Natural Gas STAR
Methane Challenge Program:
Onshore Production, Gathering and Boosting, Processing, and Transmission and Storage Supplementary Technical Information

Updated 3/9/16

Contents

Introduction

This document provides additional details to augment the Natural Gas STAR Methane Challenge Program ("Methane Challenge") Best Management Practices (BMP) Commitment Framework and Partnership Agreement documents released January 21, 2016.[1] This document provides additional information for emission sources for the onshore production, gathering and boosting, processing, and transmission and storage segments, including source descriptions, detail on mitigation options, and Greenhouse Gas Reporting Program (GHGRP) and voluntary reporting data elements that would be reported annually to the EPA to track partner progress. Where multiple mitigation options are listed, Partners can choose to implement any combination of these throughout their operations to meet their commitments.

Methane Challenge Program Reporting

The EPA will collect the following information from partner companies as part of annual reporting to provide context for participation in the Program and facilitate annual tracking of progress:

- List of included facilities that report to Subpart W (facility ID)
- List of included facilities not reporting to Subpart W (a process will be developed for generating a facility ID for facilities that do not report to Subpart W)
- List of facilities acquired/divested during the reporting year

In the following sections of this document, for each emission source, the "Reporting" table summarizes the Data Elements the Methane Challenge Program will utilize to track partner company progress towards their commitments, including the following information:

- **Emission Source**: For each Emission Source that a company has committed to address[2], the company will provide information on all occurrences of that source across company/unit operations. Data collection will include both unmitigated sources and sources that have implemented mitigation options (including supplementary information for those sources that have eliminated emissions completely).
- **Quantification Method**: For each Emission Source, there is a corresponding method or methods to quantify methane emissions.
- **Data Elements Collected via Facility-Level Reporting:** The table lists data elements to be reported by Partners, and indicates those already collected through GHGRP Subpart W reporting. Facilities not already reporting to Subpart W would report Data Elements through a supplemental reporting mechanism. Facilities already reporting to Subpart W would provide only supplemental data elements through the supplemental reporting mechanism.

In addition, annual reports will provide an opportunity for reporting optional, qualitative information to provide context for their progress each year.

[1] The Methane Challenge Program: Best Management Practices (BMP) Framework document can be found on the Natural Gas STAR website at http://www3.epa.gov/gasstar/documents/MethaneChallenge_BMP_Framework.pdf.
[2] Partners will only provide supplemental data for sources for which they have made commitments.

For reporting purposes, the Methane Challenge Program will utilize the same segment and facility definitions as Subpart W (see Appendix A). Data will be reported at the facility level. Annually, the EPA will compile the data collected and publicly release (on the Program website) all non-confidential data submitted either to the Methane Challenge Program[3] or through the GHGRP to track the progress of individual Partner companies in meeting their Program commitments.

Description of Emission Sources

Centrifugal Compressors - Venting

Source Description: Centrifugal compressor means any equipment that increases the pressure of a process natural gas by centrifugal action, employing rotating movement of the driven shaft. In wet seal centrifugal compressors, high-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated; the centrifugal compressor wet seal degassing vent releases emissions when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas. This source is focused on centrifugal compressors with wet seals.

Mitigation Options:

- Route wet seal degassing to a capture system for beneficial use to achieve at least a 95% reduction in methane emissions, or
- Route wet seal degassing to flare or control device[4] to achieve at least a 95% reduction in methane emissions, or
- Convert wet seals to dry seals or use centrifugal compressors with dry seals.

Commitment Timeframe: Partners commit to implement the specified mitigation options for all sources included in their commitment by their designated commitment achievement date, not to exceed five (5) years from the commitment start date.

Reporting – Gathering and Boosting:

Emission Source	Quantification Method	Data Elements Collected via Facility-Level Reporting	GHGRP
Centrifugal compressors	Wet Seal Oil Degassing Vent EF[5]	Number of centrifugal compressors with wet seal oil degassing vents	X
		Annual CH4 emissions (mt CH_4)	X
Centrifugal compressors with dry seals	NA	Number of centrifugal compressors with dry seals	
Voluntary action	Difference in emissions	Number of wet seal compressor de-gassing vents routed to VRU or beneficial use during reporting year	

