MiQ STANDARD

for Methane Emissions Performance for Petroleum Operations

MAIN DOCUMENT – Onshore Production

v1.0

Contents

1 Background

1.1 Introduction

Methane emissions (CH_4) from oil and gas production 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]. Methane is emitted throughout both the oil and natural gas supply chains. This Standard addresses methane emissions from the production of oil and natural gas.

Methane is emitted in the process of producing natural gas through venting, leaking and incomplete combustion from flares, burners and engines. 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 from Petroleum Operations (the Standard) combines several Standard elements – (1) a calculated Methane Intensity, (2) Producer 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 methane emissions from oil and 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 two main types of documents, to be read in the following order:

1. **Main Document – Onshore Production (this document)**
2. Subsidiary Documents
    a. *Subsidiary Document 1: Methane Intensity – Onshore Production*
    b. *Subsidiary Document 2: Company Practices – Onshore Production*

[1] According to IPCC AR6, the global warming potential (GWP) of methane is 82.5 times that of CO_2 over a 20-year period, and 25 times more potent than CO_2 over a 100-year period.

c. *Subsidiary Document 3: Monitoring Technology Deployment – Onshore Production*

1.2 About

MiQ Foundation, a non-profit entity, is the Standard Holder for this Standard. The Standard was developed to increase the transparency of, and ultimately reduce, methane emissions from the global oil and gas industries through a market-based oil and gas certification system.

1.3 Purpose

The purpose of the Standard is to incentivize continuous improvement in reporting and reduction efforts of methane emissions, including methane monitoring and abatement efforts, by creating an consistent approach for Producers to differentiate their oil natural gas production by its 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 and measure methane emissions;

c) to increase transparency regarding the methane emissions performance of oil and natural gas production, with a globally consistent methodology;

d) to enable Producers, marketers, and buyers to transact oil and natural gas based on the methane emissions performance of a Facility, and to demonstrate additional value to their customers;

e) to provide Producers, buyers, and investors a uniform, independently verified Standard consistent with environmental, social, and governance (ESG) reporting to address methane emissions from oil and natural gas production and consumption;

f) to complement regulations by incentivizing methane emissions detection and abatement actions that exceed regulatory requirements; and

g) to credibly recognize Producers who are leading their peers in methane emissions management.

2 Scope

This Standard establishes a system for the generation of an MiQ Grade which 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 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 Facilities in the onshore production segment (see Terms and Definitions);
- specifies a method to calculate the Methane Intensity of natural gas (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, and abatement and deployment of methane monitoring technology (see *Subsidiary Document 2: Company Practices* and *Subsidiary Document 3: Monitoring Technology Deployment*); and
- does not define requirements for the physical or chemical quality of oil and natural gas.

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 Producer 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 Producer's 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[2] 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

[2] Supervisory Control and Data Acquisition

Company Practices	A document, program, policy or procedure, specific to the Producer 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.
Lease Condensate	Light liquid hydrocarbons recovered from lease separators or field facilities at associated and non-associated natural gas wells. Mostly pentanes and heavier hydrocarbons. Normally enters the crude oil stream after production.[3]
Continuous Monitoring System	A methane monitoring system at a Facility that: (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

[3] Consistent with definition of lease condensate given by Energy Information Administration (EIA) per https://www.eia.gov/tools/glossary/

	include lease condensate that is later mixed into the crude stream.[4]
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.
Facility	All contiguous onshore oil and natural gas production sites and equipment (including leased, rented, or contracted) located in

[4] Consistent with definition of crude oil given by Energy Information Administration (EIA) per https://www.eia.gov/tools/glossary/

	a single geologic basin, field, or subfield under the responsibility of a common owner or operator. The Facility boundary for Onshore Production may include all upstream emissions with the potential to emit, including wellsite compression, gathering lines and treatment.
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.
Gas Ratio	The ratio defined as the total energy of natural gas throughput and the total energy of both natural gas and hydrocarbon liquids throughput of the Facility.
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_2e), which is calculated using a timeframe-specific Global Warming Potential (GWP).
Intended Emission Sources	Intentional releases 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.
Hydrocarbon Liquids	A general term encompassing all crude oil, lease condensate and any other liquid-phase hydrocarbons at the sales point of the Facility
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 inspection or 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 (in mass units) relative to the entire throughput (in energy units) of all natural gas and hydrocarbon liquids products.
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	A group of hydrocarbons including ethane, propane, normal butane, isobutane, and natural gasoline that are extracted from feedstock gas entering a natural gas processing plant. [5]
Onshore Oil and Natural Gas Production	The oil and gas supply chain segment that includes all equipment, piping, instrumentation and controls and portable non-self-propelled equipment used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate) contained on a wellsite upstream of the transfer point to a gathering system. Equipment may include, but not limited to, compressors, generators, dehydrators, storage vessels, engines, boilers,

[5] Consistent with definition of lease condensate given by Energy Information Administration (EIA) per https://www.eia.gov/tools/glossary/

	heaters, flares, separation and processing equipment, connecting pipework, gathering lines, and portable non-self-propelled equipment, which includes well drilling and completion equipment, workover equipment, and leased, rented or contracted equipment. Production equipment may also includes associated storage or measurement vessels, all petroleum and natural gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island.
Producer / Operator	The owner and operator of a Facility, responsible for operating a well or wells that recover and bring oil and gas to the surface, whether or not in conjunction with byproducts.
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 estimate. The process cross-references top-down detections and quantified emissions 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 a Producer 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	The wellpad, tank battery, or other equipment pad encompassing an oil and natural gas production well (including multi wells) and its supporting equipment, such as that used for separation, treating, compression, gathering and storage. Inspections conducted at the Site level must be able to narrow the location of the methane emission to a single wellpad or localized area for a follow up 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 a Source Level 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 the 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.
Production Throughput	Natural gas production throughput is the quantity of gas sold in the calendar year from wells. This includes gas that is routed to a pipeline but excludes gas vented or flared or used in field operations. This does not include gas injected back into reservoirs. Hydrocarbon liquids throughput is the total quantity of hydrocarbon liquids sold in the calendar year from wells.
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.

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. This Standard provides requirements for Producers to differentiate the supply of their product based on its methane emissions performance. The application of this Standard is a voluntary action taken by a Producer.

