MiQ STANDARD

for Methane Emissions Performance

MAIN DOCUMENT - LNG

v1.0.0

Contents

1 Background

1.1 Introduction

Methane emissions from the production, processing, transmission and storage of oil and gas are a significant contributor to climate change. Methane, the primary component of natural gas, is a very potent greenhouse gas with a short-term climate impact over 80 times that of carbon dioxide[1].[1] While methane is emitted throughout the oil and natural gas supply chains, this Standard addresses methane emissions from the Liquefied Natural Gas (LNG) liquefaction and regasification segments.

In the LNG supply chain, methane is emitted in the process of liquefaction, transport, storage and regasification through venting, leaking and incomplete combustion from flares, burners, turbines and engines. While technologies and processes that can prevent or significantly reduce methane emissions exist, emissions abatement actions, whether voluntary or enforced through regulation, are not yet occurring with sufficient consistency or the scale necessary to limit global warming to the 1.5 degree target put forward in the Paris Agreement.

The MiQ Standard for Methane Emissions Performance (the Standard) has been developed to improve transparency of methane emissions in the natural gas supply chain and to drive emissions abatement. It 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.

In addition, the Standard provides a methodology to calculate the Methane Intensity of LNG cargoes transported by sea in order to provide a complete analysis of the

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[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.

methane emissions along the LNG supply chain including liquefaction, shipping and regasification.

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

- **Main Document** (this document)
- Subsidiary Documents
    a. *Subsidiary Document 1: Methane Intensity – LNG*
    b. *Subsidiary Document 2: Company Practices -LNG*
    c. *Subsidiary Document 3: Monitoring Technology Deployment – LNG*
    d. *Subsidiary Document 4: Estimation of Methane Intensity for LNG shipping.*

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 the MiQ Standard is to incentivize continuous improvement in methane emissions monitoring and abatement by creating an opportunity for LNG Operators to differentiate their LNG operations by their methane emissions performance.

More specifically, the objectives of this Standard are:

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

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

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

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

c) to increase transparency regarding the methane emissions performance across the LNG supply chain with a globally consistent methodology;

d) enable buyers and sellers to transact natural gas with transparency of the methane emissions performance of LNG operations, and to demonstrate additional value to their customers;

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

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

g) credibly recognize LNG Operators that are leading their peers in methane emissions management.

2 Scope

This Standard establishes a system for the generation of MiQ certificates, which will include a defined Grade that captures the Facility's methane emissions performance.

Furthermore, this Standard:

- is applicable to Liquefaction Facilities, Roundtrip LNG Voyages and Regasification Facilities, including any gas processing and gas or LNG storage that is undertaken at such Facilities;
- specifies a method to calculate the Methane Intensity of LNG Facilities and Roundtrip LNG Voyages;
- establishes general principles for an effective methane management program for LNG Facilities, including policies and procedures focused on methane emissions prevention, detection, and abatement and deployment of methane monitoring technology;
- defines procedures for assessing the Methane Intensity of LNG Carriers; and
- does *not* define requirements for natural gas' or LNG's physical or chemical quality.

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

3 Terms and Definitions

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

Term	**Definition**
Annual Audit	The systematic, independent, and documented assessment by the Auditor prior to the intended Certification Period, verifying the information reported by the Operator against the Standard.
Auditor/Auditing Body	An individual, or organization made up of individuals, that carry out assessments to determine if a Facility meets the requirements of the Standard and recommend a performance Grade. An Auditor or Auditing Body must possess the combined demonstrated knowledge, skill and abilities, along with documented training and experience required to provide assurance services, both offsite and onsite, to determine Facility's performance against all diverse elements of the Standard.
Audit Report	A verification document prepared by an Auditing Body that contains a comprehensive analysis of the Operator's adherence to the Standard.
Ballast Voyage	The inward (preceding) ballast journey from the last unloading port or dry dock/layup location to the loading port of the same LNG Carrier being used deliver LNG at the receiving LNG facility.
Basin	An oil and gas producing region (a geologic sedimentary basin), as typically defined and referenced by national legislation.

Causal Examination	The act of following up to a detected event at the Site, Equipment or Component level to determine the likely cause of the emission, using SCADA logs, maintenance logs, operational logs, operator site visits, and Source Level detection surveys. Examinations should also, at minimum, include determination of emissions as Intended or Unintended. Causal examinations are less formal than Root Cause Analyses and do not require a systematic corrective action to be identified, recommended or implemented as part of the examination process.
Certification Period	The period (maximum 12 months) during which Certified Production at a Facility is eligible for MiQ certificates.
Company Practices	A document, program, policy or procedure, specific to the Operator that identifies effective management of methane emissions within the Facility boundaries. Company Practices is also the title of one of the subsidiary documents to this Standard.
Component	A smaller piece of equipment, such as a flange, connector, pressure relief device (PRD), thief hatch, screw or compression fitting, stem packing in a valve, pump seal or compressor component.
Continuous Gas Detection System	A monitoring system at a Facility, usually part of the Facility's more broad personnel and process safety management plans, that includes the installation of fixed devices with the primary purpose of detecting and alarming gas releases. Continuous gas detection monitors that fall under this definition include, but are not limited to, lower explosive limit (LEL) monitors and acoustic gas leak detectors. A monitoring system must be inclusive of all areas in which the possibility of fire or explosion hazard may exist under normal or abnormal conditions due to the presence of flammable, combustible or ignitable gases that have the potential to include methane. Hazardous classified location definitions determined by other safety or environmental standards can be used to determine the extent of coverage required for deployment of continuous gas monitors.
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.
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.
Liquefaction Facility	All contiguous, onshore equipment commonly owned and operated, where liquefaction of natural gas takes place. A facility boundary includes all physical property, plants, buildings, structures, equipment and emission sources downstream of (but including) the incoming natural gas metering and receiving station, including in the case of a two phase incoming pipeline, a slug catcher, and upstream of (but including) apparatus for loading LNG onto LNG Carriers up to the point of coupling to the ship and/or road transport or other means of exporting LNG from the site. A facility boundary also includes any electricity generation assets that are under common ownership, control or operation and provide a significant share of electricity used at the site.
Regasification Facility	All contiguous, onshore equipment commonly owned and operated, where regasification of LNG takes place. A facility boundary includes all physical property, plant, buildings, structures, equipment and emission sources downstream of (but including) apparatus for unloading LNG from LNG Carriers from the point of coupling to the ship and/or road transport or other means of importing LNG into the site and upstream of (but including) the outgoing natural gas metering and exporting station. A facility boundary also includes any electricity generation assets that are under common ownership, control or operation and provide a significant share of electricity used at the site.
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 (CO2e), which is calculated using a timeframe-specific Global Warming Potential (GWP).
Intended Emission	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.
Laden Voyage	Voyage of a vessel transporting a cargo of liquefied natural gas for offloading at a destination port.
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.
Liquefaction of LNG	The oil and gas supply chain segment that includes all equipment, piping and instrumentation used in the pretreatment and treatment, refrigeration, liquefaction, storage and loading of liquefied natural gas, upstream of a shipping vessel or point of transportation.
LNG	Liquefied natural gas (i.e., natural gas in its liquid state).
LNG Carrier	A seagoing cargo vessel with a unique IMO number that is engaged in carriage of liquefied natural gas in bulk, regardless of size.

Methane Intensity	The ratio of methane emissions and a selected variable. It accounts for natural gas throughput relative to crude and condensate throughput by allocating emissions that are attributable to the handling of natural gas.
MiQ LNG Voyage Model	The Excel tool that is used to estimate methane emissions for a Roundtrip LNG Voyage
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.
Operator	The party responsible for operations of a Liquefaction and/or Regasification Facility and all associated owned and leased equipment as it applies to methane emissions.
Quantification	Estimating an emission rate, such as mass per time or volume per time, or total emissions. This can be done directly through measurement of the emissions, or indirectly through emission factor methodologies, engineering calculations and modeling.
Reconciliation of Emissions	A quantitative assurance process required to ensure a more complete emissions estimate. The process cross-references top-down detections and quantified emissions with a bottom-up inventory to ensure an operator's methane intensity falls within a designated MiQ Grade band.
Regasification of LNG	The oil and gas supply chain segment that includes all equipment, piping and instrumentation used in the unloading, storage, vaporization, compression, treatment or odorization, and metering of liquified natural gas into the gaseous phase upstream of transmission.
Roundtrip LNG Voyage	The actual or assumed roundtrip voyage that includes the actual Laden Voyage (including loading and unloading) and an assumed Ballast Voyage from the unloading port back to the original loading port for the Laden Voyage on the same LNG

	Carrier, whether or not the assumed Ballast Voyage actually takes place or not.
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	The location or footprint encompassing a given liquefaction or regasification process, such as that used for storage, treatment, compression, heat exchange (refrigeration or vaporization), or metering. Leak detection at the Site Level must be able to narrow the location of the methane emission to a single localized area or Component or piece of Equipment for Causal Examination and mitigation efforts.
Source / Emission Source	A specific piece of equipment or activity that emissions originate from. The sum of emissions from all emission sources makes up a Facility's inventory.
Source Level Inspection	Application of 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.
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	The total quantity of loaded liquefied natural gas from a LNG Liquefaction Facility or the total quantity of natural gas sold, delivered or sent out by an LNG Regasification Facility in the relevant period.

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

4 Core Principles

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

1. **Relationship with ISEAL Credibility Principles**

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

2. **Voluntary nature**

   The use and adoption of this Standard is voluntary. This Standard provides requirements for LNG Operators to differentiate the supply of their product based on its methane emissions performance. The application of this Standard is a voluntary action taken by an LNG 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 Auditing 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 is eligible to liquefy, ship or regasify certified gas under this Standard under the following boundary definitions:

- **Physical boundary**

  All contiguous equipment commonly owned and operated, where liquefaction or regasification of natural gas takes place. See the definitions of Site and Facility. These definitions are adapted from CEN [5].