[3] All Methane Challenge supplemental data must be non-confidential.
[4] Control device means any equipment used for oxidizing methane vapors. Such equipment includes, but is not limited to, enclosed combustion devices, flares, boilers, and process heaters.
[5] 40 CFR 98.233(o)(10)

to reduce methane emissions during the reporting year	before and after mitigation[6]	Number of wet seal compressor de-gassing vents routed to flare or control device during reporting year	
		Number of wet seal compressors converted to dry seal[7]	
		Methodology used to quantify reductions	
		Emission reductions from voluntary action (mt CH_4)	

Reporting – Processing and Transmission and Storage

Emission Source	Quantification Method	Data Elements Collected via Facility-Level Reporting[8]	GHGRP
Each centrifugal compressor with wet seals	NA	Unique name or ID for the compressor	X
		Number of wet seals	X
		Hours in operating mode	X
		Which, if any, compressor sources are part of a manifolded group of compressor sources	X
		Indicate all of the following that apply to wet seal degassing emissions from the compressor during the year:	
		Emissions are vented to the atmosphere	
		Emissions are routed to flare	X
		Emissions are captured for fuel use or routed to a thermal oxidizer	X
		Emissions are routed to vapor recovery for beneficial use other than as fuel	X
		Compressor in not-operating-depressurized-mode all year (Y/N)	
Centrifugal compressors with dry seals	NA	Number of centrifugal compressors with dry seals	
Centrifugal compressor with wet seal degassing vented to the atmosphere	As found or continuous measurement in operating mode of individual compressor wet seal degassing vent[9] [10]	Unique name or ID for the compressor	X
		Unique name or ID for the individual vent to the atmosphere	X
		Flow rate based on measurement type:	
		a. As found: Measured flow rate (scfh)	X
		b. Continuous: Measured volume of flow during the reporting year (MMscf)	X
		Annual CH_4 emissions (mt CH_4)	X
	Site-specific	Unique name or ID for the compressor	X
		Unique name or ID for the individual vent to the atmosphere	X

[6] Partners can use a methodology of their choosing to calculate voluntary methane emission reductions from this source and must specify what that methodology is.
[7] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013, Table A-136: 2013 Data and CH4 Emissions [Mg] for the Natural Gas Processing Stage
[8] Subpart W requires facilities to report certain information per compressor and other information per vent. Information reported per individual compressor vent is also specific to that one compressor.
[9] 40 CFR 98.233(o)(1)(i)(A), (o)(2)(ii), (o)(6)(i), and (o)(11)
[10] 40 CFR 98.233(o)(1)(ii), (o)(3), (o)(7), and (o)(11)

	EF[11]	Reporter EF (scfh)	X
		Number of measured compressors (during the current year and the 2 previous years) from which the reporter EF was developed	X
		Annual CH_4 emissions (mt CH_4)	X
Voluntary action to reduce methane emissions during the reporting year	Difference in emissions before and after mitigation[12]	Number of wet seal compressor de-gassing vents routed to VRU or beneficial use during reporting year	
		Number of wet seal compressor de-gassing vents routed to flare or control device during reporting year	
		Number of wet seal compressors converted to dry seal	
		Emission reductions from voluntary action (mt CH_4)	

Reciprocating Compressors - Rod Packing Vent

Source Description: Reciprocating compressor means a piece of equipment that increases the pressure of a process natural gas by positive displacement, employing linear movement of a shaft driving a piston in a cylinder. Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere. Rod packing emissions typically occur around the rings from slight movement of the rings in the cups as the rod moves, but can also occur through the "nose gasket" around the packing case, between the packing cups, and between the rings and shaft. As the rings wear, or if the fit between the rod packing rings and rod is too loose, more compressed natural gas can escape.

Mitigation Options:
- Replace the reciprocating compressor rod packing every 26,000 hours of operation, or
- Replace the reciprocating compressor rod packing prior to every 36 months, or
- Route rod packing vent to a capture system for beneficial use to achieve at least a 95% reduction in methane emissions, or
- Route rod packing vent to flare or control device[13] to achieve at least a 95% reduction in methane emissions.

Commitment Timeframe: Partners commit to implement the specified mitigation options for all sources included in their commitment by their designated commitment achievement date, not to exceed five (5) years from the commitment start date.

