SG.17.1.8

TECHNICAL GUIDANCE DOCUMENT NUMBER 8:

WELL VENTING/FLARING DURING WELL COMPLETION FOR HYDRAULICALLY FRACTURED GAS WELLS

Introduction

This document provides technical guidance to Partners of the CCAC Oil and Gas Methane Partnership (OGMP). It is one in a series describing a core source of methane emissions from oil and natural gas production operations. The guidance documents introduce suggested methodologies for quantifying methane emissions from specific sources and describes established mitigation options that Partners should reference when determining if the source is "mitigated."[1] The OGMP recognizes that the equipment and processes described in these documents are found in a variety of oil and gas operations, including onshore, offshore, and remote operations, and the way in which the emissions are quantified and mitigated may vary across locations and operational environments. As such, operational conditions, as well as logistical, safety and cost considerations, must be evaluated on a case-by-case basis. The OGMP assumes that methane emission mitigation actions that require shut-downs of non-redundant equipment/processes (e.g., that would result in a stoppage of operations) would be carried out during regularly scheduled maintenance activities, unless the Partner deems the corrective action to be worthy of an early/additional shut-down.

Description of Source

Completion of new wells and reworking (workover) of existing gas wells in tight formations may involve hydraulic fracturing of the reservoir to increase well productivity. In such cases, operators fracture the reservoir rock with very high pressure water containing a proppant (generally sand) that keeps the fractures "propped open" after water pressure is reduced. Removing the water and excess proppant (generally sand) during completion and well clean-up may result in significant releases of natural gas and therefore methane emissions to the atmosphere. After initial drilling, all natural gas wells must undergo well completion before commencing production.

Completing these new and "workover" hydraulically fractured gas wells involves producing the fluids at a high rate to lift the excess sand to the surface and clear the well bore and formation to increase gas flow. Typically, the gas/liquid separator installed for normal well flow is not designed for these high liquid flow rates and three-phase (gas, liquid, and sand) flow. Therefore, a common practice for this initial well completion step has been to produce the well to a pit or tanks where water, hydrocarbon liquids, and sand are captured and slugs of gas vented to the atmosphere or flared. Completions can take anywhere from several hours to several weeks, during which time a substantial amount of gas may be released to the atmosphere or flared. Production levels are tested during the well completion process, and it may be necessary to repeat the fracture process to achieve desired production levels from a particular well.

[1] For reporting purposes as described in the CCAC Oil and Gas Methane Partnership Framework, Section 3.

In the U.S. Code of Federal Regulations (CFR), 40 CFR Part 98.6[2] describes a well completion as the following: "Well completions means the process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics, steps which may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment, steps that do not significantly vent natural gas to the atmosphere. This process may also include high-rate flowback of injected gas, water, oil, and proppant used to fracture or re-fracture and prop open new fractures in existing lower permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere."

Conventional wells typically do not require production stimulation due to the well-defined permeable and porous formations in conventional gas reservoirs. However, industry reports that hydraulic fracturing is also performed in some conventional gas reservoirs as well.[3]

Completions and workovers for hydraulically fractured well may be configured in a variety of ways, as shown in Table 8.1.

Table 8.1: Configurations for Well Venting/Flaring during Well Completions for Hydraulically Fractured Gas Wells

Configuration	Mitigated or Unmitigated
During completion of hydraulically fractured gas well, well is produced to a pit or tanks where water, hydrocarbon liquids, and sand are captured and slugs of gas vented to the atmosphere. Exhibit A	Unmitigated
During completion of hydraulically fractured gas well, reduced emission (green) completion is implemented, using speciality flow-back equipment if necessary, and flowback gas is routed to sales or flare as soon as feasible (e.g., gas content of flowback is sufficient) rather than vent to the atmosphere. Exhibit B	Mitigated (if confirmed to be functioning with low or no methane emissions) [A]

[A] Partner companies are requested to internally confirm proper functioning of mitigation technology, and reporting that a source is mitigated implies that this check has been done. "Low" methane emissions is defined as being consistent with "expected emissions levels if mitigation option is in place and functioning properly (e.g., flare is not extinguished, only non-combustible gas is vented, etc.)."