- **Organizational boundary**

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

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

1. **Methane Intensity**

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

2. **Company Practices**

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

3. **Monitoring Technology Deployment**

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

6.2 Grading System

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

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

Note, a separate process applies to the calculation of Methane Intensity for Roundtrip LNG Voyages, as set out in *Subsidiary Document 4: Estimation of Methane Intensity for LNG shipping*.

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

Score Requirements

Grade	Methane Intensity (%)	Company Practices (Improved Practices points)	Monitoring Technology Deployment
A	<=0.050%	10	12
B	<=0.10%	7	8
C	<=0.20%	4	4
D	<=0.50%	Mandatory minimum	Mandatory minimum
E	<=1.0%	Mandatory minimum	Mandatory minimum
F	<=2.0%	Mandatory minimum	Mandatory minimum

7 Subsidiary Documents

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

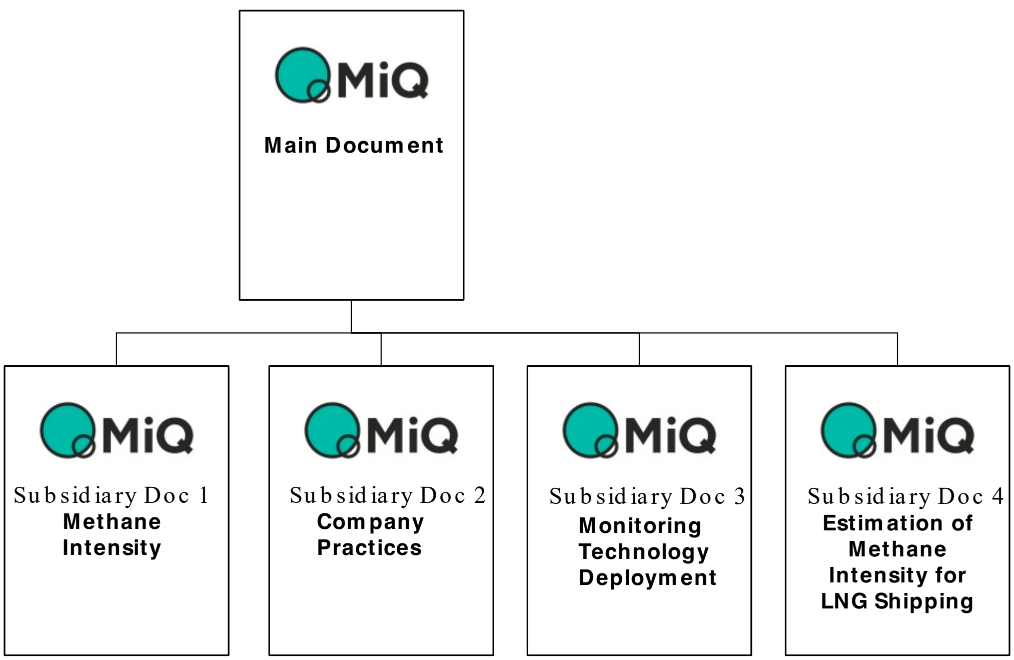

Figure 1: Document hierarchy

7.1 Subsidiary Documents

The following subsidiary documents are defined to supplement this Standard:

- *Subsidiary Document 1: Methane Intensity*
- *Subsidiary Document 2: Company Practices*
- *Subsidiary Document 3: Monitoring Technology Deployment*
- *Subsidiary Document 4: Estimation of Methane Intensity for LNG Shipping*

Annex A: Conversion Factors

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

Table 3: Conversion factors [6].

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 [7].

The higher calorific, gross or high heating value is the amount of heat produced by the complete combustion of a unit quantity of fuel [8].

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.

At the time of publication, this Standard is under technical review to align with ongoing studies for the LNG segment and may undergo changes.

B.2 Version History

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

Table 4: Version History

Version	Revision Date	Document	Summary of Change
v0.4	2021-10	All	Pilot Version
v0.5	2022-02	All	First revision
v1.0	2022-11	All	First Online Publication for technical review
V1.0.0	2024-2	Main	Removal of terms *Applicable Criteria*, *Detection and Leaker Emission Factor* from definitions section Added clarification between the difference between *Causal Examination* and *Root Cause Analysis* Clarified that the definition of *Methane Intensity includes allocation to separate products*

		Updated definition of *MiQ Program Guide* to maintain consistency with all MiQ Standards Clarified that the definition of *Quantification* includes the process of calculating total emissions from an event or source Clarified the definition of Throughput to distinguish between a LNG Liquefaction facility and a LNG Regasification facility Removed the
	Methane Intensity	Updated language in Section 3.3: *Emissions Reconciliation* to clarify the intent of the process Revised language in Section A.1.1 adding a description for the levels of data quality in methane emission inventories to assist in defining 'best available data' per emission source or emission event Updated Table 3 of Section A.1.2, aligning the presentation of allocation and minimum emission calculation requirements with other MiQ Standards for clarity and consistency In Section A.2, Clarified allowable ways for an operator to allocate emissions that are included via the operator's reconciliation process Replaced term 'volume' with 'Throughput' in Section A.2 Added a source-specific product allocation methodology including partitioning emissions to a single product based on the source and energy-based allocation when partitioning is not possible, in accordance with ISO 14067

		Revised language for how methane intensity is converted into mass of emissions per unit energy, referencing the *MiQ Program Guide* as the governing document for conversions that are ultimately reflected on MiQ certificates
	Company Practices	*UMEP-2 Source Level Detection Plan:* Corrected first attempt, repair and repair verification deadlines UMEP-1.5 *Reduced Leak Components* renamed to *UMEP-5 Reduced Leak Components:* Included additional examples for how an operator can achieve UMEP-5 and clarified the extent to which reduced leak components must be installed IMEP-2 thru 2.1 *Venting – Facility blowdowns:* Updated entire sections IMEP-2 and IMEP-2.1 to improve the clarity of to what extent the practices must be followed and to provide flexibility to allow all blowdown mitigation technological solutions to be fairly evaluated IMEP-6 *Combustion Equipment:* Updated entire section to incentivize the use of equipment known to emit lower rates of emissions compared to alternatives, and to improve the clarity of to what extent the practices must be followed across the Facility.
	Monitoring Technology Deployment	Reduced Source Level inspection frequency requirements: - 4x/yr reduced to 2x/yr for 12 points - 3x/yr reduced to 2x/yr for 8 points

		Added language to Section 3.2.3: *Equivalency Determination* allowing Source Level inspections to be conducted in place of Faciilty-Scale inspections Inserted a clause allowing for Source Level and Facility Scale inspection frequencies to be reduced upon confirmation of no additive detects within the last year. Inserted a clause allowing for additional Source-Level inspections to replace Facility Scale inspections on a 1:1 basis, on the basis that at least 1 Facility Scale inspection is performed for point totals that require it. Aligned text in Section 5.1: *Interconnection with calculated Methane Intensity* with Section 3.3: *Emissions Reconciliation* of the Methane Intensity subsidiary document
	Shipping Model	The LNG Shipping model has been updated with the following - Carbon dioxide emissions can optionally be audited against along with methane emissions - Shipping model updated to add more detail on what types of data, methodologies and models can be used in lieu of the inputs, constants, assumptions and structure of the MiQ LNG Voyage model - MiQ LNG Voyage model updated to include ability to calculate carbon dioxide emissions

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] CEN (2007). European Standard EN 1473: Installation and equipment for liquefied natural gas – Design of onshore installations, also adopted as British Standard BS EN 1473:2007. Retrieved from http://www.golng.eu/files/upload/10.1.1.470.7021.pdf.

[6] 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

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

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MiQ STANDARD

for Methane Emissions Performance

SUBSIDIARY DOCUMENT 1: METHANE INTENSITY - LNG

v1.0.0

MiQ

Contents

1. Introduction

The MiQ Standard for Methane Emissions Performance (the Standard) combines several Standard elements – (1) a calculated Methane Intensity, (2) LNG 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 and petroleum operations 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*
2. Subsidiary Documents
    a. **Subsidiary Document 1: Methane Intensity (this document)**
    b. *Subsidiary Document 2: Company Practices*
    c. *Subsidiary Document 3: Monitoring Technology Deployment*
    d. *Subsidiary Document 4: Estimation of Methane Intensity for LNG shipping.*

This subsidiary document outlines the calculation of Methane Intensity as it pertains to the Standard. In general terms, Methane Intensity is a ratio of methane emissions relative to natural gas throughput, which is a baseline indicator of methane emissions performance. See Section 4 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 LNG throughput from a Liquefaction or Regasification Facility. Further details on calculating Methane Intensity of Roundtrip LNG Voyages can be found in other MiQ Standard documentation.

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

3. Methane Intensity

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

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

3.1. Calculation

Methane Intensity is defined as the ratio of the mass of methane emissions relative to the mass of the LNG Throughput. Under this Standard, a Liquefaction or Regasification Facility's Methane Intensity is to be calculated following the methodology detailed in Annex A. It enables LNG Operators to calculate an annual Facility Level Methane Intensity from identified emission sources reconciled with emissions from surveys conducted in accordance with *Subsidiary Document: Monitoring Technology Deployment, Section 3.2.*

For Methodologies for calculating the Methane Intensity of LNG Voyages, please see details outlined in *Subsidiary Document 4: Estimation of Methane Intensity for LNG Shipping*.

The Methane Intensity is a ratio of the mass of methane emissions relative to the mass of the methane content of the LNG Throughput. It is calculated annually as a unitless ratio and communicated as a percentage.

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

3.2. Emissions Sources

A Facility's calculated Methane Intensity must include all methane emissions from all emission sources (outlined in Annex A) present in a Facility. The method detailed below attempts to capture the bulk of the methane emissions from LNG Facilities in an accurate, credible, and replicable way that is consistent with existing frameworks for reporting and disclosure. This method draws heavily on the API compendium 2021 [2] as a framework for recommending emission calculation methods by emission source, grouped for LNG in accordance with the 2015 Liquefied Natural Gas (LNG) Operations Segment [3]. Most emission sources should be captured in the sources outlined in Annex A, but it is the LNG 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.

