paragraph to Attachment 1 – Visible Emissions Form as follows:

“This form is designed to be used in conjunction with EPA Method 9, “Visual Determination of the Opacity of Emissions ~~form~~ from Stationary Sources.” Temporal changes… Following are brief descriptions of the type of information that needs to be entered on the ~~form: for~~ form. For a more detailed discussion of each part of the form…”

*Response: The Department changed “form” to “from” in the Method 9 reference and replaced the colon with a period and capitalized for, to correct the typographical and grammatical errors.*

**C-26: Attachment 1 – Visible Emissions Form, introductory page:** Each of the paragraphs presented in the 2-column section of this page should include a bullet.  Some are missing the bullet.

*Response: The Department inserted the missing bullets in the Visible Emissions Form in order to have a consistent presentation of the requested items.*

**C-27: Attachment 2 – Relocation Notification (Application Addendum):** Delete the “Location Information” section of this notification form.  The rig location by well pad/ drill site identification also requested by this attachment should be sufficient.  We see no purpose in providing the latitude/ longitude or UTM coordinates of a rig location. There is no need to document that a rig to be relocated under this permit is operating north of 69 degrees, 30 minutes North latitude. If that were not the case, the rig would not be operating under the MG-2 permit.

*Response: The Department did not delete the location information section from the relocation notification form because the location where a POGO will be operating is important information to have for compliance personnel. It will also help to determine whether a POGO is at an isolated or collocated well pad, and allow inspectors to track rig movement within a given oil and gas unit. The Department did delete the UTM coordinate field from the location section, because knowing the latitude and longitude is the appropriate data to be included in its AirTools database. The Department notes that submitting relocation notifications electronically via the Air Online Services’ Permittee Portal will automatically update the location upon submittal, allowing a Permittee to notify the Department of deviations from the pre-approved locations in real time and is the preferred method to do so.*

**Comments on the TAR**

**C-28**: Revise **Section 2, 1st paragraph at the top of page 3** by changing “liquid-fired” to “liquid fuel-fired” to add clarity.

*Response: The paragraph referenced by the Commenter is part of a Department summary of a modeling analysis conducted by the Technical Subgroup of the “Workgroup for Global Air Permit Policy Development for Temporary Oil and Gas Drill Rigs”* *(Workgroup).[[2]](#footnote-3) The Technical Subgroup used the term “liquid-fired” in their October 17, 2017 report, “*[*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)*.” Therefore, the Department kept the “liquid-fired” language in order to maintain consistency with the term used by the Technical Subgroup.*

**C-29**: Change **Section 4, 1st paragraph** as follows to correct two typographical errors:

“…that require a minor permit, ~~involved~~ involve the same or similar types of operation, involve the same type of emissions,… obtain a minor permit under 18 AAC 50.502(c)(2)(A), and they involve the same types of operation, emissions, and control requirements.”

*Response: The Department corrected both typographical errors in the first paragraph of Section 4.*

**C-30**: Change Section 4, 3rd paragraph, concluding sentence as follows to add clarity:

“The applicant does not need to obtain Department approval…prior to operating under the MG-2 general minor permit.”

*Response: The Department replaced the phrase “the general minor permit” with “MG-2” in order to clarify which general minor permit the sentence refers to.*

**C-31**: Revise Section 4, paragraph 5 as follows:

“18 AAC 50.560(g) provides a process for relocating a portable stationary source. Condition **~~Error! Reference source not found.~~** 14 requires the Permittee to notify the Department of POGO relocations differing from the original NOI by submitting a completed relocation notification described in Attachment 2

1. 1) Correct the electronic condition cross reference error that shows up in the PDF version of the public notice draft TAR as shown. The cross reference should be to permit Condition 14.

2) Adding the proposed new language gives clarity on when a notification is required for a rig move and is consistent with the permit language.

*Response: The Department received multiple, but identical, requests to add the suggested clarification to the 18 AAC 50.560(g) discussion (see Comment A-28), along with multiple requests to correct the cross-reference error (see Comment B-21). The Department corrected the cross-reference error and added a modified version of the suggested clarification (see the Department’s responses to Comment A-28 and B-21).*

**C-32: Table 1 (Permit Applicability):**  If the Department does not remove EUs 3 through 6 from the MG-2 permit as requested by AOGA in their comments regarding the permit, the potential SO2 emissions shown in this “permit applicability” table should be 42 tpy, not 2.6 tpy, and the potential VOC emissions should be 3.1 tpy, not 93.5.  The basis for this change is described in the basis we have provided with our TAR Comment #a regarding corrections to Table 2 in TAR Appendix A.

*Response: The Department corrected the potential SO2 and VOC emissions in the permit applicability table to 42 tpy and 3.2 tpy, respectively.*

**C-33**: Revise Section 6, 2nd paragraph, concluding sentence as follows to add clarity and scope:

“As such, they [nonroad engines] are not subject to the state emission standards and emissions from nonroad engines are not included in the potential or assessable emissions total.”

