

MiQ STANDARD

for Methane Emissions Performance

MAIN DOCUMENT – Gathering & Boosting and
Processing

v1.1.0





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1 Background

1.1 Introduction

Methane emissions (CH₄) from oil and gas facilities are a significant contributor to climate change. Methane, the primary component of natural gas, is a very potent Greenhouse Gas (GHG) with a short-term climate impact over 80 times that of carbon dioxide [1]¹. While methane is emitted throughout both the oil and natural gas supply chains, this Standard only addresses methane emissions from the natural gas gathering and boosting and processing segments.

Methane is emitted from natural gas gathering and boosting, and processing (G&B,P) facilities through Intended and Unintended Emissions. While technologies and processes that can prevent or significantly reduce methane emissions are well known, emissions abatement actions, whether voluntary or enforced through regulation, are not yet occurring with the sufficient consistency or scale necessary to limit global warming to the 1.5 degrees put forward in the Paris Agreement.

The MiQ Standard for Methane Emissions Performance (the Standard) combines several Standard elements – (1) a calculated Methane Intensity, (2) Operator policies and procedures focused on methane emissions prevention, detection, and abatement (Company Practices), and (3) detection and mitigation of methane emissions through Monitoring Technology Deployment – to provide a robust and reliable method to certify the emissions from natural gas facilities according to its methane emissions performance. The Standard is designed to incentivize continuous improvement in methane emissions monitoring and abatement.

The Standard consists of three main types of documents, to be read in the following order:

1. **Main Document – G&B,P (this document)**
2. **Subsidiary Documents**
 - a. *Subsidiary Document 1: Methane Intensity – G&B, P*
 - b. *Subsidiary Document 2: Company Practices – G&B, P*
 - c. *Subsidiary Document 3: Monitoring Technology Deployment – G&B, P*

¹ According to IPCC AR6, the global warming potential (GWP) of methane is 82.5 times that of CO₂ over a 20-year period, and 25 times more potent than CO₂ over a 100-year period without climate controlled feedbacks.



1.2 About

MiQ Foundation, a non-profit entity, is the Standard Holder for this Standard. MiQ and the Standard was developed in a partnership between RMI² and SYSTEMIQ³ to reduce methane emissions from the global oil and gas industries through a market-based gas certification system.

1.3 Purpose

The purpose of this Standard is to incentivize continuous improvement in methane emissions monitoring and abatement by creating an opportunity for Operators to differentiate their operations by emissions performance.

More specifically, the objectives of this Standard are:

- a) to accelerate deployment of practices and technologies that reduce and/or eliminate methane emissions;
- b) to accelerate deployment of monitoring technologies that detect, measure and quantify methane emissions;
- c) to increase transparency regarding the methane emissions performance across the natural gas supply chain, with a globally consistent methodology;
- d) to enable Operators, marketers, and buyers to transact natural gas based on the methane emissions performance of a Facility, and to demonstrate additional value to their customers;
- e) to provide Operators, buyers, and investors a uniform, independently verified Standard consistent with environmental, social, and governance (ESG) reporting to address methane emissions from natural gas supply chain and from end-users;
- f) to complement regulations by incentivizing emissions control and detection actions that exceed regulatory requirements; and
- g) to credibly recognize Operators who are leading their peers in methane emissions management.

2 Scope

This Standard establishes a system for the generation of MiQ certificates, which will include a defined Grade that captures the Facility's methane emissions performance. Performance will be assessed according to the Facility's (1) calculated Methane Intensity, (2) policies and procedures that are focused

² RMI (Rocky Mountain Institute), <https://www.rmi.org>

³ SYSTEMIQ Ltd | Transforming Systems For a Better Future, <https://www.systemiq.earth>



on methane emissions prevention, detection, and abatement (Company Practices), and (3) deployment of methane emissions-detecting and monitoring technologies (Monitoring Technology Deployment).

Furthermore, this Standard:

- is applicable to natural gas Facilities in the gathering and boosting, and processing segments (see Terms and Definitions);
- specifies a method to calculate the Methane Intensity of a natural gas Facility (see *Subsidiary Document 1: Methane Intensity*);
- establishes general principles for an effective methane management program – including policies and procedures focused on methane emissions prevention, detection, abatement and deployment of methane monitoring technology (see *Subsidiary Document 2: Company Practices* and *Subsidiary Document 3: Monitoring Technology Deployment*);
- does not define requirements for natural gas' physical or chemical quality.

While the Standard is designed to Grade a Facility on its methane emissions performance through the use of an independent Auditor and is an integral ingredient of the MiQ Program, it does not define certification procedures, issuance of MiQ certificates, or non-compliance events. (see the *MiQ Program Guide* for application of the MiQ Standard to the MiQ Program).



3 Terms and Definitions

For purposes of this Standard, the following terms have the meanings attributed below. All terms and definitions used in this Standard (including in Subsidiary documents) are defined here.

Term	Definition
Annual Audit	The systematic, independent, and documented assessment by the Auditor prior to the intended Certification Period, verifying the information reported by the Operator against the Standard.
Auditor/Auditing Body	An individual, or organization made up of individuals, that carry out assessments to determine if a Facility meets the requirements of the Standard and recommend a performance Grade. An Auditor or Auditing Body must possess the combined demonstrated knowledge, skill and abilities, along with documented training and experience required to provide assurance services, both offsite and onsite, to determine Facility's performance against all diverse elements of the Standard.
Audit Report	A verification document prepared by an Auditing Body that contains a comprehensive analysis of the Operator adherence to the Standard.
Basin	An oil and gas producing region (a geologic sedimentary basin), as typically defined and referenced by national legislation.
Causal Examination	The act of following up to a detected event at the Site, Equipment or Component level to determine the likely cause of the emission, using SCADA logs, maintenance logs, operational logs, operator site visits, and Source Level detection surveys. Examinations should also, at minimum, include determination of emissions as Intended or Unintended. Causal examinations are less formal than Root Cause Analyses and do not require a systematic corrective action to be identified, recommended or implemented as part of the examination process.
Certification Period	The forward looking period (maximum 12 months) during which certified operations at a Facility is eligible for MiQ certificates.



Company Practices	A document, program, policy or procedure, specific to the Operator that identifies effective management of methane emissions within the Facility boundaries. Company Practices is also the title of one of the subsidiary documents to this Standard.
Component	A smaller piece of equipment, such as a flange, connector, pressure relief device (PRD), thief hatch, screw or compression fitting, stem packing in a valve, pump seal or compressor component.
Condensate	A mixture of light hydrocarbon and other liquid, including both water and hydrocarbon liquids, separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions.
Continuous Monitoring System	<p>A methane monitoring system at a Facility that:</p> <ul style="list-style-type: none"> (a) is made up of a network of stationary but linked sensors, (b) autonomously collects, records and reports emissions data, (c) has an automated detection alert such that the data is interpreted, without human interference, to identify an emissions event above baseline normal operating conditions and trigger follow-up by operators, (d) collects, records and reports data within an envelope of operating conditions or documented runtime hours, (e) can pinpoint an emissions event to the Site Level to apply towards the MiQ Facility Scale monitoring requirements, and/or (f) can consistently pinpoint an emissions event to the component or Source Level to apply towards the MiQ Source Level monitoring requirements.
Crude Oil	A mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passage through separation equipment. May include lease condensate that is later mixed into the crude stream.
Directed Inspection and Maintenance Program	A documented program specific to the Facility that utilizes a process to develop effective inspection schedules for the purposes of detecting methane emissions quickly from selected sources that have a higher potential to emit



Emission Factor	A multiplier indicating typical emissions per unit of activity of a component or part of the gas system (e.g., valve, pipeline section) or from an event and can have units like [kg/km], [kg/event], or [kg/equipment type].
Equivalency determination	The process of comparing an operator's monitoring technology method(s) and emission inspection design with those in an LDAR program as prescribed by the Standard to achieve a certain evaluation, or Grade. Generally, it consists of 1) the definition of new methods, 2) application of controlled release testing results to define performance of each method, 3) simulation modeling to predict the performance of new programs and 4) field verification efforts to evaluate the accuracy of the simulation modeling.
Equivalent LDAR Program	An LDAR program undertaken by an operator utilizing a combination of Facility Scale, Source Level and Continuous Monitoring detection tools deemed to offer the same probability of detection and emission mitigation potential over the course of the year as the those required under the Standard for a given MiQ Grade. Substituted inspection methods may include various monitoring technologies with proven detection capabilities such as manned/unmanned aerial vehicles, fixed-wing aircraft, continuous monitoring devices, mass balance methods, or other methods to detect, track, repair, and report fugitive emissions, in addition to other Source Level methods such as OGI surveys.
Gathering and Boosting Facility	All contiguous, onshore natural gas gathering and boosting equipment (including leased, rented, or contracted equipment) located in a single geologic field, subfield, or basin under the responsibility of a common owner or operator with the purpose of gathering a product from production to a central point, such as a processing plant or transmission pipeline. The Facility Boundary may be split across a basin into multiple facilities if each system gathers products to different centralized points.
Processing Facility	All onshore processing equipment (including leased, rented, or contracted equipment) under the responsibility of a common owner or operator from plants that separate natural gas liquids and/or non-methane gases from produced natural gas and fractionate gas liquids. The Facility Boundary may encompass multiple processing plants if each sends their products to a common downstream Facility, such as the same transmission pipeline or NGL pipeline.
Facility Scale Inspection	Inspections undertaken by an operator using a method that covers the entire Facility's emission sources in three-dimensional space and must be capable of



	detecting and pinpointing the source of emissions to the site level at a minimum.
Grade	The performance grade of a Facility determined in accordance with this Standard by an Auditor and approved by the Issuing Body.
Greenhouse Gases (GHGs)	Carbon dioxide (CO ₂) and other gases defined in the IPCC Sixth Assessment Report including methane, nitrous oxide, sulfur hexafluoride, chlorofluorocarbons, hydrofluorocarbons, and perfluorocarbons [1]. Greenhouse Gases other than carbon dioxide can be expressed in terms of carbon dioxide equivalent (CO ₂ e), which is calculated using a timeframe-specific Global Warming Potential (GWP).
Intended Emission	Intentional release(s) of methane emissions by design, such as from equipment designed to vent, process vents, flares, and other combustion equipment within design parameters. Any emissions operating outside of design parameters are considered as Unintended.
Inventory	A documented compilation of emissions from each emission source, compiled on an annual basis for a Facility.
Issuing Body	The entity responsible for registering each Facility under the MiQ Program, for issuing MiQ certificates, and for approving Audit Reports under the MiQ Program, amongst other responsibilities.
Leak Detection and Repair (LDAR)	LDAR is frequently used to describe the regulatory practice of systematic emission detections using hand-held, Source Level tools. The term is expanded in this Standard to describe any monitoring survey which includes the systematic implementation of methane detection tools across a collection of assets to detect and repair emissions. An LDAR program describes the sensor(s), deployment or configuration strategy, temporal and spatial coverage, their operating envelope, work practices, detection capabilities of solution, follow up and repair procedures, and data management standards.
Methane Intensity	The ratio of methane emissions and a selected variable. It accounts for natural gas throughput relative to crude and condensate throughput by allocating emissions that are attributable to the handling of natural gas.
MiQ Program	The framework for handling all issues related to governance, the process of certification and use of the MiQ Registry. Please see the MiQ Program Guide for more details.



