Bakken Pool

Oil and Gas Production Facilities

Air Pollution Control
Permitting & Compliance Guidance

North Dakota Department of Health

Division of Air Quality

Effective Date May 2, 2011

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APPENDICES

1. ACRONYMS AND ABBREVIATIONS

AP-42 EPA Publication AP-42, Compilation of Air Pollutant Emission Factors (5^{th} Edition)
Bakken Pool Oil from Bakken, Three Forks, and Sanish Formations
bbl barrel
BOPD barrels of oil per day
BTEX benzene/toluene/ethyl-benzene/xylenes
Btu British thermal unit
Btu/hr Btu per hour
CO carbon monoxide
DRE destruction and removal efficiency
EF emission factor
EPA Environmental Protection Agency
gpm gallons per minute
H_2S hydrogen sulfide
HAP hazardous air pollutants
hp horsepower
lb pound
lb/lb-mole pound per pound mole
LACT Lease Automatic Custody Transfer
MMBtu one million Btu
MMscf one million standard cubic feet ($scf \times 10^6$)
MMscfd = 1,000,000 scf per day
Mscf one thousand standard cubic feet (scf × 1000)
Mscfd = 1000 SCF per day
NDDoH North Dakota Department of Health
NESHAP National Emission Standards for Hazardous Air Pollutants
NOx nitrogen oxides
NSCR Non-Selective Catalytic Reduction
NSPS New Source Performance Standards
O&G Oil and Gas
PSD Prevention of Significant Deterioration
psig pounds per square inch gauge
psia pounds per square inch absolute
PTE potential to emit
RICE reciprocating internal combustion engine
scf standard cubic foot
scf/bbl standard cubic foot per barrel
SO_2 sulfur dioxide
S/W/B standing/working/breathing losses
TEG tri-ethylene glycol
Title V Title V of the Clean Air Act Amendments of 1990
TOC total organic compounds
TPY tons per year
VOC volatile organic compounds

2. BACKGROUND

A. Introduction

The creation of this guidance document (Guidance) was a coordinated effort between the North Dakota Department of Health (NDDoH) and the Bakken VOC Task Force, which is comprised of an Emission Factor Committee and an Emission Control Committee.

This Guidance provides an approach that may be used by Bakken Pool Oil and Gas (O&G) production facility owners/operators to demonstrate compliance with the applicable North Dakota Air Pollution Control Rules (including, but not limited to the requirements established by Chapters 33-15-07 and 33-15-20, N.D. Admin. Code). This Guidance provides owners and operators of Bakken Pool O&G production facilities that have the potential to emit air pollutants below the major source thresholds (minor Bakken Pool O&G production facilities) with an alternative to obtaining North Dakota air pollution control permits. Owners and operators of minor Bakken Pool O&G production facilities may still choose to apply for facility-specific air pollution control permits. The NDDoH will consider those applications on a case-by-case basis.

It should be noted that emissions associated with the exploration and production of O&G resources cannot be predicted with any degree of precision or accuracy until after it is determined the oil or gas well will actually produce and site specific production data are collected and known. Therefore, unlike other stationary sources for which projected emissions upon startup can be estimated in advance for purposes of pre-construction air permitting, emissions from O&G exploration and production facilities are only known post-construction and completion. This situation is unique to O&G exploration and production facilities and, therefore, requires a practical regulatory response. To accommodate this reality, the NDDoH has tailored its O&G registration process and this Guidance to allow for the start-up of new exploration and production facilities, and the modification of existing facilities, to occur prior to requiring the submittal of the appropriate O&G Registration Packet, provided the owners/operators of such facilities meet certain emission control requirements that have been established within this Guidance document. This represents a rational and practical regulatory response to operational realities posed by O&G exploration and production operations.

Control requirements have been established within this Guidance for tank emissions and emissions from dehydration units, treater flares and pneumatic pumps. Emissions from other sources such as pneumatic controllers, truck loading, etc. are also included in this Guidance.

Nothing in this Guidance is intended to relieve owners and operators of Bakken Pool O&G production facilities of the responsibility to comply with all State and Federal environmental laws and rules. Owners and operators of Bakken Pool O&G production facilities with the potential to emit at or above major source thresholds must follow the normal permitting processes established in Chapters 33-15-14 and 33-15-15 of the North Dakota Air Pollution Control Rules.

B. Unique Issues with Bakken Pool VOCs

Crude oil from the Bakken Pool (defined as wells in the Bakken, Sanish and Three Forks formations) typically contains a high amount of lighter end components which have the potential to produce increased volumes of flash emissions. Because of this, customary correlations such as API's E&P Tanks and Vasquez-Beggs do not work well for estimating flash vapors in the Bakken, potentially overestimating and underestimating emissions.

Recognizing the need to predict tank emissions at Bakken Pool O&G production facilities, the NDDoH and industry collaborated and formed the Bakken VOC Task Force. The Task Force included the Emission Factor Committee and the Emission Control Committee.

The Emission Factor Committee's goal was to gather direct measurement data collected by various owners/operators within the Bakken Pool and establish an emission factor that could be used to predict tank emissions from producing Bakken Pool formation wells.

The Emission Control Committee's goal was to evaluate available emission control technologies and to recommend the best emission control for different emission scenarios.

The findings of both Committees were used as a platform to create this Guidance for Bakken Pool O&G production facilities. The data from the Bakken VOC Task Force that was used to create the default values for Bakken Pool O&G production facilities were submitted and revised by NDDoH and are available for public review upon request. Use of the Bakken default values to calculate VOC emissions is expected to result in a conservatively high estimate of VOC emissions. As an alternative to using the Bakken default values, site-specific data can be used to estimate emissions. In the vast majority of cases, the use of site-specific data instead of the Bakken default values is expected to result in lower calculated VOC emissions.

As mentioned above, Bakken Pool O&G production facilities are different from other O&G production facilities in North Dakota because of the higher potential for flash emissions. This Guidance was created to provide a consistent and more accurate approach for calculating emissions from the Bakken Pool O&G production facilities. While all producing wells in the State will need to have a registration form filed with NDDoH (see Appendix A) and emissions calculations performed, it is not expected that non-Bakken Pool O&G production facilities will require emission controls for tank emissions to the same extent as Bakken Pool production facilities.

Although the Guidance is applicable to Bakken Pool O&G production facilities, the Emission Calculation Workbook may also be used for non-Bakken Pool O&G production facilities; however, it should be noted that some of the default values in the Workbook are specific to Bakken Pool O&G production facilities. When applying the Workbook to non-Bakken Pool O&G production facilities, the user should review the Workbook to ensure that the values are appropriate for the production facility being evaluated.

C. **Applicability**

All Bakken Pool O&G production facilities (excluding those facilities on Tribal Land) within the State of North Dakota that emit regulated air contaminants into the atmosphere are subject to the requirements discussed in this Guidance and are required to submit either a new or an updated O&G registration packet to NDDoH.

Each Bakken Pool O&G production facility owner or operator will receive a letter detailing instructions on well information submissions. The following summarizes the content of the submissions.

Existing Bakken Pool O&G production facilities are those where the first date of production occurred on or before June 1, 2011. Owners/operators that have previously submitted registration forms will be required to submit the worksheet detailing well information such as controls, calculations and dates. The NDDoH will supply a blank worksheet to perform the calculations that contains all required fields. Each owner/operator must submit the spreadsheet information to the NDDoH by December 1, 2011 (note that the worksheet is in lieu of a new registration).

All owners/operators of existing Bakken Pool O&G production facilities that have not previously filed a registration form must submit a new registration packet to NDDoH by no later December 1, 2011 or within 90 days after the first date of production, whichever is later. These registrations will include information on each well, including all prior controls, in the worksheet (supplied by the NDDoH).

New Bakken Pool production facilities are those where the first date of production occurs after June 1, 2011. The owner/operator of a new Bakken Pool O&G production facility must submit a registration packet to NDDoH within 90 days after the first date of production.

D. **Potential to Emit (PTE) Action Levels**

Based on the total facility-wide emissions, there are three different registration/permit action levels that will require varying submittals for Bakken Pool O&G production facilities, regardless of location. All new and previously unregistered Bakken Pool O&G production facilities must register with the NDDoH as provided in the Applicability section above. The owner/operator of previously registered Bakken Pool O&G production facilities need only submit a summary spreadsheet as outlined in the Applicability section above. The flowchart below can be used to determine the action/actions an owner/operator needs to take depending on the potential to emit of the Bakken Pool O&G production facility.

Action Flowchart

VOC, CO, NOx <100 TPY & Combined HAP <25 TPY & Single HAP <10 TPY

- Submit Registration Packet within 90 days after the first date of production (new well) or by 12/1/11 (for existing wells)
- No further action

VOC, CO, NOx ≥100 TPY or Combined HAP ≥25 TPY or Single HAP ≥10 TPY

- Submit Registration Packet within 90 days after the first date of production (new well) or by 12/1/11 (for existing wells)
- A Permit to Construct is required
- Submit Title V Application within 365 days of the first date of production

VOC, CO, NOx ≥250 TPY

- Requires a PSD Application and Permit
- PSD is a pre-construction permit
- Contact the NDDoH for further guidance

E. Registration Only

If a Bakken Pool O&G production facility has a potential to emit (PTE) ≤100 TPY of any criteria pollutant, ≤25 TPY of combined HAP and ≤10 TPY of any single HAP, the owner/operator only needs to submit a completed registration packet for that facility within 90 days after the first date of production for new production facilities or by December 1, 2011 (whichever is later). No further action is required. See example forms in Appendices A and B.

