SG. 17.1.6

TECHNICAL GUIDANCE DOCUMENT NUMBER 6:

UNSTABILIZED HYDROCARBON LIQUID STORAGE TANKS

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

Storage vessels in the oil and natural gas sector are used to hold a variety of liquids, including crude oil, condensates, and produced water. Crude oil and condensate may be stored in fixed-roof, atmospheric pressure tanks between production wells and pipeline or truck transportation. In offshore fields, the storage tanks on production platforms, floating production, storage and offloading (FPSO) vessels and floating storage and offloading (FSO) vessels contain crude oil and/or condensate, produced from connected wells or coming from nearby platforms. Light hydrocarbons dissolved in the crude oil or condensate under pressure (i.e. unstabilized hydrocarbon liquids)—including methane and other volatile organic compounds (VOC), natural gas liquids (NGLs), hazardous air pollutants (HAP), and some inert gases—will flash (vaporize) from the liquid stored in the tank and accumulate in the vapor space between the liquid surface, the walls and roof of the tank. Fixed roof tanks can not contain any significant pressure above atmospheric pressure, and therefore these vapors must be vented.

Emissions from storage vessels are a combination of flash, working, and standing losses. Flash losses (the most significant of the three) occur when a pressurized liquid with dissolved gases is transferred from a well or vessel at higher pressure to a fixed roof, atmospheric pressure tank. The pressure drop causes gas to rapidly evolve from the liquid and/or vaporize (i.e., flash). Working losses refer to vapors above the liquid surface pushed out by rising liquid levels and agitation of liquids in tanks associated with circulation of fresh liquid through them. Standing losses refer to vapors expanding and venting associated with daily and seasonal temperature and barometric pressure changes. Onshore field production sites are generally

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

designed and operated to push the liquid from a gas/liquid separator vessel at a higher pressure to the tank so that the liquid will fill the tank without the use of a pump. This results in some flashing emissions.

The volume of vapor emitted from a fixed-roof storage tank is dependent on several factors, most significantly the pressure in the gas/liquid separator and the oil or condensate flow rate from this separator into the tank. That is, the greater the differential in pressure between the separator and tank, the higher the flashing losses. Lighter crude oils (API gravity >36°) flash more hydrocarbon vapors than heavier crudes (API gravity <36°) at the same separator pressure. Additionally, in storage tanks where oil cycling is frequent and overall throughput is high, more working losses will occur than in tanks with low throughput and where oil is held for longer periods of time.

The composition of tank vapors varies based on the type of production and the types of hydrocarbons that are being produced from the reservoir. Often methane is the primary component of tank vapors (between 40 and 80 percent for crude oil and gas condensate), but other compounds may be present in lesser quantities, including more complex hydrocarbon compounds such as ethane, propane, butanes, pentanes, natural inert gases such as nitrogen and carbon dioxide, and hazardous air pollutants, like hydrogen sulfide, benzene, toluene, ethyl-benzene, and xylene.

Hydrocarbon liquid storage tanks may be configured in a variety of ways, and the configuration should be identified to determine whether the source is mitigated or unmitigated. Some options include the following:

Table 6.1: Configurations for Unstabilized Hydrocarbon Liquid Storage Tanks[A]

Configuration	Mitigated or Unmitigated
Tank vapors are emitted to the atmosphere via routing through an open vent, unlit flare[2], and/or through openings in the fixed roof of an oil or condensate production tank (e.g., open/unsealed thief hatch, cracks/corrosion in tank roof, weighted pressure/vacuum relief valve). Exhibit A	Unmitigated
Tank vapors are recovered by routing to a Vapor Recovery Unit (VRU) system and directing to productive use (e.g., fuel gas, compressor suction, gas lift). Exhibit B	Mitigated (if confirmed to be functioning with low[B] or no emissions) **(OPTION A)**
Stabilization towers are installed ahead of tanks to reduce the amount of entrained gas and flash gas emitted from the tank(s).	Mitigated (if confirmed to be functioning with low[B] or no emissions) **(OPTION B)**
Tank vapors are routed to a flare/combustion device.	Mitigated (if confirmed to be functioning with low[B] or no emissions) **(OPTION C)**

[A] Hydrocarbon liquids withdrawn from an atmospheric pressure storage tank or vessel, or from a vapor stripping tower, are considered stabilized (i.e. volatile gases are expelled). Stabilized oil can be stored in a floating roof

[2] "Flare" in this document refers to vertical combustion devices using an open or enclosed flame.

tank, which is not considered to be a significant source of methane emissions and is therefore not considered to be a core source. Note that unstabilized oil cannot be stored in a floating roof tank.
[B]Expected emissions levels if mitigation option is in place and functioning properly (e.g., flare is not extinguished, 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. As part of their periodic evaluation plans, Partners should include inspection of mitigated tanks in their Annual Operations/Assets Surveys to ensure proper functionality. Malfunctions (e.g., VRU or stabilization towers are not functioning or an extinguished flare) may result in higher than designed methane emissions. Though unusual, situations have also been observed in which gas from the separator is permanently routed to the atmosphere (e.g., when there is no market for the gas), in which case this should count as an additional source of "unmitigated" emissions that needs to be quantified and addressed.

At times, unintended methane emissions not associated with crude oil or condensate flashing may enter and vent from tanks. For example, if a gas/oil separator dump valve sticks open due to physical erosion of valve seats or solids plugging or liquids freezing in the valve that prevents the valve from closing, bulk gas can be entrained with the oil to the tank resulting in methane emissions exceeding calculated flashing losses. Because the source of emissions is not at the dump valve, and vent emissions from an unmitigated or malfunctioning mitigated tank is assumed to come from the separator liquid, fugitive emissions monitoring may not identify this through-valve leaking component: it is related to tank operations. Partners should identify this malfunctioning source during tank inspection and repair or report emissions under the FUGITIVE COMPONENT AND EQUIPMENT LEAKS source as part of the Directed Inspection & Maintenance (DI&M) programs.

Quantification Methodology

To ensure consistent quantification of annual volumetric unstabilized hydrocarbon liquid storage tank methane emissions and comparable evaluation of mitigation options, the OGMP recommends that Partners use one of the quantification methodologies discussed below. In principle, direct measurement in conjunction with vent gas composition analysis is the most accurate method for quantifying methane emissions from flashing losses with a uniform crude oil input.[3] However, standing and working losses are less accurately quantified by direct measurement and with changes in crude oil from multiple wells. With direct measurement, and through taking steps to stop potential gas bypass and accounting for working losses, Partners can be more certain of emissions levels and economic costs and benefits (i.e., value of gas saved). As such, measurement related to crude oil throughput is encouraged whenever possible.

To achieve some level of consistency within the Methane Partnership, partner companies are encouraged to use one of the following methodologies in order to facilitate consistent, comparable approaches to quantifying emissions levels and evaluating potential reduction volumes. Individual companies may choose an alternative quantification methodology if judged to be more accurate by the company, in which case the alternative methodology will be documented and explained in the Annual Report.

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

- Direct Measurement[4]:
  When quantifying emissions via measurement, the first step is identifying the point(s) where emissions are occurring. Observing the tank roof and tank vent (if routed away from the tank) with an infrared (IR) leak imaging camera (designed to visually identify hydrocarbon emissions) both before and during measurement will show locations where gas is venting. Partners can use other portable instruments if an IR camera is not available (i.e., FID detector). A measurement is commonly taken directly from the vent of a storage tank using a flow totalizing turbine meter. Partners can also route flow from an open thief hatch to a measurement device (e.g., by attaching a length of piping to a flange that can be sealed to an open thief hatch and measuring the emissions coming through the piping).

  Partners should conduct the measurement over a long enough period to account for variability in flow during tank filling and pump-out (e.g., 3 to 24 hours). Partners can determine an appropriate time period on an individual basis, such that the long-term measurement allows for an evaluation of emissions levels during tank filling and pump-out operations. These measurements will provide the total gas flow rate relative to oil input, which is then converted to methane emissions using the methane content of the gas. The methane flow rate should be extrapolated to account for an entire year of normal operations. The annual volume of methane emitted is calculated by taking the measured average methane emissions flow rate divided by oil input, and multiplying this ratio by the annual throughput of the storage tank(s).

  It should be noted that the slight back-pressure of a turbine meter will push emissions out other openings, such as corrosion holes in the roof or the thief hatch if not sealed tightly. Viewing the tank with an IR camera during measurement will allow Partners to identify those other escape points and take measures to suppress or plug those vents during the measurement. Alternative options may include: high flow samplers; traditional bagging techniques; positive displacement metering such as wet and dry gas meters with data-logging capability.

  Note that the gas/oil separator vessel liquid level control valve can leak or stick open, whereby gas is entrained with the oil delivered to the tank. Increased emissions from storage tanks above what can be accounted for by flashing at separator pressure and temperature may be due to this leakage and also from vortexing when the separator liquid level is very low and there is no vortex breaker installed in the liquid drain nozzle. A leaking, stuck-open valve and vortexing can also contribute to increased emissions from compressor suction scrubber dump valves that drain to a fixed roof tank. This is easily avoided by observing that the gas/oil separator maintains a liquid level in the sight-glass during tank emissions measurement.

  Partners can obtain a value for methane emissions using the total vapor flow over a recorded time and knowledge of the composition of the vapors in the tank. As noted above, emissions from storage tanks are not limited to the vent and also can come from defects in the tanks, including but not limited to, visible cracks, holes, gaps in piping, loose connections, broken or missing caps, a leaking pressure/vacuum safety valve (weighted vent valve such as an ENARDO valve), loose or open thief

[4] Greenhouse Gas Reporting Program, Subpart W – Petroleum and Natural Gas Systems. Section 98.234: Monitoring and QA/QC requirements, 40 CFR 98.234(b), (c), and (d). http://www.ecfr.gov/cgi-bin/text-idx?SID=8ad69f44a8434c400c42b9cdb65f5be7&mc=true&node=se40.23.98_1234&rgn=div8

hatch, or other closure devices. Depending on the location of a leak and piping/vent configuration of a storage tank and the gas flow rate, Partners can also take an emissions measurement using a calibrated vent bag or an anemometer (vane or hotwire). Recommended measurement tools include the following:

- Turbine meter
- Calibrated vent bag
- Vane anemometer
- Hotwire anemometer
- High volume sampler

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

- Estimation Methods:
  Partners can calculate flashing, working, and standing emissions from liquid transferred to storage tanks with equation of state programs, such as AspenTech HYSYS® or E&P TANKS[5], or empirical equations, such as Vasquez-Beggs or the Griswold and Ambler GOR Chart methods. Typically, a minimum of the following parameters/operating conditions are necessary to characterize emissions using computer programs or charts: (1) separator pressure and temperature, (2) sales oil or stabilized oil American Petroleum Institute (API) gravity, (3) sales oil or stabilized oil production rate, (4) ambient air pressure and temperature, and (5) separator oil composition and Reid vapor pressure.[6] Note that if separator oil composition and Reid vapor pressure data are not available, one option is to select default values in the E&P TANKS program that most closely match separator pressure first, and API gravity second. Partners can also input more detailed information into the models. With additional data concerning crude oil property changes, tank size, shape, color, and internal and ambient temperatures, computer models can produce more accurate emissions estimates over the course of a year than direct measurement. Note that software cannot characterize separator or scrubber dump valve leakage, which can far exceed flashing losses. Comparing direct measurement results with software calculation has revealed many instances of higher emissions possibly from dump valve leakage.