Monitoring Technology Deployment	A subsidiary document of this Standard which describes the requirements for the usage of methane monitoring technologies to comply with Facility Scale and Source Level inspections to mitigate Unintended Emissions.
Natural Gas Liquids	Hydrocarbons such as ethane, propane, butane and pentane that are extracted from feedstock gas entering a natural gas processing plant.
Onshore Natural Gas Gathering and Boosting	The oil and gas supply chain segment that includes all gathering pipelines and other equipment used to collect natural gas from onshore production gas or oil wells and used to compress, dehydrate, sweeten, or transport 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.
Onshore Natural Gas Processing	The oil and gas supply chain segment that includes all equipment used for 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. 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 further fractionate gas liquids, and processing plants that do not further fractionate gas liquids.
Gathering and Boosting Operator	The owner and equipment Operator of a Facility, responsible for operating gathering and boosting equipment downstream of a production facility and upstream of a processing facility, natural gas transmission pipeline, natural gas distribution pipeline or another gathering and boosting facility.
Processing Operator	The owner and equipment Operator of a Facility, responsible for operating processing equipment downstream of a production or gathering and boosting facility and upstream of a natural gas transmission pipeline, natural gas distribution pipeline or consumer.
Quantification	Estimating an emission rate, such as mass per time or volume per time, or total emissions. This can be done directly through measurement of the emissions, or indirectly through emission factor methodologies, engineering calculations and modeling.
Reconciliation of Emissions	A quantitative assurance process required to ensure a more complete emissions inventory. The process cross-references top-down detections and



	measurement with a bottom-up inventory to ensure an Operator's Methane Intensity falls within a designated MiQ Grade band.
Root Cause Analysis (RCA)	A documented procedure whereby an Operator follows up to detected events to determine the source of the emission, identify possible causal factors, determination of the root cause, recording each event for data aggregation, and finally recommending and implementing a solution
Site	A localized area of onshore natural gas gathering and boosting or processing equipment within a Facility (i.e. gas plant, compressor station, continuous run of gathering pipeline). Inspections conducted at the Site level must be able to narrow the location of the methane emission event to a single localized area or Component or piece of Equipment for Causal Examination and mitigation efforts.
Source / Emission Source	A specific piece of equipment or activity that emissions originate from. The sum of emissions from all emission sources makes up a Facility's inventory.
Source Level Inspection	Application of detection method which uses technology that can directly inspect individual sources of emissions, down to the Equipment or Component level.
Standard Holder	The organization responsible for defining and managing all aspects of the development of the Standard, including managing the processes for making changes to the Standard documents.
Super-Emitter	A Super-Emitter's emission rate threshold is not universally defined, however these events are typically considered the largest 5% of leaks by emission rate which are responsible for more than 50% of total emissions [2] or the highest-emitting 1% of sites in a site-based distribution [3]. Super-emitters are a high-emitting emission event, due usually to abnormal process conditions, which can significantly affect the total emissions of a Facility.
Gathering and Boosting Throughput	The quantity of gas transported during the Certification Period to a downstream portion of the gas supply chain such as a natural gas processing facility, a natural gas transmission pipeline or storage facility, or another gathering and boosting facility.
Processing Throughput	The quantity of natural gas exiting the gas processing plant boundaries during the Certification Period.



Unintended Emission	Any emission occurring outside equipment designs or ideal operating procedures, including all equipment leaks and failures (sometimes known as fugitive emissions), vents, and combustion equipment operating outside their design values, and Operator-managed emissions such as manual lifts, blowdowns and compressor starts that exceed best operating procedures.
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4 Core Principles

This Standard is based upon the following core principles (in no order):

1. Relationship with ISEAL Credibility Principles

In addition to the requirements of this Standard, the principles set out as ISEAL Credibility Principles shall apply [4]. Where this Standard provides for more specific requirements than the ISEAL Credibility Principles, the specific requirements shall apply.

2. Voluntary nature

The use and adoption of this Standard is voluntary. The Standard provides requirements for Operators to differentiate the supply of their product based on its methane emissions performance. As such, the application of this Standard is a voluntary action taken by an Operator.

3. Transparency

Certification under this Standard is based on objective and publicly disclosed criteria. Access to details of the MiQ certificates Issued under this Standard should be made available to users of the MiQ Program.

5 Roles and Responsibilities

Table 1 lists all the individuals and groups engaging with the Standard and what their responsibilities are regarding this document.



Table 1: Roles and Responsibilities

Roles	Responsibilities
Standard Holder	<ul style="list-style-type: none"> defining and managing all aspects of the development of the Standard publishing the Standard and supporting documents managing updates and changes to the Standard
Auditor/Auditing Body	<ul style="list-style-type: none"> conduct Annual audit in accordance with requirements defined in this Standard the MiQ program Guide Recommend a Grade for a Facility on methane emissions performance
Operator	<ul style="list-style-type: none"> registering Facilities with an Issuing Body; selecting and contracting with an Auditing Body that fulfills the requirements of this Standard; engaging with the Auditing Body to plan and prepare for the certification process; providing all necessary information, data, and documentation as well as access to relevant personnel and field operations to the Auditing Body for it to carry out the Audits (see MiQ program Guide)
Issuing Bodies	<ul style="list-style-type: none"> registering each Facility under the MiQ Program issuing MiQ certificates approving Audit Reports under the MiQ Program

6 Methane Emissions Certification

6.1 Applicability

A Facility and its operations are eligible to be Audited under this Standard under the following boundary definitions:

- **Physical boundary**

The MiQ Standard seeks to determine a Methane Intensity and performance grade for an operating asset in order to facilitate differentiation of gas within the global supply chain. For



Gathering and Boosting, a certification boundary must encompass and represent all contiguous emissions and corresponding throughput within an operating basin, subbasin, or geologic field. For Processing, a certification boundary includes all contiguous equipment and throughput within a processing plant, and may encompass multiple processing plants if each sends their products to a common downstream Facility. See the definitions of *Site* and *Facility* for further details.

Organizational boundary

Facilities must be under the responsibility of a common owner or Operator, sharing common management practices. Certification encompasses all equipment and sources with potential to emit, including leased, rented and operated equipment.

The ability of a Facility to achieve a Facility Grade is based on its methane emissions performance which is determined by the following Standard elements:

1. Methane Intensity

The requirements to be complied with are defined in *Subsidiary Document 1: Methane Intensity*

2. Company Practices

The requirements to be complied with are defined in *Subsidiary Document 2: Company Practices*

3. Monitoring Technology Deployment

The requirements to be complied with are defined in *Subsidiary Document 3: Monitoring Technology Deployment*

6.2 Grading System

Table 2 details the grading system for the segment reflected by this specific Standard. The certificate Grade is based on the lowest achieved score of the three Standard elements: (1) Methane Intensity, (2) Company Practices, and (3) Monitoring Technology Deployment.

To achieve grades D – F, a Facility must achieve all the mandatory Company Practices and the minimum requirements for Monitoring Technology Deployment. To qualify for grades A – C, a Facility must obtain higher scores for both Company Practices and Monitoring Technology Deployment.

Table 2: Grading system - score requirements for the three Standard elements

Score requirements				
Grade	G&B Methane Intensity	Processing Methane Intensity	Company Practices (Improved Practices points)	Monitoring Technology Deployment



A	$\leq 0.050\%$	$\leq 0.050\%$	≥ 22	12
B	$\leq 0.10\%$	$\leq 0.10\%$	≥ 15	8
C	$\leq 0.20\%$	$\leq 0.20\%$	≥ 8	4
D	$\leq 0.50\%$	$\leq 0.50\%$	Mandatory minimum	Mandatory minimum
E	$\leq 1.0\%$	$\leq 1.0\%$	Mandatory minimum	Mandatory minimum
F	$\leq 2.0\%$	$\leq 2.0\%$	Mandatory minimum	Mandatory minimum

7 Subsidiary Documents

The Standard is structured with subsidiary documents as shown in Figure 1.

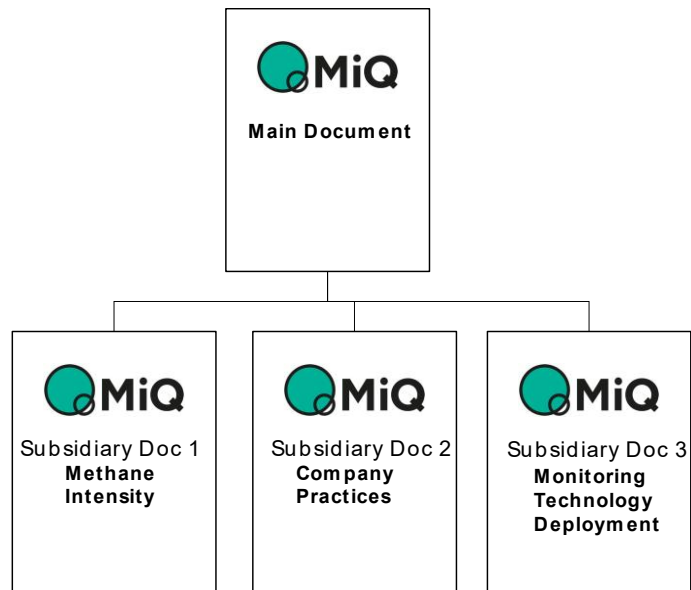


Figure 1: Document hierarchy

7.1 Subsidiary Documents

The following subsidiary documents are defined to supplement this Standard:

- *Subsidiary Document 1: Methane Intensity*
- *Subsidiary Document 2: Company Practices*
- *Subsidiary Document 3: Monitoring Technology Deployment*



Annex A: Conversion Factors

For conversion factors, please follow the values as defined in Table 3:

Table 3: Conversion factors [5]

Megawatt-hour thermal [MWh]	Million British thermal unit [MMBtu]
1	3.412141286
0.2930711	1
Standard cubic meter [Sm³]	Standard cubic feet [Scf]
1	35.31466672
0.028316847	1

For conversions related to different standard conditions and calorific values of natural gas volumes, please consult ISO 13443 – Natural gas – Standard reference conditions [6].

The higher calorific, gross or high heating value is the amount of heat produced by the complete combustion of a unit quantity of fuel [7].



Annex B: Document Status

B.1 Document Development

The MiQ Foundation, as the Standard holder, has developed this Standard through extensive peer and stakeholder review. MiQ would like to acknowledge the substantive contributions from industry experts, academic experts, consulting firms, auditing firms, environmental NGOs and government officials.

MiQ reserves the right to make updates to the Standard on a periodic basis to conform with new research, internal calibrations, and Operator access to best available technology.

B.2 Version History

Table 4: Version History

Version	Revision Date	Document	Summary of Change
Pilot v1.0	2022-05	All	Pilot Version
v1.1	2022-11	All	First Online Publication
v1.1.0	2023-11	Main	Removal of terms <i>Applicable Criteria</i> and <i>Detection</i> from definitions section
			Added clarification between the difference between <i>Causal Examination</i> and <i>Root Cause Analysis</i>
			Clarified that the definition of <i>Methane Intensity</i> includes allocation to separate products
			Clarified that the definition of <i>Quantification</i> includes the process of calculating total emissions from an event or source
		Methane Intensity	Updated language in Section 3.3: <i>Emissions Reconciliation</i> to clarify the intent of the process
			Revised language in Section A.1.1 adding a description for the levels of data quality in methane emission inventories to



assist in defining ‘best available data’ per emission source or emission event

In Section A.2, Clarified allowable ways for an operator to allocate emissions that are included via the operator’s reconciliation process

Replaced term ‘volume’ with ‘Throughput’ in Section A.2

Revised language for how methane intensity is converted into mass of emissions per unit energy, referencing the *MiQ Program Guide* as the governing document for conversions that are ultimately reflected on MiQ certificates

Revised default methane content from 0.870 to 0.934 for Gas Processing Facilities

Company Practices

UMEP-2 Source Level Detection Plan: Corrected first attempt at repair, final repair and repair verification timelines

FLR-1 Managing Methane Emissions from Flares: Revised requirement of ensuring 98% destruction efficiency of flare design to “*design*” destruction efficiency

PD-2.2 Managing Methane Emissions from Pneumatic Devices: Revised to include an either/or clause for the options an operator can implement to achieve the improved practice point

Monitoring Technology Deployment

Reduced Facility Scale Inspection frequency requirements:

- 3x/yr reduced to 2x/yr for 8 points for non-pipeline facilities
- 2x/yr to 1x/yr for 4 points for non-pipeline facilities
- 1x/yr reduced to N/A for non-pipeline facilities

Reduced Source Level Inspection frequency requirements

- 3x/yr reduced to 2x/yr for 8 points for non-pipeline facilities



- 2x/yr to 1x/yr for 4 points for non-pipeline facilities

Inserted a clause allowing for Source Level and Facility Scale inspection frequencies to be reduced upon confirmation of no additive detects within the last year.

Aligned text in Section 5.1: *Interconnection with calculated Methane Intensity* with Section 3.3: *Emissions Reconciliation* of the Methane Intensity subsidiary document



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MiQ STANDARD

for Methane Emissions Performance

SUBSIDIARY DOCUMENT 1: Methane Intensity – Gathering & Boosting and Processing

v1.1.0





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1 Introduction

The MiQ Standard for Methane Emissions Performance (the Standard) combines several Standard elements – (1) a calculated Methane Intensity, (2) Operator policies and procedures focused on methane emissions prevention, detection, and abatement (Company Practices), and (3) detection and mitigation of methane emissions through Monitoring Technology Deployment – to provide a robust and reliable method to certify natural gathering and boosting, and processing according to its methane emissions performance. The Standard is designed to incentivize continuous improvement in methane emissions monitoring and abatement.