Reporting – Gathering and Boosting:

[11] The site-specific emissions factor approach is used when an as found measurement for the compressor is conducted in not-operating-depressurized-mode during the year (and an as found measurement is not conducted in operating mode). The site-specific emissions factor is developed from as found measurements of individual seal oil degassing vent emissions from other compressors during the same year and the 2 previous years. 40 CFR 98.233(o)(1)(i)(A), (o)(2)(ii), (o)(6), and (o)(11)

[12] As calculated per the specified emission quantification methodologies for each source.

[13] Control device means any equipment used for oxidizing methane vapors. Such equipment includes, but is not limited to, enclosed combustion devices, flares, boilers, and process heaters.

<table>
<tr><th>Emission Source</th><th>Quantification Method</th><th>Data Elements Collected via Facility-Level Reporting</th><th>GHGRP</th></tr>
<tr><td rowspan="2">Reciprocating compressors</td><td rowspan="2">Reciprocating compressor venting EF[14]</td><td>Number of reciprocating compressors</td><td>X</td></tr>
<tr><td>Annual CH4 emissions (mt CH_4)</td><td>X</td></tr>
<tr><td rowspan="3">Each reciprocating compressor</td><td rowspan="3">NA</td><td>Is rod packing replacement occurring every 26,000 hours or 36 months (Y/N)</td><td></td></tr>
<tr><td>Date of last rod packing replacement</td><td></td></tr>
<tr><td>Number of operating hours since rod packing replacement</td><td></td></tr>
<tr><td rowspan="5">Voluntary action to reduce methane emissions during the reporting year</td><td rowspan="5">Difference in emissions before and after mitigation[15]</td><td>Number of reciprocating compressors with rod packing vents routed to VRU or beneficial use during reporting year</td><td></td></tr>
<tr><td>Number of reciprocating compressors with rod packing vents routed to flare or control device during reporting year</td><td></td></tr>
<tr><td>Number of reciprocating compressors for which rod packing was replaced during reporting year</td><td></td></tr>
<tr><td>Methodology used to quantify reductions</td><td></td></tr>
<tr><td>Emission reductions from voluntary action (mt CH_4)</td><td></td></tr>
</table>

<u>Reporting – Processing and Transmission and Storage</u>

<table>
<tr><th>Emission Source</th><th>Quantification Method</th><th>Data Elements Collected via Facility-Level Reporting[16]</th><th>GHGRP</th></tr>
<tr><td rowspan="14">Each reciprocating compressor</td><td rowspan="14">NA</td><td>Unique name or ID for the reciprocating compressor</td><td>X</td></tr>
<tr><td>Hours in operating-mode</td><td>X</td></tr>
<tr><td>Hours in standby-pressurized-mode</td><td>X</td></tr>
<tr><td>Hours in not-operating-depressurized-mode</td><td>X</td></tr>
<tr><td>Is rod packing replacement occurring every 26,000 hours or 36 months (Y/N)</td><td></td></tr>
<tr><td>Date of last rod packing replacement</td><td></td></tr>
<tr><td>Number of operating hours since rod packing replacement</td><td></td></tr>
<tr><td>Which, if any, compressor sources are part of a manifolded group of compressor sources</td><td>X</td></tr>
<tr><td>Indicate all of the following that apply to rod packing venting emissions from the compressor during the year:</td><td></td></tr>
<tr><td>Emissions are vented to the atmosphere</td><td></td></tr>
<tr><td>Emissions are routed to vapor recovery</td><td>X</td></tr>
<tr><td>Emissions are routed to flare</td><td>X</td></tr>
<tr><td>Emissions are captured for fuel use or routed to a thermal oxidizer</td><td>X</td></tr>
<tr><td>Emissions are part of a manifolded group of compressor sources</td><td>X</td></tr>
</table>

[14] 40 CFR 98.233(p)(10)

[15] Partners can use a methodology of their choosing to calculate voluntary methane emission reductions from this source and must specify what that methodology is.

[16] Subpart W requires facilities to report certain information per compressor and other information per vent. Information reported per individual compressor vent is also specific to that one compressor.

