MiQ STANDARD

for Methane Emissions Performance

MAIN DOCUMENT – Transmission & Storage

v1.0

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1 Background

1.1 Introduction

Methane emissions (CH_4) from the oil and gas supply chain 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 the oil and natural gas supply chains. This Standard addresses methane emissions from natural gas transmission and storage.

Methane is emitted at natural gas transmission and storage (T&S) through Intended and Unintended venting, leaking and incomplete combustion from flares 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 (the Standard) combines several Standard elements – (1) a calculated Methane Intensity, (2) Operator policies and procedures focused on methane emissions prevention, detection, and abatement (Company Practices), and (3) detection, quantification, follow-up and mitigation of methane emissions through Monitoring Technology Deployment – to provide a robust and reliable method to certify the methane emissions performance across the natural gas supply chain. 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 - T&S (this document)**
2. Subsidiary Documents
    a. *Subsidiary Document 1: Methane Intensity - T&S*
    b. *Subsidiary Document 2: Company Practices - T&S*
    c. *Subsidiary Document 3: Monitoring Technology Deployment - T&S*

[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 without climate controlled feedbacks.

1.2 About

MiQ Foundation, a non-profit entity, is the Standard Holder for this Standard. MiQ and the Standard was developed in a partnership between RMI[2] and SYSTEMIQ[3] to reduce methane emissions from the global oil and gas industries through a market-based gas certification system.

1.3 Purpose

The purpose of this Standard is to incentivize continuous improvement in emissions control and monitoring practices by creating an opportunity for Operators to differentiate their natural gas handing by its methane performance.

More specifically, the objectives of this Standard are:

a) to accelerate deployment of practices and technologies that reduce and/or eliminate methane emissions;

b) to accelerate deployment of monitoring technologies that detect, measure and quantify methane emissions;

c) to increase transparency regarding the Methane Emissions Performance across the natural gas supply chain, with a globally consistent methodology;

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

e) to provide Operators, buyers, and investors a uniform, independently verified Standard consistent with environmental, social, and governance (ESG) reporting to address methane emissions from the natural gas supply chain and from end-users;

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

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

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[2] RMI (Rocky Mountain Institute), https://www.rmi.org

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

2 Scope

This Standard establishes a system for the generation of MiQ Certificates, which will include a defined Grade that captures the Facility's methane emissions performance. Performance will be assessed according to the Facility's (1) calculated Methane Intensity, (2) policies and procedures that are focused 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 with transmission pipeline, transmission compression and/or long-term natural gas storage equipment (see Terms and Definitions);
- specifies a method to calculate the Methane Intensity of a natural gas Facility (see *Subsidiary Document 1: Methane Intensity*);
- establishes general principles for an effective methane management program – including policies and procedures focused on methane emissions prevention, detection, and abatement and deployment of methane monitoring technology (see *Subsidiary Document 2: Company Practices* and *Subsidiary Document 3: Monitoring Technology Deployment*);
- does not define requirements for natural gas' physical or chemical quality.

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

3 Terms and Definitions

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

Term	Definition

Applicable Criteria	The criteria subject to Audit by an Auditing Body to demonstrate compliance with the requirements of this Standard.
Annual Audit	The systematic, independent, and documented assessment by the Auditor prior to the intended Certification Period, verifying the information reported by the Operator against the Standard.
Auditor/Auditing Body	An individual, or organization made up of individuals, that carry out assessments to determine if a Facility meets the requirements of the Standard and recommend a performance Grade. An Auditor or Auditing Body must possess the combined demonstrated knowledge, skill and abilities, along with documented training and experience required to provide assurance services, both offsite and onsite, to determine Facility's performance against all diverse elements of the Standard.
Audit Report	A verification document prepared by an Auditing Body that contains a comprehensive analysis of the Operator adherence to the Standard.
Causal Examination	The act of following up to a detected event at the site, equipment or component level to determine the likely cause of the emission, using SCADA logs, maintenance logs, operational logs, Operator site visits, and Source Level detection surveys. Examinations should also, at minimum, include determination of emissions as Intended or Unintended.
Certification Period	The forward looking period (maximum 12 months) during which certified operations at a Facility is eligible for MiQ certificates
Company Practices	A document, program, policy or procedure, specific to the Operator, 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	Any part, or collection of parts functioning as a unit including but not limited to flanges, connectors, pressure relief devices, valves, pumps seal or compressor component, whose functionality plays a necessary role in operations and controlling emissions.
Condensate	A mixture of light hydrocarbon and other liquid, including both water and hydrocarbon liquids, separated from natural gas that

	condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions.
Continuous Monitoring System	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	A mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passage through separation equipment. May include lease condensate that is later mixed into the crude stream.
Detection	A sensed or measurable indication of methane emissions obtained using a monitoring technology or another means of inspection, such as audio, visual and olfactory (AVO) methods.
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 equipment and pipelines for the purposes of natural gas transmission, compression, treatment (i.e. liquids separation and atmospheric storage) and storage (i.e. depleted reservoirs, salt dome caverns, storage wells), metering and interconnection falling under the responsibility of a common owner and operator, including leased, rented, or contracted equipment and activities. The Facility boundary for this Standard does not include gathering pipelines connected to production facilities or stand-alone storage facilities.
Facility Scale Inspection	Inspections undertaken by an Operator using a method that covers the entire Facility's emission sources in three-dimensional space and must be capable of detecting and pinpointing the source of emissions to the site level at a minimum.
Grade	The performance grade of a Facility determined in accordance with this Standard by an Auditor and approved by the Issuing Body.
Greenhouse Gases (GHGs)	Carbon dioxide (CO_2) and other gases defined in the IPCC Sixth Assessment Report including methane, nitrous oxide, sulfur hexafluoride, chlorofluorocarbons, hydrofluorocarbons, and perfluorocarbons [1]. Greenhouse Gases other than carbon dioxide can be expressed in terms of carbon dioxide equivalent (CO_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.
Inventory	A documented compilation of emissions from each emission source, compiled on an annual basis for a Facility.
Issuing Body	The entity responsible for registering each Facility under the MiQ Program, for issuing MiQ certificates, and for approving Audit Reports under the MiQ Program, amongst other responsibilities.
Leak Detection and Repair (LDAR)	LDAR is frequently used to describe the regulatory practice of systematic emission detections using hand-held, Source Level tools. The term is expanded in this Standard to describe any monitoring survey which includes the systematic implementation of methane detection tools across a collection of assets to detect and repair emissions. An LDAR program describes the sensor(s), deployment or configuration strategy, temporal and spatial coverage, their operating envelope, work practices, detection capabilities of solution, follow up and repair procedures, and data management standards.
Methane Intensity	The ratio of methane emissions and a selected variable. It accounts for natural gas throughput relative to crude and condensate throughput and allocates emissions that are attributable to the handling of natural gas.
MiQ Program	The framework for handling all issues related to governance, the process of certification and use of the MiQ Registry. Please see the MiQ Program Guide for more details.
Monitoring Technology Deployment	A subsidiary document of this Standard which describes the requirements for the usage of methane monitoring technologies to comply with Facility Scale and Source Level inspections to mitigate Unintended Emissions.
Onshore Transmission and Storage	The oil and gas supply chain segment that includes a pipeline which transports gas from a processing facility, storage facility or gathering line to a distribution /gate station or large utility customer that is not downstream from a distribution/gate station. This segment may include, but is not limited to transmission pipelines, compressor stations, liquids separation, atmospheric storage of water and hydrocarbon liquids, metering

	equipment, as well as underground storage facilities, storage wells and storage compressors.
Operator	The party responsible for operations of a Transmission and Storage Facility and all associated owned and leased equipment, as applies to it methane emissions.
Quantification	Estimating an emission rate, such as mass per time or volume per time. This can be done directly through measurement of the emissions, or indirectly through estimations, 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 an Operator follows up to detected events to determine the source of the emission, identify possible causal factors, determination of the root cause, recording each event for data aggregation, and finally recommending and implementing a solution
Site	A localized area of onshore transmission and storage equipment within a Facility (i.e. compressor station, underground natural gas storage, metering and regulation station). 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 (i.e., Source Level Inspection) 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 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.