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

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

3.3 Emissions Reconciliation

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

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

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

1. How emissions detected through applicable methods are classified, including, but not limited to, attribution to site, equipment group, and emission source
2. How the additionality of detected emissions to a Facility's emissions inventory subject to Annex A.1.2 are analyzed, unless all detected emissions are representatively added into the inventory indiscriminatorily.
3. How the data gathered through all applicable methods are used to quantify emissions and affect the Facility's emission inventory submitted via Annex A.1.2. This must include explanation of the data used by operators to quantify emission rates and estimate time durations of events, or annualize emissions through other methods.

4 Scoring Parameters

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

A Facility's Methane Intensity score is based on its calculated Methane Intensity, as detailed in the score requirements in the *Main Document, Section 6.2: Grading System*.

As part of the Annual Audit, LNG Operators must submit a methane emissions inventory that is reconciled with emission events identified during emission surveys completed in accordance with the Monitoring Technology Deployment standard and quantified, or other relevant measurement campaigns undertaken by the operator. New certified LNG 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 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, LNG 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
Facility Description	LNG Operators must document the emissions for all potential emission sources at the Facility are accounted for in the Methane Intensity calculation. This documentation should include, for each relevant facility: owner(s) and operator(s),

	emissions estimates, and the calculation and allocation methods.
LNG Throughput	LNG Operators must document the LNG Throughput used in calculating Methane Intensity, including the source of data.
Equipment and component Counts	For use in emissions calculations, LNG Operators must document the total component and equipment counts associated with each emission source for all Equipment included within a Facility, and the method used to determine this count.
Activity data	For use in emissions calculations, LNG Operators must document the activity data associated with each emission source (e.g. operating time, estimated leaking time for leaker emission sources). LNG Operators must also document their observations of leaking components using LDAR (see *Subsidiary Document 3: Monitoring Technology Deployment* for more detail).
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. LNG Operators must document the method, assumptions used along with its rationale, and its application to the calculation. For enhanced quantification methods, LNG Operators must document all calculation and/or modelling assumptions, and/or technical specifications of measurement technologies deployed.
Reconciliation Procedure	Operator 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 campaigns, within their inventory, including details of their Facility Scale and Source Level inspections, emissions classification, and quantification methods (see Section 3.3).
Methane Intensity Calculation Inputs	*Energy content and Gas Ratio* If applicable, the allocation of methane emissions between natural gas and other hydrocarbon streams in the Facility must be documented and substantiated, including the factor used for energy content of natural gas and the factor used for

	energy content of liquids. If LNG Operators use company-specific higher heating values, the source and derivation of those values must be documented. *Methane content* The LNG Throughput is converted to mass of methane for use in the Methane Intensity calculation. The source of the data and methodology used for determining methane content must be documented.
Internal Assurance	LNG Operators must document their practice for determining and internally reviewing their Methane Intensity for accuracy. This should include a detailed record of calculation methods, parameters (emission sources, throughput values, and energy and methane content factors) used in both the Methane Intensity calculation and emissions reporting (if applicable), any internal changes to calculations (i.e. based on operational incidents and planned events), cross validation steps and the roles of reviewers.

Annex A: Methane Intensity calculation methodology

This annex outlines the Standard's recommended method to calculate Methane Intensity for LNG Facilities. This methodology leverages recommended calculation methods and hierarchies from other national and voluntary protocols. This Standard attempts to capture the majority of emissions in an accurate, credible, and replicable way that is consistent with existing frameworks for reporting and disclosure.

A.1 Emissions Calculation methods and Emission Sources

A.1.1 Emissions calculation methods

Table 2 outlines the types of calculation methods that can be used to quantify methane emissions. In general, data quality and specificity to the Facility increases in ascending order in Table 2. There are many exceptions to this rule, however, and in cases of exception, such as the usage of engineering calculations over direct measurement, the Operator should record justification for the unique approach. Table 3 outlines specific sources to be quantified in the operator's inventory and the minimum methodology requirements for each source. LNG 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. LNG 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 [4] or OGMP 2.0 Level 4/5 [5], and confirmed by the Auditor.

Table 2 outlines the types of calculation methods that can be used to quantify methane emissions.

Table 2: Types of Calculation methods

Calculation method type	Clarification
Direct Measurement	Direct measurement can occur by any means which allows for a methane emissions rate to be determined at the particular source. Typically, through a measured methane concentration and flowrate. The method of conversion and other data points used must be disclosed. The frequency of direct measurement must be disclosed.

Indirect Measurement	Quantifies methane emissions indirectly (by proxy). Typically, this involves measuring methane volume to a specific piece of equipment through a flow instrument installed in the (fuel) supply header, and multiplying this volume with an Emission Factor to quantify emissions from that piece of equipment. Additional forms of proxy measurements involve advanced spectral or concentration sensors which derive an emissions flux by applying an algorithm to a group of individual measurements in space. The frequency, spatial coverage, and uncertainty as determined by controlled releasee testing of indirect measurement must be disclosed.
Engineering Calculation	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 Liquefaction and Regasification

Methane emissions from Onshore Liquefaction and Regasification Facilities are to be accounted for from all potential emission sources. The LNG Operator is required to aggregate methane emissions estimates from all relevant emission sources in the segment of interest to calculate Methane Intensity.

Under this Standard, Liquefaction is defined as:

The oil and gas supply chain segment that includes all equipment, piping and instrumentation used in the pretreatment and treatment, refrigeration, liquefaction, storage and loading of liquefied natural gas, upstream of a shipping vessel or point of transportation.

Under this Standard, Regasification is defined as:

The oil and gas supply chain segment that includes all equipment, piping and instrumentation used in the unloading, storage, vaporization, compression, treatment or odorization, and metering of liquified natural gas into the gaseous phase upstream of transmission.

Table 3: Recommended and alternative calculation methods by Onshore Liquefaction and Regasification Emission Source

Emission[1] Source	**Product Allocation[2]**	**Minimum Emission Calculation Requirements**	**Examples of Accepted Methodologies**
Flares	Energy-allocated	Engineering calculation using flare gas flow rate, flare gas composition and a representative destruction efficiency	API Compendium 5.1 [2], OGMP TGD Flare efficiency (L3-L4) [5]; 40 CFR 98.233(n) [6]; NGER 3.3.9F.2 (Method 2A) [8]

[1] Note: Emission sources and sub-sources follow those set out in API (2015) [3]. 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.

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

Emission[1] Source	**Product Allocation[2]**	**Minimum Emission Calculation Requirements**	**Examples of Accepted Methodologies**
Catalytic and thermal oxidizers	Energy-allocated	Engineering calculation using waste gas flow rate, flare gas composition, and a representative destruction efficiency	API Compendium 5.2 [2]
Incinerators	Energy-allocated	Engineering calculation using waste gas flow rate, flare gas composition, and a representative destruction efficiency	API Compendium 5.2 [2]
Internal combustion engines/drivers	Natural gas	Emission factor-based calculation using an emission factor of incomplete combustion representative of the combustion unit type, along with fuel consumption volumes and fuel composition data	API Compendium 4.5.2; OGMP TGD Incomplete combustion (L3-L4) [5]; NGER 2.3.5 (Method 2) [8]
Turbine generators/drivers	Natural gas	Emission factor-based calculation using an emission factor of incomplete combustion representative of the combustion unit type, along with fuel consumption volumes and fuel composition data	API Compendium 4.5.2 [2]; OGMP TGD Incomplete combustion (L3-L4) [5]; NGER 2.3.5 (Method 2) [8]
Boilers, furnaces and process heaters	Energy-allocated	Emission factor-based calculation using an emission factor of incomplete combustion representative of the combustion unit type, along with fuel consumption volumes and fuel composition data	API Compendium 4.5.1; OGMP TGD Incomplete combustion (L3-L4) [4]; NGER 2.3.5 (Method 2)

Emission[1] Source	**Product Allocation[2]**	**Minimum Emission Calculation Requirements**	**Examples of Accepted Methodologies**
Dehydrator vents	Natural gas	Engineering calculations or computer modelling dependent on the type of dehydrator	API Compendium 6.5.2 [2]; OGMP TGD Glycol dehydrators (L4) [5]; OGMP TGD Purging and venting (L4) [5]; NGER 3.3.9F (Method 1) [8]
Acid gas removal units	Natural gas	Emission factor-based calculation using an emission factor representative of methane emissions from AGRU venting, along with the number of AGRUs	API Compendium 6.5.2 [2]; OGMP TGD Purging and venting (L3) [5]; GHGI[3] [9]; 40 CFR 98.233 (d) [6]; NGER 3.39F (Method 1) [8]
Liquid hydrocarbon storage vessels	Energy-allocated	Engineering Calculations or process modeling tools such as AspenTech HYSYS or TankESP accounting for parameters including upstream temperature/pressure and composition, API gravity and production rate of stabilized oil, and ambient conditions.	API Compendium 6.5.3 [2]; 40 CFR 98.233(j) [6]; NGER 3.3.9F (Method 1) [8]
LNG Loading/ Unloading	Natural gas	Emission factor-based calculation using an emission factor that is representative of the loading and unloading operation including, but not limited to, the emission controls used	API Compendium 6.7.2 [2]

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

Emission[1] Source	**Product Allocation[2]**	**Minimum Emission Calculation Requirements**	**Examples of Accepted Methodologies**
		and pipe wall insulation material.	
Pneumatic devices	Energy-allocated	Emission factor-based method using an actual inventory of each type of pneumatic device and an emission factor representative of the vent rate and actuation frequency of the device..	API Compendium 5.6 [2]; OGMP TGD Pneumatics (L3-L4) [5]; 40 CFR 98.233(a) [6]; NGER 3.3.9F (Method 1) [8]
Pneumatic pumps	Energy-allocated	Emission factor-based calculation using count of devices and default or manufacturer-specific emission factors.	API Compendium 5.6 [2]; OGMP TGD Pneumatics (L3-L4) [5]; 40 CFR 98.233(c)[6]; NGER 3.3.9A.5 (Method 1) [8]
Blowdowns (any equipment type)	Energy-allocated	Engineering calculation using the physical volume in between isolation valves, gas pressure/temperature and gas composition. Emission controls used must also be considered.	API Compendium 6.5.5 [2]; OGMP TGD Purging and venting (L4)[5]; 40 CFR 98.233(i) [6];
Compressor starts	Natural gas	Emission-factor based calculation using an emission factor representative of the compressor starter, along with the number of starts.	API Compendium 6.4.6.2 [2]; GHGI[6] [9]; NGER 3.3.9A.9 (Method 1) [8]
Equipment leaks	Energy-allocated	Population emission factor-based method using emission factors that best represent the conditions and practices of each fugitive component or equipment type prone to leakage.	API Compendium 7.2.2.2 thru 7.2.2.4 [2]; OGMP TGD Leaks (L3-L4) [5]; 40 CFR 98.233(q), 98.233(r) [6]; NGER 3.3.7A (Method 3) [8]