- Lab Analysis:
  Another alternative for estimating emissions from storage tanks is to obtain a sample of the oil in the separator and perform a lab analysis to determine how much methane will be vented from this sample as the pressure drops to tank pressure (atmospheric). Partners can then apply this ratio to the volume of oil entering the tank, and the subsequent volume of emissions can be assumed to be the vented volume.[7] Nearly all methane will flash out of solution from oil at atmospheric pressure, so this method is the least complicated in estimating methane emissions, but does not accurately characterize total gas emissions (which is necessary to economically evaluate mitigation options).

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[5] American Petroleum Institute "E&P TANKS v3.0." https://www.eptanks.com/

[6] EPA. Greenhouse Gas Reporting Program, Subpart W – Petroleum and Natural Gas Systems. Section 98.233: Calculating GHG emissions. 40 CFR 98.233(j)(1). http://www.ecfr.gov/cgi-bin/text-idx?SID=9db68a97576bb01eea9073c37d6f0e90&node=40:21.0.1.1.3.23&rgn=div6.

[7] Ibid.

- Engineering Estimate of Scrubber Dump Valve Emissions[8]:
  Lab analysis and software calculations do not account for scrubber dump valve emissions; therefore, if they determine that there is a scrubber dump valve stuck open, Partners can account for scrubber dump valve emissions by using a factor applied to a storage tank's flash emissions. Partners need to do this only if they are not using direct measurement to quantify methane emissions from storage tanks (direct measurement occurs at the storage tank atmospheric vent, and scrubber dump valve emissions go through the same vent and are therefore included). If Partners use software or lab analysis, then they should also use this method to avoid underestimating emissions from storage tanks (if a scrubber dump valve is indeed confirmed stuck open). Partners can use the equation below to estimate emissions from stuck-open valves on well pad gas-liquid separators and scrubbers:

$$E_{s,i} = \left(CF_n \times \frac{E_n}{8760} \times T_n\right) + \left(\frac{E_n}{8760} \times (8760 - T_n)\right)$$

Where:

$E_{s,i}$ = Annual total volumetric greenhouse gas (GHG) emissions at standard conditions from each storage tank (scf).

E_n = Storage tank emissions as determined via calculation, software, or lab analysis (scf/y).

T_n = Total time the dump valve is not closing properly in the calendar year (hours). T_n is estimated by maintenance or operations records such that when a record shows the valve to be open improperly, it is assumed the valve has been open for the entire time period preceding the record starting at either the beginning of the calendar year or the previous record showing it closed properly within the calendar year. If a subsequent record shows the valve is closing properly, then it is assumed from that time forward the valve closed properly until either the next record of it not closing properly or, if there is no subsequent record, the end of the calendar year.

CF_n = Correction factor for tank emissions for time period T_n for crude oil production is 3.87; for tank emissions for time period T_n for gas condensate production is 5.37; and for time period T_n for periods when the dump valve is closed is 1.0.

8,760 = Conversion to hourly emissions.

Mitigation Option A – Recover the tank vapors by installing a VRU system and directing to productive use (e.g., fuel gas, compressor suction, gas lift).

One way to reduce emissions of tank vapors is to install vapor recovery units (VRUs) on storage tanks. A VRU first draws hydrocarbon vapors out of a fixed roof storage tank under low pressure, typically between 4 ounces and 2 psi (0.0175 and 0.14 kg/cm^2) gauge pressure, and routes them through a separator (suction scrubber) to a specifically designed wet gas compressor. Proper design includes routing the suction line with only a downward slope to the suction scrubber so that a liquid trap does not occur that would inhibit

[8] EPA. Greenhouse Gas Reporting Program, Subpart W – Petroleum and Natural Gas Systems. Section 98.233: Calculating GHG emissions. 40 CFR 98.233(j)(8). http://www.ecfr.gov/cgi-bin/text-idx?SID=9db68a97576bb01eea9073c37d6f0e90&node=40:21.0.1.1.3.23&rgn=div6.

free flow of gas to the compressor. From the compressor, the vapors are routed to their desired location(s) within the facility: a gas sales line, local fuel, and/or suction of a production or gas lift compressor. The liquids from a separator can be returned to the oil storage tank or collected separately and sold to a processing plant or refinery for a premium price. The recovered vapors are rich in propane, butanes, and natural gasoline and will therefore have higher heat content and a higher value to gas processing plants than pipeline quality natural gas.

Operational Considerations

Virtually any tank battery is a potential site for a VRU. Two indicators of a potential VRU project are a regular and sufficient quantity of crude oil and/or condensate production and an economic outlet for collected products. Note that a source of electricity is highly desired to power several of the VRU's components. Included in a standard VRU are:

- Sloping downward suction pipeline manifolded to all tanks.
- Suction scrubber (separator).
- Compressor (typically electric-driven rotary vane, screw, or scroll compressor).
- Liquid transfer pump.
- Electronic Programmable Logic Controller (PLC).
- Associated discharge piping, instruments, valves, and controls.

Periodic, large flow of liquids out of the storage tanks during pump-out can cause large and rapid fluctuations in tank pressure, putting stress on the VRU. Partners may consider installing a vapor recovery tower (VRT) to ensure the VRU operates at steady state within its design capacity even with the rapid changes in pressure with liquids flow out of the storage tank(s). This is an inexpensive way to elevate the crude oil or condensate gas/oil separation and flash gas generation above the tank to isolate the vapor recovery from tank liquid movements. Working and standing losses are minimal from low vapor pressure oil gravity draining into the tank.

Wet screw compressors are often chosen for VRU applications for their ability to achieve high compression ratios (up to 20 in a single stage)[9] due to the injection of a significant amount of coolant into the compressor chamber. While this coolant injection lowers gas discharge temperature and improves compressor efficiency, the volume increase caused by the coolant decreases the effective volume for gas. Partners should model screw compressor performance using both factors.

The optimal adiabatic efficiency for a single stage screw compressor is achieved at approximately a 3:1 pressure ratio,[10] although higher pressure ratios are achievable without sacrificing significant efficiency, given suitable discharge temperature and motor limitations (typical motor operates at 3600 rpm).

Methane Emission Reduction Estimate

Ideally, in the correct operating condition, VRUs can recover nearly all vapors from a storage tank. Based on a VRU operating factor of 95 percent (allowing 5 percent yearly downtime of the VRU for maintenance), Partners can expect to reduce methane emissions from a storage tank by 95 percent after implementing this technology.

[9] Hanlon, Paul C. Compressor Handbook. 2001. Section 2.3.2.
[10] Hanlon, Paul C. Compressor Handbook. 2001. Section 14.6.

Economic Considerations

The cost of a VRU is dependent on several design/operational factors, including gas throughput to the VRU, inlet and desired outlet temperatures and pressures for the system, and composition(s) of the gas being recovered. Partners should size a VRU to handle the maximum volume of vapors expected from the storage tanks (a rule of thumb is to double the average daily volume). Partners should optimize VRU design and cost to maximize emission capture and minimize costs, for example by routing emissions from several tanks to a single VRU. In considering VRU sizing, Partners should consider production forward planning, so that the VRU can handle planned increased production to the tank battery. Also, a VRU can recover other vented or flared gas streams at a facility. This would enable Partners to capture these additional gas streams that are currently being lost to the atmosphere and can improve a proposed project's economics. Partners would need to account for the maximum throughputs associated with these gas streams in the initial VRU design. Examples include pneumatic device vents, compressor rod packing vents, Glycol Dehydrator vent (with a vent condenser), and controlled equipment blowdowns.

Estimated VRU and associated installation costs for 25 thousand cubic feet per day (Mcf/day) and 500 Mcf/day throughputs (708 standard cubic meters per/day and 14,158 scm/day) are approximately \$35,000 and \$105,000, respectively.[11,12] Partner and VRU manufacture experience has shown that installation costs range between 50 to 100 percent of the initial VRU equipment cost (75 percent was chosen for economic estimates provided here). Yearly operation (primarily electricity) and maintenance costs (O&M) associated with these VRU capacities are \$7,400 and \$16,800, respectively.[13] Note that the VRU costs provided are for recovery of hydrocarbon vapors at atmospheric pressure and approximately 70 °F (21 °C) for discharge into a typical sales gas line up to approximately 100 psig pressure and 212 °F (100 °C) temperature. Discharging gas at pressures above 100 psig (7 kg/cm^2) will likely involve a two-stage compressor.

Note that installation costs can vary widely depending primarily on the location of a site (VRU installation at remote sites will likely incur higher costs) and number of tanks being connected to the VRU system. O&M costs vary depending on the location of the VRU system (VRUs installed in a cold climate experience more wear), the quality of the gas (high acid content, CO_2 and/or H_2S have higher corrosion rates), electricity costs, and oil produced (paraffinic oil can clog VRUs more frequently and therefore require increased maintenance).[14]

Gas value savings associated with installing a VRU take into account recovered high BTU gas and the value of the recovered NGLs in the tank vapors. In most vapor recovery applications, the value of the recovered gas stream is rarely due to the value of methane alone as most tank vapors contain varying amounts of ethane, propane, butane, pentanes, and other "heavy" hydrocarbons. For those Partners that have a gas sales contract that is based upon the heating value (BTU content) of the gas, "wet gas" may sell for upwards of 2.5 times an equivalent volume of pipeline quality natural gas.

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[11] EPA. Natural Gas STAR Lessons Learned: *Installing Vapor Recovery Units on Storage Tanks.* June 2016. https://www.epa.gov/sites/production/files/2016-06/documents/ll_final_vap.pdf.

[12] Assuming typical gas inlet temperature of 21 °C and sales lines discharge pressure of roughly 7 bar. Installation costs estimated at 75 percent of VRU capital costs.

[13] The majority of electricity costs will be for powering the compressor motor. Partners can calculate an estimate of required electricity with knowledge of kWh electricity price and kWh motor consumption.

[14] EPA's Natural Gas Star Lessons Learned: *Installing Vapor Recovery Units on Storage Tanks.* June 2016. https://www.epa.gov/sites/production/files/2016-06/documents/ll_final_vap.pdf.