The Standard consists of three main types of documents, to be read in the following order:

1. *Main Document – G&B, P*
2. *Subsidiary Documents*
 - a. **Subsidiary Document 1: Methane Intensity – G&B, P (this document)**
 - b. *Subsidiary Document 2: Company Practices – G&B, P*
 - c. *Subsidiary Document 3: Monitoring Technology Deployment – G&B, P*

This subsidiary document outlines the calculation of Methane Intensity as it pertains to the Standard. In general terms, Methane Intensity is a ratio of methane emissions relative to natural gas throughput, which is a baseline indicator of methane emissions performance. See Section 3 for a detailed overview of the Methane Intensity methodology used in this Standard.

2 Scope of this Document

This subsidiary document is part of the MiQ Standard and defines the criteria and requirements to determine the Methane Intensity of a Facility. MiQ is a Standard and program designed to differentiate the natural gas supply chain by its methane intensity. The MiQ Standard requires all sources to be accounted for as part of the emissions calculation methodology. However, specific sources and their minimum requirements for determination are outlined within. This Standard and all methodology in this document are globally applicable. This document, where helpful, makes specific reference to national or generic inventory methods to guide users, yet allows for national differences in methodologies (where existing and detailed by legislation).

This subsidiary document specifies a method to calculate the Methane Intensity of Onshore Natural Gas Gathering & Boosting and Processing Facilities.



3 Methane Intensity

Under this Standard, Operators are required to calculate Methane Intensity keep detailed records of supplementary data inputs used in the Methane Intensity calculation (detailed in Section 5).

Methane Intensity is to be projected annually, using the best available data, including but not limited to historical emission calculations, measurements, as well as detected leaks or abnormal process conditions from Facility Scale and Source Level methane monitoring surveys.

3.1 Calculation

Methane Intensity is defined as the ratio of methane emissions relative to throughput, adapted and modified from the Natural Gas Sustainability Initiative (NGSI) Protocol.[1] Under this Standard, a Facility's Methane Intensity is to be calculated following the methodology detailed in Annex A. It enables Operators to calculate an annual Facility Level Methane Intensity from identified emission sources reconciled with emissions from surveys conducted in accordance with *Subsidiary Document: Monitoring Technology Deployment*, (see Section 4.2).

The Methane Intensity for Natural Gas metric is the quotient of the mass of methane emissions (after allocation and in kg CH₄) attributed to the handling of natural gas from a Facility by the mass of methane throughput. It is calculated every 12 months as a unitless ratio and communicated as a percentage. For example, an Operator can calculate its methane intensity using the following equation:

$$\text{Methane Intensity} = \frac{\text{Methane Emissions}}{\text{Production Throughput} \times \text{Methane Content}} \times 100\%$$

Methane Intensity represents the amount of methane emitted at any given Facility for a given year as attributed the boosting and gathering, and processing of natural gas using the gas ratio or allocation to the gas phase, as outlined in Table 3.

Unit conversion factors necessary to complete the Methane Intensity calculation can be found in the *Main Document, Annex A: Conversion Factors*.

3.2 Emission Sources

A Facility's calculated Methane Intensity must include methane emissions from all the Emission Sources (outlined in Annex A) that are present in a Facility. Most emission sources should be captured in the sources outlined in Annex A, but it is the operator's responsibility to document other emission sources that may not be listed.

The methods in this Standard to calculate methane emissions utilize a combination of emission factors, engineering calculations, and direct measurements. While this Standard does not prescribe a specific



calculation methodology for each source, it does require a minimum level of facility-specific data based on the emission source.

Operators are encouraged to utilize quantification methods specific to their Facility. In each case, the Operator must provide relevant information for each emission source where a quantification method is used that exceeds the minimum requirements of this Standard, including:

- For use of any chosen methodology: sufficient documentation on specifications of the methodology, such as cited performance criteria or independent scientific studies and use cases.
- For use of recognized external measurement protocols: relevant documentation outlining the approach, applied methodology and work practice.
- For use of facility-specific emission factors: details describing the measurement equipment, site selection, sampling criteria, and measurement period.
- For use of any measurement solution: technical specifications and results of controlled release testing, including calculated uncertainty, bias or confidence bounds.

3.3 Emissions Reconciliation

A Producer's accounting methodology must also include reconciliation of detected emission events, including all sources identified during leak detection surveys deployed as a requirement of the Standard (see Subsidiary Document 3: Monitoring Technology Deployment, Section 5.1 for more detail), or via monitoring and measurement data from historical surveys, parametric monitoring and any other inspections or observations for Facilities in Year 1 of the certification process (See Section 4 for more detail. For simplification purposes, all methods used to detect emissions to be reconciled are referred to as "applicable methods."

Operators must utilize a structured set of written principles, or a written protocol, to reconcile emissions that are detected through applicable methods with the emissions inventory that is submitted following the minimum requirements set forth in Annex A.1.2. The process of reconciliation must then be rolled up to calculate an annual methane emissions inventory to be used in the operator's methane intensity, as set forth in Annex A.2. Operators may develop a protocol that establishes principles for the evaluation of commonly detected and attributed emission event types and emission sources, or that evaluates each emission event separately. The operator's protocol must be able to be applied to potential unintentional emission events or uncharacterized intentional emissions that could reasonably occur at the Facility.

An operator's reconciliation protocol must include sufficient detail explaining:

1. How emissions detected through applicable methods are classified, including, but not limited to, attribution to site, equipment group, and emission source



2. How the additionality of detected emissions to a Facility's emissions inventory subject to Annex A.1.2 are analyzed, unless all detected emissions are representatively added into the inventory indiscriminatorily.
3. How the data gathered through all applicable methods are used to quantify emissions and affect the Facility's emission inventory submitted via Annex A.1.2. This must include explanation of the data used by operators to quantify emission rates and estimate time durations of events, or annualize emissions through other methods.

4 Scoring Parameters

The overall grading system for the Standard is detailed in the *Main Document*. The Initial Audit Grade and Verified Grade is based on the combination of individual scores for each of the Standard elements: (1) Methane Intensity, (2) Company Practices, and (3) Monitoring Technology Deployment.

A Facility's Methane Intensity score is based on its calculated Methane Intensity (in %), as detailed in *Main Document, Section 6.2*.

As part of the Annual Audit, operators must submit a methane emissions inventory that is reconciled with emission events identified during emission surveys completed in accordance with *Subsidiary Document 3: Monitoring Technology Deployment* and quantified, or other relevant measurement campaigns undertaken by the operator. New certified Operators must utilize results from previous emission surveys, commissioned in house or obtained from outside regional campaigns. For all grades, this must include the results of at minimum 1 annual Source Level LDAR survey. For grade C or higher, this includes at minimum 1 Facility Scale monitoring surveys¹ or 3 months of continuous monitoring results from a sample of an operator's facility that can be shown to be representative of its entire methane emissions footprint.

5 Recordkeeping Requirements

In addition to the final calculated Methane Intensity value, Operators must document the following aspects that make up the Methane Intensity calculation for Auditor review (and note the individuals or departments responsible for determining), at a minimum:

¹ Duration between Facility Scale surveys may not exceed 150% of the intended periodicity. See *Subsidiary Document 3: Monitoring Technology Deployment, Section 3.2* for more details.



Table 1: Recordkeeping Requirements

Aspect	Detail
Facility Description	Operators must document all Equipment or assets that make up a Facility, including equipment added year-by-year as a result of development activity or acquisition, or removed year-by-year due to abandonment, divestiture, or any other changes made during the Certification Period.
Segment Throughput	Operators must document the natural gas Throughput used in calculating Methane Intensity including the source of data.
Equipment Count	Operators must document the total Equipment count associated with each emission source for all Equipment included within a Facility, and the method used to determine this count.
Activity data	Operators must document the activity data associated with each emission source (e.g. operating time, estimated leaking time for leaker emission sources). Operators must also document their observations of leaking components using LDAR (see <i>Subsidiary Document 3: Monitoring Technology Deployment, Section 5.1</i> for more detail).
Calculation method	<p>For each emission source the calculation methodology used must be documented and include the equipment counts, activity data, emission factors and any engineering calculation or measurement used in calculations. Operators must document the method, assumptions used along with its rationale, and its application to the calculation.</p> <p>For enhanced quantification methods, Operators must document all calculation and/or modelling assumptions, and/or technical specifications of measurement technologies deployed.</p>
Reconciliation Procedure	Operator must provide a detailed procedure outlining their process for reconciling emission events identified during detection surveys completed in accordance with <i>Subsidiary Document 3: Monitoring Technology Deployment</i> , or other relevant LDAR or measurement campaigns, within their inventory, including details of their Facility Scale and Source Level inspections, emissions classification, and quantification methods (see Section 3.3).
Methane Intensity Calculation Inputs	<p><i>Energy content and Gas Ratio</i></p> <p>The allocation of methane emissions between natural gas handling and other hydrocarbon handling must be documented and substantiated, including the</p>



factor used for energy content of natural gas (whether default raw gas value or company-specific value) and the factor used for energy content of liquids (whether default crude oil and condensate heating value or company-specific value(s)). If Operators use company-specific values, the source and derivation of those values must be documented.

Methane content

The throughput and calculated emission volumes are converted to mass of methane, by using a facility-specific methane content value. If Operators use a facility-specific value, methodology used for determining methane content must be documented.

Processes and responsibilities

Operators must document their processes for determining and internally reviewing their Methane Intensity for accuracy. This should include a detailed record of internal changes to calculations based on operational incidents and planned events.



Annex A: Methane Intensity calculation methodology

This annex outlines the Standard’s recommended method to calculate Methane Intensity for natural gas Gathering & Boosting and Processing Facilities. This methodology leverages recommended calculation methods and hierarchies from other national and voluntary protocols. This Standard attempts to capture most emissions in an accurate, credible, and replicable way that is consistent with existing frameworks for reporting and disclosure.

A.1 Emissions Calculation methods and Emission Sources

A.1.1 Emissions calculation methods

Table 2 outlines the types of calculation methods that can be used to quantify methane emissions. In general, data quality and specificity to the Facility increases in ascending order in Table 2. There are many exceptions to this rule, however, and in cases of exception, such as the usage of engineering calculations over direct measurement, the Operator should record justification for the unique approach. Table 3 outlines specific sources to be quantified in the operator’s inventory and the minimum methodology requirements for each source. Operators shall, in their emissions reporting, indicate the method(s) used to quantify each emission source.

Measurement-informed inventories are highly encouraged throughout the Standard. Operators seeking to submit a measurement-informed inventory may do so in compliance with published measurement and reconciliation protocols such as GTI Energy’s Veritas Protocol [3] or OGMP 2.0 Level 4/5 [4], and confirmed by the Auditor.

Table 2: Types of Calculation methods

Calculation method type	Clarification
Direct Measurement	<p>Direct measurement can occur by any means which allows for a methane emissions rate to be determined at the particular source. Typically, through a measured methane concentration and flowrate. The method of conversion and other data points used must be disclosed.</p> <p>The frequency of direct measurement must be disclosed.</p>
Indirect Measurement	<p>Quantifies methane emissions indirectly (by proxy).</p> <p>Typically, this involves measuring methane volume to a specific piece of equipment through a flow instrument installed in the (fuel) supply header, and</p>



	<p>multiplying this volume with an Emission Factor to quantify emissions from that piece of equipment.</p> <p>Additional forms of proxy measurements involve advanced spectral or concentration sensors which derive an emissions flux by applying an algorithm to a group of individual measurements in space.</p> <p>The frequency, spatial coverage, and uncertainty as determined by controlled release testing of indirect measurement must be disclosed.</p>
Engineering Calculation	Utilizing simulation software such as HYSYS, Unisim, or an Excel model or mass balance, to estimate emissions with direct and indirect measurements and asset data as inputs.
Measurement-based Emission Factors	Emission factors derived from studies undertaken at a Facility or an area representative of the Facility. Different measurement-based emission factors for the same emission source should be developed for each operating condition or type of equipment that may yield a different emission factor (i.e. HDPE vs. cast iron piping, or outlet compressor pressure buckets for compressor venting)
Equipment-specific Emission Factors	Emission factors derived from vendor information or determined for individual types of emission sources based on peer-reviewed studies.
Generic Emission Factor	<p>Generic Emission Factors are often provided or referred to in national legislative reporting requirements.</p> <p>A factor or ratio for converting an activity measure (e.g. number of times a controller actuates) into an estimate of the quantity of methane emissions associated with that activity, usually expressed in emissions per activity unit and derived from representative measurement campaigns.</p>

A.1.2 Emission Sources from Gathering & Boosting and Processing Facilities

Methane emissions from natural gas Gathering & Boosting and Processing Facilities are to be accounted for from all potential emission sources. The Operator is required to aggregate methane emissions estimates from all relevant emission sources in the segment of interest to calculate Methane Intensity.

