NOTE: Please include links to information throughout the document as discussed. We have incorporated changes to the template suggested today. The final template may be different after Adrienne and Sandra review the changes.

NMED/EMNRD METHANE ADVISORY PANEL

COMPLETIONS/ STIMULATIONS REPORT

Discussion for MAP members on August 30, 2019

NOTE: The focus of this report is processes, and the associated equipment, directly related to the release or capture of methane gas. We are not requesting information on processes/equipment that are not related to the release or capture of methane gas.

1. DESCRIPTION OF PROCESS AND EQUIPMENT

Provide a description of the processes and/or equipment used in oil and/or gas extraction for this topic. Note that this report template will be used for all topics of the MAP review and, thus, not all questions or information may be relevant for each topic. If information is not relevant, indicate N/A. Note any differences expected for differing well types, industry sector, or basin location.

Technical description of the process or equipment:

A typical oil or gas well goes through several phases during its life. The first phase is the actual drilling of well. Drilling is followed by completions. After a well is completed the well can produce hydrocarbons for several years or decades. For an existing well, it may be necessary to complete a well stimulation to increase production in case of production decline. In any case, the emissions during completions/stimulations are associated with a relatively short period in a decades-long well life cycle.

All oil and natural gas wells must be “completed” after initial drilling in preparation for production. Oil and natural gas completion activities not only will vary across formations but can vary between wells in the same formation. Well completion activities include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and potentially hydraulically fracturing one or more zones in the reservoir to stimulate production.

Well stimulation is a well intervention performed on an oil or gas well to increase production by improving the flow of hydrocarbons from the reservoir into the well bore. Unconventional gas reservoirs are more dispersed and found in lower concentrations and may require stimulation (such as hydraulic fracturing) to extract hydrocarbons.

In the process of hydraulic fracturing, high-pressure fluid typically water emulsion, or inert gas, with a proppant (sand) is injected into the formation resulting in fractures of the formation rock. Typically, truck mounted pumps are used to inject the high-pressure fluid into the formation. The fracturing process is often carried out in stages on sections of the well tubing or casing. After each section of the well and formation is hydraulically fractured, plugs are inserted in the well prior to fracturing the next section. This process is repeated many times over the length of the wellbore.

Once the fracturing is completed, a workover/completion rig or coil tubing unit is used to drill through the plugs and begin the well cleaning process.

After a new or existing well has been hydraulically fractured and the plugs have been cleaned out, the well begins its flowback process which is primarily water (with additives) or inert gas and proppants. This material has to be evacuated to prepare the well for production. When flowback is initiated, various forces act on the fluid in the well tubing. These include the weight of frac fluid column itself, formation pressure, back pressure from the gas gathering line of the flowback gas and the surface equipment connected to the well. These forces have to be overcome in order for the fluids in the wellbore to come to the surface.

During the flowback, the fracturing fluid or a mix of hydrocarbons and fracturing fluid from the formation come to the surface. As the fracturing fluid flows to the surface, reservoir hydrocarbons and produced water replace the fracturing fluid in the well tubing. Thus, initially the amount of hydrocarbons coming to the surface is very limited. Initial flowback is discussed in the preamble to NSPS Subpart OOOOa regulations and can be found on Page 56630 of the following document: https://www.govinfo.gov/content/pkg/FR-2015-09-18/pdf/2015-21023.pdf. As the fracturing fluid reach the surface, they are processed per New Source Performance Standards (NSPS) regulations, 40 CFR Part 60, Subpart OOOOa which govern the managing of fluids during flowback. In most cases, NSPS OOOOa requires Reduced Emission Completions (RECs) as discussed later. The regulations are available at https://ecfr.io/Title-40/sp40.8.60.oooo_0a .The regulations related to well completions are at 40 CFR §60.5375a.

Useful information on RECs can be found at http://www.ipieca.org/resources/energy-efficiency-solutions/units-and-plants-practices/green-completions/ .

Provide the segment(s) of the industry that the equipment or process is found:

This process is found in the oil and gas production segment of the industry.

Describe how the equipment or process is used:

Reduced emission completions are mandated by NSPS Subpart OOOOa regulations for both gas and oil wells with some exceptions for certain well types. In many cases, the flowback is first routed to a solids separator (often called a sand trap). This is necessary since some of the sand that is injected in the hydraulic fracturing process comes back to the surface along with the injected water. Removal of solids is needed to prevent damage to downstream equipment. From the solids separator the fluid can be routed to additional separators where gas, oil, and water can be separated. Once gas quality is such that it can meet specifications for gas sales, it is typically routed to a sales line unless it is technically infeasible to do so. In that case, gas must be combusted until there is a fire hazard or a negative impact to tundra, permafrost or waterways.