For reference, using E&P TANKS software, for a tank holding a medium crude (30° API) at atmospheric pressure and 70° F (21 °C), the mole composition of vapors is approximately 68 percent methane, 10 percent ethane, 8 percent propane, and 3 percent each butane and isobutene. Based on these compositions, for VRU capacities of 25 Mcf/day and 500 Mcf/day (708 scm/day and 14,158 scm/day), the yearly values of these recovered gas streams[12, 15] are approximately $30,000 and $600,000 at $7/Mcf of rich tank vapors, respectively. For Partners who have access to natural gas liquid plants, tank vapors could provide a source to feed these plants. For the same mole composition references above and vapor flow rates of 25 Mcf/day and 500 Mcf/day (708 scm/day and 14,158 scm/day), the approximate values of recoverable NGLs (C_2 to C_4) are $60,000/year and $340,000/year, respectively.[16]

For more information, see Natural Gas STAR technical document "Installing Vapor Recovery Units on Storage Tanks" (https://www.epa.gov/sites/production/files/2016-06/documents/ll_final_vap.pdf).

Mitigation Option B – Install stabilization towers ahead of tanks to reduce the amount of entrained gas and flash gas emitted from the tank(s).

In petroleum and gas production facilities, the primary purpose of stabilization towers is to obtain a low oil vapor pressure suitable for loading onto ships and barges or extract more high-value natural gas liquids for gas processing. In gas processing facilities, the purpose of stabilization towers is to separate heavier hydrocarbons and lighter fractions (C_1 to C_4) prior to transporting and storing crude oil and condensate. In either case, the process separates the lightest liquid component (pentane) and heaviest gas component (butane) through distillation.[17] Stabilization towers installed ahead of crude oil storage tanks can serve a similar function as vapor recovery units in reducing methane emissions from storage tanks, with the additional feature that they can reduce the crude oil vapor pressure below atmospheric pressure. Stabilization removes virtually all methane from the crude oil or condensate.

Crude oil or condensate enters the top of stabilization towers and flows down a series of trays. When pressurized oil enters the low-pressure column, flashed vapors exit the top of the tower while "stabilized" crude oil or condensate passes through the bottom of the tower(s) and into storage. Adding a reboiler on the bottom of the column creates vapor traffic up the tower to strip more light hydrocarbons out of the oil, and reduces the vapor pressure on the crude product below atmospheric. In addition to the heated reboiler, a stripping gas such as steam may be added near the bottom of the column to provide increased vapor flow and enhance light hydrocarbon (C_1 to C_4) removal.

Given the utility of stabilization towers, some Partners already have them installed and functioning. This technology is considered "mitigated" for methane with regards to liquid petroleum product storage tanks. The possible outlets for the recovered gas from stabilization towers include being sent to a gas processing facility, a fuel gas line, a VRU, and/or combustion in a flare. Because stabilization towers are expensive and installed for the specific purposes listed above, it is not anticipated that Partners will install them as a retrofit for the sole purpose of controlling methane emissions from tanks.

[15] NGL values obtained from EPA presentation: Vapor Recovery Tower/VRU Configuration: Lessons Learned from Natural Gas STAR. August 2007. NGL values extrapolated based on methane value of $3/MMBTU. https://www.epa.gov/natural-gas-star-program/natural-gas-star-outreach-and-events#tab-2.

[16] 2007 Cost Basis obtained from EPA presentation: Vapor Recovery Tower/VRU Configuration: Lessons Learned from Natural Gas STAR. August 2007. https://www.epa.gov/natural-gas-star-program/natural-gas-star-outreach-and-events#tab-2.

[17] Mokhatab, Saeid., Poe, James A., and Speight, James G. Handbook of Natural Gas Transmission and Processing. Page 249.

Mitigation Option C – Route the tank vapors to a flare/combustion device.
Routing storage tank vapors to a flare/combustion device reduces methane emissions to the atmosphere through oxidative combustion of methane. A flare may continuously receive vent streams from one or several processes and/or pieces of equipment at a facility.

Operational Considerations
Virtually any vented storage tank's vapors with minimal sulfur content can be routed to an existing flare by installing piping which route the vapors to the flare. It is absolutely essential to include a flame arrestor in the flare line near the tank as air drawn into an atmospheric pressure storage tank can form explosive mixtures that could flash-back from the flare flame and explode the tank. If routing to an existing flare is operationally infeasible, a new flare system requires installation of the following equipment:

- Flare stack.
- Associated piping used to direct vapors from storage tank(s) to the flare.
- Flame arrestor.

Gas-fired flares may have one or more continuously burning pilot flames or be ignited with an electric spark-ignition system.

Methane Emission Reduction Estimate
Companies can expect to achieve a 98 percent reduction in methane emissions from routing storage tank vapors to a flare, assuming a properly operated flare (98 percent combustion efficiency).[18]

Economic Considerations
Minimal capital costs are associated with routing storage tank vapors to an existing flare. These costs include all piping connections and labor required to route vapors from the tank vent(s) to the flare gas line. For a new flare system, estimated total capital investment for a new flare and flame arrestor, including an auto-igniter, and associated freighting, design, and installation is estimated to be $24,300.[19] Annual costs are estimated to be approximately $1,800/year for pilot fuel (assuming $3/Mcf) and flare system maintenance.

Though flaring achieves no economic benefit in terms of gas saved, a flare is an important operational/safety device at a natural gas/oil installation as it can serve as a safe gas disposal outlet for over-pressurized equipment as well as a gas outlet for equipment undergoing maintenance and repairs, thus reducing methane emissions from these sources by combusting the gas. In addition, flaring the tank vapors means that there is less risk of exposure to harmful pollutants for the operators onsite.

For more information, see:
- EPA Natural Gas STAR Partner Reported Opportunity Fact Sheet No. 903, "Install Electronic Flare Ignition Devices" (https://www.epa.gov/sites/production/files/2016-06/documents/installelectronicflareignitiondevices.pdf).

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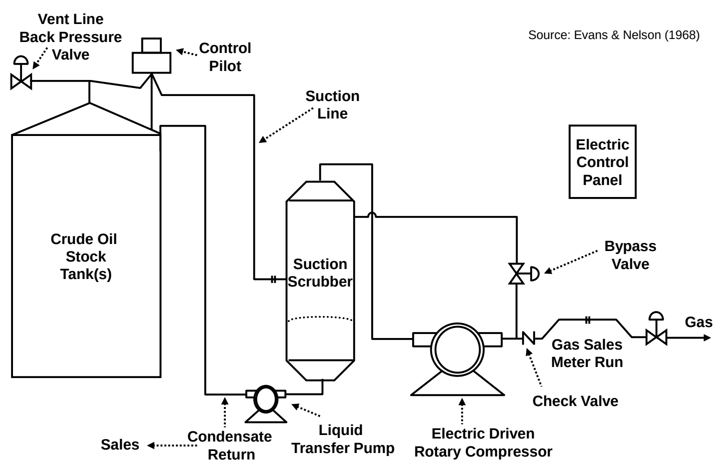
[18] EPA. AP 42, Fifth Edition, Volume I. Chapter 13, Section 5: Industrial Flares.
[19] EPA. Partner Report Opportunities Fact Sheet No. 904: Install Flares. https://www.epa.gov/sites/production/files/2016-06/documents/installflares.pdf (Price of flame arrestor estimated at $3,000).

- EPA Natural Gas STAR Partner Reported Opportunity Fact Sheet No. 904, “Install Flares” (https://www.epa.gov/sites/production/files/2016-06/documents/installflares.pdf).

Exhibit A – Unstabilized Hydrocarbon Liquid Storage Tank Vented to the Atmosphere[20]
IR Camera View

[20] US EPA's Natural Gas STAR International: 1st Asia Pacific Global Methane Initiative Oil & Gas Sector Workshop, Jakarta, Indonesia, September 23, 2011, "An Overview of Emission Reduction Best Practices," presented by EPA

Exhibit B – Unstabilized Hydrocarbon Liquid Storage Tank with Vapor Recovery Unit [21]



[21] Natural Gas STAR Producers and Processors Workshop, Billings, Montana, August 31, 2009: "Installing Vapor Recovery Units," presentation by EPA

SG.17.1.7

TECHNICAL GUIDANCE DOCUMENT NUMBER 7:

WELL VENTING FOR LIQUIDS UNLOADING

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

Over time, gas production naturally declines in non-associated gas wells as the reservoir is depleted. Initial flow (gas velocity) from a gas well is usually sufficient to entrain produced liquids as droplets and carry them through the wellhead and to a separator. However, as flow declines, the gas velocity may be insufficient to lift the produced liquid, and liquid may accumulate in the wellbore. As liquid accumulates in non-associated gas wells, the pressure of the liquid becomes greater than the gas velocity and eventually slows or stops the flow of gas to the sales line. These gas wells therefore often need to remove or "unload" the accumulated liquids so that gas production is not inhibited. Well liquids must be managed on an ongoing basis and adapted to the changes in wells' flow characteristics as wells move through their lifecycle.

Four main flow regimes normally occur in a gas well: mist flow, annular flow, slug flow, and bubble flow. Mist flow, where the gas flows and carries the liquids in mist form, is ideal. Annular flow is slower than mist flow. In annular flow, the lighter gas travels up the center of the well tubing and the heavier liquids flow along the walls of the tubing. At still slower velocities, called slug flow, liquids separated by pockets of gas flow up the tubing. Finally, at even slower velocities, the gas flows according to what is known as bubble flow. In bubble flow, the gas is dispersed in the liquid phase and flows at a very slow rate. In this phase, the gas is no longer carrying the liquids through the tubing, resulting in accumulation of the liquids.[2]

[1] For reporting purposes as described in the CCAC Oil and Gas Methane Partnership Framework, Section 3.
[2] Guo, Boyun; Ghalambor, Ali; Natural Gas Engineering Handbook, pgs. 241–254.

Because fluids slow the gas velocity, their build-up needs to be addressed. Partners can choose from several techniques to remove the liquids, including manual unloading, foam agents, velocity tubing or velocity strings, beam or rod pumps, electric submergence pumps (ESP), intermittent unloading, gas lift, and wellhead compression, as liquids unloading practices. Each method removes accumulated liquids and thereby maintains or restores gas production. Below is a summary of these methods:

- "*Manual Liquids Unloading with Atmospheric Venting*"- The well is choked with liquids built up in the tubing, substantially reducing or stopping gas production to the sales line. At that time, the sales line connection is manually shut-off, and well production is routed to an atmospheric tank with lower back-pressure than the production system. This allows reservoir (gas) pressure to lift the liquid from the well. The entrained gas is vented to the atmosphere at the tank. Subsequently the well is manually rerouted to the production system and sales gas line. In some cases, the well is shut-in for a period of time to build-up pressure before being routed to an atmospheric tank.

- *"Manual Liquids Unloading without Atmospheric Venting"*- The well is shut-in before liquids choke off gas flow, allowing the reservoir pressure to rise to shut-in pressure. The well is re-opened and flow routed to the separator with gas going to sales and liquids to storage.