Storage Tank	A tank within the Facility bound that has sits on or above the ground and has the potential to emit significant methane emissions. The Standard excludes tanks that primarily store water.
Storage Well	A natural gas well is an asset owned and operated solely by the Operator undergoing certification for the purposes of storing gas.
Super-Emitter	A Super-Emitter's emission rate threshold is not universally defined however these events are typically considered the largest 5% of leaks which are responsible for more than 50% of the total volume of leakage [2] or the highest-emitting 1% of sites in a site-based distribution [3]. In any case, super-emitters are a high-emitting emission event, due usually to abnormal process conditions, which can significantly affect the total emissions of a Facility.
Throughput	Total quantity of gas that is transferred to end users during the Certification Period, excluding gas used internally and gas stored that is not released to an end user.
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, such specific requirements shall apply.

2. **Voluntary nature**

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

3. Transparency

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

5 Roles and Responsibilities

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

Table 1: Roles and Responsibilities

Roles	**Responsibilities**
Standard Holder	• defining and managing all aspects of the development of the Standard • publishing the Standard and supporting documents • managing updates and changes to the Standard
Auditor/Auditing Body	• 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
Operator	• 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 Body for it to carry out the Audits (see *MiQ Program Guide)*

Issuing Bodies	• registering each Facility under the MiQ Program • issuing MiQ certificates • approving Audit Reports under the MiQ Program

6 Methane Emissions Certification

6.1 Applicability

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

- **Physical boundary**

  The MiQ Standard seeks to determine a Methane Intensity and performance grade for an operating asset in order to facilitate differentiation of gas within the global supply chain. To this end, a certification boundary must encompass and represent all contiguous emissions and corresponding throughput for a given asset. Application of this MiQ Standard for Transmission & Storage applies all emitting equipment and activities included in the midstream transport, compression and storage of natural gas. At present stand alone storage facilities are not graded under this Standard. See the definitions of *Facility* for further details.

  Splitting Transmission and Storage Facilities into multiple Facilities may be necessary for pipelines of substantial distance with numerous receipt and delivery points along the length of the pipeline.

- **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 Subsidiary *Document 2: Company Practices*

3. **Monitoring Technology Deployment**

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

6.2 Grading System

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

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

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

	Score Requirements		
Grade	**Methane Intensity ($t\ CH_4$/pipeline mile)**	**Company Practices** (Improved Practices points)	**Monitoring Technology Deployment**
A	≤ 3.0	≥ 20	12
B	≤ 6.0	≥ 13	8
C	≤ 12	≥ 6	4
D	≤ 25	Mandatory minimum	Mandatory minimum
E	≤ 50	Mandatory minimum	Mandatory minimum
F	≤ 100	Mandatory minimum	Mandatory minimum

7 Subsidiary Documents

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

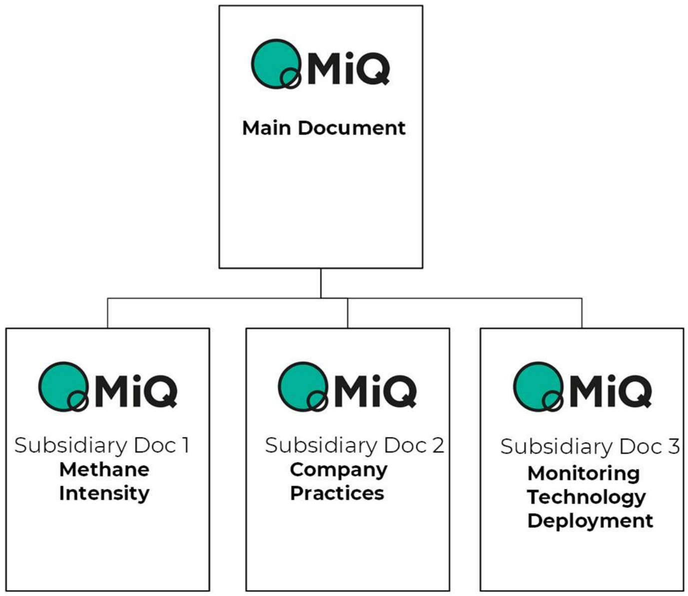

Figure 1: Document hierarchy

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 should be used for emissions and throughput determination purposes [7].

Annex B: Document Status

B.1 Document Development

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

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

B.2 Version History

Table 4: Version History

Version	Revision Date	Document	Summary of Change
v0.1	2022-01	All	Pilot Version
v0.2	2022-07	All	Revised Pilot Version
v1.0	2022-11	All	First Online Publication

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

SUBSIDIARY DOCUMENT 1: Methane Intensity – Transmission & Storage

v1.0

MiQ

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1 Introduction

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

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

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

This subsidiary document outlines the calculation of Methane Intensity as it pertains to the Standard. See Section 3 for a detailed overview of the Methane Intensity methodology used in this Standard.

2 Scope of this Document

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

This subsidiary document specifies a method to calculate the Methane Intensity of Onshore Natural Gas Transmission and Storage Facilities.

3 Methane Intensity

Under this Standard, Operators are required to calculate the Methane Intensity for the Facility 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

For the Transmission & Storage Segment, Methane Intensity is defined as the ratio of methane emissions relative to the total distance of pipeline in a Facility. Under this Standard, a Facility's Methane Intensity is to be calculated following the Methane Intensity calculation methodology detailed in Annex A.

It enables Operators to calculate an annual Facility Level Methane Intensity from all the emission sources at their Facility (see Section 3.2).

The Methane Intensity metric is the quotient of the mass of methane emissions associated with natural gas from a Facility by the total distance of pipeline at the Facility. It is calculated annually and has units of (t CH_4/mile). For example, an Operator can calculate its Methane Intensity using the following equation:

$$\text{Methane Intensity} = \frac{\text{Methane Emissions} \times \text{Gas Ratio}}{\text{Total Pipeline Distance}}$$

For some segments in the natural gas supply chain, the calculation must consider natural gas throughput relative to other liquid throughput (the gas ratio) in order to calculate an energy-allocated Methane Intensity, only accounting for methane emissions that are attributable to the handling of natural gas. However, because almost all product handled in the Transmission and Storage segment is natural gas, a gas ratio of 1 can be assumed.

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

3.2 Emission Sources

A Facility's calculated Methane Intensity must include methane emissions from all the emission sources (outlined in Annex A) that are present in a Facility. Most emission sources should be captured in the sources outlined in Annex A, but it is the operator's responsibility to document other emission sources that may not be listed. The methods in this Standard to calculate methane emissions utilize a combination of emission factors, engineering calculations, and direct measurements. While this Standard does not prescribe a specific calculation methodology for each source, it does require a minimum level of facility-specific data based on the emission source.