Provide the common process configurations that use this equipment or process:

Typical equipment used in flowback can include sand separator, two or three phase separators, frac tanks, tanks, completion combustion device, or permanent production-phase equipment. Depending upon the amount of flowback expected and the availability of equipment to be used during production, flowback can be routed to temporary equipment or the permanent equipment. The flowback period typically lasts for days or a few weeks following which the well transitions to a production phase. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. NSPS Subpart OOOOa has different gas capture requirements for initial flowback and separator flowback. During initial flowback, gas may be vented if it is technically infeasible for a separator to function (i.e., any gas present in the initial flowback stage is not subject to control under NSPS OOOOa). During separator flowback all gas must be recovered and sold or rescued if technically feasible to do so. If not technically feasible, it must be routed for combustion. NSPS Subpart OOOOa hydraulic fracturing requirements are now in place for all hydraulic fracturing operations onshore in the U.S..

What is the distribution of the equipment or process across business segments?

This process primarily relates to the onshore oil and gas production sector.

How has this equipment or process evolved over time?

Hydraulic fracturing itself has used since the 1940's in the industry

There are many reported instances where industry started voluntarily using reduced emission completions (REC). EPA's Natural Gas STAR program has reports of RECs since the 2004. These voluntary activities resulted in reduced emissions as reported by various operators. Additional information about the Natural Gas STAR program and reduced emission completions can be found at
https://www.epa.gov/sites/production/files/2016-06/documents/reduced_emissions_completions.pdf
https://www.epa.gov/sites/production/files/2017-09/documents/greencompletions.pdf

Federal regulations first addressed emission associated with completions in the 2012 NSPS regulations at 40 C.F.R. Part 60 Subpart OOOO: https://www.ecfr.gov/cgi-bin/text-idx?node=sp40.7.60.oooo . These regulations require the use of RECs to completions at gas wells following hydraulic fracturing. NSPS Subpart OOOOa, finalized in 2016, requires RECs for oil wells as well.

2. INFORMATION ON EQUIPMENT OR PROCESS COSTS, SOURCES OF METHANE EMISSIONS, AND REDUCTION OR CONTROL OPTIONS

Identify the capital and operating costs for the equipment or the process. Identify how methane is emitted or could be leaked into the air. Please **prioritize** the list to identify first the largest source of methane from the process or equipment and where there is **potential** for the greatest reduction of methane emissions. Note any differences expected for differing well types, industry sector, or basin location.

Sources of Methane:

Provide an overview of the sources of methane from this equipment or process:

During the hydraulic fracturing process itself, injection of water, or inert gas, and proppant is handled by pumps powered by engines. This process itself lasts only a few days per well depending upon the well stimulation design. The emissions during the actual hydraulic fracturing are combustion emissions associated with diesel usage.

The flowback period involves the return to surface of the fracking fluids, or inert gas, as well as some formation hydrocarbons. This is the primary source of methane emissions for completions activity. NSPS Subpart OOOOa requires that, when feasible, hydrocarbons are captured and sent to sales or combusted if sales are not technically feasible.

New Wells:

New wells that fall into the category of wildcat or delineation, wells or low-pressure wells are allowed to route the recovered gases during flowback to a completion combustion device. In this case, the emissions of methane are due to uncombusted methane from the combustion device.

Low pressure wells may also be exempted from sending entrained gas to sales instead sending the full stream of production to a well completion vessel or frac tank.

New wells that do not fall into the wildcat or delineation, category are required to route gas emissions of saleable gas to a gas sales line unless it is technically infeasible to do so, in which case the gas must be sent to a completion combustion device.

Existing Wells:

The same requirements apply to refracturing at existing wells as for new wells. It is however, less likely that existing wells will meet the definitions of a wildcat well. Note there may be technical infeasibility due to reservoir low pressure to operate control equipment on the surface.

The Grant Schreiber study (below), based on Gas Capture Plans submitted by operators in San Juan and Rio Arriba Counties in November 2018, found that 100% of Gas Capture Plans provided for either venting or flaring of recompletions—with 68.5% of recompletions vented and 31.5% of recompletions flared.