- "*Automated Liquids Unloading*"- Similar to manual unloading without atmospheric venting, except a timing and/or pressure device is used to optimize intermittent shut in of the well before liquids choke off gas flow. The reservoir pressure rises sufficiently to lift liquids to the separator (gas to sales without atmospheric venting) or direct liquids to an atmospheric storage tank (substantially less entrained gas vented to the atmosphere).

- "*Foaming Agents*"- Chemicals are added to the well that reduce the liquid density through foaming, which improve the ability of the gas to carry the liquids to the surface.

- "*Velocity Tubing or Strings*"- Installation of several smaller sized tubing strings in place of the single larger production tubing increases gas flow velocity in each small tube, thus allowing the well's gas flow to carry the liquids out.

- *"Plunger Lift System"*- A mechanical system with an automated controller that can close in the well, allowing the plunger to drop to the bottom of the well. The controller then reopens the well, allowing the gas to push the plunger to the top with a slug of liquid on top. The controller can be activated manually, by a mechanical timer, by a pressure controllers, or with an automated "smart" cycle system. Depending on the plunger system design and operation, plunger controllers may be designed to allow automatic venting if the plunger does not return when expected, thus creating an emission during ***some*** plunger trips. Other systems are designed to vent on every plunger lift trip.

- "*Sucker Rod or Beam Pumps*"- Installation of a rod pump system to lift liquids up the tubing through a series of check valves. Flow is routed to the separator with gas going to sales and liquids to the storage tank. This technology requires electric power at the well site.

- "*Electric Submersible Pump*"- Installation of an electric submersible pump to pump liquids through the well. Flow is routed to the separator with gas going to sales and liquids to the storage tank. This technology requires electric power at the well site.

- *"Jet Pumps"*- Installation of pumps that use a power liquid to transfer energy from surface pumps into reservoir fluids. Flow is routed to the separator with gas going to sales and liquids to the storage tank.

- *"Progressive Cavity Pumps"*- Installation of low-speed, downhole rotary positive displacement pumps typically driven by a rod string attached to an electric or hydraulic motor on the surface. Flow is routed to the separator with gas going to sales and liquids to the storage tank. This technology may require electric power at the wellhead.

- *"Gas Lift"*- A compressor pushes high-pressure gas downhole in order to increase total gas velocity up the well. Flow is routed to the separator with gas going to sales and liquids to the storage tank.

- *"Wellhead Compressor"*- A compressor pulls gas from the wellhead in order to reduce gas flow operating pressure from the well, which reduces gas flow pressure at well "bottom hole," which increases well bore (gas flow) velocity. Flow is routed to the separator with gas going to sales and liquids to the storage tank.

Systems for unloading well liquids can be configured in a variety of ways. Partners should identify the configuration for each well. Some options include those listed in the following table.

Table 7.1: Configurations for Well Liquids Unloading

Configuration	Mitigated or Unmitigated
Manual liquids unloading is conducted with atmospheric venting (e.g., separator is bypassed and gas vented from atmospheric tank). Exhibit A	Unmitigated
Manual liquids unloading is conducted without atmospheric venting (gas from separator going to sales).	Mitigated
Automated liquids unloading is conducted with atmospheric venting but operator has optimized the intermittent venting such that the vented emissions are substantially less than manual liquids unloading venting.	Mitigated
Automated liquids unloading is conducted without atmospheric venting.	Mitigated
Foaming agents, soap strings, and surfactants (Option A); and velocity tubing/strings (Option B) are used to abate or substantially minimize manual liquid unloading events.	Mitigated
Plunger lift is used for liquids unloading without atmospheric venting (gas going to sales and liquids to storage) (Option C). Exhibit B	Mitigated
Plunger lift is used for liquids unloading with routine atmospheric venting occurs (e.g., separator is bypassed) but	Mitigated

operator has optimized the plunger lift operations such that vented emissions are substantially less than manual liquids unloading venting (Option C). Exhibit B	
Pumps (e.g., electric submersible pump, jet pump, progressive cavity pumps) are used to removed liquids from the well and abate or negate the need for manual unloading (Option D). Exhibit C	Mitigated
Gas lift or wellsite compressor is used to remove or reduce liquids in the well (and hence abate the need for manual unloading) (Option D).	Mitigated

Configurations that are not identified above as "mitigated" for methane emissions should be quantified and evaluated for mitigation, as described in the sections below. Even in the mitigated situations described above, operators should evaluate the system to ensure that it is not malfunctioning, which could result in higher methane emission levels.

Quantification Methodology

One or more of the following methodologies should be used to quantify annual emissions that result from gas well liquids unloading in which venting during the unloading event occurs. Examples may include manual liquids unloading, intermittent unloading or plunger lift unloading in which gas is vented to the atmosphere. In principle, direct measurement can be considered as the most accurate method for quantifying methane emissions.[3] 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 possible to establish this basis.

The 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. These quantification methodologies include: direct measurement, engineering calculation, or emission factor approach. Individual Partners may choose an alternative quantification methodology if judged to be more accurate by the Partner; in this case, the Partner should document and explain the alternative methodology in the Annual Report.

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

- Direct Measurement:[4] Direct measurement may be feasible or practical for manual, intermittent, or plunger lift liquids unloading in which venting to the atmosphere occurs from a vent or storage tank.[5]

For manual, intermittent, or plunger lift wells that require venting during liquids unloading's, the well's flow during an unloading event is routed to an atmospheric production tank, where the tank acts as a separator to collect liquids, and the gas flow is released through the top of the tank, typically through an open thief hatch or other openings in the tank's fixed roof. The thief hatch is typically manually opened just for the duration of the unloading operation. However, each facility setup is unique, and some sites have dedicated open top tanks or other openings in the tank. It may be necessary for Partners to review the site flow during unloading activities. Viewing the vent with an infrared leak-imaging camera can also identify emission points that should be measured. After reviewing the site flow configuration and determining the emission location(s), then Partners can directly measure the flow from the emission point(s) with a **temporary flow meter stack** or can insert a flow meter upstream of the emission point within the process piping using a generally accepted meter, such as:

- Vane anemometer
- Hotwire anemometer
- Turbine meter

The measured flow rate then is used in the following equation to obtain the annual emissions. The whole gas emissions can then be multiplied by the methane composition to calculate the annual methane emissions.

$$E_a = F_p FR$$

Where:

E_a = Annual whole gas emissions at standard conditions in cubic feet (scf).
F_p = Frequency of the venting events (number of occurrences per year).
FR = Cumulative whole gas flow rate in cubic feet at standard conditions over the duration of the liquids unloading event (scf).

Note that the frequency of events, Fp, can be gathered from a number of approaches. In cases of manual venting, this will require data gathering from a log of manually initiated events. In the case of automated venting of plunger lift systems, this frequency can likely be collected directly from the plunger controller, which logs the number of events where the plunger did not return in the expected period and when the controller vented the well as a result.

- Engineering Calculation: If the direct measurement approach is not selected or is not feasible or practical, an engineering calculation approach can be used. The calculation methodology

[4] U.S. EPA. Greenhouse Gas Reporting Program. Subpart W – Petroleum and Natural Gas Systems. Section 98.234: Monitoring and QA/QC requirements, 40 CFR 98.234(b). http://www.ecfr.gov/cgi-bin/text-idx?SID=0be28a76d43cbee6ce31f26e5a2bc9c0&node=40:22.0.1.1.3.23&rgn=div6.
[5] Direct measurement may not be feasible or practical for well swabbing due to the nature of the activities and venting (from the well bore/wellhead). Other liquids unloading (or removal) methods such as surfactants, velocity strings, downhole pumps, and compressors in which gas is not vented do not warrant direct measurement.

for emissions from wells without plunger lifts (e.g., manual or intermittent unloading) and wells with plunger lifts are provided below.[6]

Manual or Intermittent Unloading Calculation:[7]

$$E = V \times \left((0.37 \times 10^{-3}) \times CD^2 \times WD \times SP\right) + \sum_{q=1}^{V} \left(SFR \times \left(HR_q - 1.0\right) \times Z_q\right)$$

Where:

E = Annual natural gas emissions at standard conditions, in cubic feet per year (scf).
V = Total number of unloading events per year per well.
0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (pounds per square inch absolute (psia) converted to pounds per square feet).
CD = Casing internal diameter for each well in inches.
WD = Well depth from either the top of the well or the lowest packer to the bottom of the well, for each well in feet (ft).
SP = Shut-in pressure or surface pressure for wells with tubing production or casing pressure with no packers, in psia; If casing pressure is not available, Partners can multiply the tubing pressure of each well with a casing-to-tubing pressure ratio of a well with no packer from the same sub-basin, in psia.
SFR = Average flow-line rate of gas for well at standard conditions, in cubic feet per hour (scf).
HR_q = Hours that the well was left open to the atmosphere during each unloading event, q (hr).
1.0 = Hours for average well to blowdown casing volume at shut-in pressure (hr).
Z = If HR_q is less than 1.0, then Z_q is equal to 0. If HR_q is greater than or equal to 1.0, then Z_q is equal to 1.

Plunger Lift Unloading Calculation:[7]

$$E_s = \sum_{p=1}^{W} \left[V_p \times \left(\left(0.37 \times 10^{-3}\right) \times TD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p} \left(SFR_p \times \left(HR_{p,q} - 0.5\right) \times Z_{p,q}\right) \right]$$

Where:

E_s = Annual natural gas emissions for each sub-basin at standard conditions, s, in standard cubic feet (scf).
W = Total number of wells with plunger lift assist and well venting for liquids unloading for each sub-basin.
p = Wells 1 through W with well venting for liquids unloading for each sub-basin.
V_p = Total number of unloading events in the monitoring period for each well, p.
0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).
TD_p = Tubing internal diameter for each well, p, in inches.
WD_p = Tubing depth to plunger bumper for each well, p, in feet (ft).
SP_p = Flow-line pressure for each well, p, in psia, using engineering estimates based on best available data.

[6] U.S. EPA. Greenhouse Gas Reporting Program. Subpart W – Petroleum and Natural Gas Systems. Section 98.233: Calculating GHG Emissions. 40 CFR 98.233(f)(1). http://www.ecfr.gov/cgi-bin/text-idx?SID=ba51a263399deb7722bbf4375da8d43f&mc=true&node=se40.23.98_1233&rgn=div8.

SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour (scf/h). Use Equation W-33 of this section to calculate the average flow-line rate at standard conditions.
$HR_{p,q}$ = Hours that each well, p, was left open to the atmosphere during each unloading event, q.
0.5 = Hours for average well to blowdown tubing volume at flow-line pressure.
q = Unloading event.
$Z_{p,q}$ = If $HR_{p,q}$ is less than 0.5 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 0.5 then $Z_{p,q}$ is equal to 1.