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

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

3.3 Emissions Reconciliation

An Operator's accounting methodology must also include reconciliation of detected emissions, 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).

Operators are required to submit a Reconciliation methodology that includes the following elements:

Emission event detection

- Source Level inspections: Details outlining how often surveys are conducted; which equipment is targeted; repair and validation procedures.
- Facility Scale inspections: Details outlining when and where surveys are conducted; who conducts inspections; how long until results are received; Follow-up procedures or causal examinations, including the use of Source Level inspections

Emission event classification

- Site classified emissions based on locational information from the inspection and information gathered from site operations

Causal Examination and Determination of Additionality

- Intended emissions found within design parameters and SOPs and already included in inventory (not additive)
- Unintended emissions such as leaks or abnormal process emissions found outside design conditions and SOPs (additive to emissions inventory)

Quantification process

- Operator must state how they calculate emissions from unintended emission events
  - Emission rate: must be calculated using best available techniques, i.e. tech quantification capabilities, engineering calculations, emission factors, or measurement.
  - Emission duration: must determine the process for which the duration of any emission event will be estimated.

Reconciliation process

- Operator must state how they intend to add emissions calculated from unintended emission events to its existing inventory.
- For use of recognized external reconciliation protocols, the related procedures can serve as documentation of the process.

4 Scoring Parameters

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

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

5 Recordkeeping Requirements

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

Table 1: Recordkeeping Requirements

Aspect	Detail
Transmission & Storage Facilities	Operators must document all Transmission & Storage Equipment that make up a Facility, including equipment added year-by-year as a result of development activity or acquisition, or removed year-by-year due to abandonment, divestiture, or any other changes made during the Certification Period.
Transmission & Storage Throughput	Operators must document the natural gas Throughput used in calculating Methane Intensity, including the source of data.
Equipment Count	Operators must document the total Equipment count associated with each emission source for all Equipment included within a Facility, and the method used to determine this count.
Activity data	Operators must document the activity data associated with calculating emissions from each emission source. Producers must also document their observations of leaking components using LDAR (see *Subsidiary Document 3: Monitoring Technology Deployment, Section 5.1* for more detail).

[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.

Calculation method	For each emission source the calculation methodology used must be documented and include the equipment counts, activity data, emission factors and any engineering calculation or measurement used in calculations. Operators must document the method, assumptions used along with its rationale, and its application to the calculation. For enhanced quantification methods, Operators must document all calculation and/or modelling assumptions, and/or technical specifications of measurement technologies deployed.
Reconciliation Procedure	Operators 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).
Engineering assumptions	*Energy content and Gas Ratio* The allocation of methane emissions between natural gas throughput and other hydrocarbon throughput must be documented and substantiated, including the energy content used for natural gas and liquids. If Operators use company-specific values, the source and derivation of those values must be documented. *Methane content* The Transmission and Storage Throughput is converted to mass of methane for use in the intensity calculation by using a facility-specific methane content, in mole fraction. If Operators use a facility-specific value, the methodology used for determining methane content must be documented.
Processes and responsibilities	Operators must document their processes for determining and internally reviewing their Methane Intensity for accuracy. This should include a detailed record of internal changes to calculations based on operational incidents and planned events.

Annex A: Methane Intensity calculation methodology

This annex outlines the Standard's minimum requirements to calculate methane emissions source-by-source for natural gas Transmission and Storage Facilities. These requirement levels mirror existing requirements set by a broad range of regulatory agencies globally and reasonably assess current quantification capabilities among the best operators in the natural gas industry. These requirements, as detailed below, attempt to capture most emissions in an accurate, credible, and replicable way that is maximally 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. Table 3 outlines specific sources and minimum requirements for each. Operators shall, in their emissions reporting, indicate the method(s) used to quantify each emission source.

Measurement-informed inventories are highly encouraged throughout the Standard. Operators seeking to submit a measurement-informed inventory may do so in compliance with published measurement and reconciliation protocols such as GTI Energy's Veritas Protocol [6] or OGMP 2.0 Level 4/5[7], 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 release testing of indirect measurement must be disclosed.
Engineering Calculations/Process Simulations	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 Transmission and Storage

Methane emissions from natural gas Transmission and Storage are to be accounted for from all potential emission sources. The Operator is required to aggregate methane emissions estimates from all relevant emission sources in the Transmission and Storage segment to calculate Methane Intensity.

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.

Under this Standard, Transmission and Storage Is defined as:

> The oil and gas supply chain segment that includes a pipeline which transports gas from a processing facility, storage facility or gathering line to a distribution /gate station or large utility customer that is not downstream from a distribution/gate station. This segment may include, but is not limited to transmission pipelines, compressor stations, liquids separation, atmospheric storage of water and hydrocarbon liquids, metering equipment, as well as underground storage facilities, storage wells and storage compressors.

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 Operators use more specific methodologies to calculate source-specific emissions where possible.

Table 3: Minimum Calculation Requirements for Transmission and Storage Emission Sources

Emission Source[2]	**Minimum Emission Calculation Requirements**[3]	**Examples of Accepted Methodologies**[4]
Blowdowns (transmission pipelines)	Engineering calculation using the physical volume in between isolation valves, gas pressure/temperature and gas composition. Emission controls used must also be considered.	OGMP TGD Purging and venting (L4) [7]; 2021 API Compendium 6.6.4 [5]; 40 CFR 98.233(i)[2]; WCI.353(c) [9]; AQM Eqn. 4-5a, 4-5b [8]; NGER 3.3.9B.1 (Method 1) [10]
Blowdowns (compressor stations)	Engineering calculation using the physical volume in between isolation valves, gas pressure/temperature and gas composition. Emission controls used must also be considered.	OGMP TGD Purging and venting (L4)[7]; 2021 API Compendium 6.6.4 [5]; 40 CFR 98.233(i)[2]; WCI.353(c)[9]; AQM Eqn. 4-5a, 4-5b[8]; NGER 3.3.9B.1 (Method 1) [10]
Blowdowns (storage facilities)	Engineering calculation using the physical volume in between isolation valves, gas pressure/temperature and methane content. Emission controls used must also be considered.	OGMP TGD Purging and venting (L4)[7]; 2021 API Compendium 6.6.4; 40 CFR 98.233(i)[2]; WCI.353(c)[9]; AQM Eqn. 4-5a, 4-5b[8]; NGER 3.3.9B.1 (Method 1) [10]
Incomplete Combustion	Emission-factor based calculation using an emission factor representative of the combustion unit, along with fuel consumption volumes and fuel composition.	OGMP TGD Incomplete combustion (L3-L4) [7]; API Compendium, Section 4.5[5]; WCI.353(w)[9]; AQM Eqn. 1-5, 1-5a[8]; NGER 2.3.5, 2.4.5 (Method 2) [10]
Compressor Venting	Measurement-based emission factor calculation using emission measurements of each potential	OGMP TGD Centrifugal compressors (L4) [7]; 2021 API Compendium 6.6.1.2 [5]; 40 CFR