Emission[1] Source	**Product Allocation[2]**	**Minimum Emission Calculation Requirements**	**Examples of Accepted Methodologies**
Compressor venting (dry seals)	Natural gas	Emission-factor based calculation using an emission factor that best represents seal venting emissions based on seal type and compressor operating conditions along with actual, relevant activity data (i.e. number of compressors or number of seals).	API Compendium 6.5.4.2 [2]; OGMP TGD Centrifugal compressors (L3-L4)[5]; GHGI[6] [7]; 40 CFR 98.233(o)[6]
Compressor venting (wet seals)	Natural gas	Emission-factor based calculation using an emission factor that best represents seal venting emissions based on seal type and compressor operating conditions along with actual, relevant activity data (i.e. number of compressors or number of seals).	API Compendium 6.5.4.2 [2]; OGMP TGD Centrifugal compressors (L3-L4)[5]; 40 CFR 98.233(o)[6]
Compressor venting (reciprocating compressors)	Natural gas	Emission-factor based calculation using an emission factor that best represents rod packing venting emissions based on compressor operating conditions along with actual, relevant activity data (i.e. number of compressors or number of cylinders).	API Compendium 6.4.3.1 [2]; OGMP TGD Reciprocating compressors (L4) [5]; 40 CFR 98.233(p)[6]; NGER 3.3.6A.1 (Method 2)[8]
Other emission sources	Source-dependent	Operator must disclose other emission sources within their Facility not explicitly called out in this Standard to document total emissions and demonstrate a representative calculation	

Emission[1] Source	Product Allocation[2]	Minimum Emission Calculation Requirements	Examples of Accepted Methodologies
		methodology for each source.	

To avoid double counting, where emissions are routed through to a common vent stack, flare unit, recovery system or similar, these can be used as the basis for reporting instead of quantifying the individual contributory sources. It is important for an LNG Operator to know and have records of which individual equipment is aggregated to these systems. Audits will include documentation review of active vents and which vents are routed to flare and which are not. A record of all potential vents occurring at a facility shall be kept.

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

A.2 Emissions Allocation and Methane Intensity Calculation

Where a Facility handles hydrocarbon liquids[4] and natural gas, emissions are allocated to natural gas on an energy basis ("Energy-allocated") or to the handling of Natural Gas based on the emission source, as outlined in Table 3. Operators should make best efforts to attribute individual inventory adjustments made via *Section 3.3: Emissions Reconciliation* to individual sources, but may default to energy allocation if there are uncertainties in source attribution. The methodology for calculating methane intensity associated with LNG operations is as follows:

First calculate the Gas Ratio (GR) as a unitless number:

$$E_{ng} = V_{ng} \times EC_{ng} \tag{1}$$

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

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

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

Where:

- E_{ng} is energy equivalent of natural gas (as MMBtu or MJ)
- V_{ng} is annual gas Throughput (as Mscf, or 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 hydrocarbon liquids Throughput (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)

Calculate total methane emissions (metric tons) as the sum of emissions from sources allocated based on the gas ratio ($ME_{energy\text{-}allocated}$) with the emissions allocated to the handling of natural gas ($ME_{gas\text{-}only}$). Emission sources to be co-allocated and associated to gas are denoted as "Energy-allocated" and "Natural gas" in Table 3, respectively.

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

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

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

An Operator must then calculate its Methane Intensity as:

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

Where:

- ME is the annual Methane Emissions from Facility (metric tons)
- V_{ng} is the natural gas Throughput (mcf or Sm^3, or Nm^3)
- MC is the methane content of the natural gas Throughput (volume fraction)
- M_{den} is the methane density of the throughput (metric ton/Mcf)

For integration of a Facility's methane intensity into a methane intensity estimate across multiple segments of a natural gas supply chain, MiQ converts methane intensity to units of mass of methane emissions divided by energy Throughput of natural gas, typically *g* CH_4 *per mmbtu gas Throughput*. The method for conversion is defined in the MiQ Program Guide and the term used is Reporting Methane Intensity.

References

[1] Natural Gas Sustainability Initiative (NGSI) Methane Emissions Intensity Protocol, Version 1.0, February 2021

[2] American Petroleum Institute (API) Compendium of Greenhouse Gas Emission Methodologies for the Natural Gas and Oil Industry, 2021

[3] American Petroleum Institute (API) (2015). Liquefied Natural Gas (LNG) Operations: Consistent Methodology for Estimating Greenhouse Gas Emissions, Version 1.0

[4] GTI Energy. (2022). GTI Energy Methane Emissions Measurement and Verification Initiative. Retrieved from https://www.gti.energy/veritas-a-gti-methane-emissions-measurement-and-verification-initiative/

[5] Oil & Gas Methane Partnership 2.0 (2022). Guidance documents and Templates. Retrieved from https://www.ogmpartnership.com/templates-guidance

[6] EPA (2021b). 40 CFR Subpart W – Petroleum and Natural Gas Systems. US Environmental Protection Agency. Retrieved from https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-W.

[7] Marcogaz (2019). Assessment of methane emissions for gas Transmission and Distribution system operators. Retrieved from www.marcogaz.org/publications/assessment-of-methane-emissions-for-gas-transmission-distribution-system-operators/.

[8] Australian Government Department of the Environment and Energy. (2021) National Greenhouse and Energy Reporting (Measurement) Determination 2008. Retrieved from https://www.legislation.gov.au/Details/F2021C00740/Download.

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

MiQ STANDARD

for Methane Emissions Performance

SUBSIDIARY DOCUMENT 2: Company Practices – LNG

v1.0.0

MiQ

Contents

1 Introduction

The MiQ Standard for methane emissions Performance (the Standard) combines several Standard elements – (1) a calculated Methane Intensity, (2) LNG 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 – LNG*
2. Subsidiary Documents
    a. *Subsidiary Document 1: Methane Intensity – LNG*
    b. Subsidiary Document 2: Company Practices – LNG (this document)
    c. *Subsidiary Document 3: Monitoring Technology Deployment – LNG*
    d. *Subsidiary Document 4: Estimation of Methane Intensity for LNG shipping.*

Effective management of methane emissions from LNG operations begins with a Facility design that will achieve minimal inherent methane emissions and eliminates, to the greatest degree possible, the potential for Fugitive Emissions. However, review of the Methane Intensity calculation alone is not a sufficient indicator of a Facility's effectiveness in methane emissions management. Beyond calculated Methane Intensity, LNG 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 LNG 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, LNG Operators can ensure methane emissions are managed appropriately throughout the operations lifecycle.

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

2 Scope of this Document

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

1. **General Company Practices**

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

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

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

3. **Company Practices for Managing and Reducing Intended Methane Emissions**

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

This subsidiary document covers Company Practices for liquefaction and regasification Facilities. For the avoidance of doubt, Company Practices do not apply to Roundtrip LNG Voyages.

3 Performance Criteria

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

The performance criteria can be demonstrated by an LNG Operator through formal policy or procedure. In the absence of formal policy or procedure, the LNG 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 reducing Unintended methane emissions and Intended methane emissions are categorized either as:

- **Mandatory**: Must be demonstrated by the LNG Operator in order to qualify for the Standard; or
- **Improved**: By demonstrating these practices, an LNG 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 is determined based on the lowest of the individual scores for each of the Standard elements: (1) Methane Intensity, (2) Company Practices, and (3) Monitoring Technology Deployment.

For a Facility to be certified under this Standard, **each** mandatory Company Practices performance criteria outlined below must be met. Facilities which adopt improved practices for reducing methane emissions are eligible for higher MiQ Grades (*see Main Document, Section 7.2.1*). The improved performance criteria are assessed via a points-based scoring system. Points for improved practices are indicated in Tables 1, 2, 3 below. If a Facility demonstrates **at least one** of the elements listed for an improved practice topic, it should receive all points nominated for that practice, except if two or more elements **are related (indicated by the word "and")**.

3.1 General Company Practices

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

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

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

Table 1: General Company Practices (GP)

Practice	Character	Points
(GP- 1) Employee training and awareness		
Operations staff receive training that: • emphasizes the importance of eliminating methane emissions, equipment most likely to leak, signs of methane emissions including Audial, Visual, and Olfactory (AVO) observations that may indicate a problem, and actions to take in the event of an observation; **and** • details how to log and report methane emissions for purposes of annual methane emissions calculations; **and** • is offered at least annually (detailed version for new staff, refresher version for staff with >1 year experience).	Mandatory	-
(GP- 2) Reporting Methane Emissions observations and incidents		
• A reporting system is accessible for all staff to report methane emissions related observations or incidents, including those related to incomplete combustion; **and** • Recordkeeping guidance details what type of documentation needs to be submitted when methane emissions are detected outside routine LDAR inspections; **and** • Chain of command and notification processes are clearly outlined	Mandatory	-
(GP- 3) Estimating and measuring Methane Emissions		
At minimum, LNG Operator's guidance for measurement methods and calculation of methane emissions, in line with regulatory GHG reporting where present, includes: • Details of the emission sources that should be estimated and monitored (and the circumstances under which they might not be monitored); • Quantification method for each emission source; **and** • Equipment to be used for measurement and the specific applications for that equipment; **and**	Mandatory	-