Under this Standard, Gathering and Boosting is defined as:

The oil and gas supply chain segment that includes all gathering pipelines and other equipment used to collect natural gas from onshore production gas or oil wells and used to



compress, dehydrate, sweeten, or transport 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. [1]

Under this Standard, Processing is defined as:

The oil and gas supply chain segment that includes all equipment used for 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 carbon dioxide 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. [1]

Emission sources and recommended calculation methods for each are outlined in Table 3. An Operator should include all emission sources within its Facility, including those that are not specifically stated in Table 3. An Operator can use alternative calculation methods to the methods specified in Table 3 as long as the inputs are determined at a level that is equally or more representative of the actual emission sources at the Facility.



Table 3: Minimum Calculation and Allocation Requirements for Gathering & Boosting, and Processing Emission Sources

Emission Source ²	Segment	Product Allocation ³	Minimum Emission Calculation Requirements ⁴	Examples of Accepted Methodologies ⁵
Acid Gas Removal Units	G&B + P	Natural gas	Emission-factor based calculation using an emission factor representative of AGRU venting, along with the number of AGRUs.	API Compendium 6.3.8.4 [2]; OGMP TGD Purging and venting (L3) [4]; GHGI ⁶ [7]; 40 CFR 98.233 (d) [8]; AQM 4.12 [9]; WCI.363(c) [10]
Combustion Units (Gas compressor drivers)	G&B + P	Natural gas	Emission-factor based calculation using an emission factor of incomplete combustion representative of the combustion unit type, along with fuel consumption volumes and fuel composition data	API Compendium 4.5.2 [2]; OGMP TGD Incomplete combustion (L3-L4) [4]; AQM Eqn. 1-5, 1-5a [9]; WCI.363(w), WCI.20 [10]; NGER 2.3.5 (Method 2) [11]
Combustion Units (Non-compressor drivers)	G&B + P	Energy-allocated	Emission-factor based calculation using an emission factor of incomplete combustion representative of the combustion unit type, along with fuel consumption volumes and fuel composition data	API Compendium 4.5.2 [2]; OGMP TGD Incomplete combustion (L3-L4) [4]; AQM Eqn. 1-5, 1-5a [9]; WCI.20 or WCI.363(w) depending on fuel type[10]; NGER 2.3.5 and 2.4.5 (Method 2) [11]

² An Operator's bottom-up emissions inventory does not have to be formatted as per Table 3. However, all emission sources present at the Facility must be accounted for and included in the Facility's inventory that is submitted for the Annual audit.

³ To handle co-product streams, we employ a method of allocation to the gas phase adapted from the the Natural Gas Sustainability Initiative (NGSI) Methane Emissions Intensity protocol [1] and ONE Future Methane Emissions Estimation Protocol [5], with partial modifications found within Roman-White et al (2021) [6].

⁴ These requirements are for an Operator's bottom-up emissions inventory. The reconciliation requirements listed in [Section 3.3](#) are applicable along with compliance with the requirements in Table 3.

⁵ These reference methods are a non-exhaustive list of acceptable methods for an Operator to calculate each emission source in their bottom-up inventory. The calculation methods referenced are regionally specific in some cases but reinforce that Operators have multiple options to calculate their bottom-up inventory.

⁶ The GHGI is derived to develop US-wide emission factors for certain sources. While MiQ allows these emission factors to be used to account for certain sources in a bottom-up inventory, usage of these factors will create a less facility-specific bottom-up inventory which may impact an Operator's reconciliation process. Year-over-year as measurement data becomes more available, Operator should eliminate usage of generic factors.



Blowdowns (Compressors)	G&B	Natural gas	Engineering calculation using the physical volume in between isolation valves, gas pressure/temperature and gas composition. Emission controls used must also be considered.	OGMP TGD Purging and venting (L4)[4]; 40 CFR 98.233(i) [8]; AQM Eqn. 4-5a, 4-5b [9]; WCI.353(c) [10]
Blowdowns (station venting)	G&B + P	Energy-allocated	Engineering calculation using the physical volume in between isolation valves, gas pressure/temperature and methane content. Emission controls used must also be considered.	OGMP TGD Purging and venting (L4) [4]; 40 CFR 98.233(i) [8]; AQM Eqn. 4-5a, 4-5b [9]; WCI.353(c) [10]
Blowdowns (gathering pipelines)	G&B	Energy-allocated	Engineering calculation using the physical volume in between isolation valves, gas pressure/temperature and gas composition. Emission controls used must also be considered.	OGMP TGD Purging and venting (L4) [4]; 40 CFR 98.233(i) [8]; AQM Eqn. 4-5a, 4-5b [9]; WCI.353(c) [10]
Compressor Starts	G&B + P	Natural gas	Emission-factor based calculation using an emission factor representative of the compressor starter, along with the number of starts.	API Compendium 6.4.6.2 [2]; GHGI ⁶ [7]; AQM 4.19 [9]; NGER 3.3.9A.9 (Method 1) [11]
Compressor Venting (centrifugal – dry seals)	G&B + P	Natural gas	Emission-factor based calculation using an emission factor that best represents seal venting emissions based on seal type and compressor operating conditions along with actual, relevant activity data (i.e. number of compressors or number of seals).	API Compendium 6.5.4.2 [2]; OGMP TGD Centrifugal compressors (L3-L4)[4]; GHGI ⁶ [7]; 40 CFR 98.233(o)[8]; AQM 4.9.2 thru 4.9.4 [9] ; WCI.363(I) [10]
Compressor Venting (centrifugal – wet seals)	G&B + P	Natural gas	Emission-factor based calculation using an emission factor that best represents seal venting emissions based on seal type and compressor operating conditions along with actual, relevant activity data (i.e. number of compressors or number of seals).	API Compendium 6.5.4.2 [2]; OGMP TGD Centrifugal compressors (L3-L4)[4]; 40 CFR 98.233(o)[8]; AQM 4.9.2. thru 4.9.4 [9]; WCI.363(I) [10]



Compressor Venting (reciprocating compressors)	G&B + P	Natural gas	Emission-factor based calculation using an emission factor that best represents rod packing venting emissions based on compressor operating conditions along with actual, relevant activity data (i.e. number of compressors or number of cylinders).	API Compendium 6.4.3.1 [2]; OGMP TGD Reciprocating compressors (L4) [4]; 40 CFR 98.233(p)[8]; AQM 4.9.2. thru 4.9.4 [9]; WCI.363(m) [10]; NGER 3.3.6A.1 (Method 2)[11]
Dehydrator Vents	G&B + P	Natural gas	Engineering calculations or computer modeling dependent on the type of dehydrator	API Compendium 6.3.8.1 thru 6.3.8.3 [2]; OGMP TGD Glycol dehydrators (L4) [4]; OGMP TGD Purging and venting (L4) [4]; 40 CFR 98.233(e) [8]; AQM 4.10.2 [9]; WCI.363(d) [10]
Equipment Leaks (All fugitive components)	G&B + P	Energy-allocated	Population emission factor-based method using emission factors that best represent conditions and practices of the Facility.	API Compendium 7.2.2.2 thru 7.2.2.4 [2]; OGMP TGD Leaks (L3-L4) [4]; 40 CFR 98.233(q), 98.233(r) [8]; WCI.363(n)[10]; NGER 3.3.6A (Method 3) [11]
Equipment Leaks (Gathering pipelines)	G&B	Energy-allocated	Emission-factor based calculation using an emission factor for leakage dependent on the type of material of pipeline or another differentiating factor of pipeline performance, along with the number of miles of pipeline.	API Compendium Table C-13 [2]; OGMP TGD Leaks and permeation from underground pipes [4]; 40 CFR 98.233(r)[8]; WCI.363(o)(2)[10]; NGER 3.3.6C (Method 2) [11]
Flare Stacks	G&B + P	Energy-allocated	Engineering calculation using flare gas flow rate, flare gas composition and a representative destruction efficiency.	API Compendium 5.1 [2]; OGMP TGD Flare efficiency (L3-L4) [4]; 40 CFR 98.233(n)[8]; AQM 2.3 Method 2-1 thru 2-3 [9]; WCI.353(d)[10]; NGER 3.3.9A.10 (Method 2A) [11]



Gas-driven pneumatic controllers	G&B + P	Energy-allocated	Emission factor-based method using an actual inventory of each type of pneumatic device and an emission factor representative of the vent rate and actuation frequency of the device.	API Compendium 6.3.6 [2]; OGMP TGD Pneumatics (L3-L4) [4]; 40 CFR 98.233(a) [8]; AQM 4.7.2 thru 4.7.4 [9]; WCI.363(a, b, b.1) [10]; NGER 3.3.9A.4 (Method 1) [11]
Gas-driven pneumatic pumps	G&B + P	Energy-allocated	Emission factor-based method using count of devices and default or manufacturer-specific emission factors.	API Compendium 6.3.7 [2]; OGMP TGD Pneumatics (L3-L4) [4]; 40 CFR 98.233(c)[8]; AQM 4.8.2 thru 4.8.4 [9]; WCI.363(a.1) [10]; NGER 3.3.9A.5 (Method 1) [11]
Storage Vessels (Hydrocarbon, Floating and Fixed-Roof)	G&B + P	Energy-allocated	Engineering Calculations or process modeling tools such as AspenTech HYSYS or TankESP accounting for parameters including upstream separator temperature/pressure and composition, API gravity and production rate of stabilized oil, and ambient conditions.	API Compendium 6.3.9.1 thru 6.3.9.3 [2]; 40 CFR 98.233(j) [8]; WCI.363(h) [10]; NGER 3.3.9A.3 (Method 1) [11]
Other emission sources	Source-dependent	Source-dependent ⁷	Operator must disclose other emission sources within their Facility not explicitly called out in this Standard, document total emissions, and demonstrate a representative calculation methodology for each source.	

⁷ Product allocation for methane emissions other emission sources are to be determined by the Operator and approved during the Annual Audit



A.2 Methane Intensity Calculations

Where a Facility handles hydrocarbon liquids⁸ and natural gas, emissions are allocated to natural gas on an energy basis (“Energy-allocated”) or to the handling of Natural Gas based on the emission source, as outlined in Table 3. Operators must make best efforts to attribute individual inventory adjustments made via *Section 3.3: Emissions Reconciliation* to individual sources, but may default to energy allocation if there are uncertainties in source attribution. The methodology for calculating methane intensity associated with Gathering & Boosting and Processing Facilities is as follows:

For energy-allocated emissions, first calculate the Gas Ratio as a unitless number:

$$E_{ng} = V_{ng} \times EC_{ng} \quad (1)$$

$$E_{liq} = V_{liq} \times EC_{liq} \quad (2)$$

$$GR = \frac{E_{ng}}{E_{ng} + E_{liq}} \quad (3)$$

Where:

- E_{ng} is energy equivalent of natural gas (as MMBtu or MJ)
- V_{ng} is annual gas Throughput (as Mscf, or Sm³, or Nm³)
- EC_{ng} is energy content of the gas (as MMBtu/Mscf, or MJ/Sm³, or MJ/Nm³)
- E_{liq} is energy equivalent of hydrocarbon liquids (as MMBtu or MJ)
- V_{liq} is annual hydrocarbon liquids Throughput (as US barrel or Sm³ or Nm³)
- EC_{liq} is energy content of hydrocarbon liquids (as MMBtu/US barrel or MJ/Sm³, or MJ/Nm³)

Calculate total methane emissions (metric tons) as the sum of emissions from sources allocated based on the gas ratio ($ME_{\text{energy-allocated}}$) with the emissions allocated to the handling of natural gas ($ME_{\text{gas-only}}$).

Emission sources to be co-allocated and associated to gas are denoted as “Energy-allocated” and “Natural gas” in Table 3, respectively.

$$ME_{\text{energy-allocated}} = GR \times \sum \text{energy-allocated sources} \quad (4)$$

$$ME_{\text{gas-only}} = \sum \text{gas-only sources} \quad (5)$$

⁸ Note, the energy equivalent of hydrocarbon liquids should be the sum of the separated hydrocarbon liquid product streams leaving the Facility. For example, hydrocarbon liquids product streams in Gathering and Boosting Facilities will most often be Condensate streams going to natural gas processing plants and Crude oil streams that may include blended condensate. For natural gas Processing Facilities it is assumed that natural gas plant liquids (NGLs) to export will most often be the only liquid product stream. Both examples should recognize these product streams when calculating E_{liq} and V_{liq} .



$$\text{Methane Emissions (ME)} = ME_{\text{energy-allocated}} + ME_{\text{gas-only}} \quad (6)$$

An Operator must then calculate its Methane Intensity as:

$$\text{Methane Intensity} = \frac{ME}{V_{ng} \times MC \times M_{den}} \times 100\% \quad (7)$$

Where:

- *ME* is the annual Methane Emissions from Facility (metric tons)
- *V_{ng}* is the natural gas Throughput (mcf or Sm³, or Nm³)
- *MC* is the methane content of the natural gas Throughput (volume fraction)
- *M_{den}* is the methane density of the Throughput (metric ton/Mcf)

For integration of a Facility's methane intensity into a methane intensity estimate across multiple segments of a natural gas supply chain, MiQ converts methane intensity to units of mass of methane emissions divided by energy Throughput of natural gas, typically *g CH₄ per mmbtu gas Throughput*. The method for conversion is defined in the *MiQ Program Guide*.