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	· defining and managing all aspects of the development of the Standard · publishing the Standards and supporting documents · managing updates and changes to the Standards
Auditor/Auditing Body	· conduct Annual Audit in accordance with requirements defined in this Standard and the MiQ Program Guide. · Recommend a Grade for a Facility on methane emissions performance
Producer	· 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)* · Submitting Audit Report to the Issuing Body
Issuing Body	· 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 is eligible to produce certified oil and gas under this Standard using 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 oil and natural gas within the global supply chain. To this end, a certification boundary must encompass and represent all contiguous upstream emission sources and corresponding throughput within an operating basin, subbasin or geologic field. See the definitions of *Site* and *Facility* for further details.

- **Organizational boundary**

  Facilities must fall 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 qualify for certification 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 the *Subsidiary Document 2: Company Practices*.

3. **Monitoring Technology Deployment**

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

6.2 Grading System

Table 2 details the overall grading system for the segment reflected within the Standard. The 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	**Methane Intensity (g CH_4/BOE total throughput)**	**Company Practices** (Improved Practices points)	**Monitoring Technology Deployment**
A	≤ 50.0	≥ 12	12
B	≤ 100.	≥ 8	8
C	≤ 200.	≥ 4	4
D	≤ 500.	Mandatory minimum	Mandatory minimum
E	≤ 1000.	Mandatory minimum	Mandatory minimum
F	≤ 2000.	Mandatory minimum	Mandatory minimum

7 Subsidiary Documents

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

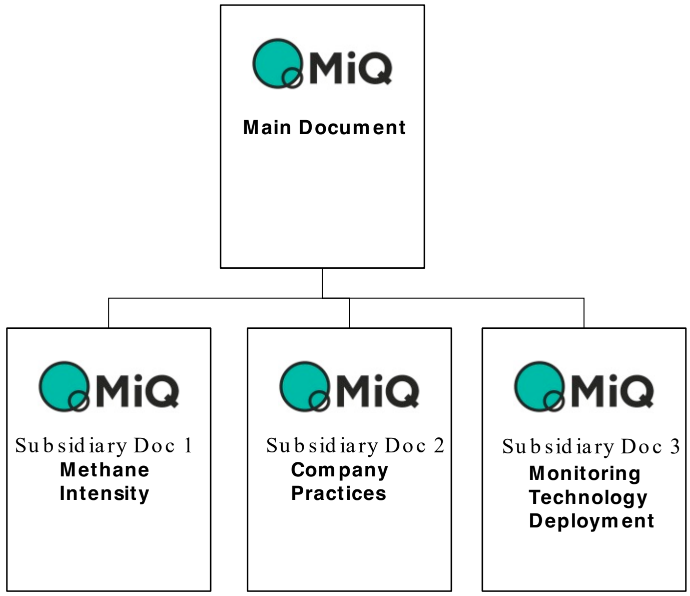

Figure 1: Document hierarchy

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 [Sm^3]	**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.

Producers currently undergoing certification must comply with the latest version of the Standard for their Annual Audit if it falls greater than 12 months from publication date.

B.2 Version History

The following table captures key changes made to the Onshore Standard.

Table 4: Version History

Version	Revision Date	Document	Summary of Change
V_draft	2024-02	All	Stakeholder Review
v1.0	2024-05	All	Final Standard version

References

[1] Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, … B. Zhou (2021). Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge, United Kingdom and New York, NY, USA: Cambridge University Press. Retrieved from https://www.ipcc.ch/report/ar6/wg1/

[2] Brandt, A. R., Heath, G. A., & Cooley, D. (2016). Methane Leaks from Natural Gas Systems Follow Extreme Distributions. Environmental Science & Technology, 50(22), 12512–12520. https://doi.org/10.1021/acs.est.6b04303

[3] Zavala-Araiza, D., Alvarez, R. A., Lyon, D. R., Allen, D. T., Marchese, A. J., Zimmerle, D. J., & Hamburg, S. P. (2017). Super-emitters in natural gas infrastructure are caused by abnormal process conditions. Nature Communications, 8(1, 1), 14012. https://doi.org/10.1038/ncomms14012

[4] ISEAL Alliance. (2013). ISEAL Credibility Principles: Principles for Credible and Effective Sustainability Standards Systems. Retrieved from https://www.isealalliance.org/defining-credible-practice/iseal-credibility-principles

[5] Society of Petroleum Engineers (SPE). (2020, February 26). Recommended SI units and conversion factors. PetroWiki. Retrieved October 26, 2020, from https://petrowiki.org/Recommended_SI_units_and_conversion_factors

[6] International Organization for Standardization. (1996). ISO 13443:1996, Natural gas — Standard reference conditions. Retrieved from https://www.iso.org/standard/20461.html

[7] Engineering Toolbox. (2005). Heat Value. Retrieved October 26, 2020, from https://www.engineeringtoolbox.com/gross-net-heating-value-d_824.html

MiQ STANDARD

for Methane Emissions Performance for Petroleum Operations

SUBSIDIARY DOCUMENT 1: Methane Intensity – Onshore Production

v1.0

Contents

1 Introduction

The MiQ Standard for Methane Emissions Performance from Petroleum Operations (the Standard) combines several Standard elements – (1) a calculated Methane Intensity, (2) Producer 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 methane emissions from oil and 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 – Onshore Production*
2. Subsidiary Documents
    a. **Subsidiary Document 1: Methane Intensity – Onshore Production (this document)**
    b. *Subsidiary Document 2: Company Practices – Onshore Production*
    c. *Subsidiary Document 3: Monitoring Technology Deployment – Onshore Production*

This subsidiary document outlines the calculation of Methane Intensity as it pertains to the Standard. Methane Intensity, ,as defined in Section 3 of the *Main Document,* is a baseline indicator of methane emissions performance. See Section 3 of this document 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 oil and natural gas supply chain by its methane intensity and performance. The MiQ Standard requires all sources to be accounted for as part of the emissions calculation methodology. 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 oil and natural gas production from onshore Facilities.

3 Methane Intensity

Under this Standard, Producers are required to calculate Methane Intensity and 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

Under this Standard, a Facility's Methane Intensity is to be calculated following the methodology detailed in Annex A. It enables Producers 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*.

Methane Intensity is calculated every 12 months, in g CH_4/BOE of total energy throughput. For example, a Producer can calculate its natural gas methane intensity using the following equation:

$$Methane\ Intensity = \frac{Methane\ Emissions\ (mass\ units)}{Total\ Energy\ Throughput\ (energy\ units)}$$

Unit conversion factors necessary to complete the Methane Intensity calculations 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 Producer'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.

Producers are encouraged to utilize quantification methods specific to their Facility. In each case, the Producer 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 indiscriminately.
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 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, as detailed in the score requirements in the *Main Document, Section 6.2*.