*Response: The Department revised the 2nd paragraph of Section 6 to add clarity to the nonroad engine status discussion for drill rig and portable engines, and how that status affects their applicability for state emissions standards and potential or assessable emissions total purposes.*

**C-34**: Revise **Section 6, 3rd paragraph, concluding sentence** as follows to clarify the statement as used in the context of a TAR:

“~~When~~ While a POGO is placed into storage mode, its engines ~~should~~ do not lose their nonroad status.”

*Response: The Department revised the 3rd paragraph of Section 6 to clarify that* ***while*** *a POGO is placed into storage mode, its engines* ***do*** *not lose their nonroad engine status (emphasis added).*

**C-35:** Revise Section 7, paragraph regarding Permit Section 1 as follows:

“Permit Table 1 lists emissions units at the source by EU #, EU Name, EU description, ~~make/model, fuel type,~~ and rating/max capacity. ~~Except as~~ Unless otherwise noted ~~elsewhere in this~~ in the permit, the information in permit Table 1 is for identification purposes only.”

1. 1)Permit Table 1 does not include the “make/model” or “fuel type” for the emissions units listed in the table.  It does include the “name” of the emissions units.

2) Make changes to clarify that “Table 1” referenced by this paragraph is permit Table 1, not TAR Table 1.

3) Inclusion of the exception as stated in the second sentence of this paragraph implies that one exists in the MG-2 permit.  We request that the Department revise the second sentence to allow for the possibility that there may be an exception without implying that there is in fact an exception in the permit.  (We do not believe there is an exception in the MG-2 permit.)

4) Make other changes to this paragraph to reflect that it is part of the TAR, not the permit.

*Response: The Department revised the Section 7 paragraph regarding Permit Section 1 to clarify that the Table 1 being referenced is in the permit, not TAR, and that the table does not include the ‘make/model’ or ‘fuel type’ for emissions units, but it does include the ‘name’ of the emissions units. It also revised the paragraph to clarify that the information provided in Table 1 is to be used for informational purposes only, unless there is an exception noted in the permit.*

**C-36:** Revise Section 7, paragraph regarding Permit Condition 10 as follows:

“Monitoring, recordkeeping, and reporting shall be conducted in accordance with the ambient air quality protection requirements listed in ~~Conditions 11 and 12~~ Condition 12.2 to ensure compliance with the sulfur compound emission standard…”

1. Condition 12.2 includes the MR&R needed to demonstrate compliance with the sulfur standard for fuel burned by heaters and boilers.  The MR&R in Condition 11 does not pertain to fuel sulfur and the rest of Condition 12 pertains to ULSD fuel, which is required to be burned by the nonroad engines (NRE) associated with a rig.  NRE are not “fuel-burning equipment”.

*Response: The Department revised the Section 7 paragraph regarding Permit Condition 10 to clarify that the standard presented in the condition applies to industrial processes and fuel-burning equipment and to clarify that the sulfur emissions standard does not apply to nonroad engines so monitoring, recordkeeping, and reporting should be conducted in accordance with Condition 12.2.*

**C-37: Section 7, paragraph regarding permit Section 5, Ambient Air Quality Protection Requirements:** There is an electronic cross references error that shows up in the PDF version of the public notice draft TAR.  We believe the appropriate conditions to be referenced here are Conditions 11 and 12, since these are the conditions that address limits and restrictions that pertain to ambient air quality protection and are the conditions described in this paragraph of the TAR.

*Response: The Department revised the Section 5 heading to correct the reference to the ambient air quality protection requirements (i.e., Conditions 11 and 12).*

**C-38: Section 7, regarding permit Section 6, General Recordkeeping, Reporting, and Certification Requirements:**  The Department has not included in the TAR a basis for permit Conditions 13 and 14.  We commented above {see Comment C-22} to move Conditions 13 and 14 to permit Section 6.  Perhaps the Department should include the bases for Conditions 13 and 14 in this part of TAR Section 7.  We believe the bases are 18 AAC 50.560(f)(2), (f)(4) and (g)(1).

*Response: The Department moved Conditions 13 and 14 (now Conditions 20 and 21) to Section 6 of the permit since these conditions are more accurately described as recordkeeping, reporting, and certification requirements than they are ambient air quality protection requirements. The Department also included bases for the annual and relocation notifications (i.e., 18 AAC 50.560(f)(2), (f)(4), and (g)(1)).*

**C-39: Section 7, paragraph regarding Condition 17, Information Requests:**  Revise the electronic condition cross reference in the heading to this paragraph as follows to correct a typographical error:

“Condition ~~16~~ 17, Information Requests”.