This methodology allows for use of some default values to calculate the Methane Intensity, though preference is given to facility-specific values. These values are listed in the tables below. For Imperial units see Table 4 and for SI units see Table 5. Reference values are taken from the API Compendium[2] as suggested by the NGSi Protocol[1].

Table 4: Imperial default values for calculating Methane Intensity

Default value			
Abbreviation	Description	Units Imperial	Default Value
EC _{ng}	Higher Heating Value natural gas	(MMBtu/Mscf)	1.235
EC _{liq}	Higher Heating Value hydrocarbon liquids and NGLs	(MMBtu/US barrel)	5.8 (HC liquids) 3.82 (NGLs)
MC	Methane Content of natural gas	(volume fraction)	0.833 (G&B) 0.934 ⁹ (Proc)
M _{den}	Methane Standard Density	MT/Mcf	0.0192

⁹ The NGSi Protocol states a methane content of 0.934 for the Transmission & Storage segment. Due to MiQ's definition of Throughput being at the exit of the Processing Facility, this value for methane content is representative of the residue gas exit stream.



Table 5: SI default values: Standard conditions, for calculating Methane Intensity

Standard at 15°C		Default value	
Abbreviation	Description	Units SI Standard	Default Value
EC _{ng}	Higher Heating Value natural gas	(MJ/Sm ³)	46
EC _{liq}	Higher Heating Value hydrocarbon liquids	(MJ/Sm ³)	38500
MC	Methane Content natural gas	(volume fraction)	0.833 (G&B) 0.87 (Proc)
M _{den}	Methane Standard Density	(MT/Sm ³)	0.000677



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MiQ STANDARD

for Methane Emissions Performance

SUBSIDIARY DOCUMENT 2: Company Practices – Gathering & Boosting and Processing

v1.1.0





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1 Introduction

The MiQ Standard for Methane Emissions Performance (the Standard) combines several Standard elements – (1) a calculated Methane Intensity, (2) Operator policies and procedures focused on methane emissions prevention, detection, and abatement (Company Practices), and (3) detection and mitigation of methane emissions through Monitoring Technology Deployment – to provide a robust and reliable method to certify natural gas production according to its methane emissions performance. The Standard is designed to incentivize continuous improvement in methane emissions monitoring and abatement.

The Standard consists of three main types of documents, to be read in the following order:

1. *Main Document – G&B, P*
2. *Subsidiary Documents*
 - a. *Subsidiary Document 1: Methane Intensity – G&B, P*
 - b. **Subsidiary Document 2: Company Practices – G&B, P (this document)**
 - c. *Subsidiary Document 3: Monitoring Technology Deployment – G&B, P*

Effective management of methane emissions from Gathering and Boosting, and Processing equipment begins with a Facility design that will achieve minimal Intended methane emissions and eliminates, to the greatest degree possible, the potential for Unintended Emissions. However, review of the Methane Intensity calculation alone is not a sufficient indicator of a Facility's effectiveness in methane emissions management. Beyond calculated Methane Intensity, Operators must demonstrate effective methane emissions management through Company Practices which exhibit an overarching cultural drive to improve methane emissions performance.

This Standard includes evaluation of Company Practices, which include policies and procedures an Operator employs to ensure it is managing and minimizing methane emissions. By establishing and implementing Company Practices to guide personnel in operating practices, design principles, methane emissions detection and repair, reporting protocols, and data evaluation, Operators can ensure methane emissions are managed appropriately during Facility operation.

An Operator should be able to produce documentation of their Company Practices and procedures and demonstrate that that employees understand, implement, and comply with those practices.



2 Scope of this Document

This subsidiary document is part of the MiQ Standard and defines the Company Practices criteria and requirements for compliance with this Standard. This document outlines the mandatory and improved Company Practices related to methane emissions management, including monitoring for Unintended methane emissions, minimizing Intended methane emissions, reporting, and operator training. The required Company Practices are broken into three categories:

1. **General Company Practices**

Outline the required general policies and procedures to demonstrate methane emissions management practices at a Facility, in accordance with a best practice approach.

2. **Company Practices for Managing and Reducing Unintended Methane Emissions**

Outline the policies and procedures required to effectively identify and fix Unintended methane emissions at a Facility.

3. **Company Practices for Managing and Reducing Methane Emissions from Individual Equipment Classes**

Outline the policies and procedures required to minimize methane emissions at a Facility from specific equipment.

This subsidiary document covers Company Practices for onshore natural gas G&B, P operations.

3 Performance Criteria

An Operator is required to provide evidence of their Company Practices relevant to methane emissions management. Specific performance criteria are based on the presence, content, and implementation of these Company Practices.

The performance criteria can be demonstrated by an Operator through formal policy or procedure. In the absence of formal policy or procedure, the Operator may present other documentation of training, analysis, report generation, record keeping and/or implementation of Company Practices at the Facility.

The performance criteria for managing and minimizing methane emissions are categorized either as:

- **Mandatory:** Must be demonstrated by the Operator in order to qualify for the Standard; or
- **Improved:** By demonstrating these practices, an Operator can achieve the additional points required to qualify for higher MiQ Grades.



The overall grading system for the Standard is detailed in the *Main Document*. The MiQ Grade for the Gathering, Boosting and Processing Facility is determined based on the individual scores for each of the Standard elements: (1) Methane Intensity, (2) Company Practices, and (3) Monitoring Technology Deployment.

For a Facility to be certified under this Standard, **each** mandatory Company Practices performance criteria outlined below must be met. Facilities which adopt improved practices for reducing methane emissions are eligible for MiQ Grades (see *Main Document, Section 7.2.1*). The improved performance criteria are assessed via a points-based scoring system. Points for improved practices are indicated in Tables 1-10 below. If a Facility demonstrates at least one of the elements listed for an improved practice topic, as outlined in Tables 1-10, it should receive all points nominated for that practice if the word “**or**” separates two elements. All elements must be complied with if two or more elements **are related (indicated by the word “and”)**. For performance criteria relevant to emission sources not found on a given Facility, the Operator automatically receives the available points.

3.1 General Company Practices

Facilities will employ general Company Practices to eliminate methane emissions to the greatest degree possible. This includes continuous cultivation of a culture of eliminating methane emissions and ensuring employees and contractors have the education and resources to implement emission management and minimization strategies.

The general policies and procedures are listed in Table 1,¹ categorized according to their character (‘Mandatory’ or ‘Improved’).

Table 1: General Company Practices (GP)

Practice	Character	Points
(GP- 1) Employee training and awareness		
Operations staff receive training that:	Mandatory	-
<ul style="list-style-type: none">emphasizes the importance of eliminating methane emissions, equipment most likely to leak, signs of methane emissions including Audial, Visual, and Olfactory (AVO) observations that may indicate a problem, and actions to take in the event of an observation; and		

¹ Company Practices are numbered by type or emission source.



- details how to log and report methane emissions for purposes of annual methane emissions calculations; **and**
- is offered at least annually (detailed version for new staff, refresher version for staff with >1 year experience).

(GP- 2) Reporting Methane Emissions observations and incidents

- | | | |
|---|-----------|---|
| <ul style="list-style-type: none"> • A reporting system is accessible for all staff to report methane emissions related observations or incidents; and • Recordkeeping guidance details what type of documentation needs to be submitted when methane emissions are detected outside routine LDAR inspections; and • Chain of command and notification processes are clearly outlined. | Mandatory | - |
|---|-----------|---|

(GP- 3) Estimating and measuring Methane Emissions

At minimum, operator’s guidance for measurement methods and calculation of methane emissions includes:	Mandatory	-
--	-----------	---

- All Site emission sources; **and**
- Quantification method for each emission source; **and**
- Reconciliation process for including all unintended emissions

(GP- 4) Continual improvement

Methane management is integrated into the Operator’s company culture, as evidenced by:	Mandatory	-
--	-----------	---

- documentation that references methane emission reduction best practices, such as educational material or an emissions incident bulletin program; **and**
- demonstrated knowledge of best practices to minimize emissions by the Facility’s operations staff; **and**
- a key performance metric for methane emissions (such as Methane Intensity) that is tracked for the Facility and regularly communicated with the staff.

3.2 Company Practices for Managing and Reducing Unintended Methane Emissions

Reducing Unintended methane emissions requires awareness and monitoring of areas where fugitive emissions may occur. Specific actions will include actively looking for Unintended methane emissions, tracking emission sources that have been repaired or replaced, developing preventative maintenance



plans, and confirming that all required repairs have been completed and verified in an appropriate timeframe. Company Practices relevant to these actions are stated below in Table 2.

Table 2: Company Practices for managing and reducing Unintended Methane Emissions (UMEP)

Practice	Character	Points
(UMEP- 1) Employee training and awareness		
Operational and maintenance team training includes:	Mandatory	-
<ul style="list-style-type: none"> Audial, Visual, and Olfactory (AVO) trainings for field personnel that detail how and why to make routine checks for methane emissions during site visits; and 		
Leak Detection and Repair (LDAR) method-specific trainings for:		
<ul style="list-style-type: none"> Method 21 [1] or equivalent - Operator's personnel responsible for carrying out inspection are trained in proper use of instruments, instrument calibration, inspection methods and regulatory requirements; and/or Optical Gas Imaging (OGI) – Operator's personnel responsible for use of OGI cameras are trained in the regulatory requirements for survey, calibration and proper use of the specific camera deployed by the Operator; and In the event LDAR surveys are carried out by third-party personnel, the Operator should be in possession of training records documenting the training of personnel hired; and/or alternative technology programs have consistent equipment operating and reporting procedures for consistent deployment. 		
(UMEP- 2) Source Level Detection Plan		
LDAR plan outlines at a minimum:	Mandatory	-
<ul style="list-style-type: none"> specific equipment/components included in LDAR survey (must reference connectors, open-ended lines, valve stem packing, PRVs blowdown/isolation valves, other compressor vent sources, access hatches and other tank vents at a minimum); and leak definition; and monitoring methodology (reference to equipment, frequency, conditions, reporting log); and repair or replacement strategy, including when to take immediate corrective action and when delay of repair is permitted; and first attempt at repair within 30 days of detection; and final repair attempt within 30 days from time of first attempt; and 		



- repair verification completed within 30 days of final repair attempt, if no safety concerns: **and**
- steps to be taken for delay of repair, including tagging, reporting, and tracking opportunities for follow-up repair, including equipment shutdowns: **and**
- clear roles and responsibilities for repair or replacement

(UMEP- 3) Directed inspection and maintenance

To manage methane emissions, Operators elect to:	Improved	1
<ul style="list-style-type: none"> • target major equipment (i.e. pneumatic controllers, thief hatches, natural gas vents, vapor recovery equipment, compressor vents, flares) for observation; and • use cumulative data to develop preventative maintenance plans; and • determine equipment to target based on accumulated historical data from LDAR inspection records [2]. 		

(UMEP- 4) Root Cause Analysis (RCA) of unintended emission events

<ul style="list-style-type: none"> • Operator has Root Cause Analysis (RCA) policies and procedures describing the process of conducting an analysis of the cause of unintended emission events and documentation of systematic corrective actions taken to limit and prevent reoccurrence. 	Improved	1
--	----------	---

3.3 Company Practices for Managing and Reducing Compressor Emissions

By implementing Company Practices to reduce methane emissions from compressors, Operators can ensure the amount of gas released is minimized.