As part of the Annual Audit, producers 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 Producer. New certified Producers 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 surveys[1] or 3 months of continuous monitoring results from a sample of a Producer'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, Producers 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:

Table 1: Recordkeeping Requirements

Aspect	Detail
Facility Description	Producers must document all Production Equipment or assets that make up a Facility, including Production Equipment added as a result of development activity, or removed due to abandonment, shut-in, divestiture, or any other changes made during the Certification Period.
Methane Intensity Calculation Inputs	Producers must document the oil and natural gas throughput used in calculating Methane Intensity including the source of data for throughput.

[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.

	If necessary for purposes of calculating product-specific methane intensities, the factor used for energy content of natural gas (and the basis for this value) and the factor used for energy content of liquids (and the basis for this value)) must be disclosed.
Equipment Counts	For use in emissions calculations, producers 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	For use in emissions calculations, producers must document the activity data associated with each emission source (e.g. operating time, vessel or well volume criteria, estimated leaking time for leaker emission sources). Producers must also document their observations of leaking components using LDAR (see *Subsidiary Document 3: Monitoring Technology Deployment, Section 5.1* for more detail).
Calculation Methods	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. Producers must document the method, assumptions used along with its rationale, and its application to the calculation. For enhanced quantification methods, Producers must document all calculation and/or modelling assumptions, and/or technical specifications of measurement technologies deployed.
Reconciliation Procedure	Producer must provide a detailed procedure outlining their process for reconciling emission events identified during detection surveys completed in accordance with *Subsidiary Document 3: Monitoring Technology Deployment*, 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 3.2).

Processes and responsibilities	Producers 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 onshore oil and natural gas Production 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. Producers shall, in their emissions reporting, indicate the method(s) used to quantify each emission source.

Measurement-informed inventories are highly encouraged throughout the Standard. Producers 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 [2] or OGMP 2.0 Level 4/5[3], and confirmed by the Auditor.

Table 2: Types of Calculation methods

Calculation method type	Clarification
Direct Measurement	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. The frequency of direct measurement must be disclosed.

Indirect Measurement	Quantifies methane emissions indirectly (by proxy). Typically, this involves measuring methane volume to a specific piece of equipment through a flow instrument installed in the (fuel) supply header and multiplying this volume with an Emission Factor to quantify emissions from that piece of equipment. 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. The frequency, spatial coverage, and uncertainty as determined by controlled releasee testing of indirect measurement must be disclosed.
Engineering Calculation/Process Simulation	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	Generic Emission Factors are often provided or referred to in national legislative reporting requirements. 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.

A.1.2 Emission Sources from Onshore Oil and Natural Gas Production Facilities

Methane emissions from Onshore Production are to be accounted for from all potential emission sources. Producers are required to aggregate methane emissions estimates from all relevant emission sources to calculate Methane Intensity.

Under this Standard, Onshore Production is defined as:

> The oil and gas supply chain segment that includes all equipment, piping, instrumentation and controls and portable non-self-propelled equipment used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate) contained on a wellsite upstream of the transfer point to a gathering system. Equipment may include, but not limited to, compressors, generators, dehydrators, storage vessels, engines, boilers, heaters, flares, separation and processing equipment, connecting pipework, gathering lines, and portable non-self-propelled equipment, which includes well drilling and completion equipment, workover equipment, and leased, rented or contracted equipment. Production equipment may also included associated storage or measurement vessels, all natural gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island.

Emissions sources must be accounted for within the Facility boundary. If there are emission sources not listed below within the Facility, these emissions also must be accounted for using calculation methodologies approved by the Auditor. The methodology requirements listed below refer to a minimum level of Facility specificity. It is strongly encouraged that Producers use more specific methodologies to calculate source-specific emissions where possible.

Table 3: Minimum Calculation and Allocation Requirements by Onshore Production Emission Sources

Emission Source[2]	**Minimum Emission Calculation Requirements**[3]	**Examples of Accepted Methodologies**[4]
Acid Gas Removal Units	Emission-factor based calculation using an emission factor representative of AGRU venting, along with the number of AGRUs.	API Compendium 6.3.8.4 [1]; OGMP TGD Purging and venting (L3) [3]; GHGI[5] [4]; 40 CFR 98.233 (d) [5]; AQM 4.12 [6]; WCI.363(c) [7]
Associated Gas Flaring	Engineering Calculation using volume of oil produced, gas to oil ratio (GOR), and volume of associated gas sent to sales; accounting for flare control as applicable.	API Compendium 5.1 [1]; OGMP TGD Flare efficiency (L3-L4) [3]; 40 CFR 98.233(m)[5]; AQM Eqn. 2-1a, 2-1b [6]; WCI.363(j) [7]; NGER 3.3.9A.10 (Method 2A) [8]
Associated Gas Venting	Engineering Calculation using volume of oil produced, gas to oil ratio (GOR), and volume of associated gas sent to sales.	API Compendium 6.3.1 [1]; OGMP TGD Purging and venting (L4) [3]; 40 CFR 98.233(m) [5]; AQM Section 4.2.2, 4.2.3 [6];WCI.363(j) [7]; NGER 3.3.2.3 (Method 4) [8]
Blowdowns (Compressors)	Emission-factor based calculation using an emission factor representative of the blown down equipment, along with the number of compressors of like type.	API Compendium 6.4.6.1 [1]; OGMP TGD Purging and venting (L3-L4) [3]; GHGI[6] [4]; 40 CFR 98.233 (i) [5]; AQM Eqn. 4-5a, 4-5b [6]; WCI.363(g) [7]; NGER 3.3.9A.9 (Method 1) [8]

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[2] A Producer'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] These requirements are for a Producer's bottom-up emissions inventory. The reconciliation requirements listed in Section 3.3 are applicable along with compliance with the requirements in Table 3.

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

[5] 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 a Producer's reconciliation process. Year-over-year as measurement data becomes more available, Producers should eliminate usage of generic factors.