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

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

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

(centrifugal compressors)	leaking component (i.e. blowdown valves, isolation valves, seals) in each mode of operation (operating, not-operating, pressurized standby etc.).	98.233(o)[2]; WCI.353(e)[9]; AQM 4.9.4[8]; NGER Method 4 principles [10]; GHGI [3][5]
Compressor Venting (reciprocating compressors)	Measurement-based emission factor calculation using emission measurements of each potential leaking component (i.e. rod packing, crankcase) in each mode of operation (operating, not-operating, pressurized standby etc.).	OGMP TGD Reciprocating compressors (L4) [7]; 2021 API Compendium 6.6.1.1 [5]; 40 CFR 98.233(p)[2]; WCI.353(f)[9]; AQM 4.9.4[8]; NGER Method 4 principles [10]
Dehydrator vents	Emission-factor based method using an actual inventory of dehydrators or an actual volume of gas dehydrated multiplied by a representative emission factor.	OGMP TGD Glycol dehydrators (L3-L4) [7]; OGMP TGD Purging and venting (L4) [7]; 2021 API Compendium 6.3.8.1 thru 6.3.8.3 [5]; 40 CFR 98.233(e)[2]; WCI.363(d) [9]; AQM 4.10.2[8]; GHGI [3]
Equipment Leaks (compressor stations and storage facilities)	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.	OGMP TGD Leaks (L3-L4) [7]; 2021 API Compendium 7.3.2.2 thru 7.3.2.4 [5]; 40 CFR 98.233(q)[2]; WCI.353(g)[9]; NGER 3.3.7A (Method 3) [10]
Equipment Leaks (transmission pipelines)	Emission-factor based method using miles of transmission pipeline and an emission factor representative of pipeline leakage.	OGMP TGD Leaks (L3-L4) [7]; 2021 API Compendium 7.3.2.1 thru 7.3.2.2 [2]; WCI.353(h) [9]; NGER 3.3.7 (Method 3) [10]; GHGI [3]
Flare Stacks	Engineering calculation using flare gas flow rate, flare gas composition and a representative destruction efficiency.	OGMP TGD Flare efficiency (L3-L4) [7]; 2021 API Compendium 5.1 [5]; 40 CFR 98.233(n) [2]; WCI.353(d) [9]; AQM 2.3 Method 2-1 thru 2-3 [8];

[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 an Operator's reconciliation process. Year-over-year as measurement data becomes more available, Operators should eliminate usage of generic factors.

		NGER 3.3.9D, 3.3.9E.2 (Method 2A) [10]
Gas-driven pneumatic controllers (all sites including M&R stations)	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.	OGMP TGD Pneumatics (L3-L4) [7]; 2021 API Compendium 6.6.3; 40 CFR 98.233(a)[2]; WCI.353(a, b, b.1)[9]; AQM 4.7.2 thru 4.7.4[8]; NGER 3.3.9E.1 (Method 1) [10]
Gas-driven pneumatic pumps	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.	OGMP TGD Pneumatics (L3-L4)[7]; 2021 API Compendium 6.3.7 [5]; 40 CFR 98.233(c)[2]; WCI.353(a.1) [9]; AQM 4.8.2 thru 4.8.4[8]; NGER 3.3.9E.1 (Method 1) [10]
Storage tank vents (compressor stations and storage facilities)	Leak measurements of tank vents not routed to an emission control device.	OGMP TGD Unstabilized liquid storage tanks (L4) [7]; 2021 API Compendium 6.6.2 [5]; 40 CFR 98.233(k) [2]; WCI.353(m) [9]; NGER 3.3.9E.1 (Method 1) [10]
Other emission sources	Operator must disclose other emission sources at their facility and document total emissions and demonstrate representative emission calculation methodologies for each source. Other sources for Transmission and Storage may include storage well venting, compressor starters, odorizers, and emission sources from metering stations.	2021 API Compendium 6.6.4 [5]; WCI.353(l) [9]

A.2 Methane Intensity Calculations

Where a Facility handles hydrocarbon in addition to natural gas, emissions are allocated between liquids and natural gas on an energy basis. For most Onshore Transmission and Storage Facilities, the only value stream will be pipeline quality gas and no allocation will be required.

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

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

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

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

Where:

- E_{ng} is energy equivalent of natural gas (as MMBtu or MJ)
- V_{ng} is annual volume of gas handled (as Mscf, or Sm^3, or Nm^3)
- EC_{ng} is energy content of the gas (as MMBtu/Mscf, or MJ/Sm^3, or MJ/Nm^3)
- E_{liq} is energy equivalent of hydrocarbon liquids (as MMBtu or MJ)
- V_{liq} is annual volume of hydrocarbon liquids (as US barrel or Sm^3 or Nm^3)
- EC_{liq} is energy content of hydrocarbon liquids (as MMBtu/US barrel or MJ/Sm^3, or MJ/Nm^3)

An Operator must calculate its Methane Intensity for segment grading (Section 4) as:

$$Methane\ Intensity = \frac{ME \times GR}{Total\ Pipeline\ Distance} \quad (4)$$

Where:

- *ME* is the Methane Emissions from the Facility (metric tons)
- *GR* is the gas ratio, as calculated above (unitless).
- $x_{pipeline}$ is pipeline distance in the Facility (miles).

To convert a Transmission & Storage Facility's intensity to be able to be integrated into an estimate of emissions across a natural gas supply chain, then intensity must be converted into mass of emissions over energy content of gas Throughput (in gCH_4/MMBtu). The method for conversion is as follows:

$$Methane\ Intensity = \frac{ME \times GR}{V_{ng}} \quad (5)$$

Where:

- *ME* is the annual Methane Emissions from a Facility (metric tons)
- V_{ng} is the natural gas Throughput (mcf or Sm^3, or Nm^3)

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

Table 4: Imperial default values for calculating Methane Intensity

	Default value		
Abbreviation	**Description**	**Units Imperial**	**Default Value**
EC_{ng}	Higher Heating Value natural gas	(MMBtu/Mscf)	1.235
EC_{liq}	Higher Heating Value hydrocarbon liquids	(MMBtu/US barrel)	5.8
MC	Methane Content of natural gas	(volume fraction)	0.934
M_{den}	Methane Standard Density	(metric ton CH_4/Mcf	0.0192

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

Standard at 15°C	**Default value**		
Abbreviation	**Description**	**Units SI Standard**	**Default Value**
EC_{ng}	Higher Heating Value natural gas	(MJ/Sm^3)	46
EC_{liq}	Higher Heating Value hydrocarbon liquids	(MJ/Sm^3)	38500
MC	Methane Content natural gas	(volume fraction)	0.934
M_{den}	Methane Standard Density	(MT/Sm^3)	0.000677

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MiQ STANDARD

for Methane Emissions Performance

SUBSIDIARY DOCUMENT 2: Company Practices – Transmission & Storage

v1.0

MiQ

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1 Introduction

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

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

1. *Main Document – T&S*
2. Subsidiary Documents
    a. *Subsidiary Document 1: Methane Intensity – T&S*
    b. **Subsidiary Document 2: Company Practices – T&S (this document)**
    c. *Subsidiary Document 3: Monitoring Technology Deployment – T&S*

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

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

An Operator should be able to not only produce documentation of their Company Practices and procedures, but also demonstrate that its employees implement and comply with those practices.

2 Scope of this Document

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

1. **General Company Practices**

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

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

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

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

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

This subsidiary document covers Company Practices for onshore natural gas T&S operations.