Table 3: Company Practices for managing and reducing methane emissions from Compression Equipment (COMP)

Practice	Character	Points
(COMP- 1) Managing Methane Emissions from Compressors		
<ul style="list-style-type: none"> • Compressors, including screw compressors or others not characterized as reciprocating or centrifugal compressors, are included in LDAR surveys; and • Operator evaluates projects to reduce emissions from wet seal oil degassing systems by routing gas to a control device, routing 	Mandatory	-



to beneficial use, using a dry seal or another solution and demonstrates progress against project plans; **and**

- Operators implement preventative maintenance strategies for all compressors and their critical components based on run time. This includes compressor overhauls and inspection and maintenance of critical components (ex. compressor rings, packing, seals, bearings etc.); **and**
- Whenever maintenance occurs (or more frequently), operator/contractor inspects for and repairs causes of excessive leakage; **and**

(COMP- 2)

In addition to the above, Operators elect to:

(COMP- 2.1)

- | | | |
|---|----------|---|
| • mitigate vented methane emissions from at least 50% of centrifugal compressor inventory, compared to an uncontrolled wet seal oil degassing system; | Improved | 1 |
| or, | | |
| • mitigate vented emissions from 90% of centrifugal compressor inventory, compared to an uncontrolled wet seal oil degassing system. | | 2 |

(COMP- 2.2)

- | | | |
|--|----------|---|
| • Replace natural-gas driven compressor starts with non-venting compressor starts for at least 50% of compressor inventory | Improved | 1 |
|--|----------|---|

(COMP- 2.3)

- | | | |
|--|----------|---|
| • Facility has policies and procedures to keep compressors pressurized before and during downtime and/or routes compressor blowdown vent line to fuel; or | Improved | 1 |
| • Facility uses another solution to minimize emissions before and during compressor downtime. | | |

3.4 Company Practices for Managing and Reducing Blowdown Emissions

By implementing Company Practices to reduce methane emissions from equipment blowdowns, Operators can ensure the amount of gas released is minimized.



Table 4: Company Practices for managing and reducing methane emissions from Equipment Blowdowns (BD)

Practice	Character	Points
(BD- 1) Managing Methane Emissions from Blowdowns		
<ul style="list-style-type: none"> Operational repairs are coordinated with routine maintenance repair schedules to minimize total blowdown events; and All methane emissions from blowdown events are calculated using engineering calculations or metered volumes in lieu of generic emission factors. 	Mandatory	-
(BD- 2)		
In addition to the above, Operators elect to:		
(BD- 2.1)		
<ul style="list-style-type: none"> evaluate projects to minimize blowdown volumes from Facility equipment segments and demonstrate progress against project plans; and evaluate projects to minimize emissions from emergency shutdown (ESD) systems during testing and demonstrate progress against project plans. 	Improved	1
(BD- 2.2)		
Have policies and procedures to mitigate emissions from non-emergency blowdown events and;	Improved	
<ul style="list-style-type: none"> mitigates methane emissions from at least 25% of non-emergency blowdown events at the Facility,; or 		1
<ul style="list-style-type: none"> mitigates methane emissions from at least 50% of non-emergency blowdown events at the Facility, or 		2
<ul style="list-style-type: none"> mitigates methane emissions from at least 75% of non-emergency blowdown events at the Facility, or 		3
<ul style="list-style-type: none"> mitigates methane emissions from at least 90% of non-emergency blowdown events at the Facility, 		4



3.5 Company Practices for Managing and Reducing Pneumatic Device Emissions

By implementing Company Practices to reduce methane emissions from pneumatic devices, Operators can ensure the amount of gas released is minimized.

Table 5: Company Practices for managing and reducing methane emissions from Pneumatic Devices (PD)

Practice	Character	Points
(PD- 1) Managing Methane Emissions from Pneumatic Devices		
<ul style="list-style-type: none"> Procedures to maintain accurate inventory of pumps and controller counts by model that are checked annually at a minimum; and Policies and procedures to ensure controllers are operating as designed, based on type of service (on/off, throttling) and type of venting (continuous or intermittent), based on published vent rates for the model² or industry equipment standards; and Gas-driven pneumatic devices are included in LDAR surveys. 	Mandatory	-
(PD- 2)		
In addition to the above, Operators elect to:		
(PD- 2.1)		
<ul style="list-style-type: none"> Have installed non-venting (e.g. no bleed, mechanical, electric, or instrument air) pneumatics in place of gas-driven pneumatics for at least 50% of pneumatic devices. 	Improved	2
(PD- 2.2)		
<ul style="list-style-type: none"> Has a program in place to replace remaining venting devices with non-venting devices within 3 years of applying for Certification, and have demonstrated progress against this program; and/or Has a policy in place to install non-venting pneumatics on all new equipment installations. 	Improved	1

3.6 Company Practices for Managing and Reducing Storage Tank Emissions

By implementing Company Practices to reduce methane emissions from storage tanks, Operators can ensure emissions are minimized. Storage tank is defined as a tank within the Facility boundary that sits



on or above the ground and has the potential to emit significant methane emissions, excluding tanks that primarily store water

Table 6: Company Practices for managing and reducing methane emissions from Storage Tanks (ST)

Practice	Character	Points
(ST- 1) Managing Methane Emissions from Storage Tanks		
<ul style="list-style-type: none"> Operator implements procedures to mitigate hydrocarbon storage tank emissions for routine operations and maintenance; and Operator routinely monitors and inspects key areas that may be a source of methane emissions from tanks at least monthly, including, but not limited to, vapor recovery systems, thief hatches, dump valve problems (on upstream separators), and pneumatic controllers; and Operator implements policies and procedures for managing tanks which include not only observation of methane emissions but also preventative maintenance procedures based on historical problems on specific components of tank equipment. 	Mandatory	-
(ST- 2)		
In addition to the above, Operators elect to:	Improved	1
<ul style="list-style-type: none"> install tank pressure monitoring systems and alarms; or remotely observe tank batteries using integrated operation centers; or utilize automated tank gauging and reporting; or install thief hatch monitoring and automated reporting systems; or a combination of the above, or another solution that monitors tanks for abnormal process conditions 		
(ST- 3)		
<ul style="list-style-type: none"> utilizes a vapor recovery unit to direct vapors to beneficial use on hydrocarbon storage tanks; or utilizes a stabilization tower ahead of tanks to limit flash on downstream atmospheric hydrocarbon storage tanks; or routes hydrocarbon storage tank vapors to a control device; or installs mechanical tank controls, like a floating roof; or a combination of the above, or another engineering solution to mitigate vented emissions 	Improved	2



3.7 Company Practices for Managing and Reducing Flaring Emissions

By implementing Company Practices to reduce methane emissions from flares, Operators can ensure the amount of uncommuted gas is minimized.

Table 7: Company Practices for managing and reducing methane emissions from Flares (FLR)

Practice	Character	Points
(FLR- 1) Managing Methane Emissions from Flare		
Operators must implement:	Mandatory	-
<ul style="list-style-type: none"> • policies to define the use of routine and non-routine flaring, and acceptable durations of flaring events; and • procedures which define stable operating range and criteria for all flare systems, considering emergency events, to ensure maximum destruction efficiency²; and • design destruction efficiency is achieved through utilizing staff and/or contractors for inspections, including LDAR surveys of flare systems [2]; and • policies to flare or combust natural gas where recovery is not possible and limit gas routed to vents (Processing only) 		
(FLR- 2)		
Flares are managed to ensure flaring functionality and efficiency through control and engineering design. Systems may include:	Improved	1
<ul style="list-style-type: none"> • SCADA systems and logic controllers to monitor flare ignition; • auto ignition system for unsupervised flare stacks with intermittent flaring; • thermocouples (temperature sensors) to ensure pilots stay lit or flame out detection device installed. 		

² Temporary flares used explicitly during well completion and short-term routine maintenance are exempt.



3.8 Company Practices for Managing and Reducing Dehydrator Emissions

By implementing Company Practices to reduce methane emissions from dehydration systems, Operators can ensure the amount of gas released is minimized.

Table 8: Company Practices for managing and reducing methane emissions from Dehydration Systems (CE)

Practice	Character	Points
(DEHY- 1) Managing Methane Emissions from Dehydrators		
Operators must demonstrate:	Mandatory	-
<ul style="list-style-type: none"> Efforts to optimize and control circulation rates for glycol dehydrators 		
(DEHY- 2)		
In addition to the above, Operators elect to:	Improved	1
<ul style="list-style-type: none"> Using flash tank separation in dehydration and recapturing the flash gas for fuel gas; and Use dehydration processes that do not have a continuous vent in place of glycol dehydration processes, such as use of desiccant 		

3.9 Company Practices for Managing and Reducing Combustion Equipment Emissions

By implementing Company Practices to reduce methane emissions from onsite combustion equipment, Operators can ensure the amount of uncombusted gas is minimized.

Table 9: Company Practices for managing and reducing methane emissions from Combustion Equipment (CE)

Practice	Character	Points
(CE- 1) Managing Methane Emissions from Combustion Equipment		
<ul style="list-style-type: none"> Annual compressor power output from lean-burn gas engines accounts for less than or equal to 75% of total annual compressor power output from the Facility, or; 	Improved	2



<ul style="list-style-type: none"> Annual compressor power output from lean-burn gas engines accounts for less than or equal to 50% of total annual compressor power output from the Facility, or; 	3
<ul style="list-style-type: none"> Annual compressor power output from lean-burn gas engines accounts for less than or equal to 25% of total annual compressor power output from the Facility, or; 	4
<ul style="list-style-type: none"> Annual compressor power output from lean-burn gas engines accounts for less than or equal to 10% of total annual compressor power output from the Facility 	5
(CE- 2)	
Operator uses measurements or emission factors developed from representative measurements to calculate methane emissions from all compressor drivers	Improved 1

3.10 Company Practices for Managing and Reducing Gathering Pipeline Emissions

By implementing Company Practices to reduce methane emissions from pipelines, Operators can manage gathering pipelines so that incidents are quickly detected and mitigated

Table 10: Company Practices for managing and reducing methane emissions from Gathering Pipelines (GaP)

Practice	Character	Points
(GaP-1) Managing Methane Emissions from Gathering Pipelines		
<ul style="list-style-type: none"> Operator demonstrates knowledge of the physical locations of all pipeline assets in a Facility, or is actively pursuing a plan to remap assets with unknown locations 	Mandatory	-
(GaP-2.1)		
<ul style="list-style-type: none"> Operator conducts visual inspection of pipelines for signs of leaks at least annually; and Operator has policies and procedures relating to corrosion monitoring for all pipeline assets in a Facility 	Improved	1



(GaP-2.2)

- | | | |
|--|----------|---|
| | Improved | 2 |
| <ul style="list-style-type: none">• Operator has pipeline integrity management program with in-situ inspection for all pipelines conducted at least once every two years | | |
-

3.11 Required Evidence Available to Auditors

The Operator's Company Practices will be reviewed by the Auditor in advance of an onsite Audit. Among the purposes of onsite Audits are to interview personnel and observe operations activities to verify the understanding and implementation of the Company Practices for methane emissions management. The Auditor will use a combination of interviews and observations to determine whether the policies reviewed are effectively understood and implemented.

Required evidence of implementation of improved practices may include, but is not limited to, facility logs, equipment run time, P&IDs of improved design and maintenance inspection records. The Auditor may request additional documentation and metrics from the Facility for the purposes of the Annual Audit or subsequent Audits .



References

- [1] US Environmental Protection Agency (EPA). (2017). Method 21 - Determination of Volatile Organic Compound Leaks. Retrieved from <https://www.epa.gov/emc/method-21-volatile-organic-compound-leaks>
- [2] Methane Guiding Principles. (2019). Reducing Methane Emissions: Best Practice Guide - Equipment Leaks. Retrieved from <https://methaneguidingprinciples.org/best-practice-guides/equipment-leaks/>

MiQ STANDARD

for Methane Emissions Performance

SUBSIDIARY DOCUMENT 3: Monitoring Technology Deployment – Gathering & Boosting and Processing v1.1.0





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1 Introduction

The MiQ Standard for Methane Emissions Performance (the Standard) combines several Standard elements – (1) a calculated Methane Intensity, (2) Operator policies and procedures focused on methane emissions prevention, detection, and abatement (Company Practices), and (3) detection and mitigation of methane emissions through Monitoring Technology Deployment – to provide a robust and reliable method to certify natural gas production according to its methane emissions performance. The Standard is designed to incentivize continuous improvement in methane emissions monitoring and abatement.

The Standard consists of three main types of documents, to be read in the following order:

1. *Main Document – G&B, P*
2. *Subsidiary Documents*
 - a. *Subsidiary Document 1: Methane Intensity – G&B, P*
 - b. *Subsidiary Document 2: Company Practices – G&B, P*
 - c. **Subsidiary Document 3: Monitoring Technology Deployment – G&B, P (this document)**

This subsidiary document outlines requirements for Monitoring Technology Deployment for detection of Unintended methane emission sources.