*Response: The Department corrected the cross-reference to Condition 17 (now Condition 15).*

**C-40**: Make the following corrections to **Appendix A, Table 2**:

1. Change the title “Total Potential to Emit Emissions” to “Total Potential to Emit ~~Emissions~~ for Permit Applicability Determination”, do not include the 90.4 tons VOC emissions for EU 3 in this total, and, if the Department does not remove EU 3 from the MG-2 permit as requested by AOGA in their comments regarding the permit, add a table note to this title indicating that VOC emissions from EU 3 are not included in the total.
2. To be clear, the row in Table 2 that refers to EU 3 pertains to emissions from new well venting/ flowbacks as indicated in permit Table 1 for EU 3 -- “(25 new wells)”. Construction phase (i.e., “new well”) flowback emissions are not subject to permit applicability review as determined by the Department in a September 21, 2005 letter to ConocoPhillips Alaska, Inc. See **Attachment A** to these comments. This is also the basis for our TAR Comment #0 to change the VOC potential emissions presented in TAR Table 1.

*Response: The Department revised Table 2 of Appendix A to clarify that the listed potential to emit is for ‘Permit Applicability Determination’ purposes and that VOC emissions for well venting/flowbacks (EU 3) do not include the 90.4 tons per year because well flow backs that occur prior to the well being placed into production should be considered ‘construction phase emissions’ as indicated in the Department’s 2005 letter to CPAI (see Attachment A to this RTC). The Department also included Table Note j, indicating that VOC emissions from EU 3 are not included in the potential to emit total for the purposes of determining permit applicability.*

**C-41**: If the Department does not remove EUs 3 through 6 from the MG-2 permit as requested by AOGA in their comments regarding the permit, make the following corrections to **Appendix A, Table 2**:

1. The SO2 emissions total shown in the “Total Potential to Emit for Permit Applicability Determination” {see Comment C-40} should include emissions from all EUs except EUs 1 and 4 (i.e., the nonroad engines).  Therefore, the SO2 emissions total in this row of Table 2 should be 42 tons, not 2.6 tons.  (Note: the Total Assessable Emissions value of 252 tons shown in Table 2 correctly includes 42 tons of SO2 emissions.)
2. The maximum rating or capacity for EU 4 should be listed as 10,774 gal/day since that was the assumption used when calculating the EU 4 PTE according to “Note c.” to Table 2.
3. The maximum rating or capacity for EU 5 should be listed as 4,661 gal/day since that was the assumption used when calculating the EU 5 PTE according to “Note d.” to Table 2.
4. The maximum rating or capacity for EU 6 should be listed as 130 MMscf/yr since that was the assumption used as the capacity for the flare when calculating the flare PTE according to “Note e.” to Table 2.

*Response: The Department revised Table 2 of Appendix A to: correct the SO2 emissions total to 42.0 tons per year and to include the assumed fuel consumption values used to calculate the PTE for EUs 4 through 6.*

**C-42**: Delete **Footnote 19 referenced in “Note h.” to Appendix A, Table 2** or correct the footnote to address the fact that the reference in Footnote 19 to the “GOR for CPF1, CPF2, and CPF3 as provided in Attachment F of the permit application” seems out of place for the MG-2 permit TAR as there was no “permit application” per se.

*Response: The Department revised Footnote 19 to reference the permit application for the Kuparuk River Unit Drill Site 2S, Minor Permit AQ1429MSS01. The Department based its calculation of VOC emissions from new well flowbacks under MG-2 on the average Gas-to-Oil Ratio for CPF1, CPF2, and CPF3.*

**BPXA’s Comments**

The following comments are submitted by BP Exploration (Alaska) Inc. (BPXA) in response to the public notice draft MG2 permit. Text to be inserted into a permit condition is shown with underline formatting while text to be deleted is shown with ~~strikeout formatting~~.

**Notification of Intent to Operate**

**B-1**: Please include a separate annual notification form or clarify which portions of the “Notification of Intent to Operate” are required for the annual notification under Condition 13 of the draft MG-2 permit.

Under an initial notification, information is required to be provided under the “Notification of Intent to Operate” form that includes information for Legal Owner, Operator, and Equipment Operated for a single POGO. The annual notification requirement in Condition 13 only requires the Permittee to identify “which well pads or drill sites they plan to operate” the POGO on. Many elements of the “Notification of Intent to Operate” are superfluous and not are required elements for the annual notification. Please create a separate form as an attachment to the MG-2 permit for an annual notification or only require the information on Page 4 of the “Notification of Intent to Operate” for the well pads/well sites to be drilled under an annual notification.

*Response: The Department split the notification form into two separate forms: a one-time (initial) application form that an applicant submits when deciding to use the MG-2 permit, and an annual notification form (Attachment 2 to the MG-2) that: identifies the drill rigs, type and location of the well pads or oil and gas unit, and the emissions unit inventory from the permit with check boxes that can be used to indicate which of EUs 1 through 6 are planned to be operated for the following year. The Department finds this information is required on an annual basis because it is subject to change each drilling season. The Department removed the applicability criteria and definition sections from the annual notification form because the Permittee is already required to submit an annual affirmation that the POGO is still accurately described by the original application.*

**B-2**: Title page. Please clarify what information is required under “Name of Prospect(s)” for an MG-2 permit issued for a Unit. Please revise the “Drilling Rig Identification” to “Drilling Rig(s) Identification”. This will allow the Permittee to identify all the drill rigs to be authorized under the single MG-2 permit. Consistent with the statement on Page 3 of the MG-2 permit, “[t]he POGO may consist of one or more drill rigs, along with miscellaneous support equipment.