Blowdowns (Vessels)	Emission-factor based calculation using an emission factor representative of the blown down equipment, along with the number of vessels of like type.	API Compendium 6.4.6.1 [1]; OGMP TGD Purging and venting (L3-L4) [3]; GHGI[6] [4]; 40 CFR 98.233 (i) [5]; AQM Eqn. 4-5a, 4-5b [6]; WCI.363(g) [7]; NGER 3.3.9A.9 (Method 1) [8]
Combustion Units (Gas compressor drivers)	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 [1]; OGMP TGD Incomplete combustion (L3-L4) [3]; AQM Eqn. 1-5, 1-5a [6]; WCI.363(w), WCI.20 [7]; NGER 2.3.5 (Method 2) [8]
Combustion Units (Non-compressor drivers)	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 [1]; OGMP TGD Incomplete combustion (L3-L4) [3]; AQM Eqn. 1-5, 1-5a [6]; WCI.20, WCI.363(w) [7]; NGER 2.3.5 and 2.4.5 (Method 2) [8]
Compressor Starts	Emission-factor based calculation using an emission factor representative of the compressor starter, a number of starts.	API Compendium 6.4.6.2 [1]; GHGI[6] [4]; AQM 4.19 [6]; NGER 3.3.9A.9 (Method 1) [8]
Compressor Venting (Centrifugal – dry seals)	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 [1]; OGMP TGD Centrifugal compressors (L3-L4) [3]; GHGI[6] [4]; 40 CFR 98.233(o) [5]; AQM 4.9.2 thru 4.9.4 [6] ; WCI.363(l) [7]
Compressor Venting (Centrifugal – wet seals)	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 [1]; OGMP TGD Centrifugal compressors (L3-L4) [3]; 40 CFR 98.233(o) [5]; AQM 4.9.2. thru 4.9.4 [6]; WCI.363(l) [7]
Compressor Venting (Reciprocating compressors)	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.	API Compendium 6.4.3.1 [1]; OGMP TGD Reciprocating compressors (L4) [3]; 40 CFR 98.233(p) [5]; AQM 4.9.2. thru 4.9.4 [6]; WCI.363(m) [7]; NGER 3.3.6A.1 (Method 2)[8]

	number of compressors or number of cylinders).	
Dehydrator Vents	Engineering calculations or computer modeling dependent on the type of dehydrator.	API Compendium 6.3.8.1 thru 6.3.8.3 [1]; OGMP TGD Glycol dehydrators (L4) [3]; OGMP TGD Purging and venting (L4) [3]; 40 CFR 98.233(e) [5]; AQM 4.10.2 [6]; WCI.363(d) [7]
Equipment Leaks (All fugitive components)	Population emission factor-based method using emission factors that best represent conditions and practices of the Facility. *Note that equipment leaks identified by non-regulatory LDAR surveys including those undertaken to meet Monitoring Technology Deployment requirements MUST also be included.*	API Compendium 7.2.2.2 thru 7.2.2.4 [1]; OGMP TGD Leaks (L3-L4) [3]; 40 CFR 98.233(q), 98.233(r) [5]; WCI.363(n)[7]; NGER 3.3.6A (Method 3) [8]
Equipment Leaks (Gathering Pipelines)	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 [1]; OGMP TGD Leaks and permeation from underground pipes [3]; 40 CFR 98.233(r)[5]; WCI.363(o)(2)[7]; NGER 3.3.6C (Method 2) [8]
Flare Stacks	Engineering calculation using flare gas flow rate, flare gas composition and a representative destruction efficiency.	API Compendium 5.1 [1]; OGMP TGD Flare efficiency (L3-L4) [3]; 40 CFR 98.233(n)[5]; AQM 2.3 Method 2-1 thru 2-3 [6]; WCI.353(d)[7]; NGER 3.3.9A.10 (Method 2A) [8]
Gas-driven pneumatic controllers	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 [1]; OGMP TGD Pneumatics (L3-L4) [3]; 40 CFR 98.233(a) [5]; AQM 4.7.2 thru 4.7.4 [6]; WCI.363(a, b, b.1) [7]; NGER 3.3.9A.4 (Method 1) [8]
Gas-driven pneumatic pumps	Emission factor-based method using an actual inventory of each type of pneumatic pump and default or manufacturer-specific emission factors.	API Compendium 6.3.7 [1]; OGMP TGD Pneumatics (L3-L4) [3]; 40 CFR 98.233(c)[5]; AQM 4.8.2 thru 4.8.4 [6]; WCI.363(a.1) [7]; NGER 3.3.9A.5 (Method 1) [8]

Liquids Unloading	Engineering Calculation using well vent time, measured or estimated gas flow rate, casing/tubing/well dimensions and pressures, and use of emission controls if applicable.	API Compendium 6.3.4 [1]; 40 CFR 98.233(f) [5]; AQM 4.18 [6]; WCI.363(e) [7]; NGER 3.3.9A.8 (Method 1, subsection 3) [8]
Storage Vessels (Hydrocarbon, Floating and Fixed-roof)	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 [1]; OGMP TGD Unstabilized liquid storage tanks (L4) [3]; GHGI[6] [4]; 40 CFR 98.233(j) [5]; AQM 4.6 [6]; WCI.363(h) [7]; NGER 3.3.9A.3 (Method 1) [8]
Upsets (PRVs)	Emission-factor based calculation using a representative emission factor, along with the number of PRVs.	API Compendium 6.3.11 [1]; GHGI[6] [4]; AQM 4.20 [6]
Well Completions (with hydraulic fracturing or from Coal Bed Methane)	Engineering Calculation using actual or representative gas production rates, flowback	API Compendium 6.2.3.1 [1]; OGMP TGD Purging and venting (L4) [3]; 40 CFR 98.233(g) [5]; AQM 4.16 [6]; WCI.363(f) [7]; NGER 3.3.2.3 (Method 4) [8]
Well Completions (without hydraulic fracturing)	Engineering Calculation using gas production rate per completed well and time that gas is vented per completed well	API Compendium 6.2.3.2 [1]; OGMP TGD Purging and venting (L4) [3]; AQM 4.16 [6]; WCI.363(f) [7]; NGER 3.3.2.3 (Method 4) [8]
Well Drilling	Emission-factor based calculation using a representative emission factor, along with the number of drilling days.	API Compendium 6.2.1 [1]; OGMP TGD Purging and venting (L3) [3]; GHGI[6] [4]
Well Workovers (with hydraulic fracturing or from Coal Bed Methane)	Engineering Calculation using actual or representative gas production rates, flowback	API Compendium 6.3.3 [1]; OGMP TGD Purging and venting (L4) [3]; 40 CFR 98.233(g) [5]; NGER 3.3.9A.8 (Method 4) [8]
Well Workovers (without Hydraulic Fracturing)	Emission-factor based calculation using an emission factor along with the number of workovers without hydraulic fracturing.	API Compendium 6.3.2 [1]; OGMP TGD Purging and venting (L4) [3]; 40 CFR 98.233(g) [5]; AQM 4.16 [6];