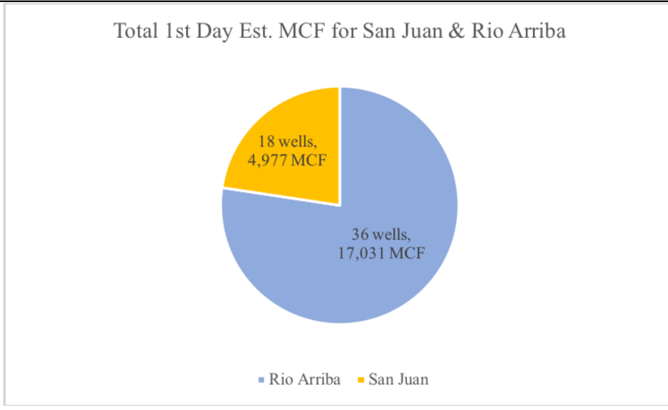
Grant-Schreiber Study

Grant Schreiber Summary of OCD Gas Capture Plans San Juan/Rio Arriba recompletions. November, 2018
Government source: OCD online/Dist. 3 office Reports of data: OCD Gas Capture Plans example attached
Published peer review: NA
Published non-peer: NA
Unpublished: NA

Date	MCF Rio Arriba / Day	MCF San Juan / Day	Vented or Flared
1/11/18	686		V
	500		F
	500		F
	500		F
	356		V
	431		V
	686		V
	500		F
	500		F
	500		F
		390	V
	502		V
	245		V
1/25/18	500		F
	500		F
2/8/18	500		F

	500		F
	500		F
	500		F
	450		F
	302		V
	234		V
	200		V
	347		V
		162	V
3/8/18	302		V
	500		F
	300		V
	180		V
	500		F
	360		V
5/3/18		300	V
	500		V
	500		V
	500		V
	500		V
	500		V
		310	V
5/17/18	500		V
	500		V
		310	F
		300	V
		300	V
		340	V
		290	V
	450		V
	500		V
		295	V
		310	F
7/12/18		290	V
		310	V
8/23/18		310	V
		310	V
11/15/18		450	V
Total MCF	(36 wells) 17,031	(18 wells) 4,977	* ** ***

*68.5% of recompletions (37 wells) are vented
**31.5% of recompletions (17 wells) are flared



Note on the study: During the Methane Advisory Panel's discussion about data located in OCD Gas Capture Plans, Director Sandoval cautioned that Gas Capture Plan data should not be used to characterize emissions that may occur after recompletions. Data entered into the Gas Capture Plans reflect estimates made prior to the project taking place and are merely estimated volumes of what could happen to produced gas. Accordingly, vented and flared volumes represented in Gas Capture Plans are estimates of what could be potentially vented or flared if there isn't a gathering or sales pipeline in place for the pipeline quality gas and are not accurate. Director Sandoval instead instructed panel members to use information on production accounting reports from the OCD when discussing green completion emissions. The data from the production accounting reports reflects actual data points following completion and are far more accurate. In addition, the data from the Grant Schreiber study as described contains no context or other explanation regarding controls, volumes, timing or whether the venting or flaring was conducted pursuant to regulation.

How are the emissions calculated for this equipment or process?

Emissions from this source can be calculated using the EPA GHG reporting rule (Subpart W) or at https://ecfr.io/Title-40/sp40.23.98.w. These are reported to EPA in accordance with the GHG reporting rule. Equations for estimating emissions from well venting during completions and workovers with hydraulic fracturing are given at 40 CFR 98.233(g), Equations W-10A and W-10B.

What data is available to quantify emissions/waste for this equipment?

EPA has discussed emissions from this source in Section 1 of the Technical Support Document for the NSPS OOOO regulation found here: https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-4550 .

In 2017, the total methane emissions reported from Petroleum and Natural Gas Systems for the entire country were 88 million metric tons CO_2e. The onshore production sector reported approximately half or 44 million metric tons CO_2e. Of these, well completion and workovers with hydraulic fracturing reported approximately 1 million metric tons CO_2e. This number is an approximation from the sector summary. Thus, the methane emissions from the well completions sector are approximately 2% of total methane emissions from the onshore production sector or approximately 1% of total methane emissions from the Petroleum and Natural Gas Systems sector.
https://www.epa.gov/sites/production/files/2018-10/documents/subpart_w_2017_industrial_profile.pdf

Allen et al (2013), University of Texas and Environmental Defense Fund (EDF) study did actual measurements from 27 completions in various areas of the country. The study can be found here:
https://www.pnas.org/content/110/44/17768

The duration of the flowbacks in their study ranged from 5 hours to 2 weeks. Measured emissions of methane over an entire completion averaged to be about 1.7 metric tons methane with a range of 0.01 to 17 metric tons. They extrapolated these values to come up with estimates of national methane emissions from completions ranging from 0.125 million metric tons of CO_2e to 0.675 million metric tons of CO_2e with an average of 0.45 million metric tons of CO_2e. These are less than the EPA GHG reported number of approximately 1 million metric tons CO_2e for 2017.

What are the data gaps in quantifying emissions/waste for this equipment?

These emissions are estimated and reported in accordance with the GHG reporting rule.

Economic Description of the Process or Equipment:

What is the per unit cost of the equipment or the costs associated with the process?

The total cost of completion events including hydraulic fracturing greatly varies depending upon the well, hydraulic fracturing setup, length of flowback, availability of permanent equipment, sales line availability and quality of gas.