*Response: The Department revised Page 1 of the Initial Application and Annual Notification Forms to clarify the information being requested is the name of the Oil and Gas Unit(s) or Well Pad(s).*

**B-3**: Page 2, Applicability section, item No. 5. Please include “and” at the end of the statement to indicate all qualifiers must be met for a POGO.

*Response: The Department included ‘and’ at the end of the statement in the Initial Application Form to indicate that all six qualifiers must be met for a POGO. The Department removed the applicability section from the Annual Notification Form because the Permittee is already required to submit an annual affirmation that the POGO is still accurately described by the original application.*

**B-4**: Page 3, Dates of Operation under This Notification. Please remove the requirement to provide “Dates of Operation under this Notification.” It may be difficult for an owner/operator to provide dates of operation for multiple years into the future because final planning decisions cannot be made. The note prior to the table indicates the dates are needed to assess “additional emission fees and the annual compliance fees for the subsequent fiscal year(s).” However, the MG2 permit does not expire unless a request is made and assessable emissions are established under Condition 4 and 5. Fees may be assessed each year that the MG-2 permit remains effective and the information is unnecessary for the notification.

*Response: The Department removed the requirement to provide the dates of operation under the application and annual notification forms because the assessable emissions billing requirements are already established in Conditions 4 and 5 of the permit. Fees may be assessed each year that the MG-2 permit remains effective and the information is unnecessary for the notification.*

**B-5**: Page 5, Form 9. Please remove Form 9 from the Notification of Intent to Operate.

Form 9 requires the Permittee to provide information such as make/model, rated capacity, installation dates, and whether or not the unit operated. These elements are not required under the draft MG-2 permit to determine compliance with any underlying condition and some of the information is redundant and provided under other permit conditions.

For example, the MG-2 permit inventory in Table 1 includes categories of emission units with no rating/size. Furthermore, the information required to be monitored under Condition 11.4 of the draft MG-2 permit will capture the required information in Form 9, such as “Date Installed” or “Date Removed”. Therefore, Form 9 is not necessary to confirm compliance.

*Response: The Department removed Form 9 from the initial application and annual notification forms because providing a complete list of all equipment on a well pad or oil and gas unit for an entire year would be difficult to provide so far in advance. Instead it included the emissions unit inventory from the permit with check boxes that can be used to indicate which of EUs 1 through 6 are expected to operate during the calendar year. This will meet the requirement under 18* *AAC* *50.560(c)(3) to identify all of the equipment to be operated under the minor general permit.*

**Minor General Permit 2**

**B-6**: Page 3, Note to Table 1. Please update the note as follows to correct a citation reference for “well servicing activities.”

Note: The Permittee is also authorized to concurrently conduct well servicing activities, as defined in 18 AAC 50.990(~~124~~125), and operate nonroad engines associated with construction activities, in accordance with the terms and conditions of this permit.

*Response: The Department corrected the regulatory reference in the note to Table 1. ‘Well servicing activities’ is defined in 18 AAC 50.990(125).*

**B-7**: Page 4, Condition 4.3. Please revise this condition as follows to provide clarity on assessable emission fees.

4.3 For ~~a single~~ each individual POGO for which the owner or operator submits…

*Response: The Department revised Condition 4.3 to clarify that the assessable emissions apply to each individual POGO.*

**B-8**: Page 4, Condition 4.4(a) and (b). Please revise these conditions as follows to provide clarity on the assessable emission fees.

4.4(a) …~~the~~ each individual POGO’s assessable potential to emit of 252 tpy; or

4.4(b) ~~the~~ each individual POGO’s projected annual rate…

*Response: The Department revised Condition 4.4a and 4.4b to clarify that the assessable emissions apply to each individual POGO.*

**B-9**: Page 7, Footnote 4. Please revise Footnote 4 as follows. Providing a manufacturer guarantee under Condition 8.1a should be dependent on beginning operation of EU 2 and not when drilling begins at a given well pad. The start of drilling may occur without the use of EU 2.

4 “Fully operational”, for purposes of this permit and as it applies to EU 2, is defined as when a unit begins operating after drilling begins at a given well pad.

*Response: The Department deleted Footnote 4, as previously discussed in its response to Comment A-13. However, the Department addressed BPXA’s valid observation that a heater or boiler may not start operating until after drilling starts, by revising the wording in Conditions 8.1a and 8.2. The certification required under Condition 8.1a is now required prior to operating the given heater or boiler under the permit, rather than before drilling begins. This change in wording simplified the permit and eliminated the need for using the “fully operational” phrase.*

**B-10**: Page 7, Condition 8.1. Please revise the condition as follows to clarify the frequency of Method 9 monitoring. As written, the requirement is ambiguous and inconsistent.