F. Permit to Construct and Title V Operating Permit (Major Source)

If a Bakken Pool O&G production facility has a PTE ≥100 TPY of any criteria pollutant, ≥25 TPY of combined HAP or ≥10 TPY of a single HAP, the facility is required to obtain a Permit to Construct and a Title V permit as required by Chapter 33-15-14. Although the O&G production facility is subject to permitting requirements, a registration packet is still required to be submitted within 90 days after the first date of production. These permitting requirements are beyond the scope of this Guidance, but more information on the permitting process can be obtained from the NDDoH website at: http://www.ndhealth.gov/AQ/AirPermitting.htm.

G. Prevention of Significant Deterioration (PSD)

A Bakken Pool O&G production facility that either emits, or has the PTE, $\geq$250 tons per year of any air contaminant regulated under North Dakota Century Code Chapter 23-25 (or $\geq$100,000 tons per year of greenhouse gases), as determined by the NDDoH, must comply with the permitting requirements of Chapter 33-15-15 (Prevention of Significant Deterioration of Air Quality).

The PSD permit is a pre-construction permit. A facility cannot construct until a permit application has been filed and the permit has been issued. The PSD permitting process is a complicated, time-consuming process that is beyond the scope of this Guidance. More information on the PSD permitting process can be obtained from the NDDoH website at: http://www.ndhealth.gov/AQ/AirPermitting.htm.

H. Potential to Emit

The federal regulations define "potential to emit" as: "The maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of fuel combusted, stored or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable."

Chapter 33-15-07 of the North Dakota Air Pollution Control Rules states, "No person may cause or permit the emission of organic compounds gases, vapors…..unless these gases and vapors are burned by flares or an equally effective control device as approved by the Department. Chapter 33-15-07 has been approved by the EPA as part of the North Dakota State Implementation Plan and as a result, is federally enforceable. Therefore, for an oil and gas production facility, the PTE of VOCs and the associated HAPs is calculated post-controls. Please refer to Appendix C for approved control devices. This Guidance is intended to assist O&G owners/operators demonstrate compliance with Chapter 33-15-07.

I. New Source Performance Standards (NSPS) and Maximum Available Control Technology (MACT) Applicability

Equipment at Bakken Pool O&G production facilities may be subject to rules and regulations under 40 CFR Parts 60 and 63. These federal regulations are beyond the scope of this document. It is the owner/operator's responsibility to determine if equipment is subject to these federal regulations. A summary of numerous Federal rules that may apply to Bakken Pool O&G production facilities is located at: www.ndhealth.gov/AQ/OilAndGasWells.htm.

J. **Regulated Air Pollutant Sources**

When registering a Bakken Pool O&G production facility, all emission sources at that particular facility must be considered to determine source status (major or minor source). Generally, the following are the most common emission sources and the type of regulated air pollutants they may emit at a typical Bakken Pool O&G production facility:

- Oil/Condensate Tanks – VOC, HAP, H_2S (NOx, CO, SO_2 when controlled)
- Produced Water Tanks – VOC, HAP, H_2S (NOx, CO, SO_2 when controlled)
- Treater Flares – VOC, HAP, NOx, CO, H_2S, SO_2
- Heaters/Burners – VOC, HAP, NOx, CO, SO_2
- Truck Loading – VOC, HAP
- RICE Engines – VOC, HAP, NOx, CO
- Pneumatic Pumps – VOC, HAP
- Pneumatic Controllers – VOC, HAP
- Fugitives – VOC, HAP

K. **Control of Bakken Pool O&G Production Facility VOC Emissions**

Based on historical information from Bakken Pool O&G production facilities, flashing emissions from the production tanks may be significant. Acceptable VOC emission control systems or devices are discussed in Appendix C. The control requirements for emissions from production tanks are outlined in Appendix D of this document.

L. **Greenhouse Gas (GHG) Emissions**

It is the responsibility of each owner/operator to determine the applicability of GHG emissions inventory reporting and permitting rules to their facilities and to comply with the rules. If multiple wells are drilled from a single pad, GHG emissions from all wells may need to be aggregated (see Multi Well Pad Statement below).

M. **Multi Well Pad Statement**

When multiple wells are drilled from a single pad, it may be necessary to aggregate all emission sources at the multiple well production facility and additional permitting requirements may apply (Title V, PSD, etc.), which are beyond the scope of this document. Questions regarding permitting requirements for multi-well production facilities should be addressed to Craig Thorstenson of the Division of Air Quality at 701-328-5188 or cthorstenson@nd.gov.

3. **FORM COMPLETION**

A. **Oil & Gas Facility Registration Process**

Within 90 days after the first date of production or recompletion of any Bakken Pool O&G production facility, the following documents (registration packet) must be submitted to the NDDoH for the facility:

Registration Packet Contents

1) A completed Oil/Gas Registration Form (AP-114)
2) A gas analysis of any gas produced from the well
3) The first 2 pages (Input and Emission Summary) of a completed Oil and Gas Facility Emission Calculation Workbook

The Registration packet, (forms and examples found at: http://www.ndhealth.gov/AQ/OilAndGasWells.htm), which includes the above three items, must be sent to the following address:

North Dakota Department of Health
Division of Air Quality
918 E Divide Ave, 2nd Floor
Bismarck, ND 58501-1947

B. Emission Calculation Workbook

The Emission Calculation Workbook can be downloaded from the NDDoH O&G website in Excel format. The workbook will serve two functions: it will provide a simple way of calculating facility-wide emissions, as well as insuring that all owner/operators are calculating emissions in a consistent manner that meets the requirements of NDDoH.

The Oil & Gas Facility Emission Calculation Workbook contains the following 10 tabs:

- **Input** – The necessary data to perform the required calculations are entered here (required to be submitted in Registration Packet).
- **RICE Input** – The necessary data to perform the required calculations for RICE are entered here (required to be submitted in Registration Packet).
- **Emission Summary** – The calculated emissions are summarized by source and pollutant here (required to be submitted in Registration Packet).
- **Oil/Condensate Tanks** – The tank vapor emissions are calculated here.
- **Treater Flare** – The treater flare emissions are calculated here.
- **Treater Burner** – The treater burner emissions are calculated here.
- **Truck Loading** – The truck loading emissions are calculated here.
- **RICE** – The RICE emissions are calculated here.
- **Pneumatic Pump** – The pneumatic pump emissions are calculated here.
- **Pneumatic Controllers** –The pneumatic controller emissions are calculated here.

C. Emission Calculation Workbook Instructions

The Emission Calculation Workbook can be completed in three steps: Calculating production numbers, calculating glycol dehydrator emissions using GRI-GLYCalc (if applicable) and entering data into the Emission Calculation Workbook.

Step 1

Thirty days after the first date of production or recompletion of a Bakken Pool O&G production facility, the average daily production for the facility needs to be calculated. Once calculated, this production data will need to be entered into the Emission Calculation Workbook in order to perform the required emission calculations.

Step 2

If the facility has a glycol dehydrator in operation, the NDDoH recommends using GRI-GLYCalc V4 or higher to calculate the emissions. Other programs may be used upon approval from the NDDoH.

Step 3

Complete the entire Emission Calculation Workbook per the detailed instructions below:

Data Input

Facility and Registration Information: Lines 1-3

Line 1: Enter the name of the facility and the well number.

Line 2: Enter the first date of production or date of recompletion of the facility.

Line 3: Enter the date that the registration packet is submitted to the NDDoH.

Production Data: Lines 4-8

Line 4: New wells: enter the average daily production in BOPD, based on the first 30 days of production, excluding any days the well was not operating during that period of time. Existing wells: enter the average daily production in BOPD, based on the most recent 30 days of production, excluding any days the well was not operating during that period of time.

Line 5: New wells: enter the average daily production of gas in Mscf per day, based on the first 30 days of production, excluding any days the well was not operating during that period of time. Existing wells: enter the average daily production in Mscf, based on the most recent 30 days of production, excluding any days the well was not operating during that period of time.

Line 6: New wells: enter 0.6 on this line. This equates to an 80% decline in production from the well during the first year of production. If the expected decline rate is less than 80%, then the expected decline rate should be used. Existing wells: in most situations, a decline factor may not be used for an existing well; therefore, enter 1 on this line. The Department will accept a decline factor other than 0.6 or 1 in the following instance: an actual decline factor (based on well production) must be submitted for each well that is producing for less than one year before June 1, 2011. Wells that have produced for more than one year before June 1, 2011 must use a decline factor of 1. See Appendix E for an explanation of the decline factor and how it relates to an 80% decline in production during the first year of production.

Line 7: No input required. This is the projected first year average daily oil production rate (BOPD). This is automatically calculated by multiplying the average daily rate entered on Line 3 by the decline factor entered on Line 5.

Line 8: No input required. This is the projected first year average daily gas production rate (Mscfd). This is automatically calculated by multiplying the average daily rate entered on Line 4, by the decline factor entered on Line 5.

Oil/Condensate Tank Data: Lines 9-19

Line 9: Using the drop down box, select the appropriate flash gas method used for determining the tank vapor emission factor (scf/bbl).

- Default Bakken EF
- Site Specific Direct Measurement
- Representative Average (This average can be established from direct measurements from a minimum of six different wells within the same field and operating under similar parameters; however, it requires a case-by-case review and approval by the NDDoH prior to submitting the registration packet).

Line 10: Enter the scf/bbl EF based on the method chosen on Line 8.

- Default Bakken EF: If site specific data is not available, the default Bakken EF of 97.91 scf/bbl should be used.
- Direct Measurement: If site specific direct measurements have been taken, enter the measured scf/bbl EF determined from taking the direct measurement.
- Representative average: Enter the representative average scf/bbl approved by the NDDoH.