Emission Source	Quantification Method	Data Elements Collected via Facility-Level Reporting[16]	GHGRP
		Compressor in not-operating-depressurized-mode all year (Y/N)	
Reciprocating compressor rod packing individual atmospheric vents	As found measurement or continuous measurement in operating mode of individual compressor[17] [18]	Unique name or ID for the compressor	X
		Unique name or ID for the individual vent to the atmosphere	X
		Flow rate based on measurement type:	
		a. As found: Measured volumetric flow at standard conditions from the rod packing vent (scfh)	X
		b. Continuous: Measured volumetric flow at standard conditions from the rod packing vent (MMscf)	X
		Annual CH_4 emissions (mt CH_4)	X
	Site-specific EF[19]	Unique name or ID for the compressor	X
		Unique name or ID for the individual vent to the atmosphere	X
		Reporter EF (scfh)	X
		Number of measured compressors (during the current year and 2 previous years) from which the reporter EF was developed	X
		Annual CH_4 emissions (mt CH_4)	X
Voluntary action to reduce methane emissions during the reporting year	Difference in emissions before and after mitigation[20]	Number of reciprocating compressors with rod packing vents routed to VRU or beneficial use during reporting year	
		Number of reciprocating compressors with rod packing vents routed to flare or control device during reporting year	
		Number of reciprocating compressors for which rod packing was replaced during reporting year	
		Emission reductions from voluntary action (mt CH_4)	

Natural Gas Continuous Bleed Pneumatic Controllers

Source Description: Natural gas pneumatic controllers are automated instruments actuated by pressurized natural gas used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Continuous bleed means a continuous flow of pneumatic supply natural gas to the process control device (e.g. level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator. Pneumatic controllers in this document are equivalent to pneumatic devices as defined in the GHGRP.

This source focuses on continuous high-bleed controllers (those with natural gas bleed rate greater than 6 standard cubic feet per hour). This source does not cover operational situations in which pneumatic controllers with a bleed rate greater than 6 standard cubic feet (scf) per hour are required based on

[17] 40 CFR 98.233(p)(1)(i)(A), (p)(2)(ii), (p)(6)(i), and (p)(11)
[18] 40 CFR 98.233(p)(1)(ii), (p)(3), (p)(7), and (p)(11)
[19] The site-specific emissions factor approach is used when an as found measurement for the compressor is conducted in standby-pressurized-mode or in not-operating-depressurized-mode during the year (and an as found measurement is not conducted in operating mode). The site-specific emissions factor is developed from as found measurements of individual rod packing vent emissions from other compressors during the same year and the 2 previous years. 40 CFR 98.233(p)(1)(i)(A), (p)(2)(ii), (p)(6), and (p)(11).
[20] As calculated per the specified emission quantification methodologies for each source.

functional needs, including but not limited to response time, safety and positive actuation. Partner companies would track and report pneumatic controllers operating under these exceptions. Intermittent bleed pneumatic controllers are not included in this source category.

Mitigation Options:

- Utilize natural gas-actuated pneumatic controllers with a continuous bleed rate less than or equal to 6 scf of gas per hour, or
- Utilize zero emitting controllers (e.g. instrument air, solar, electric, or mechanical controllers), or
- Remove natural gas pneumatics controllers from service with no replacement.

Commitment Timeframe: Partners commit to implement the specified mitigation options for all sources included in their commitment (except those specifically exempted) by their designated commitment achievement date, not to exceed five (5) years from the commitment start date.

Reporting:

Emission Source	Quantification Method	Data Elements Collected via Facility-Level Reporting[21]	GHGRP
Natural gas-actuated controllers with a bleed rate greater than 6 scf per hour	Subpart W Emission Factor(EF)[22]	Actual count of high-bleed pneumatic controllers[23]	X
		Average operating hours per high-bleed controller (hr/yr)	X
		Total CH_4 emissions from high-bleed controllers (mt CH_4)	X
		Number of high-bleed controllers claiming operational exemptions	
		Rationale for operational exemption	
Natural gas-actuated controllers with a bleed rate less than or equal to 6 scf per hour	Subpart W EF[24]	Actual count of low-bleed pneumatic controllers[25]	X
		Average operating hours per low-bleed controller (hr/yr)	X
		Total CH_4 emissions from low-bleed controllers (mt CH_4)	X
Voluntary action to reduce methane emissions during the reporting year	Difference in emissions before and after mitigation[26]	Number of high-bleed controllers converted to low-bleed	
		Number of high-bleed controllers converted to zero emitting or removed from service	
		Number of low bleed controllers converted to zero emitting or removed from service	
		Emission reductions from voluntary action (mt CH_4)	