3 Performance Criteria

An Operator seeking certification for a Facility under this Standard is required to provide evidence of their Company Practices relevant to methane emissions management. Specific performance criteria are based on the presence, content, and implementation of these Company Practices.

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

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

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

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

For a Facility to be certified under this Standard, **each** mandatory Company Practices performance criteria outlined below must be met. Facilities which adopt improved practices for reducing methane emissions are eligible for 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 1-10 below. If a Facility demonstrates **at least one** of the multiple elements listed for an improved practice topic separated by the word **"or",** as outlined in Tables 1-10, it should receive all points nominated for that practice. If two or more elements are related by the word **"and"**, each improved practice must be demonstrated to receive all points. For performance criteria relevant to emission sources not found on a given Facility, the Operator automatically receives the available points.

Independent Company Practices Evaluations must be done for each Facility undergoing certification. The Standard does acknowledge that a Facility operated by a single Operator is likely to have uniformity in Company Practices across the various Facilities, if contiguous. Company Practices that require calculations to be made (i.e.. COMP 2.1 or BD 2.2), are to be made on a Facility-wide basis and determinations are to be applied to each one equally.

3.1 General Company Practices

Facilities will employ general Company Practices to minimize methane emissions to the greatest extent possible. This includes prioritizing a culture of eliminating methane emissions and ensuring employees have the education, resources, and support to implement emission management and minimization strategies.

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

Table 1: General Company Practices (GP)

Practice	Character	Points
(GP- 1) Employee training and awareness Operations staff receive training that: • 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 (1x detailed version for all staff, refresher version for staff that have already completed detailed version and 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	-
(GP-_3) Estimating and measuring Methane Emissions		

[1] Company Practices are numbered by type or emission source. Types and emission sources include General Practices (GP), Unintended Methane Emissions Practices (UMEP), Compressor Emission Practices (COMP), Blowdown Emission Practices (BD), Pneumatic Device Emission Practices (PD), Storage Tank Emission Practices (ST), Dehydrator Emission Practices (DEHY), Flare Emission Practices (FLR), and Combustion Equipment Emission Practices (CE).

At minimum, operator's guidance for measurement methods and calculation of methane emissions includes: • All Site emission sources; **and** • Quantification method for each emission source; **and** • Reconciliation process for including all Unintended emission sources	Mandatory	-
(GP- 4) Continual improvement		
Methane management is integrated into the Operator's company culture, as evidenced by: • Documentation or communication plans that references 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	Mandatory	-

3.2 Company Practices for Managing and Reducing Unintended Methane Emissions

Reducing Unintended methane emissions requires awareness and monitoring of areas where these 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:	Mandatory	-

- 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 - Operator's personnel responsible for carrying out inspection are trained in proper use of instruments, instrument calibration, inspection methods and regulatory requirements; **and/or**
- Optical Gas Imaging (OGI) – Operator's personnel responsible for use of OGI cameras are trained in the regulatory requirements for survey, calibration and proper use of the specific camera deployed by the Operator; **and**
- In the event LDAR surveys are carried out by third-party personnel, the Operator should be in possession of training records documenting the training of personnel hired; **and/or**
- Alternative technology programs have consistent equipment operating and reporting procedures for consistent deployment

(UMEP-2) Source Level Detection Plan — Mandatory — -

LDAR Plan outlines at minimum:

- specific equipment / components included in LDAR survey (must reference connectors, open-ended lines, valve stem packing, PRVs, blowdown/isolation valves, process valves, connectors, compressor seals, other compressor vent sources, meters/instruments, regulators, pneumatic controllers at a minimum); **and**
- leak definition; **and**
- monitoring methodology (reference to equipment, frequency, conditions, reporting log); **and**
- Repair or replacement strategy, including when to take immediate corrective action and when delay of repair is permitted; **and**
- First attempt requirements within 30 days of detection; **and**
- Final repair attempt (maximum of 30 days from time of detection; **and**
- Repair verification completed within 30 days of detection if no safety concerns; **and**

• Steps to be taken for delay of repair, including tagging and reporting: **and** • Recordkeeping and tracking for delay of repair to ensure appropriate follow-up actions are taken; **and;** • Clear roles and responsibilities for repair or replacement		
(UMEP- 3) Directed inspection and maintenance To manage methane emissions, Operators elect to: • target major equipment (i.e. pneumatic controllers, compressor seals and vents) 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- 4) Root Cause Analysis (RCA) of unintended emission events • Operator has Root Cause Analysis (RCA) policies and procedures describing the process of conducting an analysis of the cause of unintended emission events and documentation of the corrective actions taken to limit and prevent reoccurrence.	Improved	1

3.3 Company Practices for Managing and Reducing Compressor Emissions

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

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

Practice	Character	Points
(COMP- 1) Managing Methane Emissions from Compressors • Compressors are included in LDAR surveys; **and**	Mandatory	-

• Operator evaluates projects to reduce emissions from wet seal oil degassing systems by routing gas to a control device, routing to beneficial use, using a dry seal or another solution and demonstrates progress against project plans; **and** • Operators implement preventative maintenance strategies for all compressors and their critical components based on run time. This includes compressor overhauls and inspection and maintenance of critical components (ex. compressor rings, packing, seals, bearings etc.); **and** • Whenever maintenance occurs (or more frequently), operator/contractor inspects for and repairs causes of excessive leakage		
(COMP- 2)		
In addition to the above, Operators elect to:		
(COMP- 2.1)		
• Mitigate vented methane emissions from at least 50% of centrifugal compressor inventory, compared to an uncontrolled wet seal oil degassing system; **or**	Improved	1
• Mitigate vented emissions from 90% of centrifugal compressor inventory, compared to an uncontrolled wet seal oil degassing system.		2
(COMP- 2.2)		
• Replace natural-gas driven compressor starts with non-venting compressor starts for at least 50% of compressor inventory	Improved	1
(COMP- 2.3)		
• Facility has policies and procedures to keep compressors pressurized before and during downtime and/or routes compressor blowdown vent line to fuel-; **or** • Facility uses another solution to minimize emissions before and during compressor downtime.	Improved	1

3.4 Company Practices for Managing and Reducing Blowdown Emissions

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

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

Practice	Character	Points
(BD- 1) Managing Methane Emissions from Blowdowns		
• Operational repairs coordinated with routine maintenance repair schedules to minimize total blowdown events; **and** • All methane emissions from blowdown are calculated using engineering calculations or metered volumes in lieu of generic emission factors; **and**	Mandatory	-
(BD- 2)		
In addition to the above, Operators elect to:		
(BD- 2.1)		
• Evaluate projects to minimize blowdown volumes from Facility equipment segments and demonstrate progress against project plans; • Evaluate projects to minimize emissions from emergency shutdown (ESD) systems during testing and demonstrate progress against project plans	Improved	1
(BD- 2.2)		
Have policies and procedures to mitigate emissions from non-emergency blowdown events and;	Improved	
• Mitigates methane emissions from at least 25% of non-emergency blowdown events at the Facility,; **or**		1
• Mitigates methane emissions from at least 50% of non-emergency blowdown events at the Facility, **or**		2
• Mitigates methane emissions from at least 75% of non-emergency blowdown events at the Facility, **or**		3
		4

- Mitigates methane emissions from at least 90% of non-emergency blowdown events at the Facility

3.5 Company Practices for Managing and Reducing Pneumatic Device Emissions

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

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

Practice	Character	Points
(PD- 1) Managing Methane Emissions from Pneumatic Devices • Procedures to maintain accurate inventory of pumps and controller counts by model that are checked annually at a minimum; **and** • Policies and procedures to ensure controllers are operating as designed, based on type of service (on/off, throttling) and type of venting (continuous or intermitted), based on published vent rates for the model[2] or industry equipment standards; **and** • Gas-driven pneumatic devices are included in LDAR surveys.	Mandatory	-
(PD- 2) In addition to the above, Operators elect to:		
(PD- 2.1) • Have installed non-venting (e.g. no bleed, mechanical, electric, or instrument air) pneumatics in place of gas-driven pneumatics for at least 50% of pneumatic devices.	Improved	2
(PD- 2.2) • Has a program in place to replace remaining venting devices with non-venting devices within 3 years of applying for certification, and have demonstrated progress against this program; **and**	Improved	1

- Has a policy in place to install non-venting pneumatics on all new equipment installations.