Detecting and abating Unintended Sources of methane emissions is a key element of methane emissions management for a Facility. Detecting and tracking emission sources helps a Facility prioritize repair and maintenance activities, manage operational practices, and improve engineering design. Methane emissions can originate from many types of equipment and processes; therefore, effective, and frequent detection is essential to quickly identify and remediate Unintended methane emissions. Methods for both detection and measurement of methane emissions include approaches that are widely available and commonly implemented (including specified by regulation), as well as new and emerging technology solutions.

Methane emissions monitoring technologies can be deployed along a spectrum of spatial and temporal scales. Top-down approaches aggregate methane emissions from multiple Emission Sources at larger spatial scales (e.g. using aerial surveys or satellites), whereas bottom-up approaches are intended to detect individual Emission Sources at smaller spatial scales (e.g. using handheld devices or perimeter sensors). Both top-down and bottom-up monitoring approaches can vary in temporal scale based on factors such as cost and time to complete, with improved emissions detection capability with more frequent deployment. Continuous monitoring methods provide greater temporal coverage, however can provide variable spatial coverage and completeness. Gimbal scanning systems or regional towers often provide more complete spatial coverage, particularly for elevated sources, compared to fixed point



monitors (perimeter sensors). Figure 1 illustrates simplified examples of methane monitoring technologies in relation to spatial and temporal scale.

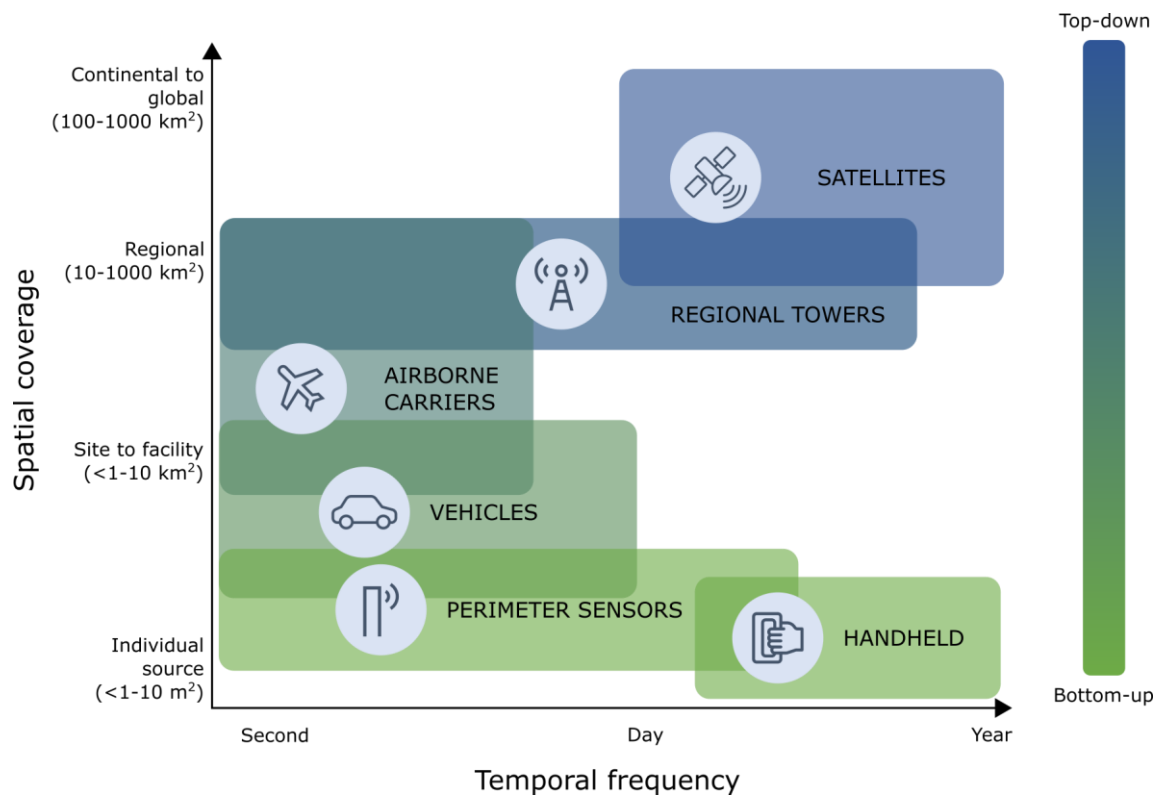


Figure 1: Methane monitoring technology across a variety of spatial and temporal scales (adapted from the National Academies of Science, Engineering, and Medicine, 2018[1])

Efforts to reconcile top-down and bottom-up Quantification approaches continue to develop through research and industry collaboration and are attempted in this Standard. The existing body of work reveals that top-down approaches often produce methane emissions estimates that are significantly higher than those from bottom-up approaches alone.[2][3]¹ These studies indicate that under-representation of abnormally high emission sources, commonly referred to as Super-Emitters, is one cause of this divergence[4]². Super-Emitters are spatially and temporally dynamic, and the characteristics that cause these emissions vary. Therefore, detection at both the Facility Level and Source Level, and at increased frequencies, is key to effective methane emissions management and mitigation.

¹ For example, David Allen et al. [2] and Adam Brandt et al. [3] examine the notable discrepancies between top-down and bottom-up methane emissions estimates.

² Brandt et al [4] examines the over representation of a majority of emissions (50%) from a small number of sources (5%) typically found in the super-emitter category.



Spatial scales referenced within the Standard, specifically with regards to methane emissions detection, are outlined below in Figure 2.

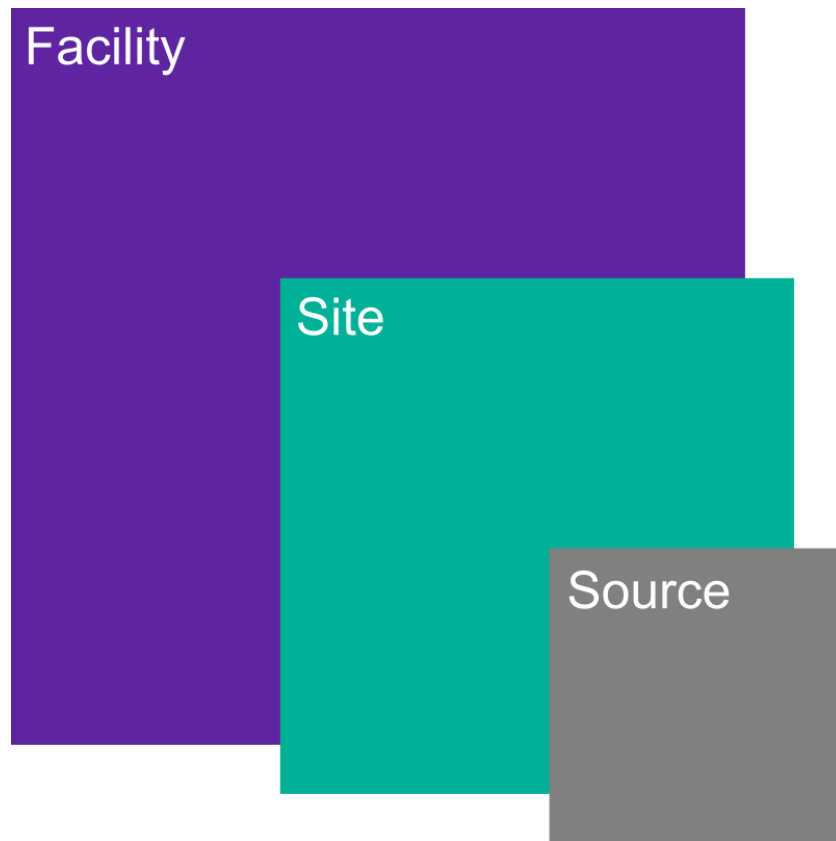


Figure 2: Spatial scales utilized within the Standard, referencing the definitions of Facility, Site, and Source as outlined in the *Main Document*, see there for reference.

2 Scope of this Document

This subsidiary document is part of the MiQ Standard and defines the Monitoring Technology Deployment criteria and requirements for compliance with the Standard. Monitoring Technology Deployment is considered a part of a holistic technology solution, which takes into consideration the sensor capabilities, deployment protocols, analysis methods and follow up protocol.

This document outlines the requirement for Monitoring Technology Deployment for the **detection** of methane emissions. This version does not require Measurement or Quantification through technology deployment currently. However, all detected emissions must be reconciled in an Operator's Inventory (see *Subsidiary Document 1: Methane Intensity Section 4*). Details of an Operator's calculations methods for quantifying or measuring detected emissions must be submitted as part of their reconciliation procedure.



As measurement technologies and their uncertainty improve and become available at scale, the Standard will be updated to reflect new required best practices.

3 Technology Deployment Objective and Performance Criteria

The primary objective of Monitoring Technology Deployment is to:

- demonstrate active management of methane emissions through identification of Unintended Sources, including Super-Emitters, followed up with necessary corrective actions.

This objective harmonizes with other elements of this Standard:

- to provide assurance of the calculated Methane Intensity using reconciliation (see *Subsidiary Document 1: Methane Intensity*)
- to implement better operating practices and equipment design for reduced methane emissions; and
- to encourage Operators to work towards Measurement of Emission Sources at their Facilities.

3.1 Key Performance Parameters

The overall grading system for the Standard is detailed in the *Main Document*. The MiQ Grade is determined based on the individual scores for each of the Standard elements: (1) Methane Intensity, (2) Company Practices, and (3) Monitoring Technology Deployment.

A Facility's score for Monitoring Technology Deployment is based on the following key parameters. These parameters are outlined in Table 1.

Table 1: Key Parameters

Parameter	Description
Frequency of	The minimum number of surveys per year.
Monitoring Technology Deployment	More frequent surveys, provide higher assurance in the identification and complementary repair and abatement of Emission Sources.



	The duration in-between surveys, should not exceed 150% of time indicated by the stated cadence ³ .
Sampling coverage of Monitoring Technology Deployment	The minimum percentage of Sites required to be surveyed within a Facility boundary. Achieving and maintaining uniformly low methane emissions levels will require detection technology deployment at a larger fraction of Sites integrating both Facility Scale and Source Level approaches over a given time-period.
Minimum Detection Limit (MDL) of Monitoring Technology	<p>The minimum rate of methane emissions detectable by a specific technology solution. Technologies with lower MDL can identify more (including smaller) methane emission sources.</p> <p>The technology solution required to achieve the desired MDL and detection probability⁴ must be applicable for the specific Facility and validated by the Auditor⁵.</p>

3.2 Performance Scoring

Tables 2 and 3 outlines the performance criteria and associated score for Monitoring Technology Deployment under the Standard. Both Facility Scale inspection for Site Level Super-Emitters, and Source Level leak inspections are specified.

An Operator is required, at a minimum, to conduct a baseline Source Level inspection over the entire Facility annually in order to be certified under this Standard. Operators can achieve a higher score by increasing the frequency and coverage of Source Level inspections, as well as Facility Scale inspections to identify Site Level Super-Emitters.

The MiQ Standard employs the concept of Equivalency to fulfill the Monitoring Technology Deployment requirements. The Frequency, Sampling coverage, and MDLs outlined in Table 2 below should be considered a benchmark for achieving a given number of points. An Equivalent LDAR program capable of detecting, characterizing, and mitigating an equivalent amount of methane emissions may be proposed

³ For example, quarterly surveys cannot be planned more than 4.5 months apart; triannual surveys cannot be planned more than 6 months apart; biannual surveys cannot be planned more than 9 months apart; annual surveys cannot be planned more than 18 months apart.

⁴ The validity of an MDL must be shown through a Probability of Detection (PoD) metric, which is the number of true positive detections divided by the number of possible detections at the emission rate. This metric can be provided by technology providers who have conducted a controlled-released field assessment at a testing facility or similar. For the purposes of this Standard, an PoD of at least 90% must be achieved for a given technology.

⁵ The methodology for determining an alternative Facility Level survey MDL (including sensor equipment, deployment characteristics, test method, and measurement period) must be presented to the Auditor during the Annual Audit period.



to the auditor, as demonstrated through a given Equivalency Determination (i.e. model and modelling assumptions, see Section 3.2.3).

The details for Facility Scale and Source Level inspection for leaks is outlined in Sections 3.2.1 and 3.2.2, respectively

Table 2: Technology Performance Criteria for all Equipment Except Gathering Pipelines

Facility Scale Inspection		Source Level Inspection ⁶	Grade Qualification ⁷
quarterly (MDL 25kg/hr)	entire Facility ⁸	quarterly	12
semi annually (MDL 25kg/hr)	entire Facility	semi annually	8
annually (MDL 25kg/hr)	entire Facility	annually	4
N/A	entire Facility	annually	0

Table 3: Technology Performance Criteria for Gathering

Facility Scale Inspection		Source Level Inspection ⁹	Grade Qualification
semi-annually (MDL 25kg/hr)	entire Facility ¹⁰	N/A	12
annually (MDL 25kg/hr)	entire Facility	N/A	8
N/A	N/A	N/A	0

⁶ Operators may choose to use alternative methods in conjunction with regulatory approved methods for Source Level inspection. AVO inspections are to be conducted in addition to this requirement (at the discretion of the Operator).