Emission Factors:[7] If the direct measurement approach is not selected or is not feasible nor practical, an emission factor approach can be used as an option to engineering equations. An emission factor that represents emissions of methane volume per year per well or per event should be applied for liquids unloading, adjusted for operating parameters. Operating parameters include whether the well does or does not have a plunger lift and the frequency of vented events. Partners are encouraged to use emission factors that best represent conditions and practices at their facilities. Default methane emission factors are provided in Tables 7.2-7.4[8].

Mitigation Methodologies

The following are example mitigation methodologies that may reduce emissions associated with well liquids unloading. Note that each of these mitigation strategies is not universally applicable and will only apply to wells operating under certain conditions, as described in the following sections.

Mitigation Option A – Foaming Agents, Soap Strings, Surfactants

Foaming agents, soap strings and surfactants reduce the density and surface tension of the liquids in the well, thereby reducing the velocity needed for the gas to carry the liquids out of the well. The surfactants are added either as a soap stick or through liquid injection. If the well is deep, injection requires a pump that can be electric, pneumatic, or mechanical.

Operational Considerations
Foam produced by surfactants works best in wells where the liquids comprise 50 percent or more water. The surfactants are not effective when mixed with hydrocarbons, so they should only be selected when producing significant water. Foaming agents generally work best where the rate of liquid accumulation is low.

Surfactants can be delivered to the well as soap sticks or as a liquid directly injected into the casing-tubing annulus. In a shallow well, the surfactant can be delivered by pouring it down the annulus of the well through an open valve. In a deep well, a surfactant injection system will be required (along with regular monitoring). The surfactant injection system includes a surfactant reservoir, a motor valve (usually with a timer, depending on the system design), an injection pump, and a power source

[7] API, ANGA. Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production. Sept 21, 2012. Retrieved from: http://www.api.org/~/media/Files/News/2012/12-October/API-ANGA-Survey-Report.pdf.
[8] "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquids Unloadings." Dr. Allen, University of Texas, Environmental Science & Technology, December 9, 2014.

for the pump. Typically, no equipment is required in the well. Options for pumps include electric, mechanical, and pneumatic. Various pump types have different advantages regarding reliability, precision, efficiency, and maintenance frequency.

If Partners plan to install a surfactant injection system, implementing this technology requires the installation of the following equipment:

- A surfactant reservoir.
- A motor valve (usually with a timer, depending on the system design).
- An injection pump (electric, mechanical, or pneumatic).
- A power source for the pump.

Methane Emission Reduction Estimate
According to Natural Gas STAR's Lessons Learned, the foaming agent saves 178 to 7,394 thousand cubic feet (Mcf) per well per year (5 to 209 thousand cubic meters (Mcm) per well per year) compared to swabbing and blowing down a well.[9]

Economic Considerations
The cost for using a foaming agent depends on whether a pump is necessary. The pump cost can range from $500 to $9,900, and the surfactants cost $500 per month.[10] The economics of foaming agents include the upfront capital cost of the surfactants and potentially a pump, the volume of gas savings if the previous practice was blowing down the well, and the revenue from increased production. Based on partner Natural Gas STAR companies, the increased production using foaming agents ranged from 360 to 1,100 Mcf (10 to 31 Mcm) per well per year.[11] Many other additional costs should be considered, including elimination of well swabbing and electricity.

Mitigation Option B – Velocity Tubing/Strings

The velocity of the gas being produced is a function of the pressure drop and the cross-sectional area of the production tubing. Therefore, one option is to install velocity tubing. Velocity tubing effectively reduces the cross-sectional area of the well, thereby increasing the velocity.

Operational Considerations
Velocity tubing requires relatively low liquid production and a higher reservoir pressure to create the necessary pressure drop. As a rule of thumb, velocity tubing can be effective with velocities above 1,000 feet/minute (ft/min) (305 meters/minute, m/min). As the velocity falls below 1,000 ft/min (305 m/min), such tubing is no longer effective. An Inflow Performance Relationship curve should be used to assess the flow of the well. Foaming agents can be used in conjunction with velocity tubing to extend the effectiveness of velocity tubing at lower velocities.

Wells that are marginal producers are candidates for velocity tubing. Marginal wells are defined as "a producing well that requires a higher price per Mcf or per barrel of oil to be worth producing, due to low production rates and/or high production costs from its location (e.g., far offshore; in deep waters;

[9] EPA. Lessons Learned: *Options for Removing Accumulated Fluid and Improving Flow in Gas Wells.* https://www.epa.gov/sites/production/files/2016-06/documents/ll_options.pdf.
[10] Ibid.
[11] Ibid.

onshore far from good roads for oil pickup and no pipeline) and/or has high co-production of substances that must be separated out and disposed of (e.g., saline water, non-burnable gases mixed with natural gas)."[12]

Implementing this technology requires the installation of:

- Tubing connections

Methane Emission Reduction Estimate

According to Natural Gas STAR's Lessons Learned, velocity tubing saves 150 to 7,400 Mcf per well per year compared to swabbing and blowing down a well.

Economic Considerations

The cost for implementing velocity tubing can range from $7,000 to $64,000 per well. This cost includes the workover rig time, downhole tools, tubing connections, and labor. The economics of velocity tubing include the upfront capital cost, the volume of gas savings if the previous practice was blowing down the well, and the revenue from increased production. According to partner companies in Natural Gas STAR, velocity tubing increases production between 9,125 and 18,250 Mcf/well per year (258 and 517 Mcm/well per year). Other additional costs that should be considered include elimination of well swabbing.

Mitigation Option C – Plunger Lift

A plunger lift system uses the energy of the gas pressure build-up in the casing and reservoir to push a plunger up the well. The plunger acts like a piston to remove undesired liquids from the well. A plunger lift system comprises a lubricator and holding component, a bumper spring at the bottom of the well, and the plunger. This system is used as the velocity decreases, indicated by a change in pressure of the casing. Because the pressure drops as the liquid level increases, the plunger lift is used when the pressure in the casing reaches a predetermined level. The plunger lift can be operated manually, with a mechanical timer, pressure controllers or with an automated "smart" cycle timer system. The gas line is closed off, the plunger drops, the well is shut to allow pressure to build up behind the plunger in the casing, and the well is then opened to the sales line lifting the plunger with the liquids out of the well.

Plunger systems are not always a mitigation technology, since plunger systems can be vented frequently enough to produce higher net emissions than from less frequent manual unloading. Per the above, plunger lifts can be considered mitigation technologies when they are optimized to achieve minimal gas venting.

Operational Considerations

A few conditions must be met before a plunger lift system can be justified. First, fluid removal needs to be necessary to maintain production. As stated previously, this situation is more common in mature wells because of the liquid build-up that occurs over time. Additionally, for the plunger to have the required force, wells must produce 400 scf (11 scm) of gas per barrel of fluid per 1,000 feet (305

[12] Interstate Oil & Gas Compact Commission (2010). Marginal Wells: Fuel for Economic Growth.

meters) of well depth. The shut-in wellhead pressure also needs to be at least 1.5 times the sales line pressure. Wells that have scale or paraffin build-up also are candidates for plunger lifts.

Implementing this technology requires the installation of the following equipment:

- Lubricator
- Plunger catcher and bumper
- Plunger

Methane Emission Reduction Estimate

Example: A well blowdown is estimated to emit 2,000 scf (57 scm) per hour. With a blowdown occurring once every month, the potential reduction is 24 Mscf (0.7 Mscm) per year, assuming 1 hour per blowdown. Overall methane emissions reductions would be the eliminated blowdown emissions minus the estimated venting from a plunger lift operation.

Economic Considerations

EPA's Natural Gas STAR technical document for installing plunger lifts on wells[13] indicates the cost for implementing a plunger lift is estimated to be $1,900 to $7,800 with a maintenance cost of $1,300 per year. The economics of a plunger lift include the upfront capital cost, the maintenance costs, the reduced emissions volume compared to the previous operational practices, and the revenue from increased production. In one example, according to Natural Gas STAR partner company data from 14 sites in Midland Farm Field, Texas, production increased by 91 Mcf/day (2.6 Mcm/day) 30 days after implementing the plunger lift. Depending on the method in place for removing the liquids before a plunger lift, many other additional costs should be considered, including the well treatment costs, electricity savings, and workover costs savings and the salvage value of any previous technology such as a beam lift. The plunger lift has no well treatment costs, has reduced electricity costs, and has reduced workover costs compared to a beam lift. Based on a Natural Gas STAR Partner's experience, installing a plunger lift could have a payback in less than two months and yield excellent gas savings as well as increased gas production.

Mitigation Option Ca – Plunger Lift with Cycle Optimization

Mitigation Option Ca1 – Simple Cycle Optimization.

Where plunger lifts exist and where they vent frequently, Partners can modify the plunger operation by using timers or other controllers that optimize the liquids unloading frequency.

This is essentially a subset or rather predecessor to applying "smart technology" outlined below. A timer or controller (e.g. pressure) may be installed on the well and engage the plunger lift (and liquids unloading events) such that the frequency of events is minimized, but the well is able to produce. Partners may be able to determine the timing in which liquids would build up in the well sufficient to cause the well to cease flowing. A timer could be set to control the frequency of the liquids unloading cycling based on the estimated time the well would fill with liquids. Another option would be to use a pressure controller to minimize the frequency of liquids unloading cycles. In this case, the pressure

[13] EPA. Lessons Learned: *Installing Plunger Lift Systems in Gas Wells.* https://www.epa.gov/sites/production/files/2016-06/documents/ll_plungerlift.pdf

controller would monitor the pressure of the well and the liquids unloading cycle would occur at a set pressure level (near the pressure point in which the well would shut in due to liquid burden).

Operational Considerations

The frequency of liquids unloading cycling would need to be established on a well by well basis. However the operating considerations are similar for plunger lifts since one is only "optimizing" the plunger lift cycles in order to minimize emissions associated with liquids unloading.

Mitigation Option Ca2 – "Smart" Well Technology[15]

Not all plungers vent, and even among those that do occasionally vent, some do not vent frequently. For those that vent frequently, "Smart" Well Technology[15] is an automated system that takes into account well conditions and determines when a plunger lift cycle needs to be actuated to determine optimally when the liquids should be unloaded.

Operational Considerations

The conditions for "smart" technology are the same as those for plunger lifts. Implementing this technology requires the installation of:

- Remote terminal unit with programmable logic controllers
- Tubing and casing transmitters
- Gas measuring equipment
- Control valve
- Plunger detector

Methane Emission Reduction Estimate

Emission reductions are a function of the flowing pressure and operational characteristics and do not lend themselves to generalization. Partners employing this option should determine baseline emissions before implementing this option and then evaluate emissions after implementation to determine emission reductions.

Economic Considerations

The cost for implementing "smart" technology is incremental above plunger lifts. One EPA Natural Gas STAR partner has estimated the cost for smart technology to be $5,700 to $18,000 per well[14]. This technology enables the user to maximize the effectiveness of a plunger lift. The user therefore sees additional increased gas production and therefore additional economic benefit.