3.6 Company Practices for Managing and Reducing Storage Tank Emissions

By implementing Company Practices to reduce methane emissions from storage tanks, Operators can ensure the amount of gas released is minimized. Storage tank is defined as a tank within the Facility bound that sits on or above the ground and has the potential to emit significant methane emissions, excluding tanks that primarily store water

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

Practice	Character	Points
(ST- 1) Managing Methane Emissions from Storage Tanks • Operator implements procedures to mitigate hydrocarbon storage tank emissions for routine operations and maintenance; **and** • Operator routinely monitors and inspects key areas that may be a source of methane emissions from tanks at least monthly, including, but not limited to, vapor recovery systems, thief hatches, dump valve problems (on upstream separators), and pneumatic controllers; **and** • Operator implements policies and procedures for managing tanks which include not only observation of methane emissions but also preventative maintenance procedures based on historical problems on specific components of tank equipment.	Mandatory	-
(ST- 2) At all storage stations, reduce methane emissions by installing flares, enclosed combustors or other emission controls on tank vents	Improved	1
(ST- 3) At storage stations, recover methane emissions by installing vapor recovery units, lower pressure second stage separators or other equipment with the purpose of	Improved	2

recovering vent gas prior to liquids entering fluid storage tanks.

3.7 Company Practices for Managing and Reducing Flaring Emissions

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

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

Practice	Character	Points
(FLR- 1) Managing Methane Emissions from Flare Operators must implement: • Policies to define the use of routine and non-routine flaring, and acceptable durations of flaring events; **and** • Procedures which define stable operating range and criteria for all flare systems, considering emergency events, to ensure maximum destruction efficiency[2]; **and** • At least 98% destruction efficiency is achieved through utilizing staff and/or contractors for inspections, including LDAR surveys of flare systems; **and** • Policies to flare or combust natural gas at storage facilities where recovery is not possible and limit gas routed to vents (**Storage only**)	Mandatory	-
(FLR- 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; • auto ignition system for unsupervised flare stacks with intermittent flaring; • thermocouples (temperature sensors) to ensure pilots stay lit or flame out detection device installed.	Improved	1

3.8 Company Practices for Managing and Reducing Dehydrator Emissions

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

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

Practice	Character	Points
(DEHY- 1) Managing Methane Emissions from Dehydrators Operators must demonstrate: • Efforts to optimize and control circulation rates for glycol dehydrators	Mandatory	-
(DEHY- 2) In addition to the above, Operators elect to: • Using flash tank separation in dehydration and recapturing the flash gas for fuel gas; **and** • Use dehydration processes that do not have a continuous vent in place of glycol dehydration processes, such as use of desiccant	Improved	1

3.9 Company Practices for Managing and Reducing Combustion Equipment Emissions

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

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

Practice	Character	Points
(CE- 1) Managing Methane Emissions from Combustion Equipment • Annual compressor power output from lean burn gas engines accounts for less than or equal to 75% of	Improved	2

total annual compressor power output from the Facility, **or;**		
• Annual compressor power output from lean burn gas engines accounts for less than or equal to 50% of total annual compressor power output from the Facility, **or;**		3
• Annual compressor power output from lean burn gas engines accounts for less than or equal to 25% of total annual compressor power output from the Facility, **or;**		4
• Annual compressor power output from lean burn gas engines accounts for less than or equal to 10% of total annual compressor power output from the Facility		5
(CE- 2)		
Operator uses measurements or emission factors developed from representative measurements to calculate methane emissions from all compressor drivers	Improved	1

3.10 Company Practices for Managing and Reducing Transmission Pipeline and Underground Storage Well Emissions

By implementing Company Practices to monitor the condition of pipeline and storage wells, Operators can ensure the assets are fit for service and reduce the probability of a release.

Table 10: Company Practices for managing and reducing methane emissions from Transmission Pipelines (PIPE)

Practice	Character	Point
(PIPE- 1) Third-Party Damage Prevention Program		
• Operator has documented policies and procedures to visibly mark and identify buried assets • Operator has targeted public education programs on the consequences of ground disturbances and best practices for ground disturbance • Operator conducts routine surveillance on the pipeline right-of-way to monitor unauthorized activities.	Mandatory	-

(PIPE- 2) Quality Assurance Program

• Operator has procedures to inspect material quality (valves, gaskets etc.) prior to field installation • Operator has procedures on bolt torquing and tensioning flanged connections • Operator has procedures for welding and written requirements for welder qualifications	Mandatory	-

(PIPE –3) Transmission Pipeline Monitoring Program

• Operator has a documented corrosion prevention program which at minimum includes pipeline coating systems and cathodic protection • Operator has inspection programs to monitor the condition of the pipeline; inline inspection or smart pigging, integrity digs, cathodic protection surveys, depth of cover surveys.	Mandatory	-

(PIPE- 4) - Underground Storage Well Monitoring Program

• Operator has a scheduled wellhead component and casing inspection program to inspect the integrity of the asset on a set frequency. • Operator has guidance documents on fit for service assessments, hazard assessments and integrity tolerances	Mandatory	-

(PIPE- 5) Preventative Maintenance Program

For non-major emitting sites, such as metering and regulation stations and valve stations, that are exempt from Facility Scale and Source Level inspection requirements (see *Subsidiary Document 3: Monitoring Technology Deployment)* operator must: • Operator has preventative maintenance strategies for components that have the potential to have significant leaks and releases, or their failure has significant environmental impact. At minimum an operator should have strategies for the following : valves (above and below ground), ESD, flanges (bolted connections), open ended lines, pump seals, PSV's, PRV's, threaded connections.	Mandatory	-

(PIPE- 6) Employee Training		
• Operator has training and competency assurance program to ensure employees trained and competent in performing specific gas-related tasks. Program at minimum must have onboarding program, task specific training modules and documented competency assessments • Operator has a contractor management process which includes trade qualification verification, hazard training and contractor performance assurance.	Mandatory	-

3.11 Required Evidence Available to Auditors

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

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

References

[1] US Environmental Protection Agency (EPA). (2017). *Method 21 - Determination of Volatile Organic Compound Leaks*. Retrieved from https://www.epa.gov/emc/method-21-volatile-organic-compound-leaks

[2] Methane Guiding Principles. (2019). *Reducing Methane Emissions: Best Practice Guide - Equipment Leaks*. Retrieved from https://methaneguidingprinciples.org/best-practice-guides/equipment-leaks/

MiQ STANDARD

for Methane Emissions Performance

SUBSIDIARY DOCUMENT 3: Monitoring Technology Deployment – Transmission & Storage

v1.0

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1 Introduction

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

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

1. *Main Document – T&S*
2. Subsidiary Documents
    a. *Subsidiary Document 1: Methane Intensity – T&S*
    b. *Subsidiary Document 2: Company Practices – T&S*
    c. **Subsidiary Document 3: Monitoring Technology Deployment – T&S (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, it 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.