Line 11: No input required. This is a calculated value determined by multiplying the adjusted BOPD value on Line 6, by the scf/bbl entered in Line 9.

Line 12: Enter the lower heating value (Btu/scf) of tank vapors. If site specific data is not available, use the Bakken default value of 2000.

Line 13: Enter the molecular weight of the tank vapors in pounds per pound-mole (lb/lb-mole). If site specific data is not available, use the Bakken default value of 45.19.

Line 14: Enter the VOC weight fraction of the tank vapor gas (C3+). If site specific data is not available, use the Bakken default value of 79.8%.

Line 15: Enter the HAP weight fraction of the tank vapor gas. If site specific data is not available, use the Bakken default value of 2.26%. A complete list of HAPs is located at http://www.epa.gov/ttn/atw/orig189.html.

Line 16: Enter the H_2S weight percent of the tank vapors.

Line 17: Enter the H_2S mole percent of the tank vapors.

Line 18: Use the drop down menu to select the type of device used to destruct tank vapors from the following options:

- Vapor Recovery Unit or Oil Stabilizer
- Enclosed Smokeless Combustor
- Utility Flare or Other 98% DRE Device
- Ground Pit Flare or other 90% DRE device

Line 19: No input required. This is a fixed destruction efficiency based on the control type selected on Line 17.

- Vapor Recovery Unit or Oil Stabilizer = 99% DRE
- Enclosed Smokeless Combustor = 98% DRE
- Utility Flare or Other 98% DRE Device = 98% DRE
- Ground Pit Flare or other 90% DRE device = 90% DRE

Treater Gas Data: Lines 20-29

Line 20: Enter the site specific Btu/scf of the wellstream gas.

Line 21: Enter the average molecular weight of the wellstream gas in lb/lb-mole.

Line 22: If it is necessary to convert specific gravity to molecular weight, enter the specific gravity of the wellstream gas.

Line 23: This is the calculated molecular weight of the wellstream gas based on the specific gravity entered on Line 22. Enter this value on Line 21.

Line 24: Enter the VOC weight fraction of the wellstream gas (C3+). Note that this is the weight percent, not the mole percent of the gas.

Line 25: Enter the HAP weight fraction of the wellstream gas. Note that this is the weight percent, not the mole percent of the gas. A complete list of HAPs is located at http://www.epa.gov/ttn/atw/orig189.html.

Line 26: Enter the H_2S weight percent of the wellstream gas.

Line 27: Enter the H_2S mole percent of the wellstream gas.

Line 28: Use the drop down menu to select the type of device used to destruct the wellstream gas from the following options:

- Enclosed Smokeless Combustor
- Utility Flare or other 98% DRE Device

- Ground Pit Flare or other 90% DRE device
- Connected to Sales Line

Line 29: No input required. This is a fixed destruction efficiency based on the control type selected on Line 25.

- Enclosed Smokeless Combustor = 98% DRE
- Utility Flare or Other 98% DRE Device = 98% DRE
- Ground Pit Flare or other 90% DRE device = 90% DRE
- Connected to Sales Line = 100% DRE

Treater Burner(s) Data: Lines 30-31

Line 30: Enter the total burner rating for the treater burner(s) in Btu/hr. If there are multiple burners at the facility, enter the total heat input of all burners.

Line 31: The burner(s) is/are assumed to operate 8,760 hours per year.

Truck Loading Data: Lines 32-38

Line 32: Use the drop down menu to choose the appropriate oil sales method. If oil is sold through a Lease Automatic Custody Transfer, no input values are required in Lines 30-35.

Line 33: Use the drop down list to choose the appropriate mode of operation. The saturation factor will automatically be selected based on mode of operation.

Line 34: Enter the molecular weight of tank vapors, lb/lb-mole. If no site specific data is available, please refer to Table 2 on the Truck Loading tab.

Line 35: Enter the true vapor pressure of liquid loaded, pounds per square inch absolute (psia). If no site specific data is available, please refer to Table 2 on the Truck Loading tab.

Line 36: Temperature of bulk liquid loaded in degrees Fahrenheit. If no site specific data is available, use an estimated average annual temperature.

Line 37: Enter the load rate of liquid loaded in barrels per hour.

Line 38: Enter the time (in hours) it takes to loadout one load.

Pneumatic Pumps Data: Lines 39-43

Line 39: Enter the number of pneumatic pumps at the facility.

Line 40: Enter the hours each pump is in operation annually. For winter months only, enter 4380 hours.

Line 41: Enter the pneumatic source consumption rate from manufacturer's data (scf/min).

Line 42: Use the drop down menu to choose the appropriate emission control type.

Line 43: No input required. Control efficiency is automatically calculated based on control type selected on Line 55.

Pneumatic Controllers Data: Lines 44-45

Line 44: Enter the number of pneumatic controllers at facility.

Line 45: Enter the average bleed rate of device (scf/hr).

Glycol Dehydrator Data: Lines 46-47

Line 46: Enter the TPY of VOC emissions calculated in GRI-GLYCalc V4 software. (If no glycol
dehydrator is installed, enter 0).

Line 47: Enter the TPY of HAP emissions calculated in GRI-GLYCalc V4 software. (If no glycol dehydrator is installed, enter 0).

<u>RICE Data Input</u>: Lines 1-97

Line 1: Enter the number of engines to be installed at the production facility.

RICE Engine #1: Lines 2-9

Line 2: Engine is assumed to operate 8,760 hours per year.

Line 3: Enter the manufacturer's maximum hp rating.

Line 4: Enter the manufacturer's emission factor, actual test results or AP-42 factor in grams per horsepower hour (g/hp-hr) for nitrogen oxides (NOx).

Line 5: Enter the manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for carbon monoxide (CO).

Line 6: Enter the manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for volatile organic compounds (VOC).

Line 7: Enter the NOx control efficiency of any applicable controls (NSCR catalyst, AFRC, etc.) obtained from manufacturer data or actual test results.

Line 8: Enter the CO control efficiency of any applicable controls (NSCR catalyst, AFRC, etc.) obtained from manufacturer data or actual test results.

Line 9: Enter the VOC control efficiency of any applicable controls (NSCR catalyst, AFRC, etc.) obtained from manufacturer data or actual test results.

Repeat the above input instructions for line 2 through 9 for each additional engine at the facility.

4. EMISSION SOURCE DETAILS

A. Oil/Condensate Tanks

Vapors containing regulated pollutants are released from solution in hydrocarbon liquids as the liquids are transferred from higher to lower pressure, such as from a separator to an atmospheric storage tank. These vapors are called flashing losses.

Vapors escaping from hydrocarbon liquids while they are stored in atmospheric tanks are called standing/working/breathing (S/W/B) losses. Standing losses are essentially evaporation losses. Working losses are those caused by decreased tank vapor space occurring as the tank is filled. Breathing losses are those promoted by ambient changes such as increased air temperatures.

As used in this Guidance, the term, tank emissions include all S/W/B losses and flashing emissions together.

B. Calculating Tank Emissions

Tank emissions are calculated using the Oil & Gas Facility Emission Calculation Workbook. The workbook calculates the tank emissions by using either an actual direct measurement (scf/bbl) taken by the owner/operator, a representative average or by using the default Bakken Pool emission factor of 97.91 scf/bbl described below. In addition to the scf/bbl value, the workbook uses the molecular weight, lower heating value of the fuel and the VOC and HAP weight fractions of the tank vapors to calculate the tank vapor emissions.

C. Bakken Pool Tank Vapor Emission Factor

In conjunction with the NDDoH, a VOC Emission Factor Committee was formed in 2010 to determine an emission factor that could be used for the Bakken Pool crude when calculating tank vapor emissions.

The VOC Emission Factor Committee consisted of representatives from various O&G companies, as well as several environmental consultants. After reviewing the data from 89 direct measurements taken by several owner/operators within Mountrail County, the average emission factor of all measurements taken was 55.26 scf/bbl.

Many of the facilities could actually have emissions which are considerably higher than the average emission factor. Therefore, to better represent some of the higher emitting facilities and to avoid underestimating emissions, the 90^{th} percentile (97.91 scf/bbl) will be utilized. If an owner/operator does not have direct measurement data to support a site specific emission factor, or an NDDoH pre-approved average scf/bbl emission factor established from direct measurements taken from a minimum of 6 different locations operating under similar parameters (representative sample), the owner/operator must use the default value of 97.91 scf/bbl.

D. **Tank Emissions Control Threshold**

Tank emissions require control in accordance with Appendix D of this document.

E. **Tank Emissions Control Requirements**

Emission control requirements for tank emissions are outlined in Appendix D of this document. Also see Appendix C for a list of acceptable control systems or devices.

F. **Produced Water Tanks**

At sites where tank emissions must be controlled by at least 90%, VOC and HAP emissions from all active produced water tanks shall be controlled by at least 90% within 60-days after the first date of production. See Appendix C for a list of acceptable control systems or devices.

G. **Glycol Dehydrators**

Glycol, usually tri-ethylene glycol (TEG), is used in dehydration units to absorb water from wet produced gas. "Lean" TEG contacts the wet gas and absorbs water. The TEG is then considered "rich." As the rich TEG is passed through a reboiler and a flash separator (if installed) for regeneration, steam containing hydrocarbon vapors are released. These are then vented from the dehydration unit flash separator and/or reboiler still vent.

H. **Calculating Glycol Dehydrator Emissions**

The NDDoH recommends using GRI-GLYCalc V4.0 or higher to determine potential uncontrolled VOC and HAP emissions from the process vents of the dehydration unit associated with the projected (decline factor applied) first year average daily gas production rate. Other emission calculation programs may be used upon approval from the NDDoH.