Fixed Roof, Atmospheric Pressure Hydrocarbon Liquid Storage Tanks

Source Description: Atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced

[21] Pneumatic device data for onshore production and gathering and boosting facilities is aggregated at the basin level for reporting under subpart W, which is equivalent to reporting at the facility level. Data for the transmission compression and underground storage industry segments are aggregated at the facility level.
[22] 40 CFR 98.233(a)
[23] This source is equivalent to GHGRP "pneumatic devices"
[24] 40 CFR 98.233(a)
[25] This source is equivalent to GHGRP "pneumatic devices"
[26] As calculated per the specified emission quantification methodologies for each source.

liquids from onshore petroleum and natural gas production and gathering and boosting facilities.

Mitigation Options:

- Route gas to a capture system (e.g. a vapor recovery unit or VRU) for beneficial use[27] to achieve at least a 95% reduction in methane emissions[28], or
- Route gas to a flare or control device[29] to achieve at least a 95% reduction in methane emissions.

Commitment Timeframe: Partners commit to implement the specified mitigation options for all sources included in their commitment by their designated commitment achievement date, not to exceed five (5) years from the commitment start date.

Reporting

Emission Source	Quantification Method	Data Elements Collected via Facility-Level Reporting[30]	GHGRP
For gas-liquid separators or gathering and boosting non-separator equipment (e.g., stabilizers, slug catchers) with annual average daily throughput of oil greater than or equal to 10 barrels per day, and for wells flowing directly to atmospheric storage tanks without passing through a separator with throughput greater than or equal to 10 barrels per day: • Tanks venting to atmosphere • Tanks routing gas to a flare • Tanks routing gas to capture system for beneficial use	Subpart W calculation methods 1 or 2, adjusted as needed for vents routed to VRU (beneficial use) or flare[31]	Sub-Basin ID or county ID, as applicable depending on the industry segment	X
		Calculation method used	X
		Count of atmospheric tanks that vent directly to the atmosphere	X
		Count of atmospheric tanks with vapor recovery system emission control measures	X
		Count of atmospheric tanks with flaring emission control measures	X
		Annual CH_4 emissions from flashing in atmospheric tanks venting directly to the atmosphere (mt CH_4)	X
		Annual CH_4 emissions from flashing in atmospheric tanks equipped with vapor recovery systems (mt CH_4)	X
		Annual CH_4 emissions from flashing in atmospheric tanks that control emissions with flaring (mt CH_4)	X
For hydrocarbon liquids flowing to gas-liquid separators or non-separator equipment or directly to atmospheric storage tanks with throughput of oil less than 10 barrels/day: • Tanks venting to the	Subpart W calculation method 3, adjusted as needed for vents routed to VRU (beneficial use) or	Sub-Basin ID or county ID, as applicable depending on the industry segment	X
		Count of tanks that vent directly to atmosphere	
		Count of tanks equipped with vapor recovery system emission control measures	
		Count of tanks with flaring emission control measures	X

[27] Beneficial use means routing natural gas for use such that the gas is not vented to the atmosphere or flared. This includes natural gas reinjection, electricity generation, natural gas liquefaction, and natural gas sales.
[28] May be used in conjunction with a vapor recovery tower.
[29] Control device means any equipment used for oxidizing methane vapors. Such equipment includes, but is not limited to, enclosed combustion devices, flares, boilers, and process heaters.
[30] For reporting under subpart W, atmospheric tank counts and emissions data are aggregated at the sub-basin level for onshore production facilities, and at the county level for onshore gathering and boosting facilities.
[31] 40 CFR 98.233(j)(1); 40 CFR 98.233(j)(2)

Emission Source	Quantification Method	Data Elements Collected via Facility-Level Reporting[30]	GHGRP
atmosphere • Tanks with gas routed to a flare • Tanks with gas routed to a capture system for beneficial use	flare[32]	Annual CH_4 emissions from venting direct to atmosphere (mt CH_4)	
		Annual CH4 emissions from flashing in tanks equipped with vapor recovery systems (mt CH4)	
		Annual CH4 emissions from flashing in tanks that control emissions with flaring (mt CH_4)	X
Voluntary action to reduce methane emissions during the reporting year	Difference in emissions before and after mitigation[33]	Number of tanks routed to VRU or beneficial use	
		Number of tanks routed to flare or controls device	
		Emission reductions from voluntary action (mt CH_4)	

Transmission Pipeline Blowdowns between Compressor Stations

Source Description: Blowdown means the release of gas from a pipeline or section of pipeline that causes a reduction in system pressure or a complete depressurization.