8.1 For each heater or boiler operated as EU 2, verify compliance with Condition 8 by performing one of the following:

a. ~~Obtaining~~Obtain a certified manufacturer guarantee, prior to the POGObecoming fully operational,4 that the heaters and boilers operating as EU 2 will comply with the visible emission standard;

b. ~~Conducting~~Conduct a visible emissions observation following the procedures of 40 C.F.R. 60, Appendix A-4, Method 9, for 18 minutes to obtain 72 consecutive 15-second opacity observations, using one of the following methods:

i. Within ~~within~~ 90 days after each individual EU 2 ~~the POGO~~ becomes fully operational;

ii. Conduct subsequent Method 9 observations each calendar year ~~and within 12 consecutive months of the previous Method 9 observation~~; or

iii. For an emission unit not operating during the scheduled observation, conduct the next observation within 90 days of start-up of the unit.

c. ~~Including~~Include documentation with the first operating report required by Condition 20, that is submitted after the POGO becomes fully operational, to show that a Method 9 observation was completed on each heater and boiler, operating as EU 2, within 12 months prior to the POGO becoming fully operational and that the results of those observations show compliance with the standard in Condition 8. Afterwards, conduct subsequent observations according to Condition 8.1bii.

*Response: The Department received multiple proposals as to how Condition 8.1 could be clarified (see Comment A-11). The Department made minor editorial revisions to Condition* *8.1a to enhance clarity, and revised Conditions 8.1b and 8.1c as previously described in its response to Comment A-11.*

**B-11**: Page 7, Condition 8.3. Please revise Condition 8.3 as follows to simplify and clarify the condition language.

8.3 When using Condition 8.1b or 8.1c to verify initial compliance of a heater or boiler operated as EU 2, submit a copy of the observation records ~~developed under Condition 8.1b or 8.1c~~ (use the form in Attachment 1), ~~as applicable, to the first operating report submitted under Condition 20 for the period that covers the 30th day after the unit becomes fully operational. Attach a copy of the observation records developed under Condition 8.1b, if applicable,~~ ~~to~~ with the operating report required under Condition 20 that covers the period when the observations were completed.

*Response: The Department received multiple comments as to how Condition 8.3 could be clarified (see Comment A-12). The Department revised Condition 8.3 as previously discussed in its response to Comment A-12.*

**B-12**: Page 7, Condition 8.4. Please clarify the language as indicated below. As written, the condition requires Visible Emission (VE) observations on the flares at potentially two different intervals. The first sentence of the condition requires that VEs be completed annually. Annually means once per calendar year. If a flare VE was completed in January 2019 to complete the annual VE requirement, the next “annual” VE would be due no later than December 2020. However, the next sentence states that if a VE has not been completed within the previous 12 months, a VE must be completed during the next daylight flare event. This creates two conflicting compliance schedules. The below language clarifies the requirement.

8.4 For each flare operated as EU 6, while it is onsite, observe one daylight flare event ~~annually~~ per calendar year. If there is no qualifying flare event within the previous calendar year ~~12-month period~~, then the Permittee shall observe the next daylight flare event for that flare when it is operated onsite.

*Response: The Department received multiple comments as to how Condition 8.4 could be clarified (see Comment C-12). The Department revised Condition 8.4 as previously discussed in its response to Comment C-12.*

**B-13**: Page 7, Footnote 5. Please revise Footnote 5 to Condition 8.4 as follows to indicate that flare events include a minimum of 18 consecutive minutes that is consistent with the standard permit conditions for monitoring flare events.

5  For purposes of this permit, a “flare event” is flaring of gas at a rate that exceeds the source’s de-minimis pilot, purge, and assist gas rates for a minimum of 18 consecutive minutes ~~for greater than one hour as a result of scheduled release operations, i.e. maintenance or well testing activities~~. It does not include non-scheduled release operations, i.e. process upsets, emergency flaring, or de-minimis venting of gas incidental to normal operations.

*Response: The Department revised Footnote 5 (now Footnote 4) to allow Method 9 observations to occur (and still “count”) for flaring events lasting less than an hour (but at least 18 minutes). This provides additional flexibility by allowing qualified observers to perform Method 9 observations of unscheduled flaring that otherwise meet the event requirements (daylight and lasting at least 18 minutes), but do not last for an hour. This could result in more frequent observations, thus providing a more comprehensive record of flaring opacity.*

**B-14**: Page 8, Condition 8.6. Please revise the condition as follows to indicate when a subsequent Method 9 is required after corrective action is taken.

8.6 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 19, take corrective actions, and conduct follow-up Method 9 observations within 30 days after completing corrective actions until the standard in Condition 8 is met.

*Response: The Department revised Condition 8.6 to indicate that Method 9 observations must be performed ‘as soon as possible’ after corrective actions are taken to ensure compliance with the opacity standard. The Department finds that allowing a 30 day timeframe after completing corrective actions is too long to wait for conducting follow-up Method 9 observations, because the intent of the follow-up observations is to ensure the visible emissions standard is no longer being exceeded.*

**B-15**: Page 9, Condition 11.2. Please clarify this condition as follows. The current language indicates that any operation is prohibited while conducting hydraulic fracturing of unconventional resources. The suggested language clarifies that operating a POGO simultaneously with unconventional fracing is prohibited.