Partners should quantify and evaluate for mitigation any of the configurations above that are not identified as "mitigated" for methane emissions, per the sections below. It should be noted that, even in the "mitigated" situations described above, Partners should evaluate the system to ensure that it is not malfunctioning in some way resulting in higher methane emission levels (e.g., a flare has blown out, venting system is malfunctioning, only non-combustible gas with too high concentration of nitrogen and/or carbon dioxide is vented rather than flared or produced to a sales line, etc.).

Quantification Methodology

It is recommended that one or more of the following methodologies be used to quantify volumetric methane emissions from venting during each well completions of hydraulically fractured wells. In principle, direct

[2] "Mandatory Greenhouse Gas Reporting - Subpart A - General Provisions. §98.6 Definitions." http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl.

[3] Natural Gas STAR Technical Document "Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells." https://www.epa.gov/sites/production/files/2016-06/documents/reduced_emissions_completions.pdf.

measurement can be considered as the most accurate method for quantifying methane emissions[4]. Where a sound basis is in place, measurement can contribute to greater certainty on emissions levels and economic costs and benefits (i.e., value of gas saved). As such, measurement is highly encouraged whenever it is possible to establish this basis. These measurements and calculations can give a flow rate for whole gas that is then converted to methane emissions using the methane content of the gas being vented, and then extrapolated for the duration of the completion. An annual volume of methane emissions is calculated by multiplying the measured methane emissions flow rate by the annual number of completions and workovers for a well. An alternative quantification methodology is provided for situations in which direct measurement is not feasible.

The CCAC OGMP recommends partner companies to use one of the following methodologies to assure the consistent quantification of emissions and the comparable evaluation of mitigation options. Individual companies may choose an alternative quantification methodology if judged to be similar or more accurate by the company, in which case the alternative methodology shall be documented and explained in the Annual Report.

- Direct Measurement and Calculation Methodology: Partners can quantify methane emissions from venting during well completion for hydraulically fractured wells using direct measurement and engineering calculations using existing quantification methodologies, such as the one shown in 40 CFR Part 98.233 (g) (Subpart W of the Mandatory GHG Reporting Rule).[5] If the produced gas is directed to a storage tank or a three-phase separator, Partners can measure the flowback rate at the vent stack of either unit using a recording flow meter. Recommended measurement tools include the following:

  - Vane Anemometer.
  - Hotwire Anemometer.
  - Turbine meter.
  - Orifice meter.

  For more details regarding each measurement tools recommended above, including applicability and measurement methods, please refer to Appendix A.

  Since the flowback rate is not consistent throughout the duration of the flowback, Partners should calculate the total flowback volume from the recorded flowback rates and use the equation below to estimate emissions. In the case where the flowback process is not continuous, Partners should add all the recorded flowback volumes to determine the overall flowback volume, deducting any amount of CO_2 or N_2 injected into the reservoir during the energized fracture job. This calculation methodology is shown in the following equation.

$$E_{s,n} = \left[FV_{s,\,p} - EnF_{s,\,p} \right]$$

Where:

$E_{s,n}$ = Annual volumetric total gas emissions in cubic feet at standard conditions from gas well venting during completions or workovers following hydraulic fracturing for a well.

$FV_{s,p}$ = ……

[4] Measurements should be conducted with appropriately calibrated instruments and per the manufacturer instructions for conducting measurements. Measurements should also be conducted under different operating conditions, to the extent that those can affect emissions levels. Guidance on instrument use can be found in the Appendix A to the Technical Guidance Documents. Where companies seek to generate Emission Factors for their operations, direct measurement should be based on a statistically sound number of measurements and gas analyses to understand the content of methane and other valuable hydrocarbons.

[5] Mandatory Greenhouse Gas Reporting – Subpart W – Petroleum and Natural Gas Systems - Section 98.233 Calculating GHG Emissions. 40 CFR 98.233(g). http://www.ecfr.gov/cgi-bin/text-idx?SID=9db68a97576bb01eea9073c37d6f0e90&node=40:21.0.1.1.3.23&rgn=div6.