Mitigation Option D – Pumps and Compressors

Pumps, gas lift, and wellsite compression may be mitigation measures implemented in some wells to abate venting associated with manual, intermittent and plunger lift liquids unloading in which atmospheric venting occurs.

Downhole Pumps, reciprocating (rod or beam) and rotating (progressive cavity): A rod (or beam) pump, either electric or natural gas, can pump the liquids to the surface. These methods can extend the lifetime of the well beyond that possible with the plunger lift, but will have normal operating and maintenance costs.

Gas Lift: Another potential technique to combat the liquids unloading issue in horizontal wells is gas lift. Gas lift systems send high-pressure gas into the casing of the well, which increases the pressure differential between the bottom of the well and the wellhead. The velocity of gas returning up the

[14] EPA. Lessons Learned: *Options for Removing Accumulated Fluid and Improving Flow in Gas Wells.* https://www.epa.gov/sites/production/files/2016-06/documents/ll_options.pdf.

tubing increases, allowing the gas to carry liquids from the well. The major requirement for gas lift is a readily available high-pressure wellsite compressor.

Sequential Lift: In addition, Muskegon Development Company has used a technology called sequential lift to combat liquid build-up. This technology uses a series of pumps that follow the horizontal well and pump liquids from the well. Muskegon Development Company reports that sequential lift was more effective than gas lift for managing liquids and minimizing emissions from their wells. The Artificial Lift R&D Council (ALRDC) collects and reports developments for horizontal gas wells.[15]

Operational Considerations

Example. A rod pump can remove liquids when there is a lower pressure drop than is needed for a plunger lift to work. Furthermore, the rod pump can remove the liquids regardless of the gas velocity, thereby extending the lifetime of the well beyond other liquid removal techniques.

Implementing this technology requires the installation of:

- Sucker rod and tubing
- Rod guides, or
- Pump, and
- Pump motor

Methane Emission Reduction Estimate

Example. In some cases, rod pumps can save an estimated 770 to 1,600 Mcf/well per year.[16]

Economic Considerations

Example. The cost for implementing a rod pump is estimated to be $25,900 to $51,800 with a maintenance cost of $1,300 to $19,500 per year, well treatment cost of $13,200, and electricity cost of $1,000 to $7,300 per year.[17] The economics of a rod pump include the upfront capital cost, the maintenance costs, and the volume of gas savings if the previous practice was blowing down the well, the revenue from increased or extended production (or both), the electricity cost, and the well treatment costs.

ESTIMATING MITIGATED EMISSIONS

For the purpose of this Technical Guidance Document, it is suggested that mitigated emissions be determined using an emissions hierarchy of direct measurement, engineering equations, and emissions factors.

For wells that employ foaming agents, surfactants, or velocity strings/tubing as a mitigation measure, the estimated mitigated emissions are the estimated emissions of the well prior to the mitigation (e.g. foaming agent) minus the estimated emissions after mitigation.

[15] Artificial Lift R&D Council (ALRDC), Artificial Lift in Horizontal Wells. "Selection of Artificial Lift Systems for Deliquifying Gas Wells" Prepared by Artificial Lift R&D Council. http://www.alrdc.com/recommendations/horizontalartificiallift/index.htm.
[16] Ibid.
[17] EPA. Lessons Learned: *Options for Removing Accumulated Fluid and Improving Flow in Gas Wells.* https://www.epa.gov/sites/production/files/2016-06/documents/ll_options.pdf.

For wells that are manually unloaded, but then converted to plunger lift liquids unloading, the mitigated emissions are the estimated emissions from manually unloading (presuming the same frequency as plunger lift cycles) minus the mitigated estimated emissions associated with plunger lift operations.

For wells that employ liquids unloading cycle optimization (e.g., intermittent timing on non-plunger lift wells and mechanical timers, pressure controllers, or "Smart" well technology on plunger lift wells), the estimated mitigated emissions are the estimated emissions of the well prior to the mitigation measure minus the estimated emissions after mitigation (i.e., reductions are primarily due to the reduced frequency and volume of venting).

For wells that employ or are equipped with liquid unloading methods that remove the liquids (e.g., beam pumps, submersible pumps, cavity pumps, gas lift, wellhead compression) from the well and "mitigate" the need to implement manual, intermittent, or plunger lift unloadings methods, the mitigated emissions would be the estimated emissions prior to mitigation minus estimated emissions after mitigation (which presumably should be zero since this mitigation measure abates the need for liquids unloading).

Emission Factors

Emissions factors for liquids unloading were developed from available public data are summarized in the Tables below.

Table 7.2: Methane Emission Factors for Liquids Unloading (Source: API and ANGA report[18])

Source	Methane Emission Factor	
	(thousand scm/year/well)	(thousand scf/year/well)
Liquids Unloading Venting – without using plunger lifts	9	304
Liquids Unloading Venting – using plunger lifts	14	345

[18] From API, ANGA. Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production. Sept 21, 2012. Retrieved from: http://www.api.org/~/media/Files/News/2012/12-October/API-ANGA-Survey-Report.pdf.

Table 7.3: Methane Emission Factors for Liquids Unloading (Source: Adapted from 2012 and 2013 reports to the US Greenhouse Gas Reporting Program[19])

Source	Methane Emission Factor	
	(scm/year/event)	(scf/year/event)
Liquids Unloading Venting – without using plunger lifts	96.3	3,400
Liquids Unloading Venting – using plunger lifts	4.7	166

Table 7.4: Methane Emissions Factors for Liquids Unloading (Source: UT Study[20])

Source	Methane Emissions Factor		
	scm/event	scf methane/event	Average Events/Year
Liquids Unloading without Plunger Lift (manual venting to atmosphere)			
< 10 events per year	609	21,500	2.9
11 to 50 events per year	682	24,100	20.3
51 to 200 events per year	991	35,000	75.6
Liquids Unloading with Plunger Lift			
Plunger Lift < 100 events/year	273	9,650	7.7
Plunger Lift > 100 events/year	36	1,260	1200

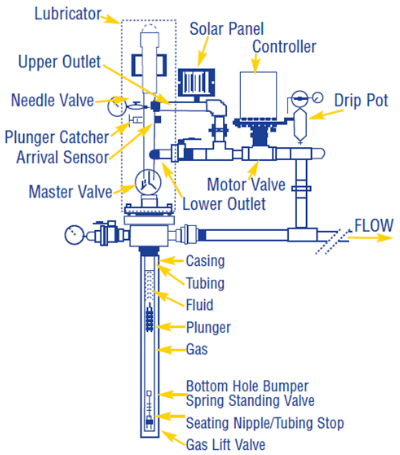
[19] Average of 2012 and 2013 Method 1 liquids unloading emissions for wells with plunger lift from GHGRP reporting to EPA (data released November 30, 2014).
[20] "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquids Unloadings." Dr. Allen, University of Texas, Environmental Science & Technology, December 9, 2014.

Exhibit A – Well Venting for Liquids Unloading[21]

Taken by Arlington Fire Department. From Star-Telegram article

Exhibit B – Well Liquids Unloading with Plunger Lift System[22]

[21] CCAC Oil and Gas Methane Partnership: webinar March 30, 2015: ''Well Venting/Flaring During Well Completion for Hydraulically Fractured Gas Wells and Well Venting for Liquids Unloading,'' presentation by UNEP
[22] Natural Gas STAR Producers Technology Transfer Workshop, College Station, Texas, May 17, 2007: ''Producers Best Management Practices and Opportunities,'' presentation by EPA


Lubricator
Solar Panel
Controller
Upper Outlet
Needle Valve
Drip Pot
Plunger Catcher
Arrival Sensor
Master Valve
Motor Valve
Lower Outlet
FLOW
Casing
Tubing
Fluid
Plunger
Gas
Bottom Hole Bumper
Spring Standing Valve
Seating Nipple/Tubing Stop
Gas Lift Valve


CEO

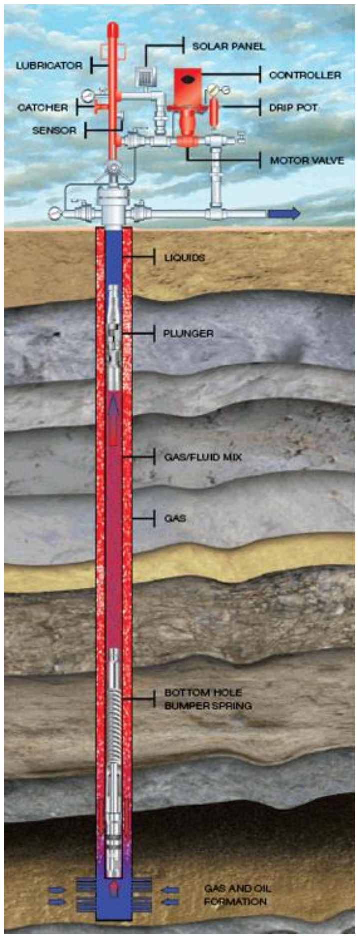
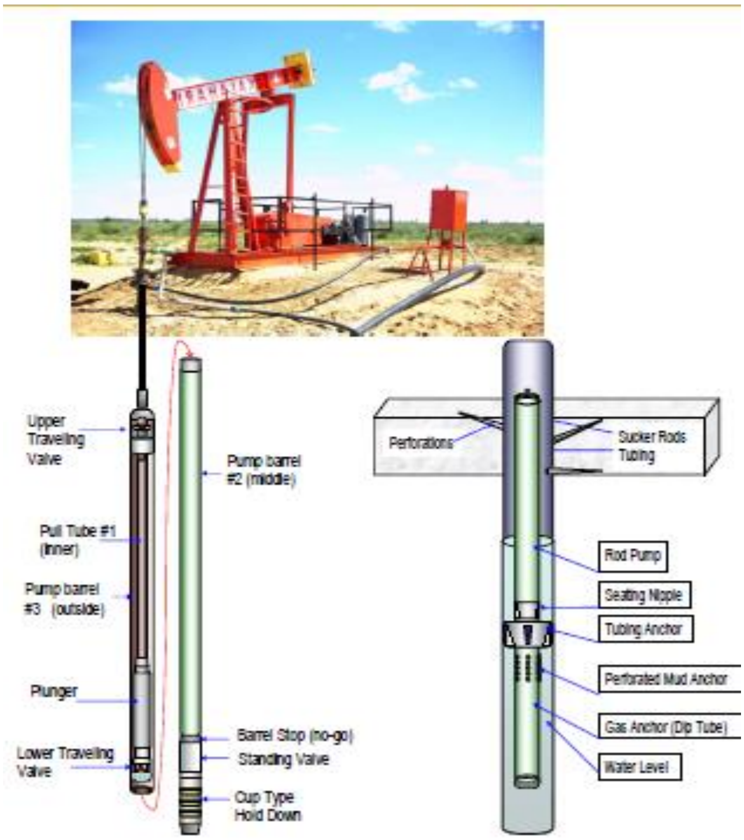

SOLAR PANEL
LUBRICATOR
CONTROLLER
CATCHER
DRIP POT
SENSOR
MOTOR VALVE
LIQUIDS
PLUNGER
GAS/FLUID MIX
GAS
BOTTOM HOLE
BUMPER SPRING
GAS AND OIL
FORMATION

Exhibit C – Well Liquids Unloading with Beam Pump[23]



[23] CCAC Oil and Gas Methane Partnership: webinar March 30, 2015: "Well Venting/Flaring During Well Completion for Hydraulically Fractured Gas Wells and Well Venting for Liquids Unloading," presentation by UNEP

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.