		WCI.363(f) [7]; NGER 3.3.9A.8 (Method 1) [8]
Well Testing	Engineering Calculation using oil and gas production rates (GOR), average annual flow rate, and testing durations	API Compendium 6.2.2 [1]; OGMP TGD Purging and venting (L4) [3]; 40 CFR 98.233(l) [5]; AQM 4.16 [6]; WCI.363(f)[7];
Other emission sources	Producers must disclose other emission sources at their Facility not explicitly called out in this Standard, document total emissions, and demonstrate a representative emission calculation methodology for each source. Other sources for onshore production may include casinghead gas venting, produced water tanks, truck loading, and mud degassing.	API Compendium 6.3.11 [1]

A.2 Methane Intensity Calculations

The methodology for calculating methane intensity associated with this Standard is as follows:

Calculate total methane emissions (metric tons) as the sum of methane emissions from all sources and reconciled according to Section 3.3 of this subsidiary document. Divide total methane emissions by the total energy throughput of the Facility in energy units.

$$\textit{Methane Emissions (ME) = total } CH_4 \textit{ emissions of the Facility (in MT)} \quad (1)$$

Where, *ME* is in metric tons.

Methane intensity is then calculated as follows,

$$Methane\ Intensity = \frac{ME}{E_{ng}+E_{liq}} * 10^6 \quad (2)$$

Where:

- E_{ng} is the total annual energy of natural gas throughput (as barrels of oil equivalent [BOE[6]])
- E_{liq} is the total annual energy of hydrocarbon liquids throughput (as BOE
- *Methane Intensity* is in units of grams CH_4 emissions per BOE of total energy throughput

In certain cases, including when an operator reports a measurement-informed inventory using an external, published measurement and reconciliation protocol, the operator may need to calculate a product-specific methane intensity. In this case, the operator must calculate methane intensity as follows:

$$Methane\ Intensity_{ng} = \frac{ME * GR}{E_{ng}} * 10^6 \tag{3}$$

$$Methane\ Intensity_{liq} = \frac{ME * (1 - GR)}{V_{liq}} * 10^6 \tag{4}$$

Where,

- E_{ng} is the total annual energy of natural gas throughput (in MMBtu)
- *V_{liq} is the total annual volume of hydrocarbon liquids throughput (in barrels of oil)*
- *Methane Intensity$_{ng}$ is in units of grams CH_4 emissions per natural gas throughput (in MMBtu)*
- *Methane Intensity$_{oil}$ is in units of grams CH_4 emissions per hydrocarbon liquids throughput (in barrels of oil), and*
  - $GR = Gas\ Ratio = \frac{E_{ng}}{E_{ng}+E_{liq}}$ (5)

Equations 3 and 4 should yield the same methane intensity for both natural gas and hydrocarbon liquids products.

Default 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 [1].

[6] Operators must calculate BOE of natural gas by dividing natural gas volumetric throughput by the conversion rate of 5.8 Mscf/BOE (see Table 5)

Table 4: Imperial default values for calculating Methane Intensity

	Default value		
Abbreviation	**Description**	**Units Imperial**	**Default Value**
-	Conversion rate for natural gas volume to BOE	Mscf/BOE	5.8
EC_{liq}[7]	Higher Heating Value hydrocarbon liquids	MMBtu/US barrel	5.8

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

Standard at 15°C	**Default value**		
Abbreviation	**Description**	**Units SI Standard**	**Default Value**
-	Conversion rate for natural gas volume to BOE	Sm^3/BOE	0.20
EC_{liq}	Higher Heating Value hydrocarbon liquids	MJ/Sm^3	38500

[7] Operator may choose to use a Facility-specific value along with documentation on how that Facility-specific value was determined

References

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[3] Oil & Gas Methane Partnership 2.0 (2022). Technical Guidance Documents. Retrieved from https://www.ogmpartnership.com/templates-guidance

[4] US Environmental Protection Agency (EPA). (2017, February 8). Inventory of U.S. Greenhouse Gas Emissions and Sinks. Reports and Assessments. Retrieved October 28, 2020, from https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks

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MiQ STANDARD

for Methane Emissions Performance for Petroleum Operations

SUBSIDIARY DOCUMENT 2: Company Practices – Onshore Production

v1.0

Contents

1 Introduction

The MiQ Standard for Methane Emissions Performance from Petroleum Operations (the Standard) combines several Standard elements – (1) a calculated Methane Intensity, (2) Producer 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 oil and 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 – Onshore Production*
2. Subsidiary Documents
    a. *Subsidiary Document 1: Methane Intensity – Onshore Production*
    b. Subsidiary Document 2: Company Practices – Onshore Production (this document)
    c. *Subsidiary Document 3: Monitoring Technology Deployment – Onshore Production*

Effective management of methane emissions from oil and gas production begins with a Facility design that will achieve minimal inherent methane emissions and eliminates, to the greatest degree possible, the potential for Fugitive 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, Producers must demonstrate effective methane emissions management through Company Practices which exhibit an overarching cultural drive to improve methane emissions performance.

This Standard requires evaluation of Company Practices, which include policies and procedures a Producer employs to ensure it is managing and minimizing methane emissions. By establishing and implementing Company Practices to guide personnel in methane emissions detection and repair, reporting protocols, and data evaluation, Producers can ensure methane emissions are managed appropriately throughout the operations lifecycle.

A Producer should be able to produce documentation of their Company Practices and procedures, and demonstrate 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 Intended Methane Emissions**

   Outline the policies and procedures required to minimize Intended methane emissions at a Facility.

This subsidiary document covers Company Practices for production from onshore Facilities.

3 Performance Criteria

Under this Standard, a Producer 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 a Producer through formal policy or procedure. In the absence of formal policy or procedure, the Producer 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 reducing Unintended methane emissions and Intended methane emissions are categorized either as:

- **Mandatory**: Must be demonstrated by the Producer in order to qualify for the Standard; or
- **Improved**: By demonstrating these practices, a Producer 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 is determined based on the lowest of 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 higher 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, 2, 3 below. If a Facility demonstrates **at least one** of the elements listed for an improved practice topic, as outlined in Tables 1-3 it should receive all points nominated for that practice, except if two or more elements **are related (indicated by the word "and")**. For performance criteria relevant to emission sources not found within a given Facility (I.e. flaring requirements for dry gas production) the Producer automatically receives the improved points.

3.1 General Company Practices

Facilities will employ general Company Practices to eliminate methane emissions to the greatest degree possible. This will include building a culture of eliminating methane emissions as well as employing design strategies for both operations and maintenance activities.