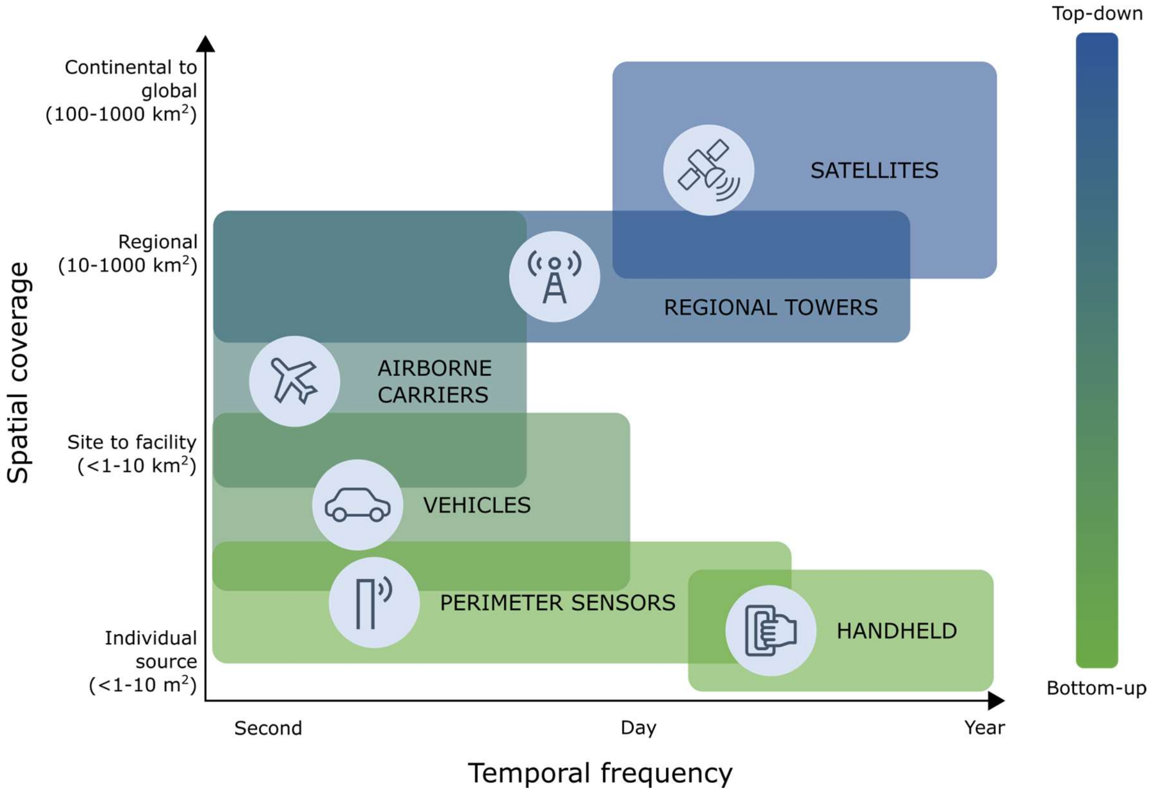

Figure 1: Methane monitoring technology across a variety of spatial and temporal scales (adapted from the National Academies of Science, Engineering, and Medicine, 2018[1])

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.

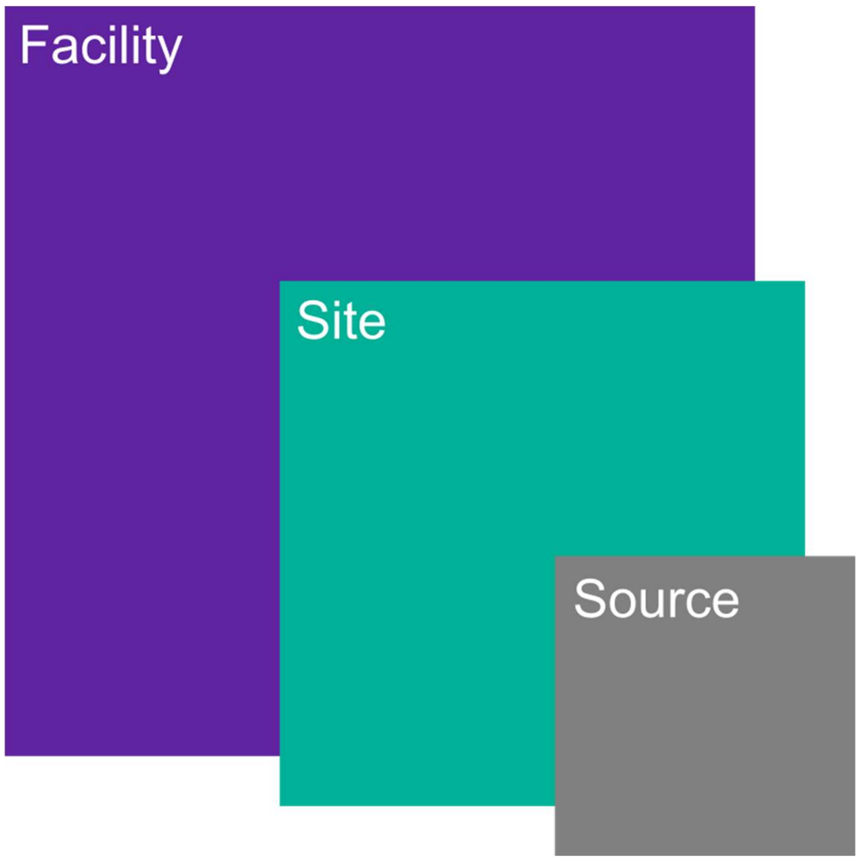

Figure 2: Spatial scales utilized within the Standard, referencing the definitions of Facility, Site, and Source as outlined in the *Main Document*, see there for reference.

[2] 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.

2 Scope of this Document

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

This document outlines the requirement for Monitoring Technology Deployment for the **detection** of methane emissions. This version does not require Measurement or Quantification through technology deployment currently. However, all detected emissions must be reconciled in an Operators Inventory (see *Subsidiary Document 1: Methane Intensity T&S Section 4*). Details of an Operators 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 (see *Subsidiary Document 1: Methane Intensity*);
- to implement better operating practices and equipment design for reduced methane emissions; and
- to encourage Operators to work towards Measurement or Quantification 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 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.

3.2 Performance Scoring

Table 2 outlines the performance criteria and associated score for Monitoring Technology Deployment under the Standard. Both Facility Scale inspections, and Source Level leak inspection frequencies are specified.

An Operator is required, at a minimum, to conduct a baseline inspection over the entire Facility annually to be certified under this Standard. Operators can achieve a higher score by increasing the frequency of both Source Level inspections as well as Facility Scale inspections.