$EnF_{s,p}$ = Volume of CO_2 or N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job for the well. If the fracture process did not inject gas into the reservoir or the injected gas is CO_2, then $EnF_{s,p}$ is 0.

- Emission Factor Approach: Partners can estimate methane emissions from well venting during well completions for hydraulically fractured wells using the emissions factors shown in Table 8.2 at the end of this document. To quantify emissions, Partners should multiply the emission factor with the number of completions of each type.

Mitigation Option - Conduct reduced emission (green) completions, using speciality flowback equipment if necessary, and route flowback gas to sales or flare rather than vent.

Reduced emission completions (RECs) are a successful established methane reduction technology, in which operators use specialty flowback equipment and route completion flowback gas to a sales line or flare rather than venting to the atmosphere. For RECs, operators install portable equipment during the final stage of a well completion that is particularly designed and sized for the initial production (essentially the high flowback) rate of water, sand, and gas. The objective of the technology is to capture and deliver gas to the sales line or flare rather than venting it.

Produced gas often needs additional treatment to remove any solids and water for the gas to be considered pipeline quality. The treatment process includes passing the produced gas through sand traps, plug catchers, dehydrators, and three-phase separators to remove finer solids, large solids such as drill cuttings, water, and condensate, respectively. Partners can conduct the dehydration step using a permanent glycol dehydration unit or a portable glycol or desiccant dehydrator. The condensate (i.e., liquid hydrocarbons) recovered during the three-phase separation may be sold for additional revenue.

The specialty portable equipment used during RECs is required solely during the final stage of a well completion and can be transferred to another well site upon completion. Additional temporary piping may need to be installed for connections. A gas producer might find it economical for a basin with high drilling activity to build its own REC skid. On the other hand, Partners that have used third-party providers to perform RECs find it most beneficial to combine the scheduling of completions with the annual drilling program. Note that some Partners have reported installing permanent equipment that is oversized to handle the initial flowback and that then remains onsite to handle the normal operations from the well.

Operational Considerations

The mitigation option for this emission source, namely RECs, is appropriate only for gas wells that undergo well completions using hydraulic fracturing. Additionally, for capturing and delivering gas to the sales line, as opposed to flaring, the system should already have a sales line in place.

When installing the portable equipment, the piping configuration is critical, as the high-velocity water and sand can erode holes in steel pipe elbows, creating "washouts" with water, sand, hydrocarbon liquids, and gas in unmitigated flows to the pad. Along with piping, Partners might consider installing additional equipment for treating produced gas to remove impurities for the gas to be considered pipeline quality.

Methane Emission Reduction Estimate

The amount of methane emissions that can be reduced using RECs varies widely based on reservoir characteristics and other parameters, including length of completion, number of fractured zones, pressure, gas composition, and fracturing technology/technique. "Energized" fractures, in which inert gases such as nitrogen or carbon dioxide are injected with the initial water, have a flowback composition that cannot initially be directed to a gas sales line. Some reservoirs are so low pressure that the flowback would be too slow and inefficient to be directed through the REC equipment. In these cases or malfunction of the REC equipment (plugging), some of the flowback gas should be directed to a flare or combustion device if feasible, which generally achieves greater than 95 percent reduction in methane emissions compared to venting the gas.[6]

Economic Considerations

The incremental costs of performing an REC are estimated to be from $800 to $7,500 per day and well completion flowback lasts approximately three to 10 days.[7] This cost range represents the incremental cost of performing a REC over a traditional completion, when the gas is typically vented or combusted because of no REC equipment. The low end of the cost range ($800/day) represents completions and workovers where key pieces of equipment to perform the REC (e.g., a dehydrator or three-phase separator) are already onsite and are of suitable design and capacity to use during flowback. The high end of the cost range ($7,500/day) represents situations where key pieces of equipment to perform the REC are temporarily brought on site and then relocated after the completion or workover. The cost of the equipment depends on the number of days of flowback, the initial production rate, and the availability of treatment equipment such as a permanent glycol dehydration unit.