Mitigation Options:

- Route gas to a compressor or capture system for beneficial use, or
- Route gas to a flare, or
- Route gas to a low-pressure system by taking advantage of existing piping connections between high- and low-pressure systems, temporarily resetting or bypassing pressure regulators to reduce system pressure prior to maintenance, or installing temporary connections between high and low pressure systems, or
- Utilize hot tapping, a procedure that makes a new pipeline connection while the pipeline remains in service, flowing natural gas under pressure, to avoid the need to blow down gas.

Partners commit to maximize blowdown gas recovery and/or emission reductions through utilization of one or more of these options to reduce methane emissions from non-emergency blowdowns by at least 50%[34] from total potential emissions each year. Total potential emissions equals calculated emissions from all planned maintenance activities in a calendar year[35], assuming the pipeline is mechanically evacuated or mechanically displaced using non-hazardous means down to atmospheric pressure and no mitigation is used.[36]

Commitment Timeframe: Partners commit to achieve the specified annual reduction rate by their designated commitment achievement date, not to exceed five (5) years from the commitment start date, and maintain at least that rate moving forward.

[32] 40 CFR 98.233(j)(3)
[33] As calculated per the specified emission quantification methodologies for each source.
[34] Partners are encouraged to designate a higher reduction rate.
[35] Total potential emissions amounts will likely be different each year.
[36] The reference to atmospheric pressure is intended to assist in defining total potential emissions, not an indication that companies must reduce pressure to atmospheric pressure for every blowdown.

Reporting:

Emission Source	Quantification Method	Data Elements Collected via Facility-Level GHGRP Reporting[37]	GHGRP
Pipeline blowdowns between compressor stations[38]	Subpart W Method 1, based on volume, temperature, and pressure[39]	Total number of blowdowns per equipment or event type[40]	X
		Total CH_4 emissions (mt CH_4) per equipment or event type	X
	Subpart W Method 2, based on measurement[41]	Total number of blowdowns	X
		Total CH_4 emissions (mt CH_4)	X
Voluntary action to reduce methane emissions during the reporting year	Difference in potential and actual emissions[42]	Total number of blowdowns	
		Number of blowdowns that routed gas to a:	
		Compressor or capture system for beneficial use	
		Flare[43]	
		Low-pressure system	
		Number of hot taps utilized that avoided the need to blowdown gas to the atmosphere	
		Total potential emissions (mt CH_4)	
		Emission reductions from voluntary action (mt CH_4)	

Liquids Unloading

At this time, EPA is not finalizing BMP commitment details for this source. Details for this source will be released as soon as they are available.

[37] Under Calculation Method 1, subpart W requires aggregated reporting of blowdown counts and emissions per equipment or event type at the facility level. Under Calculation Method 2, subpart W requires aggregated reporting of the emissions per facility, but the number of blowdown events or number of stacks monitored is not reported. For transmission pipeline facilities, subpart W also requires reporting the total number of blowdown events and total emissions aggregated over both methods at the state level.

[38] Emergency blowdown events are not included in this source for the BMP Option.

[39] 98.233(i)(2), based on the volume of pipeline segment between isolation valves and the pressure and temperature of the gas within the pipeline

[40] Event types are as follows: pipeline integrity work (e.g., the preparation work of modifying facilities, ongoing assessments, maintenance or mitigation), traditional operations or pipeline maintenance, equipment replacement or repair (e.g., valves), pipe abandonment, new construction or modification of pipelines including commissioning and change of service, operational precaution during activities (e.g. excavation near pipelines), and all other pipeline segments with a physical volume greater than or equal to 50 ft3.

[41] 98.233(i)(3), based on the measurement of emissions using a flow meter

[42] As calculated per the specified emission quantification methodologies for each source.

[43] 98.233 (n) provides flaring quantification guidance.