The cost of RECs with and without combustion has been discussed in detail in the Technical Support Documents to the EPA NSPS Subparts OOOO and OOOOa regulations. The costs are with and without any anticipated savings from sale of recovered gas. Note that the Technical Support Documents provide economic date that is generalized across the Onshore industry for both gas (2012) and oil (2015) wells, and that this data is not specific to New Mexico.

The Technical Support Document for NSPS OOOO regulations discusses emissions and control options in Sections 1 through 4 of
https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-4550

The Technical Support Document for NSPS OOOOa regulations discusses emissions and control options in Section 3 of
https://www.regulations.gov/contentStreamer?documentId=EPA-HQ-OAR-2010-0505-7646&attachmentNumber=6&contentType=pdf

Detail spreadsheet about the costs associated with the controls is found in this attachment to the Technical Support Document:
https://www.regulations.gov/contentStreamer?documentId=EPA-HQ-OAR-2010-0505-7646&attachmentNumber=14&contentType=excel12book

Note that in certain circumstances that the Technical Support Documents are no longer representative in that the economic data is not always reflective of current design, but they do have the best data we have thus far. The oil and gas completions and stimulation industry is regularly evolving. While traditional stimulation activities and equipment exist, the data does not take into account permanent facility utilization.

What are the annualized operating costs for the equipment or costs associated with the process?

See above

If the equipment or process is powered, what are the costs?

See above

What is the useful life of the equipment?

The REC and rig/stimulation equipment is used for several hours or weeks during the completion, stimulation and flowback operations. Well servicing, coil tubing and stimulation equipment have a useful life primarily based upon the power unit, but is also limited based upon technological advances requiring a different tool for the job.

What are the maintenance and repair requirements for existing or new equipment?
Maintenance costs are included in the cost of the equipment above.

Existing Reduction Strategies:

How has industry reduced emissions/waste from this equipment or process historically?
NSPS requirements have been applicable to completions following hydraulic fracturing for gas wells since 2012 and for oil wells since 2016. Prior to 2012, while many operators practiced voluntary RECs, various configurations were prevalent including allowing the flowback to flow into frac tanks with the gas being vented or combusted.

Voluntary reductions from completions with hydraulic fracturing are also discussed in Section 5.0 of the NSPS OOOO Technical Support Document at: https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-4550

There are many reported instances where industry started voluntarily using reduced emission completions. EPA's Natural Gas STAR program has reports of RECs since the 2004. These voluntary activities resulted in reduced emissions as reported by various operators. Additional information about the Natural Gas STAR program and reduced emission completions can be found at
https://www.epa.gov/sites/production/files/2016-06/documents/reduced_emissions_completions.pdf
https://www.epa.gov/sites/production/files/2017-09/documents/greencompletions.pdf

New Wells:
Existing Wells:
How have the emission/waste reductions been measured?
Emissions from completions are reported annually to EPA's GHG reporting program. Based on industry sector summaries of Petroleum and Natural Gas systems, the methane emissions from completions have decreased from approximately 7 million metric tons CO_2e in 2012 to approximately 1 million metric ton CO_2e in 2017. References for the above estimates are found on Pages 7 and 9 respectively of the following documents:
https://www.epa.gov/sites/production/files/2015-07/documents/petroleumandnaturalgassystemsector2012.pdf
https://www.epa.gov/sites/production/files/2018-10/documents/subpart_w_2017_industrial_profile.pdf

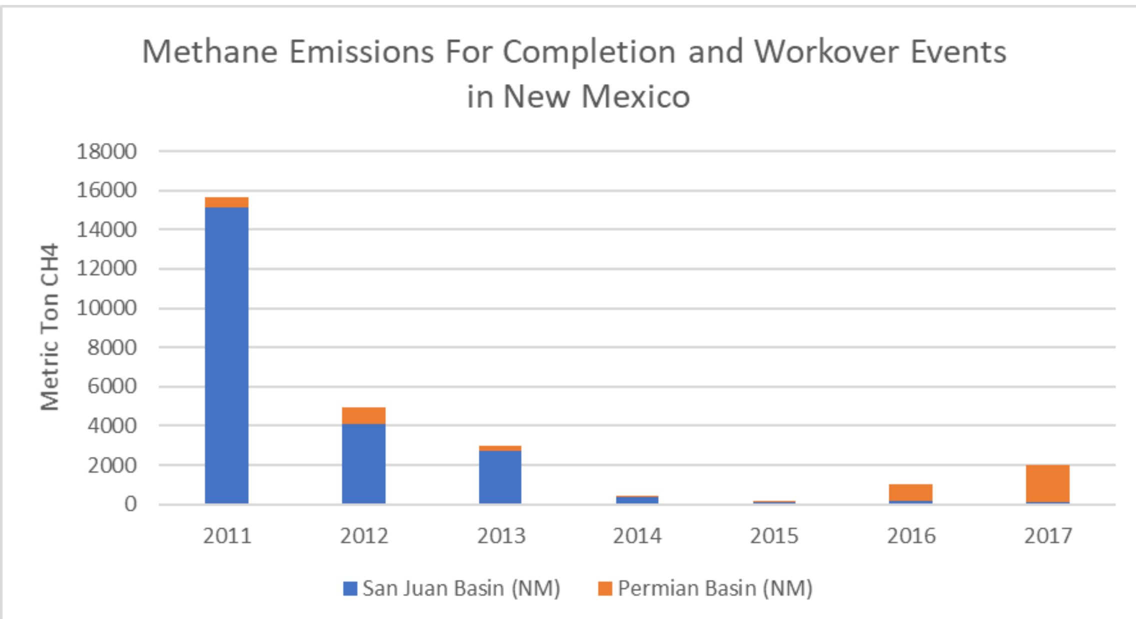
EPA's GHG Emissions database EnviroFacts allows for download and additional analysis of reported GHG emissions. The database can be accessed here:
https://www.epa.gov/enviro/greenhouse-gas-customized-search