After running the program, print a copy of the report and include it with the Registration Packet submittal. The estimated VOC and HAP emission values also must be entered on Line 59 & Line 60 on the Input Tab of the Emission Calculation Spreadsheet.

I. **Glycol Dehydrator Control Threshold**

Emissions that meet or exceed the following thresholds require the still vent vapors be routed to a control device: ≥ 5.0 TPY of any combination of HAPs, or ≥ 15.0 TPY any combination of VOCs.

J. **<u>Glycol Dehydrator Control Requirements</u>**

The following control systems or devices are accepted by the NDDoH for glycol dehydrator emissions:

1) An enclosed, smokeless combustion device or flare that is designed and operated to reduce the mass content of VOC and total HAP emissions in the vapors vented to the device by at least 98% by weight.
2) Any other control device (e.g. condenser or ground pit flare) or configuration that can be demonstrated to reduce the mass content of total HAP and VOC in the process gases vented to the device or configuration by at least 90% by weight.
3) Glycol dehydrator emission controls may be removed after one year of operation provided emissions have declined to <15 TPY VOC and <5 TPY HAP. An updated GRI-GLYCalc run with new calculations must be submitted to the NDDoH with a request for control removal. No controls may be removed prior to obtaining written approval from the NDDoH.

K. **<u>Glycol Dehydrator Federal Regulations</u>**

A Federal regulation (40 CFR 63, Subpart HH) may be applicable to glycol dehydrators located at Bakken Pool O&G production facilities. This regulation is beyond the scope of this document, but listed below is a brief summary of the regulation:

40 CFR 63, Subpart HH – National Emission Standards for Hazardous Air Pollutants from Oil and Gas Production Facilities

This federal regulation applies to all Bakken Pool O&G production facilities that are major and area sources of HAPs with the following exceptions:

1) A facility that exclusively processes, stores or transfers black oil.
2) A major source prior to the point of custody transfer with a facility-wide annual average natural gas throughput < 18.4 thousand cubic meters/day and a facility-wide annual hydrocarbon liquid throughput < 37,700 liters/day.

L. **<u>Calculating Treater Gas Flare Emissions</u>**

The treater flare emissions are calculated within the Oil & Gas Facility Emission Calculation Workbook using the following:

1) The projected first year average daily gas production rate. This is automatically calculated by multiplying the average daily rate entered on Line 1, by the decline factor entered on Line 3.
2) VOC & HAP weight fraction of gas
3) H_2S mole percent of treater gas
4) Lower heating value of gas
5) Average molecular weight of gas

6) NOx & CO emissions are based on AP-42 emission factors for industrial flares.

M. **Control Requirements for Treater Gas**

Treater gas must be routed to a gas gathering pipeline as soon as practicable in accordance with the North Dakota Industrial Commission requirements. When a pipeline is not available, treater gas is required to be routed to a control system or device. See Appendix C for a list of acceptable control systems or devices. That stated, the current opportunities to capture and transmit treater gas emissions necessitates the intermittent, or otherwise, use of combustion devices.

N. **Natural Gas Fired Heaters & Burners**

Some of the byproducts of natural gas combustion in process heaters, boilers, burners, etc. are regulated air pollutants. NOx, CO, VOC, HAP & SO_2 emissions from process unit heaters are calculated within the Oil & Gas Facility Emission Calculation Workbook using the emission factors (EF) below from EPA AP-42, Tables 1.4-1, 1.4-2 and 1.4-3:

Table 1.4-1 Emission Factors from Natural Gas Combustion (Excerpt from AP-42, Tables 1.4-1, 1.4-2 and 1.4-3)

Pollutant	**Natural Gas EF***
NOx	100 lb/MMscf
CO	84 lb/MMscf
VOC	5.5 lb/MMscf
HAPS	1.89 lb/MMscf

*Based on an average heating value of 1020 Btu/scf of natural gas.

O. **Truck Loading**

When oil and condensate are loaded into tank trucks, the hydrocarbon vapors released from the tanker lines, as the truck is filling, contain regulated air pollutants. VOC emissions from loading oil or condensate into tank trucks are calculated within the Workbook by using the following formula with data from AP-42 tables.

$LL = 12.46 \times S \times P \times M/T$

Where: LL = loading loss, pound per 1,000 gallons of liquid loaded (lb/1000 gal)

S = a saturation factor (See Table 5.2-1 below)
P = true vapor pressure of liquid loaded (psia)
M = molecular weight of tank vapors (lb/lb-mol)
T = temperature of bulk liquid loaded (ºR) (ºR = ºF + 460)
"S" values are obtained from Table 5.2-1.
"M" and "P" values are obtained from Table 7.1-2.

Table 5.2-1 Saturation (S) Factors for Calculating Petroleum Liquid Loading Losses (Excerpt from AP-42, Table 5.2-1)

Cargo Carrier	Mode of Operation*	S Factor
Tank Truck and Rail Tank Cars	Submerged loading of a clean cargo tank	0.50
	Submerged loading: dedicated normal service	0.60
	Submerged loading: dedicated vapor balance service	1.00

* Splash loading is not permitted in accordance with NDAC 33-15-07.

Table below may be used to provide the “P” and “M” values for the above equation:

Table 7.1-2 Properties of Selected Petroleum Liquids (Excerpt from AP-42, Table 7.1-2)

Petroleum Liquid	Vapor MW at 60 F M_V(lb/lb-mole)	Condensed Vapor Density at 60F W_{VC}(lb/gal)	Liquid Density at 60F W_L(lb/gal)	True Vapor Pressure, P_{va} (psi) at various temperatures in F						
				40	50	60	70	80	90	100
Crude Oil RVP 5	50	4.5	7.1	1.8	2.3	2.8	3.4	4.0	4.8	5.7

P. **Truck Loading Control Requirements**

Bakken Pool O&G production facilities are not required to route emissions displaced from truck loading activities to a control system or device due to safety concerns. However, the owner/operator shall follow any operating and/or construction requirements established in Chapters 33-15-07 and 33-15-20 of the North Dakota Air Pollution Control Rules.

Q. **Reciprocating Internal Combustion Engines (RICE)**

The emission calculation workbook requires g/bhp-hr values for VOC, NOx and CO in order to perform calculations for any particular engine. Those values may be obtained in three different manners and are listed below in order of preference.

Engine Emission Factor in Order of Preference

1) Actual Stack Test
2) Manufacturer’s Engine Data
3) AP-42 Values

While any of the three emission factors are acceptable by the NDDoH, actual test data from a particular engine, is usually the most accurate and preferred method. When test data is not readily available, manufacturer data for that particular engine model is the next best emission factor to be used. If neither test data, nor manufacturer data is available, AP-42 values should be used.

R. **RICE Control Requirements**

The NDDoH does not require any specific air pollution control equipment for RICE; however, the RICE must be in compliance with all State and Federal Rules and Regulations.

S. **Federal Regulations for RICE**

There are several Federal regulations that may be applicable to RICE located at Bakken Pool O&G production facilities. These regulations are beyond the scope of this document, but listed below is a brief summary of the Federal regulations that may be applicable. These regulations can be found at the following: http://ecfr.gpoaccess.gov.

40 CFR 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines: Applies to any compression-ignition internal combustion engine where construction is commenced after July 11, 2005 and the engine is manufactured after April 1, 2006.

40 CFR 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines: Applies to any spark-ignition internal combustion engine where construction is commenced after June 12, 2006 and the engine is manufactured:

- After July 1, 2007 for engines > 500 hp
- After January 1, 2008 for lean-burn engines 500 < hp < 1350
- After July 1, 2008 for engines < 500 hp
- After January 1, 2009 for emergency engines

40 CFR 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines: Applies to any (new, existing, modified and reconstructed) RICE located at a major source or an area source of HAPs.

T. **Pneumatic Pumps**

If a pneumatic pump uses natural gas as the motive gas, the pump will release VOC and HAP emissions each time it strokes since all motive gas is vented by the pump. The Workbook calculates emissions from the pump based on the following:

1) Manufacturer's information regarding gas usage (scf/hr)
2) The VOC & HAP weight fraction of the motive gas
3) Molecular weight of motive gas
4) Hours of operation

U. Pneumatic Pump Control Requirements

Bakken Pool O&G production facilities are required to control pneumatic pumps that use natural gas as the motive gas, if the PTE of VOCs from the pneumatic pump is >5 TPY per pump.

V. Pneumatic Controllers

If a pneumatic controller uses natural gas as the motive gas, the device will release VOC and HAP emissions each time it operates. The Workbook calculates emissions from the pump based on the following:

1) Manufacturer’s information regarding gas usage (scf/hr)
2) The VOC & HAP weight fraction of the motive gas
3) Molecular weight of motive gas
4) Hours of operation

W. Pneumatic Controller Control Requirements

Bakken Pool O&G production facilities are not required to install add-on controls for emissions from these types of devices.

5. **EFFECTIVE DATE**

This policy is effective on the date shown below. This policy does not supersede any applicable state or federal rule, regulation or law.

Any questions about this document should be directed to:

North Dakota Department of Health
Division of Air Quality
918 E Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947
Phone: 701-328-5188

This document is available at: http://www.ndheath.gov/aq

Approved: Terry O'Clair Date: May 2, 2011

Terry L. O'Clair, P.E.
Director
Division of Air Quality
North Dakota Department of Health

APPENDIX A

Oil & Gas Production Facility Registration Form

Following is a copy of the NDDoH Oil/Gas Production Facility Registration Form (AP-114) which must be submitted as part of the registration packet within 90 days after the first date of production of a Bakken Pool O&G production facility. The form can be downloaded from the NDDoH website (http://www.ndhealth.gov/AQ/OilAndGasWells.htm) and is available in both Word and PDF formats. Also required is a copy of the gas analysis for the well and the first three pages of the Emission Calculation Workbook.