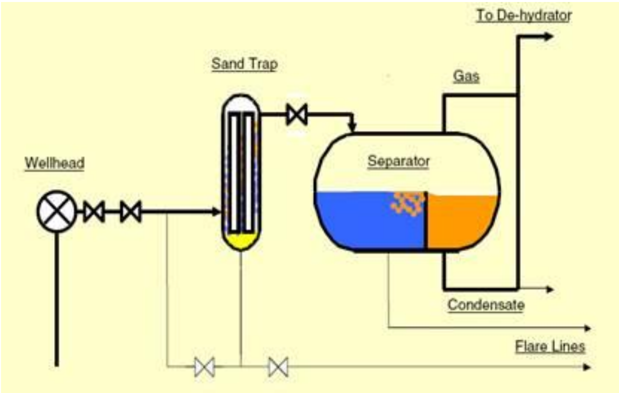
[14] EPA. 2014. Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2012. http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.

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

TECHNICAL GUIDANCE DOCUMENT NUMBER 9: CASINGHEAD GAS VENTING

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 describe 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 stop 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

Casinghead gas is gas that collects in the annular space between the casing and tubing in an oil well. Usually beneficial, casinghead gas forces the produced oil up the tubing. In a mature oil well equipped with a beam pump or electric submersible pump, however, this gas can begin restricting oil flow, decreasing a well's production by vapor locking the pump. Combined with the backpressure of an oil well's surface equipment, pressure from casinghead gas can severely restrict production. Partners must remove casinghead gas pressure build-up in a well's annular space to maintain production. One of the methods to do this is to vent the casinghead gas to the atmosphere at or near the wellhead.
Casinghead gas venting can occur, and may be mitigated, in a variety of ways. Partners are encouraged to identify and deploy appropriate controls for each oil well. Some options include those listed in the following Table 9.1.

For the purposes of the OGMP, Partners will quantify and evaluate for mitigation any configuration presented in Table 9.1 that is identified as "unmitigated" for methane emissions, as described in the sections below. Even for "mitigated" configurations, Partners should evaluate the system to ensure that it is functioning properly and minimizing methane emission levels. Possible equipment failures resulting from improperly functioning systems include a well compressor malfunction, a VRU malfunction, or an extinguished flare. Moreover, Partners should evaluate gases routed to a flare (flow rate, composition) to estimate methane emissions resulting from the flare combustion efficiency.

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

Table 9.1: Configurations for Casinghead Gas Venting

Configuration	Mitigated or Unmitigated
Casinghead gas is vented directly to the atmosphere, either continuously or periodically to relieve pressure build-up. Exhibit A	Unmitigated
Casinghead gas is recovered by a wellhead compressor/vapor recovery unit (VRU) and routed to sales or for on-site use. Exhibit B	Mitigated (if confirmed to be functioning with low[A] or no emissions) **(OPTION A)**
Casinghead gas is routed to tanks with new or existing VRU systems and routed to sales or for on-site use.	Mitigated (if confirmed to be functioning with low[A] or no emissions) **(OPTION B)**
Casinghead gas is routed to a flare.[2] Exhibit C	Mitigated (if confirmed to be functioning with low[A] or no emissions) **(OPTION C)**

[A] Expected emissions levels if mitigation option is in place and functioning properly (e.g., flare is not extinguished, etc.).

<u>Quantification Methodology</u>

To ensure consistent quantification of annual, volumetric, casinghead gas venting emissions and comparable evaluation of mitigation options, the OGMP recommends that Partners use one of the following two quantification methodologies: direct measurement or engineering calculation. In principle, direct measurement is the most accurate method for quantifying methane emissions.[3] With direct measurement, Partners can be more certain of emissions levels and economic costs and benefits (i.e., value of gas saved). As such, measurement is highly encouraged whenever possible. Individual Partners may choose an alternative quantification methodology if judged to be more accurate by the Partner; in this case, the Partner should document and explain the alternative methodology in the Annual Report.

- <u>Direct Measurement</u>[4]:
  These methodologies give the flow rate for total gas, which is then converted to methane flow rate using the methane content of the gas. The methane flow rate then needs to be extrapolated over the

[2] "Flare" in this document refers to a vertical combustion device using an open or enclosed flame.
[3] Partners should conduct measurements with appropriately calibrated instruments and per the instrument manufacturer instructions. Measurements should also be conducted in different operating conditions, to the extent that those can affect emissions levels. Appendix A to the Technical Guidance Documents includes guidance on instrument use. Partners seeking to generate Emission Factors for their operations should use direct measurement based on a statistically sound number of measurements and gas analyses to understand the content of methane and other valuable hydrocarbons.
[4] Greenhouse Gas Reporting Program. Subpart W – Petroleum and Natural Gas Systems. Section 98.234: Monitoring and QA/QC requirements, 40 CFR 98.234(b). http://www.ecfr.gov/cgi-bin/text-idx?SID=82b3acbd3d06d1ee2c38a34ba97f132b&mc=true&node=sp40.23.98.w&rgn=div6#se40.23.98_1234.

entire year. The annual volume of methane emissions is calculated by multiplying the measured methane flow rate by the operating hours of the well.

Determining the point where the casinghead gas is being vented is essential so that accurate measurements can be taken. Typically, an oil wellhead has a designated gas vent line for casinghead gas. Each wellhead setup is unique, however, and a wellhead could have multiple lines for venting casinghead gas. Partners should confirm the locations of all lines before measuring casinghead gas. Recommended measurement tools include the following:

- Turbine meter.
- Hotwire anemometer.
- Vane anemometer.

Viewing all gas lines with an infrared leak-imaging camera (designed to visually identify hydrocarbon emissions) during venting of casinghead gas will also help to identify potential fugitive leak emissions.

For more details regarding each measurement and detection tool, including applicability and measurement methods, please refer to Appendix A.

- Engineering Calculation:
  An engineering calculation relies on a representative sample of well production taken with no casinghead gas venting: i.e. capture all gas and oil entering the well casing. This may be more costly and less accurate than direct measurement, given the sampling method can affect the production rate and composition. From this sample a gas/oil ratio (GOR) may be determined. For mature wells, Partners should use the estimated well's producing GOR (scf/bbl or scm/bbl) multiplied by the production rate of oil per year (bbl/year) and the methane content of the gas to estimate annual methane emissions. Oil wells with casinghead gas venting are typically mature and thus pump nearly "dead" crude from the reservoir. This crude contains a very small amount of dissolved gas, most of which escapes into the casing before the crude is pumped up the tubing to the surface. Periodic venting the casinghead gas often is necessary to avoid vapor locking the down-hole pump.

Mitigation Option A – Install compressors/VRUs to capture casinghead gas.

Partners have found that using a small wellhead reciprocating compressor can facilitate recovery of previously vented casinghead gas to sell or to use on site as fuel. Drawing down the casing pressure can also increase oil production. Traditionally, companies have used a skid-mounted compressor to recover vented gas. Ideally, the compressor would maintain the casinghead gas pressure as close as possible to zero pounds per square inch gauge (psig) without pulling a vacuum. Maintaining a constant zero pressure helps stabilize the oil line pressure and reduces fluctuations in flow. When feasible, multiple wells can be connected to a single compressor to optimize cost.

Partners can use either a wellhead reciprocating compressor or a VRU to recover casinghead gas. Depending on the characteristics and the destination of the recovered gas, one of these options might make more sense than the other. A typical VRU is designed to maintain a suction pressure near-atmospheric pressure. For wet-screw, rotary-vane, or scroll-type, single-stage compressors, the discharge is limited to about 100 psig (7 kg/cm^2) by the compression ratio. If the gas destination is at a pressure greater than 100 psig (7 kg/cm^2), Partner will need to use two-stage compression with intercooling, which might require a reciprocating compressor.

Operational Considerations

For capturing wet casinghead gas at near-atmospheric pressure, a skid-mounted VRU type wellhead compressor is best. Viable compressor types include rotary-vane, rotary-screw, and scroll. For high compression ratios, such as a strong vacuum on the casing or high discharge pressure or both, Partners can use two- or three-stage compression. Rotary-vane compressors generally have proven to be the most cost-effective when handling small volumes of casinghead gas. Casinghead gas typically is wet because it flashes off from the underground oil reservoir that has a specific gravity of around 0.85 (16 gallons of liquid per Mscf gas)[5] (2.1 liters liquid per scm gas). Both rotary-vane and scroll compressors can handle wet gas effectively, but reciprocating compressors generally cannot, so the first stage in multi-stage compression should be one that handles wet gas effectively. All compressors, and all compression stages in multistage compressors, must have a suction scrubber to handle liquid slugs.

Skid-mounted compressors can be powered by an electric motor or a combustion engine, typically ranging from 10 to 200 horsepower (HP). The availability of a power source, either electricity or fuel gas, primarily determines which option is more viable. If electricity is not available, a beam-mounted compressor is an option. Beam-mounted compressors use the mechanical energy from a well's rod pumping unit to pull gas from the casing and discharge it into a flow line. These compressors can be single- or double-acting (able to compress on both strokes). Not all wells respond favorably to reduced casinghead pressure, and there is no quick means to predict the response. Companies might want to test some wells in a reservoir before they purchase or lease compression equipment to determine how the wells will respond. If the response is favorable, testing also can confirm whether the increased productivity is temporary or sustained. Every well and reservoir have different characteristics. Specific gravity, gas volume, and pressure of the discharge line for the casinghead gas are some critical factors that Partners should consider when purchasing or designing a wellhead compressor or VRU. Even wells from the same formation can respond differently to casinghead gas capture, which also points to the need for testing. A general guideline is if oil production increases remain constant 30 to 45 days after testing, venting casinghead gas is appropriate.

Experience has shown that casinghead gas capture typically is more successful for wells with water or carbon dioxide floods. Wells with enhanced oil recovery (where produced gas can be reinjected into the reservoir) also are good candidates for casinghead gas capture. One vendor estimated that approximately 65 percent of mature oil wells are appropriate for casinghead gas capture.[6] To avoid a large pressure drop, the compressor or VRU should not be placed too far from the wellhead.