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: • 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** • 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).	Mandatory	-
(GP- 2) Reporting Methane Emissions observations and incidents • 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	-

[1] Company Practices are numbered by type. Practice types include General Practices (GP), Unintended Methane Emissions Practices (UMEP), and Intended Methane Emissions Practices (IMEP).

(GP- 3) Estimating and measuring Methane Emissions		
At minimum, Producer's guidance for measurement methods and calculation of methane emissions, in line with regulatory GHG reporting where present, includes: • Quantification method for each emission source; **and** • Reconciliation process for including all unintended emissions	Mandatory	-
(GP- 4) Continual improvement		
Methane management is integrated into the Producer's company culture, as evidenced by: • a Health, Safety & Environment (HSE) communication plan that includes methane emissions 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.	Mandatory	-

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	Point
(UMEP- 1) Employee training and awareness		
Operational and maintenance team training includes: • 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: • Method 21 [1] or equivalent - Producer'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) – Producer'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 Producer; **and** • In the event LDAR surveys are carried out by third-party personnel, the Producer 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	Mandatory	-
(UMEP- 2) Source Level Detection Plan		
LDAR plan outlines at a minimum: • specific equipment / components included in LDAR survey (must reference process valves, connectors, compressor seals, open-ended lines, meters, pressure relief valves, regulators, and pneumatic controllers); **and** • leak definition; **and** • monitoring methodology (reference to equipment, frequency, conditions, reporting log); **and**	Mandatory	-

- repair or replacement strategy, including when to take immediate corrective action and when delay of repair is permitted; **and**
- first attempt at repair requirements within 30 days of detection; **and**
- final repair attempt within 30 days of detection; **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) Managing Methane Emissions from tanks

• Policies for managing tank emissions must address all key stages of tank use, including tank filling, tank breathing and tank cleaning; **and** • Producers inspect and monitor key areas that may result in methane emissions from tanks including vapor recovery systems, thief hatches, upstream dump valves, pneumatic controllers, and other areas; **and** • Policies and procedures for managing tanks include observation for methane emissions **and** preventative maintenance based on historical inspection findings.	Mandatory	-

(UMEP- 3.1)

In addition to the above, Producers elect to: • install tank pressure monitoring systems and alarms; **and/or** • remotely observe tank batteries using integrated operation centers; **and/or** • utilize automated tank gauging and reporting; **and/or** • install thief hatch monitoring and automated reporting systems; **and/or** • centralize tanks from multiple locations to eliminate sources of methane emissions; **and/or** • utilizes a vapor recovery tower to capture vapor and limit flash on atmospheric tanks; **and/or**	Improved	2

- design facilities which eliminate the use of tanks

(UMEP- 4) Directed inspection and maintenance		
To manage methane emissions, Producers elect to: • target major equipment (i.e. pneumatic controllers, thief hatches, natural gas vents, vapor recovery equipment operation, compressor stations, 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].	Improved	1
(UMEP- 5) Root Cause Analysis (RCA) of unintended emission events		
• Producer 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 Intended Methane Emissions

Though Facilities can be designed to minimize methane emissions, certain equipment operations and maintenance activities, by design or by definition, result in the release of natural gas (and therefore methane) to the atmosphere. By implementing Company Practices to reduce Intended methane emissions, Producers can ensure the amount of gas released is minimized.

Table 3: Company Practices for managing and reducing Intended methane emissions (IMEP)

Practice	**Character**	**Point**
(IMEP- 1) Venting - Manual liquid unloading		

Company Practices require that the manual unloading process is monitored onsite by personnel, and that venting to atmosphere is shut off as soon as possible once liquids have been removed and gas begins to vent.	Mandatory	-
(IMEP- 1.1)		
Producers implement non-venting unloading processes (manual or automated). The Auditor must verify evidence that non-venting unloading processes are attempted before vented unloading where applicable.	Improved	1
(IMEP- 2) Venting - Production Equipment Pumpdown		
Producer coordinates operational and routine maintenance repairs to minimize the number of pumpdowns required.	Mandatory	-
(IMEP- 2.1)		
Producers implement: • policies and procedures for removal of natural gas from equipment or systems scheduled for repair to the greatest extent possible prior to pumpdown, while maintaining safe operations; **and/or** • Production Equipment to service, which address purging the equipment of air prior to restoring operations while minimizing natural gas emitted during purging operations; **and/or** • natural gas vented during pumpdowns is routed to a flare to minimize methane emissions.	Improved	1
(IMEP- 3) Venting - Pneumatic Devices		
Producers with operations utilizing natural gas driven pneumatic devices must implement: • procedures to maintain accurate inventory of pumps and controllers (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	Mandatory	-

intermittent)) based on regulatory published limits or industry equipment standards; **and** • Devices are included in regular inspection in LDAR plan as emission source.		
(IMEP- 3.1)		
Producers have: installed non-venting (i.e. no-bleed, electric, mechanical, or instrument air) pneumatic controllers, actuators and pumps in place of gas-driven pneumatics for >50% of inventory).	Improved	2
(IMEP- 3.2)		
Producers have: • Implemented a program (dated >1yr prior to time of audit) to replace remaining natural gas driven devices with non-venting devices within 3 years of applying for the Standard, and have demonstrated progress against this program; **and/or** • Implemented program that all new construction will include non-venting pneumatic devices.	Improved	1
(IMEP- 4) Venting - Compressors		
• Producers implement policies to replace reciprocating compressor rings on a fixed schedule based on run hours; **and** • Producers have estimated methane loss from reciprocating compressor rod packing and evaluated the economic threshold for replacement.	Mandatory	-
(IMEP- 4.1)		
Producers have evaluated controls to address compressor seal methane losses and outlined a program to: • replace centrifugal compressor wet seals with dry seals or route seal oil gas such that it is recovered or flared; **and**	Improved	1

• upgrade of reciprocating compressor packing cups, rings, gaskets, rods based on indication of leak from rod packing inspection, or gas emitted is routed to recovery or flare.		
(IMEP- 5) Well completions and workovers		
• Producers implement a Reduced Emissions Completions (RECs) practice at hydraulic fractured wells, to capture natural gas that is produced during completions or workovers to limit venting to atmosphere; **and** • Where implementing a REC is infeasible due to reservoir characteristics, gas is recovered and routed to a combustion device.	Improved	1
(IMEP- 6) Well operations		
Producers implement policies and procedures to address casinghead gas venting by: • evaluating appropriate emission controls at oil wells based on operational considerations (well and reservoir characteristics); **and** • capturing and routing casinghead gas for onsite recovery, sales or flare where possible.	Improved	1
(IMEP- 7) Flaring		
Producers must implement: • policies to define the use of flaring (routine and non-routine event categories, acceptable durations); **and** • flaring or combusting natural gas when recovery is not possible, and limiting gas routed to vent (including for oil wells at the facility); **and** • procedures which define stable operating range and criteria for all flare systems, considering emergency events, for good combustion efficiency [3];[2] **and**	Mandatory	-