While nationally emissions have decreased, in the Permian Basin, total GHG emissions (including both CO_2 and methane) from completions have increased from approximately 82,481 million metric tons CO_2e in 2015 to approximately 615,096 million metric tons CO_2e in 2016 and 974,877 million metric tones in 2017. Further, the CO_2e figures are converted from raw methane at a GWP of 25 rather than the current 100-year GWP recognized by the IPCC of 36 suggesting that, along with the 25,000 metric ton GHGRP reporting threshold, the EPA figures represent a potentially significant underestimation of completion emissions.

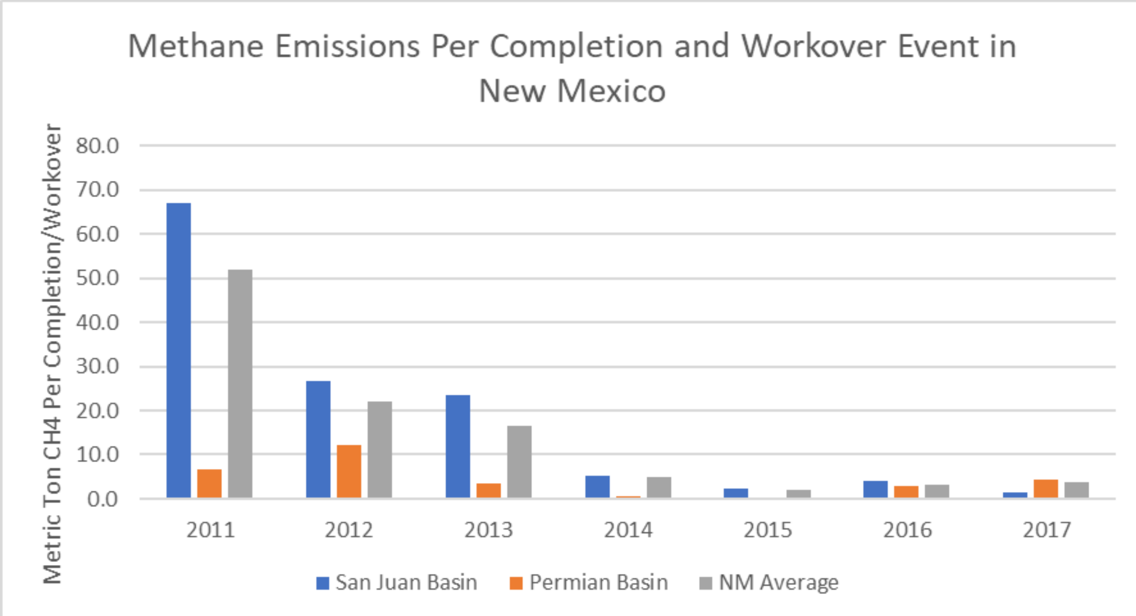
In 2017, as reported to EPA and downloaded from EPA's EnviroFacts database, emissions associated with completions and workovers in the Permian basin are 7,773 metric tons of methane relative to 184,941 metric tons of methane from all sources in the onshore petroleum and natural gas production sector for Permian basin. Thus, the emissions are approximately 4% of the total onshore production sector emissions.