• Information to be collected and reported from Detection and/or Measurement inspections; **and** • Reference to and protocols for applying Leaker Emissions Factors or OGI Leak/No Leak Emissions Factors; **and** • Reconciliation process for including all unintended emission sources		
(GP-4) Continual improvement Methane management is integrated into an LNG Operator's company culture, as evidenced by: • A zero-venting policy in place, with procedures that support such a policy; **and** • a Health, Safety & Environment (HSE) communication plan that includes methane emissions reduction best practices, such as educational material or an emissions incident bulletin program; **and** • demonstrated knowledge of best practices to minimize emissions by the Facility's operations staff; **and** • Preventive maintenance processes that ensure relevant preventative maintenance is carried out at regular intervals; **and** • a key performance metric for methane emissions (such as Methane Intensity) that is tracked for the Facility and regularly communicated with the staff	Mandatory	**-**
(GP-4.1) In addition to the above, the LNG Operator further evidences that methane management is deeply integrated into the company culture through: • The voluntary disclosure of methane emissions that goes significantly beyond regulatory requirements; **or** • Rewards staff for improved monitoring coverage; **or** • The implementation of a measurable and actionable methane emissions reduction plan, which may include progress indicators, evaluation of abatement potentials, cost-free best practices identified; **or** budget for improvement, and the LNG Operator can evidence progress towards its targets.	Improved	1

(GP- 5) Low-carbon energy supply		
To the extent possible, substantially all electricity generated on-site, imported or purchased by the Facility is generated from renewable sources, as evidenced by certificates of origin, power purchasing agreements or other recognized evidential documentation.	Improved	1

3. 2 Company Practices for Managing and Reducing Unintended Methane Emissions

Reducing Unintended methane emissions requires awareness and monitoring of areas where fugitive emissions may occur. Specific actions will include actively looking for Unintended methane emissions, tracking emission sources that have been repaired or replaced, developing preventative maintenance plans, and confirming that all required repairs have been completed and verified in an appropriate timeframe. Company Practices relevant to these actions are stated below in Table 2.

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

Practice	Character	Point
(UMEP- 1) Employee training and awareness		
Operational and maintenance team training includes: • Audial, Visual, and Olfactory (AVO) trainings for field personnel that detail how and why to make routine checks for methane emissions during site visits; **and** • A methane emissions profile overview of the Facility, which may include: Facility layout, production output, methane intensity, history of failures or super emitting events, regulations or mandatory disclosures (if applicable); **and** • An overview of Measuring, Reporting, and Verification (MRV) procedures and guidance in place at the Facility; **and** Leak Detection and Repair (LDAR) method-specific trainings for: • Method 21 [1] or equivalent – LNG Operator's personnel responsible for carrying out inspection are trained in	Mandatory	-

proper use of instruments, instrument calibration, inspection methods and regulatory requirements; **and/or**

- Optical Gas Imaging (OGI) – LNG 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 LNG Operator; **and**

In the event LDAR surveys are carried out by third-party personnel, the LNG Operator should be in possession of training records documenting the training of personnel hired; **and**

- alternative technology programs have consistent equipment operating and reporting procedures for consistent deployment

(UMEP- 2) Source Level Detection Plan

LDAR plan outlines at a minimum:	Mandatory	-

- specific equipment / components included in LDAR survey (must reference process valves, connectors, compressor seals, open-ended lines, meters, pressure relief valves, regulators, and pneumatic controllers); **and**
- leak definition; **and**
- monitoring methodology (reference to equipment, frequency, conditions, reporting log); **and**
- repair or replacement strategy, including when to take immediate corrective action and when delay of repair is permitted; **and**
- first attempt requirements within 5 days of detection; **and**
- requirement for final repair attempt to repair or replace within fifteen (15) days of detection; **and**
- repair verification completed within fifteen (15) days of repair; **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 action is taken; **and**
- clear roles and responsibilities for repair or replacement.

(UMEP- 3) Managing Methane Emissions from tanks		
LNG Operators must: • Have policies and procedures in place that address methane emissions during all stages of tank use, including LNG entering tanks, LNG stored in tanks, LNG removal from tanks and maintenance and inspections of tanks and that not only include observation for methane emissions but also require preventative maintenance based on historical problems (including, for example assignment of identification numbers and records on specific problem pieces of equipment); **and** • Inspect and monitor key areas that may be a source of methane emissions from tanks including vapor/BOG recovery systems connection points, and pneumatic controllers; **and** • Install engineering controls such as tank pressure monitoring systems and alarms, remotely observe storage tanks using integrated operation centers and utilize automated tank gauging and reporting.	Mandatory	-
(UMEP- 4) Directed inspection and maintenance		
To manage methane emissions, LNG Operators elect to: • target major equipment (i.e. PRVs, vapor recovery equipment, gas-powered compressor vent sources, flare stacks) for observation; **and** • use cumulative data to develop preventative maintenance plans; **and** • determine equipment to target based on accumulated historical data from LDAR inspection records [2].	Improved	1
(UMEP-5) Reduced Leak Components	Improved	1
To manage fugitive emissions from components, LNG Operators may choose to further prevent leaks by installing components with reduced or eliminated leak risk across a minimum of at least 50% of two component types or equipment at the Facility or 100% of one component, which may include: • Sealless/leakless valves including welded bonnet bellows and diaphragm valves; **or** • Relief valves equipped with a rupture disc and pressure monitoring or routed to a control device; **or**		

- Extreme weather-resistant connections; or
- Flange washers with increased elasticity in the bolting system; **or**
- Low-temperature- and temperature-fluctuation-resistant joints and equipment; **or**
- Gaskets resistant to extreme temperatures, below -75°C, such as flexible graphite and polytetrefluoroethylene (PTFE); **or**
- Low-emission valves and controllers for LNG service, such as leak-proof cryogenic thermal insulation valves and process control valves.

3.3 Company Practices for Managing and Reducing Intended Methane Emissions

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

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

Practice	Character	Point
(IMEP- 1) Venting – Loading/Unloading LNG Operators must: • Have processes in place for loading/unloading operations to be carried out according to industry standards and regulations; **and** • Monitor Methane Content in loading/unloading lines and ensure that loading/unloading lines contain minimal amounts of LNG before disconnecting transfer equipment; **and** • Have procedures in place to minimize methane emissions during loading/unloading operations and Transfer Starts and Transfer Stops; **and** • Have procedures in place to limit methane venting to the concentration limit set by the relevant Port Authority during the gassing up of a LNG tanker; **and** • Have procedures in place to limit vapor generation during normal operations to the design limit of boil-off	Mandatory	-

gas compression equipment (i.e. initial cool down procedures, loading rate procedures); **and** • Ensure reduced emissions loading and unloading procedures according to regulations and standards, monitoring methane content until the concentration lowers to <10,000 ppmv using an approved monitoring methodology		
(IMEP- 2) Venting – Facility blowdowns LNG Operators must: • Coordinate operational repairs with routine maintenance repair schedules to minimize total blowdown events; **and** • Calculate methane emissions from blowdown events using engineering calculations or metered volumes: **and** • Document any venting of blowdown gas that occurs, including the justification for why gas flaring was not feasible and the composition of the gas that was vented.	Mandatory	-
(IMEP-2.1) In addition, LNG operators may also implement policies and procedures to mitigate emissions from all blowdown events, and; • mitigate methane emissions from at least 75% of total blowdown events at the Facility; **or** • mitigate methane emissions from at least 95% of total blowdown events at the Facility	Improved	1 2
(IMEP- 2.2) In addition, LNG Operators may also implement: • Policies and procedures under which no gas from Facility blowdowns is vented or flared and all gas is used productively.	Improved	1
(IMEP- 3) Venting – Pneumatic Devices LNG Operators with operations utilizing natural-gas-driven pneumatic devices must:	Mandatory	-

• Implement procedures to maintain an accurate inventory of pumps and controllers that is checked annually, at a minimum (the Inventory); **and** • Implement policies and procedures to ensure controllers are operating as designed (based on type of service (on/off, throttling) and type of venting (continuous or intermittent)) based on regulatory published limits or industry equipment standards; **and** • Ensure that such devices are included in regular inspections in the LDAR plan as an emission source.		
(IMEP- 3.1) In addition, LNG Operators may: • Have installed non-venting (i.e. no-bleed, electric, mechanical, or instrument air) pneumatic controllers, engines and pumps in place of gas-driven pneumatics for at least 95% of the Inventory.	Improved	2
(IMEP- 4) Venting - Compressors LNG Operator must: • Implement policies to replace natural gas reciprocating compressor rings on a fixed schedule based on run hours unless the vent gas is re-routed to be either recovered or flared; **and** • Implement policies to minimize starts and stops from compressor gas starters.	Mandatory	-
(IMEP- 4.1) LNG Operators have evaluated controls to address compressor seal methane losses and have: • Replace all wet seal centrifugal compressors with dry seal centrifugal compressors with nitrogen loop or dry seal centrifugal compressor with vent line recovery; **and/or** • Scheduled upgrades for reciprocating compressor packing cups, rings, gaskets, rods as part of the preventive maintenance.	Improved	1
(IMEP- 5) Flaring LNG Operators must: • Implement policies that define the use of flaring and that are limited to events such as maintenance, startup,	Mandatory	-

shutdown and emergencies, plus other tightly-defined events, with defined duration limits for each; **and**

- Implement procedures that define stable operating ranges for applicable criteria (i.e. combustion zone net heating value, flare gas velocity) for all flare systems, considering emergency events, to promote good combustion efficiency [3][2] **and**
- Implement policies and procedures to ensure flares are managed and maintained to ensure flare functionality, flares are targeted during LDAR surveys, and good combustion efficiency is achieved through utilizing staff/consultants for inspections (AVO and engineering & maintenance inspections); **and**
- Have measurable and actionable plans in place to reduce the amount of natural gas that is flared, for example via installation of additional flare gas compression capacity; **and**
- Have flaring systems installed that in their design account for ambient conditions and gas composition to maximize combustion efficiency; **and**
- Have installed flow meters with a maximum uncertainty of 7% (as required by the EU-ETS) on flares.