11.2 Prohibit the hydraulic fracturing (fracing) of unconventional resources while ~~operating~~ engaged in POGO activities at a given well pad…

*Response: The Department revised Condition 11.2 to clarify the type of operation that is limited if fracing of unconventional resources occurs on the same well pad (i.e., POGO activities).*

**B-16**: Page 10, Condition 11.4. Please revise the condition as follows to adequately describe all required information to determine compliance with the underlying limits of Table 2.

11.4 In each operating report required under Condition 20, the Permittee shall record the following ~~drill rig identification, pad identification and pad category (collocated~~~~11~~ ~~or isolated), dates occupied by the rig(s), the drilling category(s) (routine or developmental), and the start and end dates when any nonroad engine operated as EU 1 and/or any heater/boiler operated as EU 2, operate concurrently with fracing~~ during the reporting period:

* 1. Drill rig identification;
	2. Pad identification;
	3. Pad category (collocated11 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 conventional fracing; and
	7. Start and end dates when any heater/boiler operated as EU 2 operate concurrently with conventional fracing.

*Response: The Department received multiple requests to clarify Condition 11.4 (see Comment A-16). The Department revised Condition 11.4 to explicitly require the Permittee to record and report the information needed to demonstrate compliance with the fuel consumption limits in Table 2. It also revised the format of Condition 11.4 to more adequately describe the information in a list format.*

**B-17**: Page 10, Footnote 11. Please clarify the footnote to address wells sites and well pads that are aggregated under Title V permit but otherwise not aggregated with the stationary source. For a Title V renewal permit that has not been issued, wells sites and well pads may not have been disaggregated. On August 7, 2012, the Summit Decision (Summit Petroleum v. United States Environmental Protection Agency; Lisa Jackson Nos. 09-4348;10-4572) was made and was upheld on May 30, 2014 by the United States Court of Appeals for the District of Columbia Circuit. Oil and gas facilities can only be aggregated if they are within one quarter of a mile of each other. Therefore, well sites and well pads that are further than one quarter of mile from the main production facility should not be aggregated. Some Title V permits for the North Slope have not been revised to reflect the Summit Decision due to various reasons, but the well sites and well pads greater than a quarter mile are not aggregated with the main production facility and should not be considered collocated.

11  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 for the purpose of the MG-2.

*Response: The Department revised Footnote 11 to clarify that, for the purpose of the MG-2, well pads or well sites that are currently aggregated under a Title V permit, but do not meet the definition of collocated under Footnote 11, then the well site or well pad will be considered isolated.*

**B-18**: Page 14, Condition 14. Please revise this condition as follows to remove the 10-day notification because no underlying basis exists. On the MG-2 permit title page, ADEC cites the requirement to obtain the MG-2 permit is under Alaska Statute (AS) 46.14.120(g). AS 46.14.120(g) requires a permit before constructing, installing, modifying, operating, or establishing a stationary source subject to the requirements in AS 46.14.130(c). The basis for the 10-day notification requirement for temporary sources is required in AS 46.14.215 for stationary sources subject to the permitting requirements in AS 46.14.130(b). AS 46.14.130(b) requires permits for facilities that are subject to Title V operating permits. The MG-2 permit is a minor permit with a potential to emit for each individual New Source Review (NSR) pollutant less than 100 tons per year and therefore the source is not subject to the permitting requirements in AS 46.14.130(b). The requirements for a 10-day notification in AS 46.14.215 are not applicable to the MG-2 permit.

BPXA acknowledges that ADEC needs to know which well sites or well pads the POGO’s are operating at, however, there is no underlying regulatory requirement that requires the notification to be made at least 10 days prior to operating on a well pad or well site not identified in the annual report required by Condition 13. A 10-day notification may not always be feasible if a pad has changed from the annual report required by Condition 13. Many factors can affect drilling plans on short notice. For example, if a bird’s nest was discovered on a wellhouse only a few days before the rig move, the rig would be moved to a different well site to avoid disturbance of the bird nest per other environmental regulations. Because it was not anticipated to be moved to a different well pad, the POGO may be moved to a site that was not included in the annual report. Because the nest was only discovered a few days before the rig move, it would not have been feasible to provide a notification at least 10 days prior to the rig move. To prevent high idling costs while a rig move is stalled to adhere to a 10-day notification schedule, ADEC must allow well site changes to be made on short notice without delay to the drilling schedule.

ADEC will still receive the notification as soon as practicable and be able to inspect the POGO at the alternative well site or well pad.

Secondly, please revise when Attachment 2 is required to be submitted. As stated, Attachment 2 is an MG-2 Application Addendum. The MG-2 Notice of Intent to Operate (NIO) may identify all the potential locations that the POGO is going to operate. The annual report may only include the locations that are anticipated for the upcoming year. Therefore, the annual report may have not anticipated the POGO at a specific location, as long as the well site or well pad was identified in the NIO, the change in location would not qualify as an application addendum. If the location of the POGO was not included in the NIO, then Attachment 2 would be required.