Appendix A: Segment and Facility Definitions

Onshore Production

For purposes of the Methane Challenge Program, onshore petroleum and natural gas production means all equipment on a single well-pad or associated with a single well-pad (including but not limited to compressors, generators, dehydrators, storage vessels, engines, boilers, heaters, flares, separation and processing equipment, and portable non-self-propelled equipment, which includes well drilling and completion equipment, workover equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This equipment also includes associated storage or measurement vessels, all petroleum and natural gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island. Onshore petroleum and natural gas production also means all equipment on or associated with a single enhanced oil recovery (EOR) well pad using CO_2 or natural gas injection.

A facility means all natural gas equipment on a single well-pad or associated with a single well-pad and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in 40 CFR 98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

Gathering and Boosting

For purposes of the Methane Challenge Program, onshore petroleum and natural gas gathering and boosting means gathering pipelines and other equipment used to collect petroleum and/or natural gas from onshore production gas or oil wells and used to compress, dehydrate, sweeten, or transport the petroleum and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline, or a natural gas distribution pipeline. Gathering and boosting equipment includes, but is not limited to, gathering pipelines, separators, compressors, acid gas removal units, dehydrators, pneumatic devices/pumps, storage vessels, engines, boilers, heaters, and flares. Gathering and boosting equipment does not include equipment reported under any other industry segment defined in subpart W. Gathering pipelines operating on a vacuum and gathering pipelines with a gas to oil ratio (GOR) less than 300 standard cubic feet per stock tank barrel (scf/STB) are not included in this industry segment (oil here refers to hydrocarbon liquids of all API gravities).

A gathering and boosting facility for purposes of reporting under Methane Challenge means all gathering pipelines and other equipment located along those pipelines that are under common ownership or common control by a gathering and boosting system owner or operator and that are located in a single hydrocarbon basin as defined in 40 CFR 98.238. Where a person owns or operates more than one gathering and boosting system in a basin (for example, separate gathering lines that are not connected), then all gathering and boosting equipment that the person owns or operates in the basin would be considered one facility. Any gathering and boosting equipment that is associated with a single gathering and boosting system, including leased, rented, or contracted activities, is considered to be under common control of the owner or operator of the gathering and boosting system that contains the pipeline. The facility does not include equipment and pipelines that are part of any other industry segment defined in subpart W.

Natural Gas Processing

For purposes of the Methane Challenge Program, natural gas processing means the separation of natural gas liquids (NGLs) or non-methane gases from produced natural gas, or the separation of NGLs into one or more component mixtures. Separation includes one or more of the following: forced extraction of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or the capture of CO_2 separated from natural gas streams. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing plant. This industry segment includes processing plants that fractionate gas liquids, and processing plants that do not fractionate gas liquids but have an annual average throughput of 25 MMscf per day or greater.

A natural gas processing facility for the purposes of reporting under the Methane Challenge is any physical property, plant, building, structure, source, or stationary equipment in the natural gas processing industry segment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

Natural Gas Transmission Compression & Underground Natural Gas Storage

For purposes of the Methane Challenge Program, onshore natural gas transmission compression means any stationary combination of compressors that move natural gas from production fields, natural gas processing plants, or other transmission compressors through transmission pipelines to natural gas distribution pipelines, LNG storage facilities, or into underground storage. In addition, a transmission compressor station includes equipment for liquids separation, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression that is part of onshore natural gas processing plants are included in the onshore natural gas processing segment and are excluded from this segment.

Underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs

A natural gas transmission compression facility or underground natural gas storage facility for the purposes of reporting under the Methane Challenge is any physical property, plant, building, structure, source, or stationary equipment in the natural gas transmission compression industry segment or underground natural gas storage industry segment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

Onshore Natural Gas Transmission Pipeline

For purposes of the Methane Challenge Program, onshore natural gas transmission pipeline means all natural gas pipelines that are a Federal Energy Regulatory Commission rate-regulated Interstate pipeline, a state rate-regulated Intrastate pipeline, or a pipeline that falls under the "Hinshaw Exemption" as referenced in section 1(c) of the Natural Gas Act, 15 I.S.C. 717-717(w)(1994).

An onshore natural gas transmission pipeline facility for the purpose of reporting under the Methane Challenge is the total U.S. mileage of natural gas transmission pipelines owned or operated by an onshore natural gas transmission pipeline owner or operator. If an owner or operator has multiple pipelines in the United States, the facility is considered the aggregate of those pipelines, even if they are not interconnected.