OIL/GAS PRODUCTION FACILITY REGISTRATION
NORTH DAKOTA DEPARTMENT OF HEALTH
DIVISION OF AIR QUALITY
SFN 14334 (2-11)

GENERAL

Type of Report ☐Initial ☐Amended		Well Status ☐Initial Completion ☐Recompletion	
Name of Owner/Operator			
Official to Contact on Air Pollution Matters	Email address	Title	Telephone Number
Name of Applicant		Title	Telephone Number
Mailing Address		City	State / Zip Code

FACILITY DATA

Well(s) Name	Producing Pool	Field Name
Legal Description of Well Site Surface Location 1/4 1/4, Section , Twp. N., Rge. W	Permit Number	Date of Completion/Recompletion

Location of Treater
☐On-site
* ☐At Central Tank Battery, Specify Location 1/4 1/4, Section , Twp. N, Rge. W

Location of Storage Tanks
☐On-site
* ☐At Central Tank Battery, Specify Location 1/4 1/4, Section , Twp. N, Rge. W

Location of Flare
☐On-site
* ☐At Central Tank Battery, Specify Location 1/4 1/4, Section , Twp. N, Rge. W

Other Air Pollution Equipment (e.g., Internal Combustion Engines @ x HP - compressors, generators, etc., whose collective HP rating exceeds 500 HP), Specify:

* The emissions for the entire facility must be included in the section titled "EMISSIONS". Include well name and file number in the section titled "COMMENTS" on any additional well(s) using the central tank battery.

GAS INFORMATION

Gas/Oil Ratio (cf/bbl)	Date of GOR	H2S Content in Gas "ATTACH GAS ANALYSIS" ppm or mole % (1% = 10,000 ppm)

Disposition of Gas (check all that apply)
☐Flared, Estimate Amount Mcf/day ☐Used on Lease, Estimate Amount Mcf/day
☐Sold to ☐Currently Flared Scheduled to be Tied-in
To By

EQUIPMENT

Flare System ☐Equipped with Automatic Ignitor ☐Equipped with Continuous Pilot, Specify Pilot Fuel		Flare Stack Height Above Ground Feet
STORAGE TANKS		
Number of Saltwater	Number of Oil	Estimate Total Amount of Gas Generated From Storage Tanks Mcf/day with ppm H2S
Tank Gas Emissions Are: ☐Controlled by Vapor Recovery Unit ☐Burned by Flare (Include Amount of SO2 Produced in "EMISSIONS" Section) ☐Burned by Treater (Include Amount of SO2 Produced in "EMISSIONS" Section)		☐Vented to Atmosphere ☐Other, Specify
TREATER		
Treater Fuel	If Sour ppm H2S	Treater Stack Height Above Ground Feet

SFN 14334 (2-11) Page 2

EMISSIONS

Annual Total S Emissions (Note: For facilities comp/recomp prior to 7/1/87, if Total S is 10 T/yr or greater, registration must be submitted. All facilities comp/recomp on or after 7/1/87 must submit registration.)

S = (Flared + Lease Use + Vented) (mole % H2S) (0.00042)

Mcf/Day	*	% H2S	*	Days/Year	*	0.00042	=	Tons/year (total S)

Annual Total SO2 Emissions (Note: This calculation is necessary to determine if prevention of significant deterioration (PSD) or Title V permitting is required.)

SO2 (tons/year) = (Flared + Lease Use) (mole % H2S) (days operation/year) (0.00084)

Mcf/Day	*	% H2S	*	Days/Year	*	0.00084	=	Tons/year (SO2)

If SO2 > 100 tons/year, additional permitting is required.

Annual Total VOC Emissions
VOC Emissions: tons/year (uncontrolled) tons/year (controlled)

COMMENTS

Certification of Truth, Accuracy and Completeness

As an authorized company representative, I certify that to the best of my knowledge the information contained in this Oil/Gas Production Facility form and additional sheets is true, accurate and complete.

Signature of Applicant	Date
X	

ND Department of Health
Division of Air Quality
918 E Divide, 2nd Floor
Bismarck, ND 58501-1947

Telephone: (701)328-5188
Fax: (701)328-5185

APPENDIX B

Oil & Gas Production Facility Emission Calculation Workbook Screenshots

The following pages represent screenshots of the Emission Calculation Workbook. The workbook is available for download from the NDDoH website in Excel format at: (http://www.ndhealth.gov/AQ/OilAndGasWells.htm

The workbook is intended to provide an easy way for owner/operators to calculate emissions for a Bakken Pool O&G production facility. With all owner/operators using the same emission workbook, it will help ensure that all emissions are calculated in a consistent manner from one owner/operator to another. It will also assist the NDDoH in tracking statewide emissions from Bakken Pool O&G production facilities.

Please note: the only Emission Calculation Workbook pages required in the Registration Packet are the Input Data Page, RICE Input Data Page and the Emission Summary Page (applies to all submittals).

INPUT DATA PAGE

NORTH DAKOTA DEPARTMENT of HEALTH

GREEN = Requires input
RED = No input required. This is a calculated value.

	Facility Information		
Line 1	North Dakota Well #1		Name of the facility and the well number.
Line 2	1/13/2011		First date of production or the date of modification of the facility.
Line 3	3/12/2011		Date registration packet is submitted to the NDDoH.
	Production Data		**Description**
Line 4	BOPD	240	Average daily production in barrels of oil per day (BOPD), based on the first 30 days of production.
Line 5	Mscfd	150	Average daily production of gas in Mscf per day, based on the first 30 days of production.
Line 6	Decline Factor	0.6	Expected decline factor for the first year of operation. Enter the default value 0.6; anything lower needs prior approval from the NDDoH.
Line 7	Adjusted BOPD	144	This is the calculated BOPD expected to be produced using the above entered decline factor.
Line 8	Adjusted Treater Gas (Mscfd)	90	This is the calculated mcfd of gas the well is expected to produce using the above entered decline factor.
	Oil/Condensate Tank Data		**Description**
Line 9	Flash Gas Method: Default Bakken EF		Use the drop down menu to choose the appropriate flash gas method.
Line 10	Bakken EF scf/bbl	97.91	The scf/bbl from direct measurement or representative sample. If specific data is not available, use the Bakken default of 97.91.
Line 11	Estimated Tank Vapors (scfd)	14099.04	This is the estimated scfd of tank vapors based on the following: adjusted BOPD multiplied by the scf/bbl entered on Line 9.
Line 12	Lower Heating Value	2000	Lower heating value (Btu/scf) of tank vapors. If site specific data is not available, use the Bakken default value of 2000.
Line 13	Molecular Weight	45.19	Molecular weight of the tank vapors in pounds per pound-mole (lb/lb-mole). If site specific data is not available, use the Bakken default value of 45.19.
Line 14	VOC%	79.80%	VOC weight fraction of the tank vapor gas (C3+). If site specific data is not available, use the Bakken default value of 79.8%.
Line 15	HAP%	2.26%	HAP weight fraction of the tank vapor gas. If site specific data is not available, use the Bakken default value of 2.26%.
Line 16	H_2S weight %	0.000%	H_2S weight percent of the tank vapor gas.
Line 17	H_2S mole %	0.000%	H_2S mole percent of the tank vapor gas.
Line 18	Vapor Recovery Unit or Oil Stabilizer		Use the drop down menu to choose the appropriate emission control type.
Line 19	Control Destruction Efficiency	99%	Control efficiency of any applicable controls. This is a fixed number based on control type.
	Treater Gas Data		**Description**
Line 20	Btu/scf	1500	Btu/scf of wellstream gas.
Line 21	Molecular Weight	28.96	Average molecular weight of the wellstream gas in lb/lb-mole.
Line 22	Specific Gravity	1	If necessary to convert specific gravity to molecular weight, enter the specific gravity of the wellstream gas.
Line 23	Calculated Molecular Weight	28.96	This is the calculated molecular weight based on the specific gravity entered above. Please enter this number on Line 21.
Line 24	VOC%	32.00%	VOC weight fraction of the wellstream gas (Note: Weight%, not Mole%).
Line 25	HAP%	0.50%	HAP weight fraction of the wellstream gas. (Note: Weight%, not Mole%).
Line 26	H_2S weight %	0.000%	H_2S weight percent of the wellstream gas
Line 27	H_2S mole %	0.000%	H_2S mole percent of the wellstream gas
Line 28	Connected to sales line		Use the drop down menu to choose the appropriate emission control type.
Line 29	Control Destruction Efficiency	100%	Control efficiency of any applicable controls (combustor, pit flare, utility flare, etc).
	Treater Burner(s)		**Description**
Line 30	Total Btu/hr	500,000	Total burner rating for the heater treater burner(s) in btu/hr. If there are multiple burners, add the total heat input together.
Line 31	Hours of Operation	8,760	The burner(s) is/are assumed to operate 8,760 hours per year.
	Truck Loading		**Description**
Line 32	Oil is hauled by truck		Use the drop down menu to choose the appropriate oil sales method. If oil is sold through a LACT, no input values are required in Lines 30-35.
Line 33	Submerged loading: dedicated vapor balance service	1	Use the drop down list to choose the appropriate mode of operation. The saturation factor will automatically be selected based on mode of operation.
Line 34	Molecular Weight	50.00	Molecular weight of tank vapors in lb/lb-mole If no site specific data is available, please refer to Table 2 on the Truck Loading tab.
Line 35	Vapor Pressure	2.30	True vapor pressure of liquid loaded, pounds per square inch absolute (psia) If no site specific data is available, please refer to Table 2 on the Truck Loading tab.
Line 36	Temperature	50.00	Temperature of bulk liquid loaded in Farenheit. If no site specific data is available, use an estimated average annual temperature.
Line 37	Load Rate (bbl/hr)	180	Load rate of liquid loaded in barrels per hour.
Line 38	Load Time (hrs)	1.00	The time it takes to loadout one load (hrs).
	Pneumatic Pumps		**Description**
Line 39	Number of Pneumatic Pumps	2	Number of pneumatic pumps at facility.
Line 40	Hours of Operation	4380	Hours the pump is in operation annually. For winter months only, please enter 4380 hours.
Line 41	scf/min	0.50	Pneumatic source consumption rate as per manufacturer data (scf/min).
Line 42	Routed exhaust back into closed loop system		Use the drop down menu to choose the appropriate emission control type.
Line 43	Control Efficiency	100%	Control efficiency of any applicable controls (combustor, routing exhaust to fuel supply, VRU, etc).
	Pneumatic Controllers		**Description**
Line 44	Number of Pneumatic Controllers	10	Number of pneumatic controllers at facility.
Line 45	Bleed rate (scf/hr)	0.00	Average bleed rate of device (scf/hr).
	Glycol Dehydrator		**Description**
Line 46	VOC (TPY)	10.00	VOC emissions calculated in GRI-GLYCalc software (if no glycol dehydrator enter 0).
Line 47	HAP (TPY)	6.00	HAP emissions calculated in GRI-GLYCalc software (if no glycol dehydrator enter 0).