Completion and workover emissions with hydraulic fracturing for New Mexico for 2017 were downloaded from the EnviroFacts Database and are as follows.
San Juan Basin (NM only)– 124 metric tons methane
Permian Basin (NM only) - 1867 metric tons methane
NM emissions for both basins – 1994 metric tons methane

The trend from methane emissions associated with completions and workover emissions with hydraulic fracturing is shown in the chart



On a per-completion basis, methane emissions are as follows:

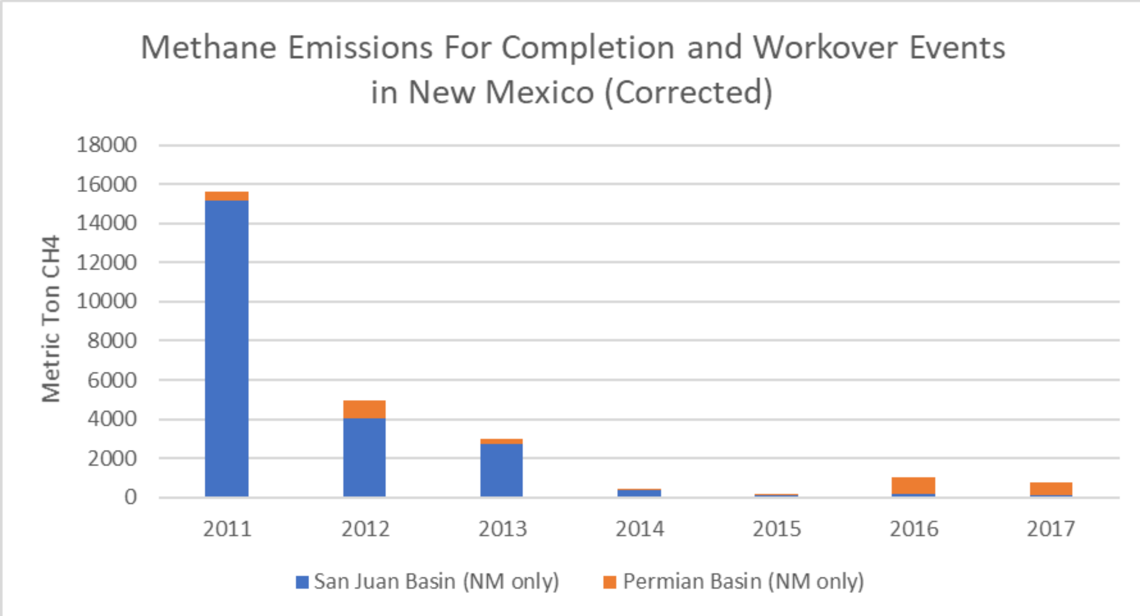


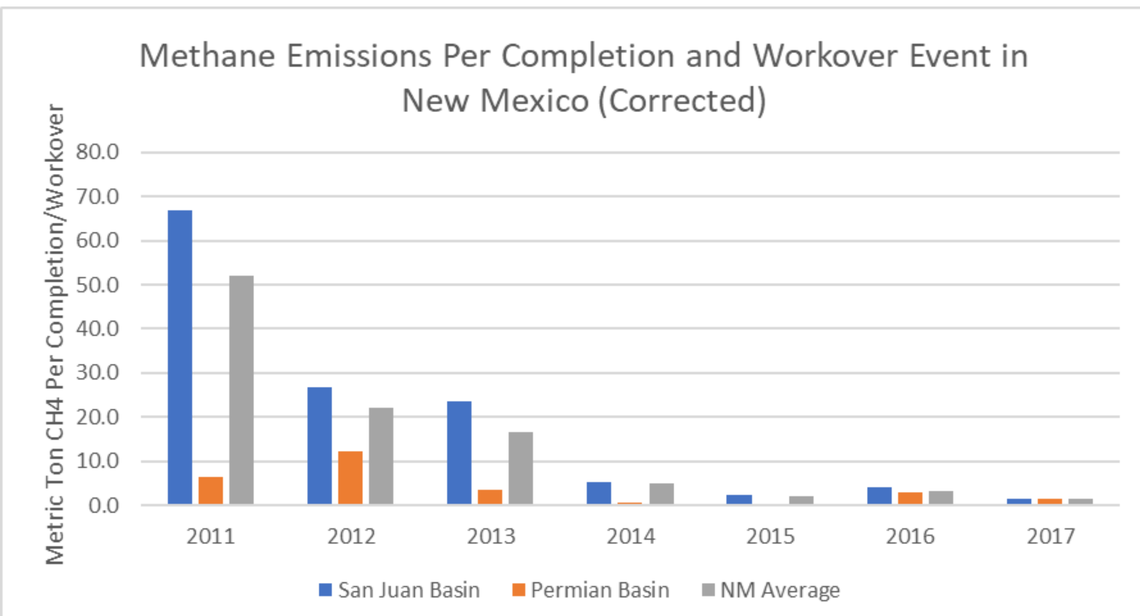
Further analysis of the data indicated an operator had relatively elevated emissions compared to the number of completions. When contacted, the operator revealed that some of the reported emissions were in error and that corrected data has been submitted to EPA. However, the EPA database has not been updated with the corrected data as of September 2017.