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

• policies and procedures to ensure flares[3] are managed and maintained to ensure flare functionality, flares are targeted during LDAR surveys, and design combustion efficiency is achieved through utilizing staff/consultants for inspections (AVO and engineering & maintenance inspections).		
(IMEP- 7.1) Producers have implemented policies to minimize the use of routine flaring (applicable to both gas and oil wells), except in the event of an emergency [2]. • Policies in place to check infrastructure takeaway is in place before well packages come online; **and** • Utilize a flare gas capture system to reduce the volume of gas flared.	Improved	2
(IMEP- 7.2) Flares are managed to ensure flaring functionality and efficiency through control and engineering design. Systems may include: • SCADA systems and logic controllers to monitor flare ignition; **and/or** • auto ignition system for unsupervised flare stacks with intermittent flaring; **and/or** • flare capacity and production level is maintained to ensure flare's combustion efficiency matches range of production and does not overload; **and/or** • thermocouples (temperature sensors) to ensure pilots stay lit or flame out detection device installed.	Improved	1

3.4 Required Evidence Available to Auditors

The Producer's Company Practices will be reviewed by the Auditor in advance of an onsite Audit. The purpose of onsite Audits is 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 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. Retrieved from https://methaneguidingprinciples.org/best-practice-guides/

[3] US Environmental Protection Agency (EPA). (2012). Parameters for Properly Designed and Operated Flares. US EPA Office of Air Quality Planning and Standards (OAQPS). Retrieved from https://www3.epa.gov/airtoxics/flare/2012flaretechreport.pdf

MiQ STANDARD

for Methane Emissions Performance for Petroleum Operations

SUBSIDIARY DOCUMENT 3: Monitoring Technology Deployment – Onshore Production

v1.0

Contents

1 Introduction

The MiQ Standard for Methane Emissions Performance (the Standard) combines several Standard elements – (1) a calculated Methane Intensity, (2) Producer 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 oil and natural gas and 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 – Onshore Production*
2. Subsidiary Documents
    a. *Subsidiary Document 1: Methane Intensity – Onshore Production*
    b. *Subsidiary Document 2: Company Practices – Onshore Production*
    c. **Subsidiary Document 3: Monitoring Technology Deployment – Onshore Production (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. Gimbled 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.

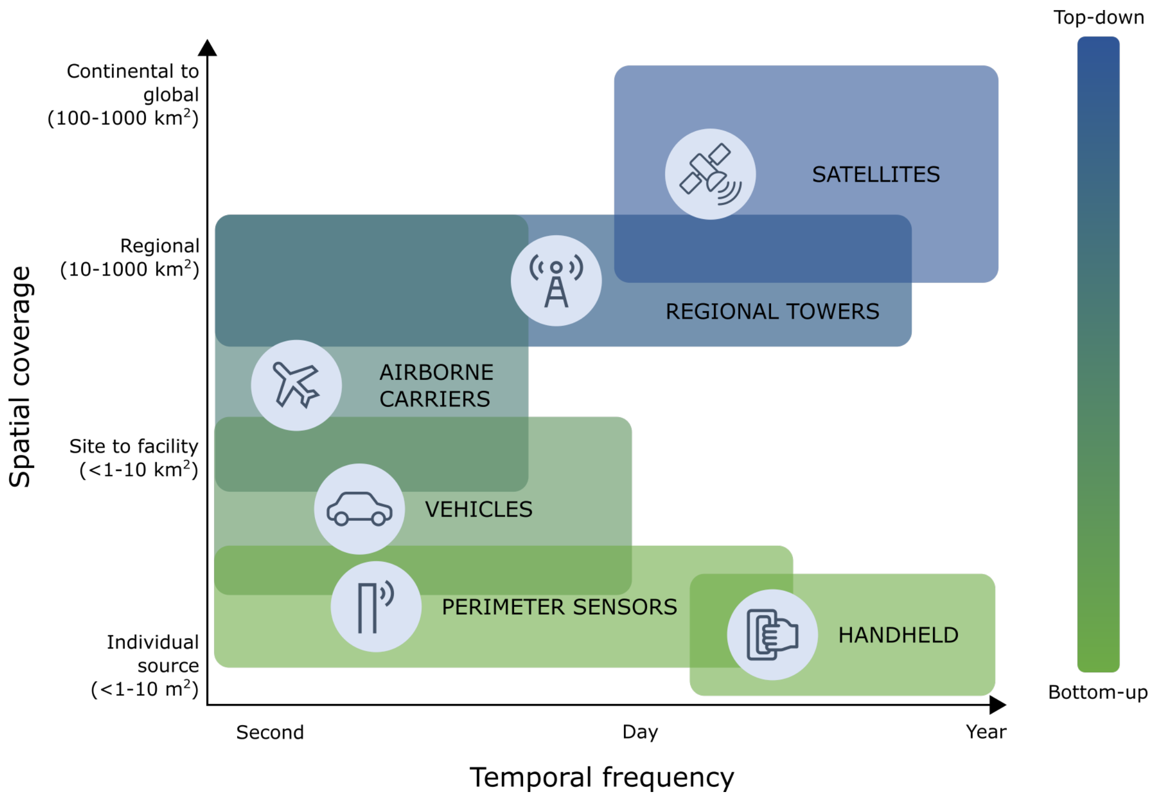

Figure 1: Methane monitoring technology across a variety of spatial and temporal scales (adapted from the National Academies of Science, Engineering, and Medicine, 2018 [1])

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

[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.

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.