The total cost per well was assessed based on an average of daily cost and the number of days per completion. The average incremental cost is $4,150 per day and the average completion lasts seven days.[8] Based on these averages, the overall incremental cost is $29,000 per well for a REC versus an unmitigated completion.[9] Partners should include an additional $700 to account for transporting and placing equipment, giving a total incremental cost of $29,700 per well.[10] RECs are considered one-time events per well. Therefore, annual costs can be conservatively assumed to be the same as capital costs.

The amount of gas that can be recovered from RECs varies widely based on several different variables (i.e., reservoir pressure, production rate, amount of fluids lifted, and total completion time). The savings associated with the additional gas captured to the sales line can be estimated based on a natural gas value of $3/MMBtu. It can be assumed that all gas captured will be included as sales gas. As a result, assuming that 90 percent of the gas that was previously vented to the atmosphere is captured and sold, this equals a total recovery of 8,260 Mcf (234 thousand scm)[11] of natural gas per hydraulically fractured completion or workover. The estimated value of the recovered natural gas for an example natural gas well with hydraulic fracturing is approximately $24,780. In addition, RECs typically recover an estimated average of 34 barrels of condensate per completion or workover.[12] The recovered condensate is valued at about $2,400 (assuming a condensate value of $70 per barrel[13]), which brings total savings to $27,180 per well. When considering these savings, the net cost for this REC (completion or workover) example is now $2,520 per well. For these average economics of a process with a wide range of gas and condensate recoveries, approximately half the applications will have positive economics.

[6] U.S. EPA. "Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution." *Background Technical Support Document for Proposed Standards*. https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry.

[7] Ibid.

[8] Ibid

[9] Ibid.

[10] Ibid.

[11] Ibid.

[12] Ibid.

[13] Ibid.

Emission Factors

Table 8.2: Default Emission Factors for Well Completions of Hydraulically Fractured Wells[A]

Source	Methane Emissions Factor[14]	
	(scm/completion)	(scf/completion)
Hydraulically fractured gas well completions and workovers with venting only	60,287	2,128,764
Hydraulically fractured gas well completions and workovers with flaring only	7,352	259,605
Hydraulically fractured gas well completions and workovers with RECs	4,411	155,763
Hydraulically fractured gas well completions and workovers with RECs and flaring	8,822	311,527

[A] The emission factors presented were developed using data from hydraulically fractured gas wells in the United States, where the use of RECs is well established. The factors apply to only onshore gas wells.

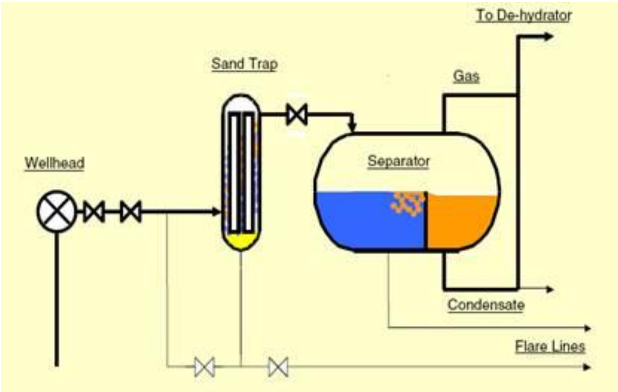
[14] EPA. 2014. Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2012. http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.

Exhibit A – Post Hydraulic Fracture Backflow to an Open Tank or Pit[15,16]

[15] Natural Gas STAR Producers Technology Transfer Workshop, Vernal, Utah, March 23, 2010: photo during field trip to hydraulic fracture operation

[16] Producer Technology Transfer Workshop, Vernal, Utah, March 23, 2010: "Process Optimization Review," presentation by Newfield Exploration Company

Exhibit B – Post Hydraulic Fracture Backflow Through Reduced Emissions Completion Skid[17]



[17] Methane to Markets, Oil & Gas Subcommittee Technology Transfer Workshop, Monterrey, Mexico, January 28, 2009: "Reduced Emission Completions / Plunger Lift and Smart Automation," presented by EPA