(IMEP- 5.1) Flare functionality (control and engineering design) In addition, LNG Operators manage flaring operations to ensure flaring functionality and efficiency through control and engineering design, including: • SCADA systems and logic controllers to monitor flare ignition or thermocouples (temperature sensors) to ensure pilots stay lit or flame out Detection device installed; **or** • Auto ignition system; **or** • Flare capacity and production level is maintained to ensure flare's combustion efficiency matches range of production and does not overload.	Mandatory	-

[2] For reference, flare performance studies by the US EPA determined a 98% conversion of organic compounds to carbon dioxide, or greater, as good combustion efficiency. This good combustion efficiency is achieved through flare design, flame stability, and operating envelope parameters (heat content, velocity, gas composition etc.). This is also the OGMP 2.0 reference value.

(IMEP- 5.2)		
In addition, LNG Operators: have installed a closed flare or be able to justify that ambient conditions do not require a closed flare to reach sufficient level of combustion efficiency (including factors such as wind and precipitation conditions and gas composition)	Improved	1
(IMEP-6) Combustion Equipment To better manage methane emissions from incomplete combustion from the combustion of natural gas, LNG Operators: • Utilize gas-powered turbines, or alternative combustion equipment with equal or lesser methane slip, for at least 95% of on-site combustion, by percentage of natural gas consumed. • Catalytic converters for gas-driven engines that reduce methane emissions; **or** • Engine design features to improve combustion, such as placing the exhaust recycling structure close to the engine or reducing crevice spaces and cool areas to avoid unburnt methane.	Improved	2

3.4 Required Evidence Available to Auditors

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

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

References

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

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

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

MiQ STANDARD

for Methane Emissions Performance

SUBSIDIARY DOCUMENT 3:

Monitoring Technology Deployment – LNG

v1.0.0

Contents

1 Introduction

The MiQ Standard for Methane Emissions Performance (the Standard) combines several Standard elements – (1) a calculated Methane Intensity, (2) LNG 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 liquefaction and regasification 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 – LNG*
2. Subsidiary Documents
   a. *Subsidiary Document 1: Methane Intensity – LNG*
   b. *Subsidiary Document 2: Company Practices – LNG*
   c. **Subsidiary Document 3: Monitoring Technology Deployment – LNG (this document)**
   d. *Subsidiary Document 4: Estimation of Methane Intensity for LNG shipping.*

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

Methane emissions monitoring technologies can be deployed along a spectrum of spatial and temporal scales. Top-down approaches aggregate methane emissions from multiple emission sources at larger spatial scales (e.g. using aerial surveys or satellites), whereas bottom-up approaches are intended to detect individual emission sources at smaller spatial scales (e.g. using handheld devices or perimeter sensors). Both top-down and bottom-up monitoring approaches can vary in temporal scale based on factors such as cost and time to complete, with improved emissions detection capability with more frequent deployment. Continuous monitoring methods provide greater temporal coverage, however can provide variable spatial coverage and completeness. Gimbled scanning systems or regional towers often provide more complete spatial coverage, particularly for elevated sources, compared to fixed point monitors (perimeter sensors). Figure 1 illustrates simplified examples of methane monitoring technologies in relation to spatial and temporal scale.

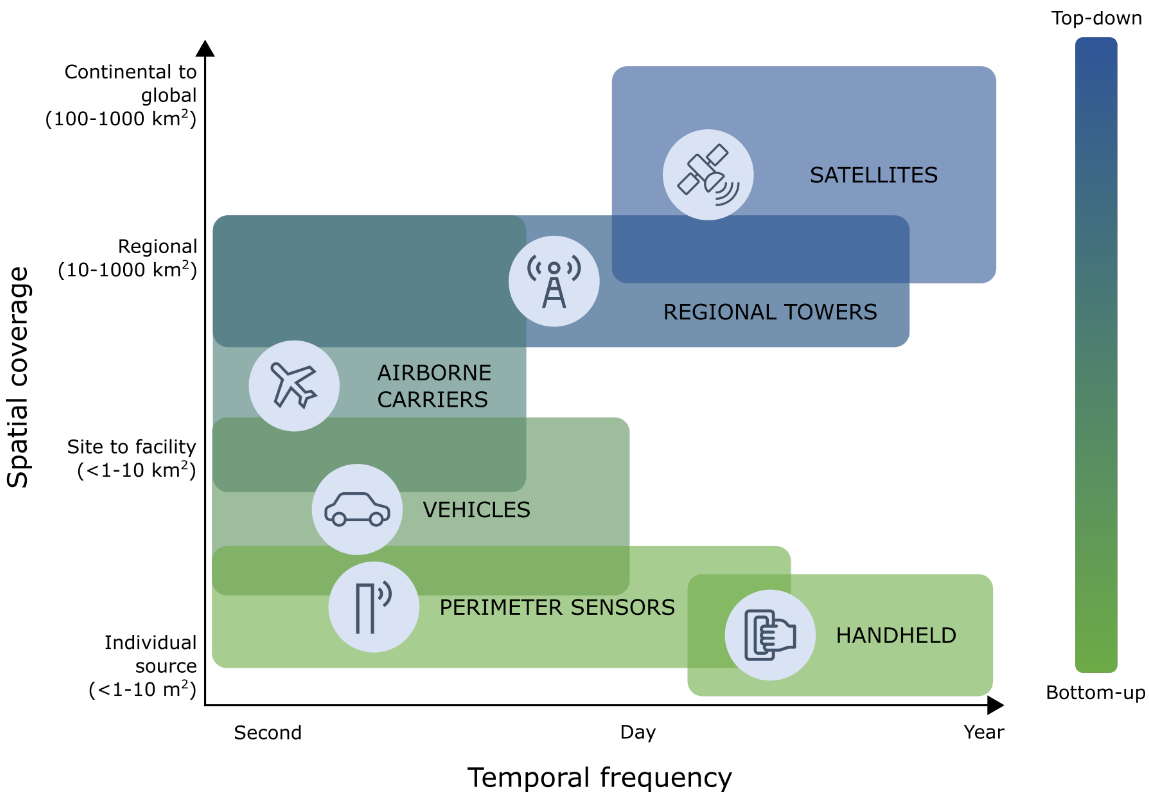

Figure 1: Methane monitoring technology across a variety of spatial and temporal scales (adapted from the National Academies of Science, Engineering, and Medicine, 2018 [1])

Efforts to reconcile top-down and bottom-up Quantification approaches continue to develop through research and industry collaboration and are attempted in this Standard. The existing body of work reveals that top-down approaches often produce methane emissions estimates that are significantly higher than those from bottom-up approaches alone.[2, 3][1] These studies indicate that under-representation

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

of abnormally high emission sources, commonly referred to as Super-Emitters, is one cause of this divergence[4][2]. Super-Emitters are spatially and temporally dynamic, and the characteristics that cause these emissions vary. Therefore, detection at both the Facility Level and Source Level, and at increased frequencies, is key to effective methane emissions management and mitigation.

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

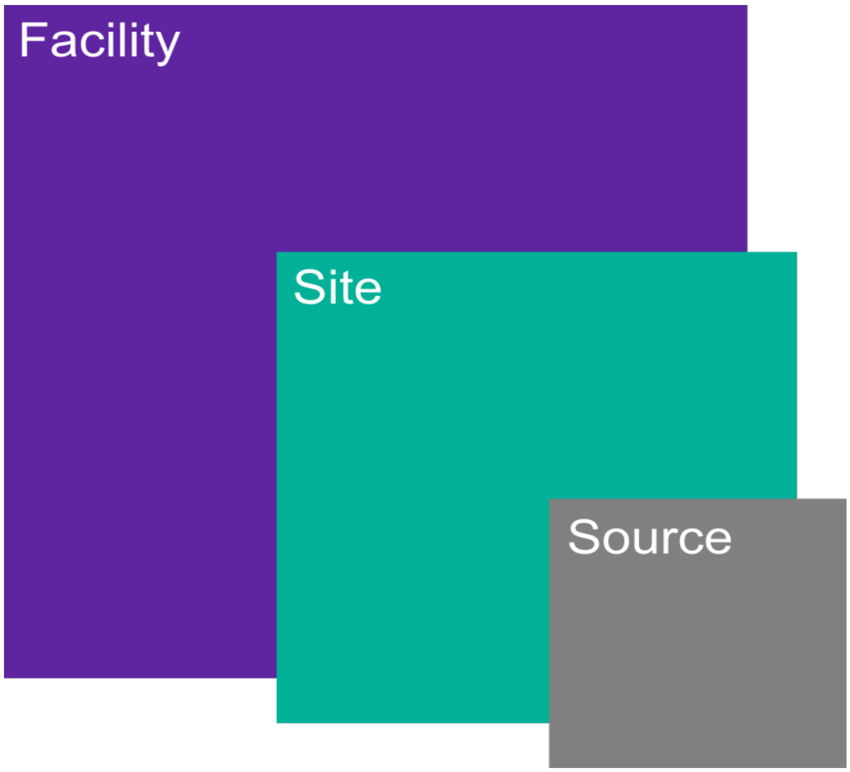

Figure 2: Spatial scales utilized within the Standard, referencing the definitions of Facility, Site, and Source as outlined in the *Main Document*, see there for reference.

2 Scope of this Document

This subsidiary document outlines requirements for Monitoring Technology Deployment for detection of Unintended methane emission Sources at a

[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.

Liquefaction or Regasification Facility. For the avoidance of doubt, the requirements of Monitoring Technology Deployment do not apply to Roundtrip LNG Voyages.

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 protocols.

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

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

3 Technology Deployment Objective and Performance Criteria

The primary objective of Monitoring Technology Deployment is to:

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

This objective harmonizes with other elements of this Standard:

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

3.1 Key Performance Parameters

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

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

Table 1: Key Parameters

Parameter	Description
Frequency of 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 or sources 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 or sources integrating both Facility Scale and Source Level approaches over a given time-period.
Minimum Detection Limit (MDL) of Monitoring Technology	The minimum rate of methane emissions detectable by a specific technology solution. Technologies with lower MDL can identify more (including smaller) methane emission sources. The technology solution required to achieve the desired MDL and detection probability[4] must be applicable for the specific Facility and validated by the Auditor.