In some situations, a compressor or VRU can be linked to multiple wells. The connected wells should be located near each other and have similar surface pressures. This will help ensure the compressor or VRU pulls on the wells equally, allowing their surface pressures to be closer to zero psig (zero kg/cm^2) gauge pressure. Also, the closer the wells are to each other and to the compressor or VRU, the smaller the pressure drop will be in the suction flow lines. Partners should take into consideration for this option, however, that depending on a single unit could be problematic when the compressor or VRU is down for repair or maintenance, and gas from several wells requires venting.

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[5] Natural Gas STAR Partner Update. Winter 2010. *Technology Spotlight: Casinghead Gas Capture*. https://www.epa.gov/sites/production/files/2016-06/documents/ngspartnerup_winter10.pdf .
[6] Ibid.

The compressor or VRU to capture casinghead gas would be installed when the well is down. When the adequate sales gas line capacity and/or existing infrastructure for recovered gas is available, the installation requires:

- Piping.
- Equipment to treat liquids (e.g., drip pots, suction scrubber, gas/liquid separator).
- Pressure regulators.
- Wellhead compressor or VRU system (includes suction scrubber/separator; compressor[7]; liquid transfer pump; electric programmable logic controller (PLC); associated discharge piping, instruments, valves, and controls).

Methane Emission Reduction Estimate

In general, Partners can reduce methane emission from casinghead gas venting by approximately 95 percent after implementing this project.[8] Theoretically, compressors or VRUs can recover nearly all casinghead vapors, an operating factor of 95 percent allows for 5 percent annual compressor downtime due to maintenance.

Economic Considerations

The major costs associated with this project are:

- Equipment costs of compressor package/VRU system, piping, liquid treatment equipment, pressure regulators.
- Installation costs.
- Annual operating and maintenance (O&M) costs for electricity or fuel.

Costs will vary among well sites and depend on the compressor type/size, piping distance from the wellhead to the compressor, and distance from the compressor to the destination for the gas. The following scenario example is taken from the Natural Gas STAR technical document *Install Compressors to Capture Casinghead Gas*.[9] Capital costs for connecting casinghead gas to a new compressor would be approximately $12,500 for a 30-HP electric rotary compressor capable of delivering up to 200 Mscf (5.7 Mscm) of gas per day[10] into a 100-psig (7 kg/cm^2) sales line.[11,12] Installation costs are assumed to be 1.5 times the equipment cost, bringing the total implementation cost to nearly $32,000.[13] Additional operating costs would include the electricity to power the compressor, which (assuming the compressor operates for half the year and electricity costs $0.075 per kilowatt-hour (kWh)) would bring the annual operating costs to $7,350.[14]

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[7] Typically electric-driven rotary vane, rotary screw, or scroll compressor. For more information, see Technical Document Number 6 for a description of Hydrocarbon Liquid Storage Tanks.

[8] EPA. 40 CFR Part 60, Subpart OOOO: Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews. Final Rule. pg. 49526. August 16, 2012. http://www.gpo.gov/fdsys/pkg/FR-2012-08-16/pdf/2012-16806.pdf.

[9] EPA. PRO #702: *Install Compressors to Capture Casinghead Gas.* June 2016. https://www.epa.gov/sites/production/files/2016-06/documents/installcompressors.pdf.

[10] Assumes design capacity is double the average vapor recovery rate.

[11] EPA. Lessons Learned: *Installing Vapor Recovery Units on Storage Tanks*. pg. 5. June 2016. https://www.epa.gov/sites/production/files/2016-06/documents/ll_final_vap.pdf.

[12] EPA. PRO #702: *Install Compressors to Capture Casinghead Gas*. pgs. 1, 2. 2016. https://www.epa.gov/sites/production/files/2016-06/documents/installcompressors.pdf.

[13] Ibid.

[14] Ibid.

The primary benefit of this project is the additional revenue received from the increased oil production. Secondary benefits include the sales of previously uncollected associated gas and the reduction in emissions. As illustrated in the example in Table 9.2, the value of the recovered gas would be $104,800 annually based on a gas price of $3 per thousand Standard cubic feet (Mscf) - a quick payback for this project. The value of the increased oil production, however, is likely to be even greater.

Table 9.2: Project Costs and Savings for Casinghead Vent Gas Recovery with a Compressor (Example Scenario)

Project Component	Implementation Costs	Annual Costs
Capital Cost[A]	$12,500	–
Installation Costs[B]	$18,750	–
O&M Costs (Electricity)[C]	–	$7,350
Gas Savings[D]	–	-$104,800
Total	**$31,250**	**-$97,450**

[A] For a 30-HP electric rotary compressor able to deliver up to 200 Mscf (5.7 Mscm) of gas per day to a 100-psig (7 kg/cm^2) sales line.
[B] Assumed to be 1.5 times equipment cost.
[C] O&M = engine horsepower × operating factor × 8,760 hours/year × electricity cost.
[D] Half of design capacity with a 95% operating factor, $3/Mcf gas value.

For more information, see the Natural Gas STAR technical document *Install Compressors to Capture Casinghead Gas* (https://www.epa.gov/sites/production/files/2016-06/documents/installcompressors.pdf).

Mitigation Option B – Connect casing to tanks equipped with vapor recovery units.

Tanks near wells that vent casinghead gas might already have a VRU installed. VRUs can have a wide application at production sites that have crude oil or condensate storage tanks with significant vapor emissions. Partners can take advantage of the similarities in gas composition, pressure, and flow rates between tank emissions and casinghead gas.

Operational Considerations

Partners should take advantage of VRU equipment that is the already available at their sites. Partners also should install pressure regulators if low-pressure casinghead gas is joined with sources having higher pressure (e.g., dehydrator flash tank separator) at the VRU suction point. Connecting casinghead gas to an existing VRU is convenient and cost-effective because only small-diameter piping and pressure regulators are required to join the vent to VRU suction. This project is applicable to wells producing through tubing with packerless completions.[15]

Partners will connect the casinghead gas to a VRU during well downtime to minimize incremental production loss. The connection requires installing:

[15] EPA. PRO #701: *Connect Casing to Vapor Recovery Unit*. pgs. 1, 2. 2016. https://www.epa.gov/sites/production/files/2016-06/documents/connectcasingtovaporrecoveryunit.pdf.

- Piping.
- Pressure regulators.

Methane Emission Reduction Estimate

Theoretically, VRUs can recover nearly all casinghead vapors routed to a storage tank. Based on a VRU operating factor of 95 percent (allowing 5 percent annual downtime of the VRU for maintenance), Partners can expect to reduce methane emissions by up to 95 percent after implementing this technology.[16]

Economic Considerations

Costs for routing casinghead gas to a VRU would be approximately $4,300.[17] Additional operating costs include the increased electricity consumption, reported by Partners to be approximately $3,400 per year (at $0.075 per kWh).[18] As with a newly installed compressor or VRU, cost savings would derive from increased oil production and the capture and sale of previously vented gas. For annual gas savings of 7,800 Mscf (221 Mcm) at $3 per Mscf, the value of the recovered gas would be $23,400. The value of this recovered gas would help pay back the additional electricity and piping costs for this project and the value of the increased oil production is likely to be even greater.

For more information, see the Natural Gas STAR technical document *Connect Casing to Vapor Recovery Unit* (https://www.epa.gov/sites/production/files/2016-06/documents/connectcasingtovaporrecoveryunit.pdf).

Mitigation Option C – Route casinghead gas to flare.

Two possible scenarios for this project are: route to an existing flare or route to a newly installed flare. If an existing flare is within reasonable proximity, however, this scenario is preferred, as routing casinghead gas to an existing flare, provided operational and safety conditions allow, rather than installing a new one is easier and lower cost for Partners. The more casinghead vents that can be routed to a single flare will help improve project viability, in terms of cost versus methane reductions achieved, in addition to other benefits. Partners should route casinghead gas to a recovery outlet whenever possible; sending the gas to a flare should be a last resort. Additionally, in some cases a lit flare might have higher greenhouse gas emissions than an unlit flare, (i.e. taking into account the safety flaring: purge gas and pilot gas burned to ensure the safe operation of the flare), which Partners should take into account when considering implementing this project.

Operational Considerations

A wellhead can have a flare stack for emergency releases, blowdowns, etc. For this project, if a flare is installed, all that would then be required is additional piping to route the casinghead gas vent to the flare. If no flare exists, however, Partners will have to install one. Partners should also consider proximity of the flare to the well(s) when deciding to implement this project.

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[16] EPA. 40 CFR Part 60, Subpart OOOO: Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews. Final Rule. pg. 49526. August 16, 2012. http://www.gpo.gov/fdsys/pkg/FR-2012-08-16/pdf/2012-16806.pdf.

[17] EPA. PRO #701: *Connect Casing to Vapor Recovery Unit*. pgs. 1, 2. 2016. https://www.epa.gov/sites/production/files/2016-06/documents/connectcasingtovaporrecoveryunit.pdf.

[18] Ibid.

Partners would connect casinghead gas to the flare during downtime to minimize incremental production loss. The connection requires installing:

- Piping.
- Flare stack (if there is no existing flare in proximity).

Methane Emission Reduction Estimate

The methane reductions achieved will depend on the combustion efficiency of the flare. For a typical production flare using a continuous ignition source with an independent external fuel supply, Partners can generally expect to reduce methane emissions from casinghead venting by more than 95 percent after implementing this technology.[19]

Economic Considerations

Costs for routing casinghead gas to an existing flare stack likely would be negligible because the primary cost is for additional piping. The operating cost for supplying additional pilot or fuel gas to the flare, if necessary, might be slightly higher. This incremental cost should also be negligible, however, when compared to a Partner's other costs. If a new flare stack and a continuous ignition source are installed, the cost could be approximately $21,000.[20]

[19] EPA. 40 CFR Part 60, Subpart OOOO: New Source Performance Standards (NSPS). Background Technical Support Document (TSD). §60.5412, page 35897. June 2016. https://www.federalregister.gov/documents/2016/06/03/2016-11971/oil-and-natural-gas-sector-emission-standards-for-new-reconstructed-and-modified-sources

[20] EPA PRO Fact Sheet 904: Install Flares, June 2016. https://www.epa.gov/sites/production/files/2016-06/documents/installflares.pdf

Exhibit A – Manually Venting Casinghead Gas[21]

Exhibit B – Casinghead Gas Recovered by a Wellhead Compressor[22]

[21] Global Methane Initiative, Natural Gas STAR International, Bucaramanga, Colombia, May, 2012: "Ecopetrol Eco-Efficiency, Methane Emission Reduction Opportunities," presented by EPA

[22] Natural Gas STAR Annual Implementation Workshop, Denver, Colorado, April 12, 2012: "Salem Unit Casinghead Gas Project," presented by Citation Oil & Gas Corp. and Hy-Bon Engineering

Exhibit C – Casinghead Gas Routed to a Flare[23]

[23] Natural Gas STAR Annual Implementation Workshop, Denver, Colorado, April 12, 2012: "Salem Unit Casinghead Gas Project," presented by Citation Oil & Gas Corp. and Hy-Bon Engineering