14. The Permittee shall notify the Department if there is a revision to the well pads/drill sites identified in the notification submitted under Condition 13 ~~at least 10 days~~ as soon as practicable prior to operating at the new well pad/drill site. If the new well pad/drill site was not included in the MG-2 NIO, ~~U~~use the form in Attachment 2 to make this notification.

*Response: The Department revised Condition 14 (now Condition 21) to require the relocation notification to be submitted to the Department ‘as soon as possible’ prior to operating at the new well pad/drill site to allow for additional flexibility in the event of an unexpected rig move. The term ‘as soon as practicable’ was not used because the Department finds it would be difficult to evaluate based on respective thoughts and intentions. ‘As soon as possible’ is intended to mean a test of feasibility and physical possibility, but in any event to occur prior to operating at the new site.*

**B-19**: Page 16, Condition 19.1c(i). Please revise the condition as follows to include the clause “of discovery.” As written, a permit deviation may occur for failure to report within the timeline if an event is unknown or not discovered.

19.1(c)(i) within 30 days of the end of the month in which emissions or deviation occurs or is discovered, except as provided in Conditions 19.1c(ii) and 19.1c(iii);

*Response: The Department did not revise Condition 19.1(c)(i) (now Condition 17.1(c)(i)) to include the proposed clause ‘or is discovered’ because it would undermine the need for complying with the permit conditions. Permittees are responsible for maintaining continual compliance with the terms and conditions of their permit. Part of maintaining continual compliance is to establish robust procedures for identifying permit deviations and excess emissions. Those procedures should be able to detect noncompliance early enough to be able to report it the following month. The Department considers the length and severity of an infraction when dealing with a compliance issue. Therefore, Permittees should have a desire to minimize the duration of a permit infraction, including infractions of the reporting requirement. Providing an exception clause reduces the apparent need for continual compliance, which undermines a basic goal of the permit program.*

**B-20**: Page 17, Condition 21. Please revise this condition as follows. The TAR states on page 8 that the requirement to have an annual affirmation “applies to stationary source not subject to Title V permitting.” Since this is specific to Title V avoidance, this affirmation should reflect that sentiment.

21 Annual Affirmation of Qualification. The Permittee shall submit to the Department by March 31 of each year an affirmation certified according to Condition 15 of whether the POGO still qualifies for this permit and that Title V permitting has not been triggered by the POGO activities. ~~is still accurately described by the application and this permit, and whether any changes have been made to the POGO equipment inventory that would trigger the requirement for a new permit under 18 AAC 50.~~

*Response: The Department received multiple, but identical, requests regarding Condition 21 (see Comment A-23). The Department revised Condition 21 (now Condition 19) as discussed in its response to Comment A-23.*

**Technical Analysis Report**

**B-21**: Page 5, Section 4, 2nd full paragraph. Please correct the condition reference which currently reflects a missing reference in the electronic file.

…Condition **Error! Reference source not found.** requires…

*Response: The Department received multiple requests to correct the cross-reference error (see Comment C-31). The Department corrected the hyperlink so that the discussion now references Condition 21 of the permit (relocation notification).*

**B-22**: Page 7, Section 5, header. Please correct the condition reference which currently reflects a missing reference in the electronic file.

**Conditions 11 –** Error! Reference source not found.**, Ambient**…

*Response: The Department corrected the cross reference to remove the error message.*

**B-23**: Appendix A, Table 2. Please remove reference to an applicable limit for EUs 4 and 5. Note b to the table indicates a combined daily fuel consumption limit of 15,435 exists for EUs 4 and 5. However, no operational limit is included in the draft MG-2 permit for these units.

*Response: The Department revised Table Note b to remove the reference to an applicable fuel limit for EUs 4 and 5 as no such limit exists, rather the potential to emit for EUs 4 and 5 were calculated based on a combined daily fuel consumption of 15,435 gallons which is conservatively estimated based on the fuel consumption limits for EUs 1 and 2.*

**Hilcorp’s Comments**

**H-1**: We strongly feel that the permit should clarify how drilling operations are to occur in areas in which existing Title V permits contain drilling restrictions. We feel that it has been clearly demonstrated in the TAR that POGO operations do not have significant impacts on ambient air quality. As a result we request that a process be established for removing drilling restrictions from Title V permits to allow for the use of the MG2 Permit at collocated sources that have existing Title V permits. We believe such requests qualify as administrative revisions since the substantive and technical work associated with the revisions will have all been completed and undergone public comment by the time any such requests are received by the Department.

Specifically, The TAR at page 9, item 8 should clearly state that once the MG2 is secured, requests to remove POGO-related language from previously issued and existing permits and for revocation of POGO-specific minor source specific and Title V (TV) permits qualify as administrative revisions.