RICE INPUT DATA PAGE

Line 1	**Number of Engines**	2	Enter the number of engines that will be installed at the production facility.

	RICE Engine #1		**Description**
Line 2	Hours of Operation	8760	Engine is assumed to operate 8,760 hours per year.
Line 3	Maximum HP Rating	100	Manufacturer's maximum hp rating.
Line 4	NOx g/hp-hr	10	Manufacturer's emission factor, actual test results or AP-42 factor in grams per horsepower hour (g/hp-hr) for nitrogen oxides (NOx).
Line 5	CO g/hp-hr	5	Manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for carbon monoxide (CO).
Line 6	VOC g/hp-hr	4	Manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for total organic compounds (TOC or THC).
Line 7	NOx Control Efficiency	90%	NOx control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.
Line 8	CO Control Efficiency	75%	CO control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.
Line 9	VOC Control Efficiency	70%	VOC control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.

	RICE Engine #2		**Description**
Line 10	Hours of Operation	8760	Engine is assumed to operate 8,760 hours per year.
Line 11	Maximum HP Rating	100	Manufacturer's maximum hp rating.
Line 12	NOx g/hp-hr	10	Manufacturer's emission factor, actual test results or AP-42 factor in grams per horsepower hour (g/hp-hr) for nitrogen oxides (NOx).
Line 13	CO g/hp-hr	5	Manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for carbon monoxide (CO).
Line 14	VOC g/hp-hr	4	Manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for total organic compounds (TOC or THC).
Line 15	NOx Control Efficiency	90%	NOx control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.
Line 16	CO Control Efficiency	75%	CO control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.
Line 17	VOC Control Efficiency	70%	VOC control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.

	RICE Engine #3		**Description**
Line 18	Hours of Operation	0	Engine is assumed to operate 8,760 hours per year.
Line 19	Maximum HP Rating	100	Manufacturer's maximum hp rating.
Line 20	NOx g/hp-hr	10	Manufacturer's emission factor, actual test results or AP-42 factor in grams per horsepower hour (g/hp-hr) for nitrogen oxides (NOx).
Line 21	CO g/hp-hr	5	Manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for carbon monoxide (CO).
Line 22	VOC g/hp-hr	4	Manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for total organic compounds (TOC or THC).
Line 23	NOx Control Efficiency	90%	NOx control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.
Line 24	CO Control Efficiency	75%	CO control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.
Line 25	VOC Control Efficiency	70%	VOC control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.

	RICE Engine #4		**Description**
Line 26	Hours of Operation	0	Engine is assumed to operate 8,760 hours per year.
Line 27	Maximum HP Rating	100	Manufacturer's maximum hp rating.
Line 28	NOx g/hp-hr	10	Manufacturer's emission factor, actual test results or AP-42 factor in grams per horsepower hour (g/hp-hr) for nitrogen oxides (NOx).
Line 29	CO g/hp-hr	5	Manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for carbon monoxide (CO).
Line 30	VOC g/hp-hr	4	Manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for total organic compounds (TOC or THC).
Line 31	NOx Control Efficiency	90%	NOx control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.
Line 32	CO Control Efficiency	75%	CO control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.
Line 33	VOC Control Efficiency	70%	VOC control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.

	RICE Engine #5		**Description**
Line 34	Hours of Operation	0	Engine is assumed to operate 8,760 hours per year.
Line 35	Maximum HP Rating	100	Manufacturer's maximum hp rating.
Line 36	NOx g/hp-hr	10	Manufacturer's emission factor, actual test results or AP-42 factor in grams per horsepower hour (g/hp-hr) for nitrogen oxides (NOx).
Line 37	CO g/hp-hr	5	Manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for carbon monoxide (CO).
Line 38	VOC g/hp-hr	4	Manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for total organic compounds (TOC or THC).
Line 39	NOx Control Efficiency	90%	NOx control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.
Line 40	CO Control Efficiency	75%	CO control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.
Line 41	VOC Control Efficiency	70%	VOC control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.

EMISSION SUMMARY PAGE

Facility:
North Dakota Well #1

Emission Summary
North Dakota Department of Health*

*The NDDH PTE is post-control

Emission Source	PTE (TPY)					
	VOC	HAP	NOx	CO	H_2S	SO_2
Oil/Condensate Tanks	2.05	0.14	0.35	1.90	N/A	N/A
Treater Flare	0.00	0.00	0.00	0.00	0.00	0.00
Treater Burner	0.01	0.00	0.21	0.18	N/A	N/A
RICE Engine	2.32	NA	1.93	2.41		
Truck Loading	2.23	NA				
Pneumatic Pump	0.00	0.00				
Pneumatic Controllers	0.00	0.00				
Glycol Dehydrator	10.00	6.00				
Totals (TPY)	**16.62**	**6.15**	**2.50**	**4.50**	**0.00**	**0.00**

Emission Control Requirements

Emission Source	Controls Required	Initial Control Installation Deadline	Additional Control Installation Deadline
Oil/Condensate Tanks	YES	1/13/2011	NA
Treater	YES	1/13/2011	
Pneumatic Pump	NO	NA	
Glycol Dehydrator	YES	1/13/2011	

Document/Permit Requirements*

Document/ Permit Required	YES/NO	Due Date
Registration Packet	YES	4/13/2011
Title V Permit	NO	NA
PSD Permit	NO	NA

*Owners and operators of O&G facilities with the potential to emit at or above major source thresholds must adequately control emissions or follow the normal permitting process established in Chapters 33-15-14 and 33-15-15 of the North Dakota Air Pollution Control Rules.

OIL/CONDENSATE TANKS

North Dakota Well #1

Tanks

Flare Gas Volume	**14,099** scf/day
Lower Heating Value	**2000** Btu/scf
Molecular Weight	**42** lb/lb-mole
VOC wt Fraction	**72.00%**
HAP wt Fraction	**5.00%**

Controlled emissions are calculated based on a 99% destruction efficiency of the VOC gas.

VOC: **587** scf/hr x 1/379 scf/lb-mole x 42 lb/lb-mole x 72.00% x 99% = **0.47** lb/hr

0.47 lb/hr x 8760 hr/yr x 1 ton/2000 lb x 99% = **2.05** TPY

HAP **587** scf/hr x 1/379 scf/lb-mole x 42 lb/lb-mole x 5.00% x 99% = **0.03** lb/hr

0.03 lb/hr x 8760 hr/yr x 1 ton/2000 lb x 99% = **0.14** TPY

NOx: **587** scf/hr x **2,000** Btu/scf x 1 MMBtu/1,000,000 Btu x 0.068 lb/MMBtu = **0.08** lb/hr

0.08 lb/hr x 8760 hr/yr x 1 ton/2000 lb = **0.35** TPY

CO: **587** scf/hr x **2,000** Btu/scf x 1 MMBtu/1,000,000 Btu x 0.370 lb/MMBtu = **0.43** lb/hr

0.43 lb/hr x 8760 hr/yr x 1 ton/2000 lb = **1.90** TPY

NOx & CO emission factors are from AP-42 Table 13.5-1
(Emission Factors for Flare Operations).

TREATER FLARE

North Dakota Well #1

Treater Flare

Flare Gas Volume	90,000 scfd
Lower Heating Value	1500 Btu/scf
Avg. Molecular Weight	28.96 lb/lb-mole
VOC wt fraction	32.00%
HAP wt fraction	0.50%

Controlled emissions are calculated based on 100% destruction efficiency of the VOC gas.