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

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

3.2 Performance Scoring

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

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

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

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

Table 2: Technology Performance Criteria

Facility Scale Inspection		**Source Level Inspection**[5]		**Points**
quarterly (MDL 25kg/hr)	entire Facility	semi annually	entire Facility	12
semi annually (MDL 25kg/hr)	entire Facility	semi annually	entire Facility	8
annually (MDL 25kg/hr)	entire Facility	annually	entire Facility	4
N/A		annually	entire Facility[6]	0

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

[6] All LNG Operators are required to conduct a minimum annual Source Level inspection over 100% of sites. Sites or equipment deployed with unmanned stationary or continuous monitors are not exempt from this requirement.

3.2.1 Facility Scale Inspection

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

- must cover the entire certified Facility including elevated sources in three-dimensional space and buried sources
- must be deployed at the frequency designated in Table 2 above
- must meet the designated MDL of 25kg/hr[7] at 90% POD proven through single blind, controlled release testing (see Table 3 for additional record keeping requirements).
- must attribute the source to a single site spatial boundary for follow up inspection
- may utilize multiple inspection methods in combination
- Continuous Monitoring Systems are an accepted form of Facility Scale inspection provided they meet the performance criteria above (See Table 3 and Table 4 for additional LDAR program and recordkeeping requirements).
    - LNG Operators may choose to demonstrate equivalent monitoring using Continuous Monitoring Systems over a subset of Sites (<100% coverage) paired with Source Level methods and/or other periodic Facility Scale survey methods, to achieve the same level of detection and mitigation potential as outlined in Table 2 (see Section 3.2.3. for more information on demonstrating equivalency).

Emission events detected via Facility Scale inspections must be documented, repaired and/or mitigated following the timelines and requirements listed in *Subsidiary Document 2: Company Practices.* Facility Scale inspections may also identify emissions from planned events or from intended sources that are already accounted for in a Facility's emission inventory. The detected source must still be

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

investigated to determine if the source exceeds the expected rate and ascertain if the event requires follow-up or mitigation.

If inspections across the last 12 months detect no additive emissions for the entire Facility, the survey frequency can be reduced to the next lower score level, either via Table 2 or the Operator's equivalency determination. For Operators using Facility Scale Inspection technologies with a MDL less than 25 kg/hr at a 90% probability of detection survey frequency can also be reduced if the operator does not detect additive emissions from any site that total greater than 25 kg/hr. Operators may not reduce Facility Scale inspection frequency using this clause any lower than once per year for the Facility and achieve at least 4 points.

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

3.2.2 Source Level Inspection

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

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

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

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

For localized areas of the Facility, such as an individual treatment, compression, or refrigeration unit, which have no additive detections over the last 12 months, the survey frequency can be reduced to the next lower score level, either via Table 2 or through results of the Operator's equivalency determination. Equivalency determinations must still be made at the score the Operator is being evaluated at (see Section 3.2.3 for more detail). Operators may not reduce Source Level inspection frequency using this clause any lower to once per year for any localized area.

Sources with confirmed detections must be scheduled for repair or replacement, as per the LNG 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 LNG Operator's 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.

Equivalency models currently do not maintain robust generic emissions distributions derived from measurements for LNG facilities. In the absence of this and other critical inputs required to perform equivalency modeling, additional Source Level Inspections can be conducted in place of Facility-Scale Inspections. However, at least one Facility Scale Inspection must be performed for point totals that require at least one Facility Scale Inspection[8].

4 Recordkeeping and Reporting Requirements

LNG 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. LNG Operators can choose to aggregate the recordkeeping elements to minimize administrative overhead. LNG Operators must have adequate Company Practices in place which underpin accurate recordkeeping and reporting structures.

[8] For example, to receive 12 points following Table 2 the operator must conduct 4 Facility Scale inspections and 2 Source Level inspections, each covering their entire Facility. The operator could elect to perform up to three more Source Level inspections in place of Facility Scale inspections as long as at least six total inspections are still conducted.

4.1 Minimum Recordkeeping and Reporting Requirements

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

Recordkeeping element	Details

Detection Technology Specifications	• Sensor and instrumentation details
	• Method in which the sensor was deployed (i.e. fixed-wing, drone-based, stationary-mounted)
	• Performance specifications including minimum detection limit and probability of detection curves
	• Details of independent, single-blind testing, including
	  o Third party used to conduct testing
	  o Confirmation of single-blind nature of testing
	  o Operating conditions of equipment used for testing
	  o Variables tested that could affect the sensitivity of the technology and the ranges tested (i.e. humidity, temperature, wind speed, groundcover, obstruction, solar irradiation)
	  o Calibration protocols used during testing
	  o If operator uses technology for quantification, characterization of emission rate uncertainty

Work Practice Specifications	• Frequency of surveys and routes taken if sensors are not deployed in stationary positions.
	• Alarm criteria, including the alarm threshold used for each type of event.
	• Deployment specifications for individual Sites to replicate location and environmental criteria determined during controlled released testing.
	  o If a third party is contracted for the survey, this should also include contractor or data service provider information.
	  o To include details for both Facility Level and Source Level inspections.

Detection Follow up Protocols	• Emission detection workflow (i.e. follow-up processes taken after alarm) • Emission classification workflow (i.e. tracking new events, allowable events detected, and failed repair validations) • Data system that stores and manages detected emission events • Repair planning and repair validation procedure • Causal Examination procedures
Facility Scale and Source Level/LDAR inspection recordkeeping form	For each emission source, includes component/equipment/site ID and type, date of all repair efforts (first attempt, additional attempts, final attempt), repair validation date, success of repair or replacement, and (if applicable) a reason for delay to repair or replace and the date rectified.
Source Level/LDAR monitoring location log	Includes a list of monitoring locations (for at least the Certification Period) and visited for each survey (categorized by of component 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 LNG 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 LNG Operator response to monitor downtime (i.e. backup monitoring plan) • Monitoring equipment calibration protocols (i.e. frequency, technology-specific parameters that are calibrated)

5 Interconnections with other Standard Elements

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

5.1 Interconnection with calculated Methane Intensity

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

This Standard also allows LNG 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 A, Table 2* for more detail). Inspections undertaken by the operator that include emissions measurement capabilities must be utilized if the operator develops Facility-specific Emission Factors for individual emission sources.

5.2 Interconnection with Company Practices

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

- Monitoring Technology Deployment for LDAR;

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

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

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MiQ STANDARD

for Methane Emissions Performance

SUBSIDIARY DOCUMENT 4:

Estimation of Methane Intensity for LNG Shipping

v1.0.0

Contents

1. Introduction

This Subsidiary Document summarises the critical inputs for the estimation of methane emissions, and optionally carbon dioxide (CO_2) emissions, relating to ocean transportation of LNG cargoes. Under this Standard, methane intensity, and optionally CO_2 intensity, for LNG shipping is estimated with vessel and voyage-specific information where available.

Methane emissions for most segments of the natural gas supply chain are heavily dependent on several variables, including the type and number of specific sources or pieces of equipment for a given facility, throughput, and occurrence of abnormal process conditions, some leading to super-emitter events. For LNG shipping, key variables which primarily contribute to an LNG cargo's emission profile and resulting methane intensity include:

- Full voyage being undertaken (both in terms of time and distance or speed) which includes the actual LNG Carrier used, the actual Laden Voyage itself and the preceding Ballast Journey to the loading port; and
- Engine type, for estimating methane slip during combustion of natural gas in vessels' main and auxiliary engines; and
- Venting of boil-off gas.

While other sources of fugitive emissions and leaks may exist for LNG shipping, they are currently deemed to have a negligible impact and are quickly identified if a fugitive event occurs based on safe operating practices [1].

2. Scope

The scope of this Standard as it relates to the ocean transport of LNG, covers:

- Methane emissions, and optionally total CO_2 emissions, including a common metric for calculating emissions intensity; and
- Only emissions relating to the ocean transport of LNG and not emissions upstream or downstream of the LNG voyage (which are separately covered in this and other MiQ Standards); and
- Only the ocean transportation of LNG cargoes directly *en-route* from a loading port to an unloading port (and excludes, for example, floating storage of LNG).

3. Data requirements

A detailed estimate of methane and CO_2 emissions from the voyage of a LNG Carrier uses inputs relating to:

- the LNG Carrier used including but not limited to year of construction, vessel cargo capacity, main and auxiliary engine and generator types and ratings, and other processes on the LNG Carrier that may consume LNG boil-off);
- details of the specific stages of the voyages including the Laden and Ballast Voyages, idle time, and time spent loading and unloading the LNG Carrier
  - data inputs for each stage of the voyage include but are not limited to duration of each stage and distance travelled for Laden and Ballast voyages; and
- technical data of the operation of the LNG Carrier including but not limited to fuel consumption rates during propulsion, idle and loading/unloading stages and any other auxiliary uses, LNG composition, and emission factors relating to each process with the potential to emit.

Tables 1 and 2 provide a list of important inputs relating to LNG Carriers and voyage stages. The technical parameters of the LNG Carrier and data for the voyages must be provided from verifiable sources and relate to the actual LNG Carrier and voyages in question. Such sources may include data from the voyage log, forms provided by the shipyard that built the vessel and the bill of lading. Such information should be available for audit if necessary. Voyage data may be confirmed using third-party data (such as AIS tracking[1]).

Table 1. Inputs relating to LNG Carriers

Item	Example Units
Vessel IMO number	######
Year of construction	YYYY
Available cargo capacity	m^3 LNG

[1] automatic identification system (AIS) is an automatic tracking system that uses transceivers on ships and is used by vessel traffic services (VTS).