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

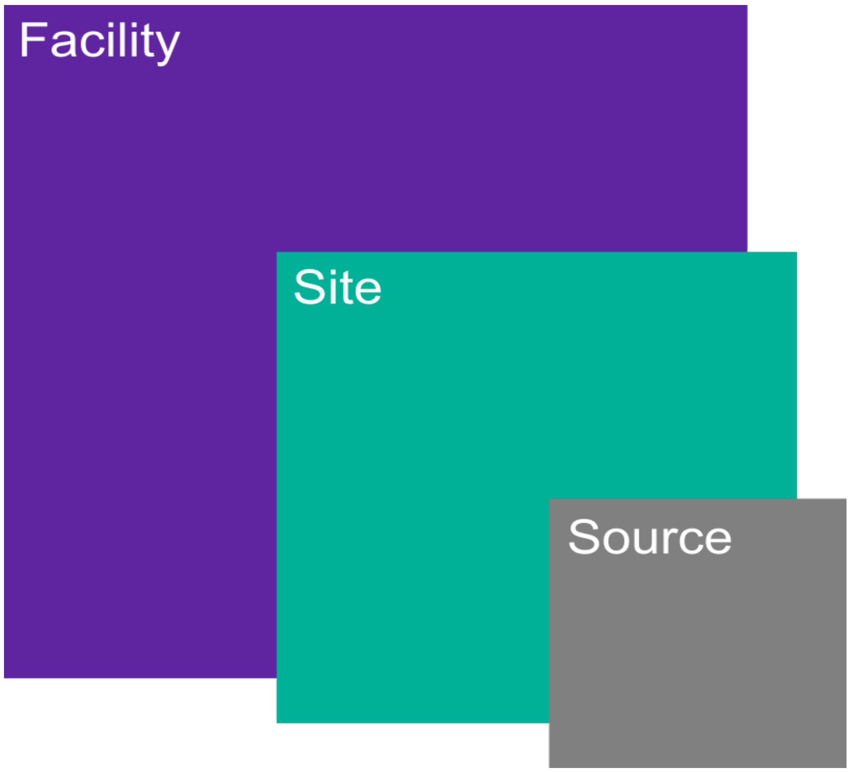

Figure 2: Spatial scales utilized within the Standard, referencing the definitions of Facility, Site, and Source as outlined in the *Main Document*, see there for reference.

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

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[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.

technology solution, which takes into consideration the sensor capabilities, deployment protocols, analysis methods and follow up protocols.

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 a Producers Inventory (see *Subsidiary Document 1: Methane Intensity Section 4*). Details of a Producers 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 Producers 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 Monitoring Technology Deployment	The minimum number of surveys per year. 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	The minimum rate of methane emissions detectable by a specific technology solution. Technologies with lower MDL can identify more (including smaller) methane emission sources. The technology solution required to achieve the desired MDL and detection probability[4] must be applicable for the specific Facility and validated by the Auditor.

[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, a PoD of at least 90% must be achieved for a given technology.

3.2 Performance Scoring

Table 2 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.

A Producer 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. Producers 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. A Equivalent LDAR program capable of detecting, characterizing, and mitigating an equivalent amount of methane emissions may be proposed 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 are outlined in Sections 3.2.1 and 3.2.2 , respectively.

Table 2: Technology Performance Criteria

Facility Scale Inspection		**Source Level Inspection**[5]		**Points**
quarterly (MDL 25kg/hr)	Entire Facility	quarterly	50% of Sites	12
semi annually (MDL 25kg/hr)	Entire Facility	tri annually	50% of Sites	8
annually (MDL 25kg/hr)	Entire Facility	semi annually	50% of Sites	4

[5] Producers may choose to use alternative methods in conjunction with legislatively approved methods for Site Level monitoring. AVO inspections are to be conducted in addition to this requirement (at the discretion of the Producer).

N/A	annually	All Sites[6]	0

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 Table 2 above
- must meet the designated MDL of 25kg/hr[7] at 90% POD proven through single blind, controlled release testing (see Table 3 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 3 and Table 4 for additional LDAR program and recordkeeping requirements).
    - Producers 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).

[6] All producers are required to conduct a minimum annual Source Level inspection over 100% of sites. sites deployed with unmanned stationary or continuous monitors are not exempt from this requirement. As outlined in Table 2, semiannual, triannual or quarterly inspections over at least 50% of sites are in *addition* to the annual Source Level inspection. For example, to achieve 12 points a producer may conduct 100%+50%+50%+50% for a total of 250% coverage for the upcoming year.

[7] 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].

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 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 Producer must be detailed in the Producer'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).

Sampling coverage is defined in the Standard as the percentage of Sites covered, inclusive of all equipment necessary to support production activities. For example, 50% of Sites monitored at the Source Level, may include wellheads, separation, treating, compression, manifolds, storage (i.e. tank batteries) or pipelines. A minimum percentage of Sites monitored is intended to enable a Producer to focus their methane emissions program on targeted sources based on cumulative data or maintenance programs, as outlined in *Subsidiary Document 2: Company Practices*. The monitoring location selection criteria and justification must be disclosed in a company's LDAR practice documentation and could, for example, include:

- selection of marginal producers or wells with a higher ratio of emissions to production;
- age of infrastructure;
- presence of emission reduction equipment; and
- historical observations.

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

For Sites or Production 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 Production Equipment.

Sources with confirmed detections must be scheduled for repair or replacement, as per the Producer'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 Table 2, in order to achieve the same number of points. Modeling inputs and assumptions include, at minimum

- emissions distribution curve representative of the Production 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 3 and 4) and minimum coverage requirements outlined above.

4 Recordkeeping and Reporting Requirements

Producers 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 3 outlines the minimum recordkeeping requirements for Monitoring Technology Deployment. Producers can choose to aggregate the recordkeeping elements to minimize administrative overhead. Producers must have adequate Company Practices in place which underpin accurate recordkeeping and reporting structures.

4.1 Minimum Recordkeeping and Reporting Requirements

Table 3: Minimum recordkeeping requirements for Facility Scale and Source Level inspection

Recordkeeping element	Details
Detection Technology Specifications	• Sensor and instrumentation details • Method in which the sensor was 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 o Third party used to conduct testing o Confirmation of single-blind nature of testing o Operating conditions of equipment used for testing o Variables tested that could affect the sensitivity of the technology and the ranges tested (i.e. humidity, temperature, wind speed, groundcover, obstruction, solar irradiation) o Calibration protocols used during testing o If operator uses technology for quantification, characterization of emission rate uncertainty
Work Practice Specifications	• 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.
	  ○ 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	• 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 (for at least the Certification Period) and visited for each survey (categorized by of Well 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 towards meeting the requirements of a Facility Scale or Source Level inspection. Table 4 outlines the minimum records a Producer must submit to the Auditor for use of Continuous Monitoring System.

Table 4: 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 o Producer 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*, Producers 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 *Subsidiary Document 1: Methane Intensity, Section 3.3* for requirements of incorporating emissions discovered during Facility inspections.

This Standard also allows Producers 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.

References

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