Using the corrected data the emissions are as follows:

San Juan Basin (NM only)– 124 metric tons methane
Permian Basin (NM only) - 645 metric tons methane (instead of 1867 metric tons methane)
Total NM for both basins – 769 metric tons methane (instead of 1994 metric tons methane)

The revised charts are presented below:





<u>How have states and the federal government reduced emissions/waste from this equipment or process historically? In addition, please identify voluntary reductions achieved whether or not they were in response to a regulatory action/requirement.</u>

Voluntary reductions were achieved by operators as reported to EPA's Natural Gas Star program and have been discussed earlier in this document.

Completions following hydraulic fracturing have to meet the emission standards outlined in federal NSPS regulations. NSPS OOOO regulations (2012) addressed emissions from gas wells. NSPS OOOOa regulations (2015) added oil well requirements for completions beginning November 2016.

The requirements for completions in the NSPS OOOOa regulations can be found at https://ecfr.io/Title-40/sp40.8.60.oooo_0a.

The regulations related to well completions are at 40 CFR §60.5375a. In addition, the federal register notice contains information about the requirements for completions. https://www.govinfo.gov/content/pkg/FR-2015-09-18/pdf/2015-21023.pdf
.

In general, the regulations classify completions at four categories of wells:

1. Nonwildcat and non-delineation wells
2. Wildcat and delineation wells
3. Low pressure wells
4. Low gas-oil ratio (GOR) wells

Non-wildcat and non-delineation wells
For these wells, the flowback period of a well completion has been defined as consisting of two distinct stages, the ‘‘initial flowback stage’’ and the ‘‘separation flowback stage.’’ The initial flowback stage begins with the onset of flowback and ends when the flowback is routed to a separator. Routing of the flowback to a separator is required as soon as a separator is able to function (i.e., the operator must route the flowback to a separator unless it is technically infeasible for a separator to function). Any gas in the flowback prior to the point at which a separator begins functioning is not subject to control. The point at which the separator can function marks the beginning of the separation flowback stage. During this stage, the operator must do the following, unless technically infeasible to do so as discussed below: (1) Route all salable quality gas from the separator to a gas flow line or collection system; (2) re-inject the gas into the well or another well; (3) use the gas as an onsite fuel source; or (4) use the gas for another useful purpose that a purchased fuel or raw material would serve. If the operator assesses all four options for use of recovered gas, and still finds it technically infeasible to route the gas as described, the operator must route the gas to a completion combustion device with a continuous pilot flame and document the technical infeasibility assessment. No direct venting of gas is allowed during the separation flowback stage unless combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways.

Wildcat and Delineation wells
A wildcat well, also referred to as an exploratory well, is a well drilled outside known fields or is the first well drilled in an oil or gas field where no other oil and gas production exists. A delineation well is a well drilled to determine the boundary of a field or producing reservoir.
For these wells regulations require either (1) routing all flowback directly to a completion combustion device with a continuous pilot flame (which can include a pit flare) or, at the option of the operator, (2) routing the flowback to a well completion vessel and sending the flowback to a separator as soon as a separator will function and then directing the separated gas to a completion combustion device with a continuous pilot flame. For option 2, any gas in the flowback prior to the point when the separator will function is not subject to control. In either case, combustion is not required if combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways.

Low Pressure wells
Low pressure well means a well that satisfies at least one of the following conditions: (1) The static pressure at the wellhead following fracturing but prior to the onset of flowback is less than the flow line pressure at the sales

meter; (2) The pressure of flowback fluid immediately before it enters the flow line, is less than the flow line pressure at the sales meter; or (3) Flowback of the fracture fluids will not occur without the use of artificial lift equipment.

Regulatory standards for low pressure wells are the same as that for a wildcat well.

Low GOR wells
While subject to the rule, wells with a GOR of less than 300 scf of gas per stock tank barrel of oil produced have no well completion requirements. The reason for the proposed threshold GOR of 300 is that based on industry experience separators typically do not operate at a GOR less than 300. Though in theory any amount of free gas could be separated from the liquid, in reality this is not practical given the design and operating parameters of separation units operating in the field.

A majority of the wells in New Mexico that are undergoing completions at this time fall into the non-wildcat and non-delineation wells and the full requirements of the NSPS regulations, i.e., REC and combustion devices apply to these wells.

Use of combustion devices
On Pages 56628 and 56629 of the Federal Register notice (see reference below) EPA has discussed the infeasibilty of traditional combustion devices such as flares or enclosed combustion devices because the flowback following hydraulic fracturing consists of liquids, gases and sand in a high-volume, multiphase slug flow.
https://www.govinfo.gov/content/pkg/FR-2015-09-18/pdf/2015-21023.pdf

What are examples of process changes/modifications that reduce or eliminate emissions/waste from this equipment or process?