VOC:	3,750 scf/hr	x	1/379 scf/lb-mole	x	28.96 lb/lb-mole	x	32.00%	x	100%	=	0.00 lb/hr
	0.00 lb/hr	x	8760 hr/yr	x	1 ton/2000 lb	x	100%	=	0.00 TPY		
HAP	3,750 scf/hr	x	1/379 scf/lb-mole	x	28.96 lb/lb-mole	x	0.50%	x	100%	=	0.00 lb/hr
	0.00 lb/hr	x	8760 hr/yr	x	1 ton/2000 lb	x	100%	=	0.00 TPY		
H_2S	3,750 scf/hr	x	1/379 scf/lb-mole	x	28.96 lb/lb-mole	x	0.00%	x	100%	=	0.00 lb/hr
	0.00 lb/hr	x	8760 hr/yr	x	1 ton/2000 lb	x	100%	=	0.00 TPY		
SO_2	3,750 scf/hr	x	1/379 scf/lb-mole	x	64 lb/lb-mole	x	0.00%	x	100%	=	0.00 lb/hr
	0.00 lb/hr	x	8760 hr/yr	x	1 ton/2000 lb	x	100%	=	0.00 TPY		
NOx:	3,750 scf/hr	x	1,500 Btu/scf	x	1 Mmbtu/1,000,000 Btu	x	0.068 lb/MMB	=	0.38 lb/hr		
	0.38 lb/hr	x	8760 hr/yr	x	1 ton/2000 lb	=	1.68 0.00 TPY				
CO:	3,750 scf/hr	x	1,500 Btu/scf	x	1 Mmbtu/1,000,000 Btu	x	0.370 lb/MMB	=	2.08 lb/hr		
	2.08 lb/hr	x	8760 hr/yr	x	1 ton/2000 lb	=	9.12 0.00 TPY				

NOx & CO emission factors are from AP-42 Table 13.5-1
(Emission Factors for Flare Operations).

TREATER BURNER

North Dakota Well #1

Heater Treater Burner

Burner Rating | **500,000** Btu/hr

NOx:	0.10 lb/MMBtu	x	0.50 MMBtu/hr			=	**0.05** lb/hr
	0.0490 lb/hr	x	8,760 hr/yr	x	1 ton / 2000 lb	=	**0.21** TPY
CO:	0.08 lb/MMBtu	x	0.50 MMBtu/hr			=	**0.04** lb/hr
	0.04 lb/hr	x	8,760 hr/yr	x	1 ton / 2000 lb	=	**0.18** TPY
VOC:	0.01 lb/MMBtu	x	0.50 MMBtu/hr			=	**0.00** lb/hr
	0.00 lb/hr	x	8,760 hr/yr	x	1 ton / 2000 lb	=	**0.01** TPY
HAP:	0.002 lb/MMBtu	x	0.50 MMBtu/hr			=	**0.00** lb/hr
	0.00 lb/hr	x	8,760 hr/yr	x	1 ton / 2000 lb	=	**0.00** TPY

NOx, CO & VOC Emission Factors are from AP-42 Table 1.4-1 and 1.4-2 (Emission Factors for Nitrogen Oxides (NOx) and Carbon Monoxide (CO) from Natural Gas Combustion).

0.21	NOx TPY
0.18	CO TPY
0.01	VOC TPY
0.00	HAP TPY

TRUCK LOADING

North Dakota Well #1

Truck Loadout Emission Calculation

		Saturation Factor (S)		Vapor Pressure (P)		Molecular Weight (MW)		Temp + 460		Load Loss lb/1000 gal
12.46	x	0.60	x	2.30	x	50.00	/	510.00	=	1.69

LL lb/1,000 gal		Truck Load Rate bbl/hr		Load Time hrs		gal/bbl		Emissions lb/hr
1.69	x	180.00	/	1.00	x	42.00	=	12.78

LL lb/1,000 gal		Annual bbl/yr		gal/bbl		lb/ton		Emissions TPY VOC	C3+ VOC
1.69	x	438000.00	x	42.00	/	2000.00	=	15.54	11.19

Uncontrolled	Control %		VOC Emissions TPY
11.19	0.00	1.00	11.19

(EPA AP-42 Values) Table 1 below is required to supply the saturation factor variable in the above equation.

Cargo Carrier	Mode of Operation	S Factor
Tank Trucks and Rail Tank Cars	Submerged loading of a clean cargo tank	0.50
	Submerged loading: dedicated normal service	0.60
	Submerged loading: dedicated vapor balance service	1.00

(EPA AP-42 Values) Table 2 below may be used to provide the vapor pressure and molecular weight values for the above equation.

Petroleum Liquid	Vapor MW at 60F Mv(lb/lb-mole)	Condensed Vapor Density at 60F Wvc(lb/gal	Liquid Density at 60F W1(lb/gal)	True Vapor Pressure, Pva (psi) at various temperatures in F						
				40	50	60	70	80	90	100
Crude Oil RVP 5	50	4.5	7.1	1.8	2.3	2.8	3.4	4	4.8	5.7

RICE

North Dakota Well #1

Reciprocating Engine Emissions

ENGINE #1

	100 MAX HP		90% NOx DRE		75% CO DRE		70% VOC DRE					
NOx:	10.00 g/HP-HR	x	100 HP	x	1 lb / 453.6 grams	=	2.20 lb/hr	x	8760 hr/yr	x	1 ton / 2000lb	= 0.97 NOx TPY
CO:	5.00 g/HP-HR	x	100 HP	x	1 lb / 453.6 grams	=	1.10 lb/hr	x	8760 hr/yr	x	1 ton / 2000lb	= 1.21 CO TPY
VOC:	4.00 g/HP-HR	x	100 HP	x	1 lb / 453.6 grams	=	0.88 lb/hr	x	8760 hr/yr	x	1 ton / 2000lb	= 1.16 VOC TPY

ENGINE #2

	100 MAX HP		90% NOx DRE		75% CO DRE		70% VOC DRE					
NOx:	10.00 g/HP-HR	x	100 HP	x	1 lb / 453.6 grams	x	2.20 lb/hr	x	8760 hr/yr	x	1 ton / 2000lb	= 0.97 NOx TPY
CO	5.00 g/HP-HR	x	100 HP	x	1 lb / 453.6 grams	x	1.10 lb/hr	x	8760 hr/yr	x	1 ton / 2000lb	= 1.21 CO TPY
VOC	4.00 g/HP-HR	x	100 HP	x	1 lb / 453.6 grams	x	0.88 lb/hr	x	8760 hr/yr	x	1 ton / 2000lb	= 1.16 VOC TPY

ENGINE #3

	100 MAX HP		90% NOx DRE		75% CO DRE		70% VOC DRE					
NOx:	10.00 g/HP-HR	x	100 HP	x	1 lb / 453.6 grams	=	2.20 lb/hr	x	0 hr/yr	x	1 ton / 2000lb	= 0.00 NOx TPY
CO:	5.00 g/HP-HR	x	100 HP	x	1 lb / 453.6 grams	=	1.10 lb/hr	x	0 hr/yr	x	1 ton / 2000lb	= 0.00 CO TPY
VOC:	4.00 g/HP-HR	x	100 HP	x	1 lb / 453.6 grams	=	0.88 lb/hr	x	0 hr/yr	x	1 ton / 2000lb	= 0.00 VOC TPY

PNEUMATIC PUMPS

North Dakota Well #1

Emissions from Pneumatic Pumps

Emissions (lb/hr) = PSCR (scf/min) x (60 min/1hr) x (1/379 scf/lb-mole) x (VOC wt. Fraction)
Emissions (TPY) = (lb/hr VOC) x (8760 hr/yr) x (1 ton/2000)

Where:

PSCR = Pneumatic Source Consumption Rate (scf/min), as per manufacturers literature
Gas MW = Supply Gas Average Molecular Weight (lb/lb-mole)

						Supply Gas MW		VOC wt fraction		
0.5 scfm/min	*	60 min/1 hr	*	1/379 scf/lb-mole	x	28.96	x	32.00%	=	0.73 lb/hr VOC Uncontrolled
				lbs/hr		Hours (winter months)				
				0.73	x	4380	x	2000 lbs/ton	=	3.20 TPY VOC Uncontrolled
						Supply Gas MW		HAP wt fraction		
0.5 scfm/min	*	60 min/1 hr	*	1/379 scf/lb-mole	x	28.96	x	0.50%	=	0.01 lb/hr HAP Uncontrolled
				lbs/hr		Hours (winter months)				
				0.01	x	4380	x	2000 lbs/ton	=	0.04 TPY HAP Uncontrolled

Control Efficiency	**100%**	
Number of Pumps	**2**	
Total Controlled Emissions	**0.00**	**TPY VOC**
Total Controlled Emissions	**0.00**	**TPY HAP**

PNEUMATIC CONTROLLERS

North Dakota Well #1

Emissions from Pneumatic Controllers

Emissions (lb/hr) = PSCR (scf/hr) x (1/379 scf/lb-mole) x (VOC wt. Fraction)
Emissions (TPY) = (lb/hr VOC) x (8760 hr/yr) x (1 ton/2000)

Where:

PSCR = Pneumatic Source Consumption Rate (scf/min), as per manufacturers literature
Gas MW = Supply Gas Average Molecular Weight (lb/lb-mole)

						Supply Gas MW		VOC wt fraction		
0 scf/hr	x	60 min/1 hr	x	1/379 scf/lb-mole	x	**28.96**	x	**32.00%**	=	**0.00** lb/hr VOC
				lbs/hr		Hours (winter months)				
				0.00	x	**0**	x	2000 lbs/ton	=	**0.00** TPY VOC
						Supply Gas MW		HAP wt fraction		
0 scf/hr	x	60 min/1 hr	x	1/379 scf/lb-mole	x	**28.96**	x	**0.50%**	=	**0.00** lb/hr HAP
				lbs/hr		Hours (winter months)				
				0.00	x	**0**	x	2000 lbs/ton	=	**0.0** TPY HAP

APPENDIX C

NDDoH ACCEPTABLE CONTROL SYSTEMS OR DEVICES

The following VOC control systems or devices are accepted by the NDDoH:

1. A ground pit flare (including, but not limited to pit flares, shop built flares or other similar oilfield type flares) or other 90% or greater DRE device. If a ground pit flare is utilized, the NDDoH will allow a 90% DRE to be assumed. This is considered the minimum level of control for tank and treater gas emissions.