⁷ Grade qualification will be evaluated based on both Table 2 and Table 3's requirements. Operator will receive the lowest of the two point totals. Point totals from Table 2 and Table 3 are not additive.

⁸ Facility Scale coverage must include all operated equipment within the Facility. For example, this could include an entire gas processing plant, all equipment within compressor station batteries or batteries with other process equipment, such as acid gas removal units or dehydrators and all gathering pipelines in the Facility. If the Facility is not aware of the exact location of equipment, especially underground equipment, that Facility should develop and implement a plan to locate this equipment during certification.

⁹ Operators may choose to use alternative methods in conjunction with regulatory approved methods for Source Level inspection. AVO inspections are to be conducted in addition to this requirement (at the discretion of the Operator).

¹⁰ Facility Scale coverage must include gathering lines within the Facility.



3.2.1 Facility Scale Inspection

The intention of a Facility Scale inspection is to provide assurance that potential abnormally high emissions are being monitored while more efficiently screening for unintended emissions sources that may be followed up for Source Level detection and repair prioritization. This Standard is technology neutral, however a Facility scale inspection:

- must cover the entire certified Facility including elevated sources in three-dimensional space and buried sources
- must be deployed at the frequency designated in Tables 2 and 3 above
- must meet the designated MDL of 25kg/hr¹¹ at 90% POD proven through single blind, controlled release testing (see Table 4 for additional record keeping requirements).
- must attribute the source to a single Site spatial boundary for follow up inspection
- may utilize multiple inspection methods in combination
- Continuous Monitoring Systems are an accepted form of Facility Scale inspection provided they meet the performance criteria above (See Table 4 and Table 5 for additional LDAR program and recordkeeping requirements).
 - Operators may choose to demonstrate equivalent monitoring using Continuous Monitoring Systems over a subset of Sites (<100% coverage) paired with Source Level methods and/or other periodic Facility scale survey methods, to achieve the same level of detection and mitigation potential as outlined in Table 2 (see Section 3.2.3. for more information on demonstrating equivalency).

Emission events detected via Facility Scale inspections must be documented, repaired and/or mitigated following the timelines and requirements listed in *Subsidiary Document 2: Company Practices*. Facility Scale inspections may also identify emissions from planned events or from intended sources that are already accounted for in a Facility's emission inventory. The detected source must still be investigated to determine if the source exceeds the expected rate and ascertain if the event requires follow-up or mitigation.

If inspections across the last 12 months detect no additive emissions for the entire Facility, the survey frequency can be reduced to the next lower score level, either via Table 2 or the Operator's equivalency determination. For Operators using Facility Scale Inspection technologies with a MDL less than 25 kg/hr

¹¹ Facility Scale MDLs chosen to best encompass possible super-emitters from the supply chain, based on learnings from Brandt et al [3] where the largest 5% of leaks which are responsible for more than 50% of the total volume or the highest-emitting 1% of sites in a site-based distribution (Zavala-Araiza et al. [5]).



at a 90% probability of detection survey frequency can also be reduced if the operator does not detect additive emissions from any site that total greater than 25 kg/hr. Operators may not reduce Facility Scale inspection frequency using this clause any lower than once per year for the Facility and achieve at least 4 points.

An inspection recordkeeping form and corrective actions log must be populated for each survey and available for Audit (refer to Section 4).

3.2.2 Source Level Inspection

The intention of the Source Level inspection is to identify and detect sources of Unintended methane emissions to the equipment and component level, for repair or replacement and as a key ingredient of operational hygiene. The Source Level inspection methods employed by the Operator must be detailed in the Operator's LDAR program.

This Standard is technology neutral, however the following are applied to Source Level monitoring methods:

- Spatial resolution must be sufficiently low to reliably attribute emission sources to the component or equipment level for repair, maintenance, or mitigation
- be deployed at or above the specified frequency outlined in Table 2, unless using an Equivalent LDAR Program.
- distinguish methane emissions from incomplete combustion from fugitive leaks or excess vented emissions, especially in the case of vented emission sources that are located near an exhaust stack.
- may utilize multiple inspection methods in combination
- Continuous Monitoring Systems which meet the above criteria may be applied towards Source Level inspection over the percentage of Sites where it is deployed. For such usage, detection capabilities based on placement, data analysis and relay, must be evaluated by the Auditor during the Annual Audit (refer to Section 4.2 for required evidence).

Follow-up of an emission detected to using a Source Level inspection method *can count* towards an Operators' compliance with the requirements in Table 2.

For Sites, Gathering & Boosting Equipment or Processing Equipment which have no additive detections over the last 12 months, the survey frequency can be reduced to the next lower score level, either via Table 2 or through results of the Operator's equivalency determination. Equivalency determinations must still be made at the score the Operator is being evaluated at (see Section 3.2.3 for more detail). Operators may not reduce Source Level inspection frequency using this clause any lower to once per year for any Site or Equipment.



Sources with confirmed detections must be scheduled for repair or replacement, as per the Operator's LDAR program. The validation of repaired leaks must be specified in the program and occur within the time period defined in *Subsidiary Document 2: Company Practices*. Repair validations completed with the approved Source Level inspection methodology *do not count* towards the Source Level inspection frequency.

An LDAR Site inspection recordkeeping form and repair log must be populated for each survey event and available to the Auditor. Changes to the Monitoring Technology Deployment program arising from adverse weather conditions (affecting personnel safety and/or the technology operating envelope), difficult to monitor locations, and delay to repair or replacement for any other reason must be logged and communicated with the Auditor (refer to Section 4).

3.2.3 Equivalency Determination

The frequency and spatial coverage of monitoring technology deployment in the Standard has been constructed to apply to generic Facilities in varying geographies. Demonstration of equivalent emissions detection and mitigation capabilities from a substitute or Equivalent LDAR program utilizing a combination of aerial, ground-based, Continuous Monitoring, or other methods for a given Facility may be provided using accepted equivalency models or simulations (such as FEAST, LDAR-SIM[6][7], or other). Evidence must be provided to the Auditor including models inputs and assumptions supporting the conclusion that a given monitoring strategy can meet or exceed the same emissions detection and mitigation, as that outlined in Tables 2 and 3, in order to achieve the same number of points. Modeling inputs and assumptions include, at minimum

- emissions distribution curve representative of the facility and included sources
- emissions durations or temporal intermittency
- monitoring technology capabilities, frequency of deployment and spatial coverage
- latency in processing and reporting of emissions
- time to follow up and repair.

Equivalent LDAR Programs must meet the same program and recordkeeping requirements (see Table 4 and 5) and minimum coverage requirements outlined above

4 Recordkeeping and Reporting Requirements

Operators are required to record and disclose information related to methane emissions Monitoring Technology Deployment plans and implementation under the Standard. Deployment plans and supporting implementation information must be disclosed to the Auditor during the Annual Audit. Proof



of implementation of the deployment of each monitoring technology solution must be disclosed to the registry during the Certification Period and to the Auditor during the subsequent years' Annual Audit. Table 4 outlines the minimum recordkeeping requirements for Monitoring Technology Deployment. An Operator can choose to aggregate the recordkeeping elements to minimize administrative overhead. An Operator must have adequate Company Practices in place which underpin accurate recordkeeping and reporting structures.

4.1 Minimum Recordkeeping and Reporting Requirements

Table 4: Minimum recordkeeping requirements for Facility Scale and Source Level inspection

Recordkeeping element	Details
Detection Technology Specifications	<p>Technology specifications are required for methods that meet Facility Scale and Source Level requirements</p> <ul style="list-style-type: none"> • Sensor and instrumentation details • Method in which the sensor deployed (i.e. fixed-wing, drone-based, stationary-mounted) • Performance specifications including minimum detection limit and probability of detection curves • Details of independent, single-blind testing, including <ul style="list-style-type: none"> ○ Third party used to conduct testing ○ Confirmation of single-blind nature of testing ○ Operating conditions of equipment used for testing ○ Variables tested that could affect the sensitivity of the technology and the ranges tested (i.e. humidity, temperature, wind speed, groundcover, obstruction, solar irradiation) ○ Calibration protocols used during testing ○ If operator uses technology for quantification, characterization of emission rate uncertainty
Work Practice Specifications	<ul style="list-style-type: none"> • Frequency of surveys and routes taken if sensors are not deployed in stationary positions • Alarm criteria, including the alarm threshold used for each type of event • Deployment specifications for individual Sites to replicate location and environmental criteria determined during controlled released testing. <ul style="list-style-type: none"> ○ If a third party is contracted for the survey, this should also include contractor or data service provider information.



- To include details for both Facility Level and Source Level inspections.

Detection Follow up Protocols	<ul style="list-style-type: none"> • Emission detection workflow (i.e. follow-up processes taken after alarm) • Emission classification workflow (i.e. tracking new events, allowable events detected, and failed repair validations) • Data system that stores and manages detected emission events • Repair planning and repair validation procedure • Causal Examination procedures
Facility Scale and Source Level/LDAR inspection recordkeeping form	For each Emission Source, includes component/equipment/site ID and type, date of all repair efforts (first attempt, additional attempts, final attempt), repair validation date, success of repair or replacement, and (if applicable) a reason for delay to repair or replace and the date rectified.
Source Level/LDAR monitoring location log	Includes a list of monitoring locations planned (for at least the Certification Period) and visited for each survey (categorized by Site ID or similar unique identifier).
QA/QC	Includes chain of custody sign off on data collected for accuracy (collector to independent reviewer), analytical settings as appropriate, calibration of monitoring equipment, and reference to the test method used.

4.2 Recordkeeping and Reporting Requirements for Continuous Monitoring Technology

As discussed in Section 3.2.1 and 3.2.2, a Facility may choose to utilize a Continuous Monitoring System over all or part of their Sites to meet the requirements of a Facility Scale or Source Level inspection. Table 5 outlines the minimum records an Operator must submit to the Auditor for use of Continuous Monitoring System.

Table 5: Recordkeeping requirements for continuous monitoring systems

Recordkeeping element	Details
Continuous/High Frequency Monitoring System details	Documentation should include details of the System, including but not limited to:



-
- Placement and coverage characteristics of monitors based on independent, single-blind testing
 - Probability of detection curve and MDL
 - Temporal coverage or duty cycle
 - Analysis used for monitor placement
 - Data communication system (i.e. cell tower, wired data)
 - Meteorological data collected for source identification and emission rate determination
 - Location where meteorological data is taken
 - Interconnection between data collection system, alarm system and work order processing system
 - Operator response to monitor downtime (i.e. backup monitoring plan)
 - Monitoring equipment calibration protocols (i.e. frequency, technology-specific parameters that are calibrated)
-



5 Interconnections with other Standard Elements

Each of the Standard Elements (Methane Intensity, Company Practices, and Monitoring Technology Deployment) is to be assessed separately; however, all are interconnected given their collective role in indicating effective methane emissions management. Monitoring Technology Deployment tangibly intersects with, and influences the score for, the other two Standard Elements.

5.1 Interconnection with calculated Methane Intensity

When calculating annual methane emissions for use in the Methane Intensity calculation as required by *Subsidiary Document 1: Methane Intensity*, Operators must reconcile methane emissions discovered from an inspection using the technology's quantification capabilities, engineering calculations, or other methods representative of emissions events discovered. See *Section 3.3 Emissions Reconciliation* for requirements of incorporating emissions discovered during Facility inspections.

This Standard allows Operators to incorporate Facility-specific emission calculation methodologies to characterize a Facility's methane emissions profile more accurately (refer to *Subsidiary Document 1: Methane Intensity, Annex A, Table 2* for more detail). Inspections undertaken by the operator that include emissions measurement capabilities must be utilized if the operator develops Facility-specific Emission Factors for individual emission sources.

5.2 Interconnection with Company Practices

A Monitoring Technology Deployment plan is detailed as required Company Practices, to ensure follow up actions are taken from an inspection where a methane emissions detection was observed, specifically:

- Monitoring Technology Deployment for LDAR;

and its implementation in large part rests on the effectiveness of these and other Company Practices, including:

- employee training and awareness;
- estimating and measuring methane emissions; and
- other Practices designed to reduce Intended and Unintended methane emissions.



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