Some operators have been voluntarily practicing reduced-emission completions for this source over the past several years. These reductions have been reported to the EPA Natural Gas Star program:
https://www.epa.gov/sites/production/files/2016-06/documents/reduced_emissions_completions.pdf
https://www.epa.gov/sites/production/files/2017-09/documents/greencompletions.pdf

Furthermore, federal requirements apply to all new completions. While there are exemptions from the full REC requirements for some types of completions it would be technically infeasible to extend the full REC requirements to exploratory, low-pressure, or low GOR wells.

Technology Alternatives:

List of technology alternatives with link to information or contact information for the company/developers.

Name/Description of Technology	Link (and contact info for company if available)	Availability	Feasibility	Cost Range (choose one)
		In use or in development		Low Medium High

Would new technology or equipment be needed to reduce methane emissions?

As discussed earlier most well completions are subject to the NSPS REC requirements. Additional control requirement for non-wildcat and non-exploratory wells are not easily identifiable. In addition, at this stage, it is not evident that there are technology options available to extend the full REC requirements to exploratory, low-pressure, or low-GOR wells.

What technology alternatives exist to reduce or detect emissions?
At this stage, it is not clear what additional technology alternatives exist to reduce emissions further from these wells.

What are the pros and cons of the alternatives?
NA

What is needed and available for new wells?
NA

What is needed and available for existing wells?
NA

What technology alternatives exist for this equipment or process itself?
NA

What are the pros and cons of the alternatives?
NA

Costs of Methane Reductions:

What is the cost to achieve methane emission reductions?
NA

What would be the implementation cost?
For new wells?
NA
For existing wells?
NA

Are there low-cost solutions available?
NA

If a solution is high-cost, why is that the case?
NA

Are there additional technical analyses needed to refine benefits/costs estimates?
NA

3. IMPLEMENTATION

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

Implementation Feasibility:

What is the feasibility of implementation (availability of required technology or contractors, potential permitting requirements, potential for innovation)?

Reduced emission completion technology has been required for all gas completions since 2012 and for all completions since 2016 with limited exceptions outlined in the regulations. This is an accepted process and is readily available for most completions across the country.

What is the useful life of equipment?

Completion activities typically last from several days to several weeks. Depending upon the specific circumstances, operators have the option of using either (permanent) equipment installed for production purposes or rental equipment. If rental, operators source this equipment for the expected duration of completion activities.

What are the maintenance and repair requirements for equipment required for methane reduction?

The separators and any temporary equipment including frac tanks is sourced by the operator prior to the commencement of flowback following completion activities. Perhaps the most critical aspect of the flowback period is the necessity to remove sand using an effective sand separator to prevent damage to downstream equipment.

How would emissions be detected, reductions verified and reported?

Operators continue to report emissions from flowback activities in accordance with EPA GHG reporting program.

4. CHALLENGES AND OPPORTUNITIES TO ACHIEVE METHANE REDUCTION IN NEW MEXICO

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

What regulatory gaps exist for this equipment or process? Are there regulatory gaps filled by the proposed implementation?

As discussed earlier, NSPS standards apply to essentially all completions across the country. Due to technical considerations, wildcat, low-pressure, and low-GOR wells are not required to meet the same standards as non-wildcat and non-delineation wells. For technical feasibility reasons, it is important to have these different standards for completions at these special categories of wells. EPA considered and ultimately did not require prior approval for the technical feasibility exemptions for reasons discussed in the previously referenced preamble to the NSPS OOOOa regulations.

EPA requires operators to record the basis for a claim of technical infeasibility to comply with the reduced emission completion requirement, and to provide the recorded information to EPA in an annual compliance report. 40 C.F.R. Section 60.5420a(c). There is no requirement that operators notify EPA, or the delegated state agency, prior to claiming an exception. One potential improvement to the federal requirements would be for the state to require operators to notify the state prior to claiming an exception from the reduced emission completion requirement. The notice could require the same information EPA currently requires operators record as the basis for the exception claim. The state could require approval of an exception claim prior to completions commencing. This would provide more information to the state as to how many operators are claiming exceptions, and the reasons for such claims. Additional oversight as to the grounds for exception requests could lead to additional emission reductions were the state to find that some exception requests are not warranted (e.g., increased coordination between upstream and midstream operators prior to drilling may lead to the availability of gas pipeline infrastructure being in place prior to completions, thereby making reduced emission completions technically feasible).

Other considerations or comments (e.g. particular design or technological challenges/opportunities, non-air environmental impacts, etc?):

NA