The MiQ Standard employs the concept of Equivalency to fulfill the monitoring technology deployment requirements. The Frequency, Sampling coverage, and MDLs outlined in Table 2 below should be considered a benchmark for achieving a given number of points. An Equivalent LDAR program capable of detecting and characterizing an equivalent amount of methane emissions may be proposed to the auditor, as demonstrated through a given equivalency model and modelling assumptions (see Section 3.2.3).

The details for Facility Scale and Source Level detection 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[6, 7]	quarterly	100% of sites[8]	12

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

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

[6] Facility Scale coverage must include all transmission compressor stations and sites storing natural gas that have aboveground equipment such as storage wellheads and equipment for injection and withdrawal of natural gas.

[7] Each individual Facility will be evaluated separately for both Facility Scale and Source Level inspection frequencies.

[8] Source Level coverage must include all equipment at transmission compressor stations and sites storing natural gas that have aboveground equipment such as storage wellheads and equipment for injection and withdrawal of natural gas.

semi-annually (MDL 25kg/hr)	Entire Facility	tri-annually	100% of sites	8
annually (MDL 25kg/hr)	Entire Facility	semi-annually	100% of sites	4
N/A	Entire Facility	annually	100% of sites	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[9] 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).
    - Operators may choose to demonstrate equivalent monitoring using Continuous Monitoring Systems over a subset of sites (<100% coverage) paired with Source Level methods and/or other periodic Facility Scale survey methods, to achieve the same level of detection and mitigation

[9] Facility Scale MDLs chosen to best encompass possible super-emitters from the supply chain, based on learnings from Brandt et al [4] 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].

potential as outlined in Table 2 (see Section 3.2.3. for more information on demonstrating equivalency).

Due to the sprawling nature of T&S infrastructure, Facility Scale inspections will target infrastructure elements known to be significant sources of emissions: compressor stations and sites used for storing natural gas that have aboveground equipment including, storage tanks and storage well sites. Other sites with less emission sources including metering and regulation stations and valve stations are exempt from the Facility Scale inspection requirements but must comply with the inspection requirements listed in *Subsidiary Document 2: Company Practices*.

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.

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. Unintentional methane emissions may include fugitive component leaks, excess venting from intentional emission sources (i.e. leaky reciprocating compressor rod packing, leaking wet seal oil degassing system, malfunctioning pneumatic controller), excess methane emissions from combustion sources including engine drivers and process flares due to poor hydrocarbon destruction performance or any other non-engineered releases.

The Source Level inspection methods employed by the Operator must be detailed in the Operator's LDAR program.

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

- Spatial resolution must be sufficiently low to reliably attribute emission sources to the component or equipment level for repair, maintenance, or mitigation

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

Due to the sprawling nature of T&S infrastructure, Source Level inspections will target infrastructure elements known to be significant sources of fugitive emissions: compressor stations, storage tanks and storage well sites. All equipment located within a transmission compressor station, storage compressor station, or storage wellhead with exception to elevated exhaust stacks from combustion sources (excluding process flares) are subject to each Source Level inspection but must comply with the inspection requirements listed in *Subsidiary Document 2: Company Practices*.

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

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

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

3.2.3 Equivalency Determination

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

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

Equivalent LDAR Programs must meet the same program and recordkeeping requirements (see Table 3 and 4) and minimum coverage requirements outlined above.

4 Recordkeeping and Reporting Requirements

Operators are required to record and disclose information related to methane emissions Monitoring Technology Deployment plans and implementation under the Standard. Deployment plans and supporting implementation information must be disclosed to the Auditor during the Annual Audit. Proof of implementation of the deployment of each monitoring technology solution must be disclosed to the registry during the Certification Period and to the Auditor during the subsequent years' Annual Audit. Table 3 outlines the minimum recordkeeping requirements for Monitoring Technology Deployment. An Operator can choose to aggregate the recordkeeping elements to minimize administrative overhead. An Operator must have adequate Company Practices in place which underpin accurate recordkeeping and reporting structures.

4.1 Minimum Recordkeeping and Reporting Requirements

Table 3: Minimum recordkeeping requirements

Recordkeeping element	Details

Detection Technology Specifications	Technology specifications are required for methods that meet Facility Scale and Source Level requirements
	• Sensor and instrumentation details
	• Method in which the sensor deployed (i.e. fixed-wing, drone-based, stationary-mounted)
	• Performance specifications including minimum detection limit and probability of detection curves
	• Details of independent, single-blind testing, including
	  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 planned (for at least the Certification Period) and visited for each survey (categorized by site ID or similar unique identifier).
QA/QC	Includes chain of custody sign off on data collected for accuracy (collector to independent reviewer), analytical settings as appropriate, calibration of monitoring equipment, and reference to the test method used.

4.2 Recordkeeping and Reporting Requirements for Continuous Monitoring Technology

As discussed in Section 3.2.1 and 3.2.2, a Facility may choose to utilize a Continuous Monitoring System over all or part of their sites towards meeting the requirements of a Facility Scale or Source Level inspection. Table 4 outlines the minimum records an Operator 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 Operator response to monitor downtime (i.e. backup monitoring plan) • Monitoring equipment calibration protocols (i.e. frequency, technology-specific parameters that are calibrated)

5 Interconnections with other Standard Elements

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

5.1 Interconnection with calculated Methane Intensity

When calculating annual methane emissions for use in the Methane Intensity calculation as required by the Methane Intensity Document, Operators must reconcile methane emissions discovered from an inspection using the technology's quantification capabilities, engineering calculations, or other methods representative of emissions events discovered.

For Facilities located outside of the US, but subject to methane emissions regulation in the jurisdiction where the Facility is located, Operators can substitute country-specific Leaker Emission Factors for the same emission sources, if backed up by a transparent and peer-reviewed process. These Leaker Emission Factors should be applied to components with a total time of assumed leakage based on time duration between Source Level/LDAR survey frequency. The Operator must reconcile results from each inspection survey when calculating methane emissions and Methane Intensity.

This Standard also allows Operators to incorporate Facility-specific measured Emission Factors in order to characterize a Facility's methane emissions profile more accurately (refer to *Subsidiary Document 1: Methane Intensity, Annex Table 2* for more detail).

Unintended abnormally high emissions (Super-Emitters) detected from Facility Scale inspection must be estimated or quantified using best available techniques (BAT), reconciled and included in the Facility emissions inventory, for use in the Methane Intensity calculation.

5.2 Interconnection with Company Practices

Due to the nature of Transmission & Storage emission source distributions, high pressure conditions, and the role of integrity monitoring of pipelines and storage wells for prevention of Super-emitter scale leaks, the Standard heavily leverages condition monitoring programs as outlined in *Subsidiary Document: Company Practices Section, Section, 3.10* to complement external leak detection found here in *Monitoring Technology Deployment*. By implementing Company Practices to proactively monitor and assess the integrity of the pipeline and storage wells, Operators can mitigate incidents that have the potential for catastrophic releases.

Non targeted sites for Facility Scale and Source Level inspection, such as metering and regulation stations and valve stations, are deemed to pose a lower risk to unintended emission sources. These sites, however, must comply with the inspection requirements listed in *Subsidiary Document 2: Company Practices, Section 3.10.*

A Monitoring Technology Deployment plan is as also a required Company Practice, 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

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