*Response: The Department is unable to create a generic approach for removing select terms and conditions of an existing Title* *V or minor source specific (MSS) permit. Each permit includes its own nuances due to the unique aspects of the given stationary source. The permit outline has also changed over time, along with the wording. Applicants have also asked for various approaches for imposing operational limits over the years. For example, some permits may contain fuel consumption limits, while others may contain limits on the hours of operation or cumulative capacity of select equipment. It is therefore impossible to clearly identify, within a minor general permit, the conditions that would be automatically revised or rescinded in each existing Title* *V and MSS permit with POGO-related terms.*

*The proper approach for revising an existing MSS permit is to submit a minor permit application under 18* *AAC* *50.508(6). The applicant would need to clearly identify which terms and conditions that they want revised or revoked. However, the applicant could likely reference the extensive work already conducted in developing the MG-2 permit when providing the explanation required under 18* *AAC* *50.540(k)(2). This should save the applicant substantial time and effort. The subsequent permit action would be subject to public comment, as required under 18* *AAC* *50.542(d). The administrative provision described under 18* *AAC* *50.546(b) could not be used since that process is limited to “non-substantive elements” of the minor permit – which is not the case. The bulk of the justification may have already been conducted, but the requested change is still substantive.*

*The proper approach for revising an existing Title V permit is described in 40* *C.F.R.* *71.7(d)* *– (e), which the Department has adopted by reference in 18 AAC 50.040(j). In this case, the administrative process could likely be used to incorporate a revised MSS permit into the Title V permit. However, revisions to a stand-alone Title V permit would likely need to be conducted under the provisions described in 40 C.F.R. 71.7(e).*

*The Department encourages Permittees to discuss their case-specific details with the Department in order to find the most expedient and defensible path for removing past POGO-related terms from an existing permit.*

**Other Revisions Made by the Department**

* + - 1. The Department corrected the cross-reference listed in Footnote 2.
			2. The Department corrected a numbering error in the Condition 20 sub-conditions.
			3. The Department revised Condition 16 (now Condition 14) to update the order by which it prefers submittals be made (i.e., AOS is preferred, then email, lastly by hard copy).
			4. The Department included a calendar year field in the Title of the Annual Notification Form.
			5. The Department changed the title of the MG-2 permit, Application Form, and Annual Notification Form from Oil and Gas Drilling Rigs to Portable Oil and Gas Operations.
			6. The Department revised Total Rating/Size row for Well Venting/Flow backs (EU 3) the EU Inventory, Annual Notification Form, and Permit Application from ‘90 tons VOC (25 new wells)’ to ‘Varies’ which is a more accurate description since the MG-2 permit does not limit well venting or flow backs to 25 new wells.
			7. The Department moved the phrase ‘during the reporting period’ up in Condition 11.4 from the end of the list (item g) to the beginning of the list for clarity because the reporting requirements apply to all seven items during each reporting period.
			8. The Department revised Footnote 10 to clarify that drill sites that are not physically adjacent to or contiguous with a Title V production facility **are** treated as isolated pads for ambient air quality protection purposes. If a well pad or well site is aggregated **with a production facility** under an existing Title V permit, but otherwise does not meet the definition of collocated as stated above, that well site or well pad **is** considered isolated (emphasis added).
			9. The Department revised Condition 14 to clarify that all of the reports, compliance certifications, and/or other documents submitted via email or post must be certified. The condition was unclear and could have been interpreted to imply that certification is not mandatory in some cases.
			10. The Department revised Condition 17.1c(i) for consistency with the Air Permit Program’s Standard Permit Condition III ([http://dec.alaska.gov/air/air-permit/standard-conditions](http://dec.alaska.gov/air/air-permit/standard-conditions/)).
			11. The Department revised the Relocation Notification Form to allow for multiple well pads/drill sites to be identified.
			12. The Department revised the Finding No. 5 in the TAR to clarify its discussion related to well flow back emissions that occur prior to the wells being placed into production.
			13. The Department revised Section 8 of the TAR to clarify how the permit administration will work for existing Title V sources that obtain an MG-2 permit for POGO related activities. This language was proposed by members of the Drill Rig Work Group.
			14. Revised Condition 12.1 to clarify that maximum concentration of sulfur in diesel fuel is 0.0015 percent sulfur by weight.

**Attachment A to CPAI Comments**

**Letter from Tom Chapple (ADEC) to**

**Ken Donajkowski (CPAI)**

**September 21, 2005**

**Re: VOC Emissions from Well Construction Activity**

1. *AOGA-ASIA notified the Department of a typographical error in the EU reference in an April 14, 2018 email from Brad Thomas (CPAI) to Aaron Simpson (Department). AOGA-ASIA clarified that the reference to “EU IDs 3-5” should have been “EU IDs 3-6.” The Department has therefore revised the stated EU ID numbers as requested by AOGA-ASIA.* [↑](#footnote-ref-2)
2. *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*](http://dec.alaska.gov/air/air-permit/oil-gas-drill-workgroup) [↑](#footnote-ref-3)