2. A vapor recovery unit or oil stabilizer that is designed and operated to reduce the mass content of VOC and total HAP emissions in the vapors vented to the device by at least 99% by weight. (Caution: a vapor recovery unit and oil stabilizer is used only to control tank emissions.)

3. An enclosed, smokeless combustion device or utility flare that is designed and operated to reduce the mass content of VOC and total HAP emissions in the vapors vented to the device by at least 98% by weight. A utility flare is any flare that is designed and operated in accordance with the requirements of NDAC 33-15-12-02, Subpart A 60.18 (40 CFR 60.18). Requirements of 40 CFR 60.18 include, but are not limited to the following:

    - Flare shall be designed and operated with no visible emissions except for periods not to exceed a total of 5 minutes during any 2 consecutive hours;
    - Flare shall be operated with a flame present at all times;
    - An owner/operator has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) and the maximum tip velocity specifications in paragraph (c)(4) <u>or</u> adhering to the requirements in (c)(3)(i);
    - Flares used to comply with this section shall be steam-assisted, air-assisted or nonassisted;
    - Owners/operators of flares shall monitor the control devices to ensure that they are operated and maintained in conformance with their designs;
    - Flares shall be operated at all times when emissions may be vented to them;
    - Method 22 of Appendix A shall be used to determine the compliance of flares with the visible emission provisions of this subpart. The observation is 2 hours and shall be used according to Method 22;
    - The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame. Daily checks by an operator to verify the existence of a visible flame or to verify proper operation of the igniter may be used in lieu of a physical device.

4. Control devices other than those listed above may be utilized upon approval from the NDDoH.

For safety and air pollution control purposes on all wells: each flare must be equipped and operated with an automatic ignitor or a continuous burning pilot, which must be maintained in good working order as outlined in NDAC 33-15-07-02. This is required even if the flare is used for emergency purposes only. Flares operating with automatic pilot systems are not required to operate with thermocouples.

Each combustion device must be installed with a thermocouple or any other equivalent device approved by the NDDoH designed to ensure the presence of a pilot on the device. Additionally, a continuous burning pilot is required if this department determines that an automatic ignition system is ineffective due to production characteristics.

Emissions control equipment, systems or devices, all vent lines, connections, fitting, valves, relief valves, hatches or any other appurtenance employed to contain and collect vapors and transport them to the emission control system or device must be maintained and operated during any time a well is producing such that the emissions are controlled as outlined in Appendix D.

The owner/operator shall maintain and operate all air pollution control equipment in accordance with the manufacturer's recommendations and in a manner consistent with good air pollution control practice for minimizing emissions. All reasonable precautions shall be taken by the owner/operator to prevent and/or minimize opacity from the operation of the flare or combustion device. A properly operating flare should be virtually free of opacity and a minimum of a visual check of a flare for opacity should be done whenever an operator is on site. Improperly operating equipment should be thoroughly inspected and if necessary, repaired as soon as possible. Compliance with opacity requirements will be based on applicable EPA Reference Methods.

The Department acknowledges that emission control equipment under an operating and maintenance plan will be off-line during routine maintenance and does not expect redundant equipment to be installed unless the uncontrolled emissions during that time cause the Bakken Pool O&G production facility emissions to exceed Title V or PSD thresholds.

APPENDIX D

CONTROL REQUIREMENTS FOR TANK EMISSIONS

The following procedure must be followed to determine the level of control required for tank emissions from Bakken Pool O&G production facilities:

1. For production facilities where the first date of production occurred after June 1, 2011, tank emissions must be controlled by a ground pit flare (including, but not limited to pit flares, shop built flares or other similar oilfield type flares) or other control device that achieves at least a 90% DRE for VOCs upon startup of the facility.

2. For production facilities where the first date of production occurred after June 1, 2011, the owner/operator must calculate the VOC potential to emit (PTE) from tank emissions within 90 days after the first date of production and control VOC emissions as outlined in 2.a and 2.b below. For production facilities where the first date of production occurred on or before June 1, 2011, the owner/operator must calculate the VOC PTE from tank emissions by September 1, 2011 and control VOC emissions as outlined in 2.a and 2.b below.

    a. If the PTE for VOC tank emissions is less than 20 tons/year, then a minimum of a ground pit flare (or other control device that achieves at least a 90% DRE for VOCs) is required to control VOC tank emissions.

    b. If the PTE for VOC tank emissions is greater than or equal to 20 tons/year, then a control device that achieves at least a 98% DRE for VOCs must be installed and operated.

3. It is possible that the PTE for VOC tank emissions will initially be calculated to equal or exceed 20 tons/year (which requires a control device with at least a 98% DRE for VOCs), but future calculations may result in a PTE for VOC tank emissions below 20 tons/year (which requires at least a ground pit flare or other control device that achieves at least a 90% DRE for VOCs). In this case, the owner/operator may replace the 98% DRE control device with a 90% DRE control device after receiving written approval from NDDoH. A revised well registration packet shall be submitted to the NDDoH prior to the replacement of the control device.

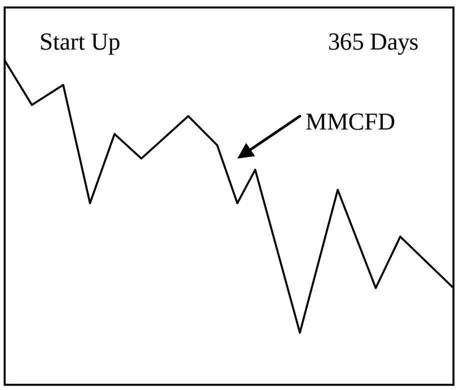
4. At a minimum, tank emissions must be controlled by a ground pit flare (or other control device that achieves at least a 90% DRE for VOCs). In the event of a breakdown of any control equipment used to control tank emissions, the control equipment must be repaired in a timely manner.

APPENDIX E

The Basis for the 0.6 Factor and How it Relates to 80% Decline in Production for the First Year

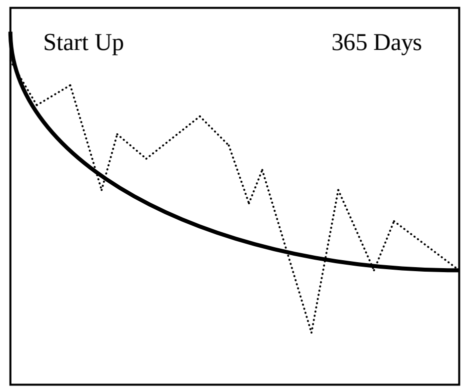
The first year daily production rates are represented by the jagged line in **BOX 1**. The area under the line represents the total actual production volume for the first year. It is difficult to calculate the total volume under the jagged line so it is smoothed out in **BOX 2** using statistical methods.

BOX 1



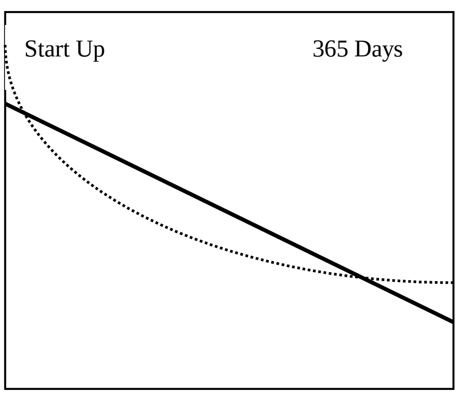
Actual production during the first year is represented by the area under the jagged line which ultimately turns out to be ~730 MMCF.

BOX 2



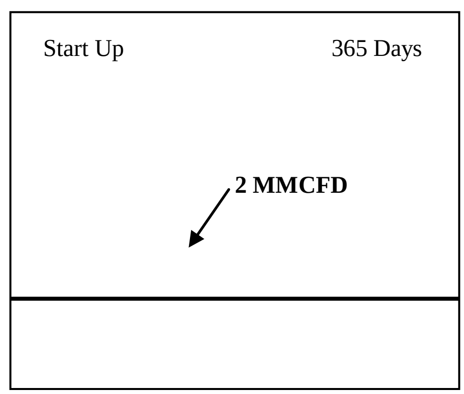
The jagged line representing daily production is “smoothed” out using statistical methods.

BOX 3



The “smoothed” curve in BOX 2 is “straightened” out using mathematical methods.

BOX 4



Leveled” out, projected daily gas production rate vs. time

Total projected production for the first year is represented by the area under the straight line

2 MMCFD x 365 days = 730 MMCF

The smoothed curve is straightened out in **BOX 3**, and then leveled out in **BOX 4**. Now the production for the first year is represented by the area under the line in **BOX 4** which is easily calculated. Production curves from a large sampling of wells indicate the average well declines by 80% during the first year. That 80% decline is represented by the level line in **BOX 4** after the first 30-day average production rate is multiplied by 0.6.

Example: For the first month the well makes an average 3.333 MMCFD. With 80% decline during the first year, the well will make 0.667 MMCFD at the end of the first year (3.333 – 0.8(3.333) = 0.667). Then the average daily production rate over 365 days is (3.33 + 0.667)/2 = 2.0 MMCFD which is the same as 3.333 x 0.6 = 2.0 MMCFD.