Main engine / propulsion type	# of steam, diesel, high- and/or low-pressure dual fuel engines
Main engine rated output	kilowatt
Auxiliary engine/generator type(s)	# of steam, diesel, high- and/or low-pressure dual fuel
Auxiliary engine/generator rated output	kilowatt
Fuel consumption rates – Main engine(s)	tonnes FOE day^{-1} @ varying speeds, or similar mass or volumetric unit
Fuel consumption rates – Auxiliary engine(s)	tonnes FOE day^{-1} or similar mass or volumetric unit

Table 2. Inputs relating to LNG voyages

Item	Unit
Name of loading port / departure point	-
Name of unloading port / arrival point	-
Laden/Ballast voyage distance	nautical miles or km
Laden/Ballast voyage duration	days
Additional durations (idle/maneuvering, loading, unloading, refueling, etc.)	days
Quantity of LNG cargo delivered	tonnes LNG
Chemical composition of LNG (C1-C6)	mass fraction

3.1. Ballast Voyage

For each LNG cargo delivered under a Laden Voyage, there is an unladen voyage (or Ballast Voyage), where the LNG Carrier travels empty to a new loading port to collect its next LNG cargo. There are emissions that result from the Ballast Voyage for the same reasons that arise for Laden Voyages. A proper estimate of emissions caused by the shipping of LNG must therefore account for emissions in the Ballast Voyage as well as the Laden Voyage. Failing to include an estimate of the Ballast Voyage could in theory result in the underestimate of total emissions of the LNG fleet by up to 50%.

The starting point of the Ballast Voyage is the unloading port or dry dock location of the preceding inward Ballast Voyage to the loading port. Information relating to the Ballast Voyage must be provided. Not all charterers and LNG buyers will have access to primary data for the Ballast Voyage. In this case third-party data (such as AIS tracking) may be provided for the calculation of methane emissions from the Ballast Voyage.

3.2. Estimating engine methane slip

To estimate methane slip in most cases, the consumption of LNG as fuel and the rate of methane slip to the atmosphere is needed. Cases may exist where methane slip is measured directly and fuel consumption may not be needed as a direct input. In the absence of primary fuel consumption data for each stage of the voyage (i.e. propulsion, idle time, and loading/unloading for both laden and ballast stages), a conservative assumption must be used that the engines will operate exclusively on LNG and that boiloff will be forced to the extent that natural boiloff provides insufficient fuel. In other words, assume a maximum quantity of LNG fuel that does not account for commercial and operational choices that the charterer may make regarding fuel switching from LNG to other marine fuels in the absence of primary fuel consumption data. This is generally consistent with other public greenhouse gas emissions modelling efforts for ocean transportation of LNG [2]. Both directly metered fuel consumption rates and engineering estimates based on primary measurement data of the combustion technology present on the LNG Carrier may be used to estimate fuel consumption.

Among other potential variables, methane slip is dependent on engine type, additional post-combustion control technologies and engine load. Estimation of methane emissions from incomplete combustion of methane in a vessel's engines and generators can be done via direct measurement during the voyage with preference to measurement methods with published measurement testing results, the use of methane slip curves specific to the type of engines and generators used such as in Balcombe et al. [1], and preferably based on the actual average load of each stage of the voyage such as in Pavlenko et al [3]. Should the operator not have available data regarding the average load of the combustion equipment, slip factors representative of the engine type may still be used but should be estimated conservatively with the risk of underestimation being actively evaluated.

In the absence of representative methane slip curves, methane slip can be conservatively estimated using emission factors derived from published measurement studies of representative engine types, with the risk of underestimation being actively evaluated.

3.3. Estimating other Methane Emissions

The quantity of natural boiloff gas produced shall be based on either directly measured rates of boiloff during the voyage, studies of boiloff rates that are representative of the voyage, or the maximum guaranteed boil off rates guaranteed to the ship owner by the shipyard. The data source selected should be the one most representative of the specific voyage of the data available. If representativeness is hard to ascertain, then the most reasonable conservative estimate should be used. When such vessels are underway, a large proportion of boiloff is typically consumed in the vessels' engines, and little is left for other purposes or as waste to be combusted under normally operating circumstances.

Calculations should assume that all boiloff gas is first used to meet the energy requirements of both the main and auxiliary engines if LNG is the combusted fuel. Any remaining natural boiloff that is not required by the engines is then typically used in processes including re-liquefaction, steam dump or combustion in gas combustion units, depending on the specific processes of the relevant LNG Carrier. To the extent that there is boiloff gas that cannot be dealt with by any of these means, it must be assumed to be vented to the atmosphere.

Depending on the equipment on board, the re-liquefaction efficiency of the re-liquefaction plant, combustion efficiency of steam boilers or destruction efficiency of gas combustion units should be applied to the balance of boiloff production after main and auxiliary engine/generator use.

The amount of natural boiloff calculated should be compared with the total quantity of LNG used as fuel during each operational state of the LNG Carrier during the Laden Voyage and during the Ballast Voyage. Where the engines consume less than the natural boiloff gas generated, the relevant efficiencies for other processes aboard the LNG Carrier must be applied to calculate total emissions. If the operator calculates an average emissions rate per day, this must be multiplied by the time that the vessel is in each operation during each leg of the LNG Voyage.

Due to a current lack of data and scalable methods for collecting such data, leaks from equipment and other fugitive emissions are out of scope for estimation in the MiQ LNG Voyage Model.

3.4. Alternative Methods

MiQ has developed an Excel-based model called the LNG Voyage Model which estimates both methane and carbon dioxide emissions from individual voyages of LNG Carriers using the methodologies described above. Appendix A contains tables and other information regarding the inputs, constants and assumptions of the LNG Voyage Models. Other known publicly available LNG shipping greenhouse gas emission models include the model associated with Rosselot et. al's 2023 study [4]. Due to the specific assumptions made for critical activity factors in this study, usage of this model must be justified according to the requirements below.

If a party applying this Standard determines that the methane or CO_2 emissions calculated according to the latest version of the LNG Voyage Model associated with this Standard does not accurately represent the Roundtrip LNG Voyage in question, then such party may submit alternative methods for the Auditor. In this case, the party must:

- submit detailed inputs and methods for calculating Methane Intensity where such methodologies and inputs differ from the guidance set forth in this Standard;
- include data considered alternative to the data set out in Section 3; and
- 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 Carrier-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.

4. Methane and Carbon Dioxide Intensity

Total methane emissions for the Roundtrip LNG Voyage is calculated as the sum of the total engine methane slip for the main and auxiliary engines for each stage of the voyage, plus the total other emissions for each stage. Optionally, total carbon dioxide emissions of the voyage must be calculated using the average carbon content of each fuel combusted (i.e. moles of carbon divided by moles of combusted fuel) and subtracting total LNG boiloff slip from the total combusted LNG boiloff.

Methane and carbon dioxide Intensity is calculated from the total emissions based on the quantity of LNG delivered at the unloading port.

The methane intensity (MI) and carbon dioxide intensity (CI) is calculated as:

$$MI = \frac{ME_{LNG}}{M_{LNG} * MC}$$

, or

$$MI = \frac{ME_{LNG}}{M_{LNG} * E_{LNG}}$$

, and

$$CO_2I = \frac{CO_2E_{LNG}}{M_{LNG} * E_{LNG}}$$

Where:

a) ME_{LNG} is the mass of Total methane emissions for the Roundtrip LNG Voyage;

b) M_{LNG} is the mass of LNG cargo unloaded in the same units as ME_{LNG}; and

c) MC is the methane content of the LNG Throughput (mass fraction).

d) E_{LNG} is the energy density mass of total carbon dioxide emissions for the Roundtrip LNG Voyage (t LNG/mmbtu LNG)

e) CO_2I is the carbon dioxide intensity of LNG (t CO_2/mmbtu LNG)

f) CO_2E_{LNG} are carbon dioxide emissions (t CO_2)

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Appendix A: MiQ Voyage Model Inputs, Constants and Assumptions

Table 3: LNG Carrier Specifics and Fuel Consumption Inputs from the MiQ Voyage Model

MiQ LNG Voyage Model
Input Sheet: Vessel information

Item		Unit	ENTER DATA IN THIS COLUMN Input value
Vessel name			
Vessel IMO number			
Year of construction			
Available cargo capacity		cubic metres LNG	
Maximum guaranteed boil-off rate, Laden Voyage		% of available cargo capacity per day	
Maximum guaranteed boil-off rate, Ballast Voyage		% of available cargo capacity per day	
Main engines – type			
Main engines – maximum rated output		kW	
Main engines – number			
Auxiliary engines – type			
Auxiliary engines – maximum rated output		kW	
Auxiliary engines – number			
Steam dump capacity		% of available cargo capacity per day	
Reliquefaction capacity		% of available cargo capacity per day	
Gas combustion unit capacity		% of available cargo capacity per day	
Steam dump boiler methane destruction efficiency (if applicable)		% of methane destroyed (combusted)	
Reliquefaction efficiency (if applicable)		% of BOG that is reliquefied	
Gas combustion unit methane destruction efficiency (if applicable)		% of methane destroyed (combusted)	
Fuel consumption of main engines, Laden Voyage at	19.5 knots	mt FOE/day	
Fuel consumption of main engines, Laden Voyage at	19.0 knots	mt FOE/day	
Fuel consumption of main engines, Laden Voyage at	15.0 knots	mt FOE/day	
Fuel consumption of main engines, Laden Voyage at	14.5 knots	mt FOE/day	
Fuel consumption of main engines, Laden Voyage at	14.0 knots	mt FOE/day	
Fuel consumption of main engines, Ballast Voyage at	19.5 knots	mt FOE/day	
Fuel consumption of main engines, Ballast Voyage at	19.0 knots	mt FOE/day	
Fuel consumption of main engines, Ballast Voyage at	15.0 knots	mt FOE/day	
Fuel consumption of main engines, Ballast Voyage at	14.5 knots	mt FOE/day	
Fuel consumption of main engines, Ballast Voyage at	14.0 knots	mt FOE/day	
Fuel consumption of auxliary engines for hotel load		mt FOE/day or mt LNG/day	
Fuel consumption of auxliary engines for loading operations		mt FOE/day or mt LNG/day	
Fuel consumption of auxliary engines for unloading operations		mt FOE/day or mt LNG/day	

The MiQ Voyage model calculates total fuel consumption based on operator inputs of daily fuel usage rate at differing speeds, and fuel usage rate for each stage of the voyage. The rated output of the main and auxiliary engines/generators is a listed input to calculate the average load of each engine/generator in order to estimate methane slip (see Table 5). For remaining LNG boiloff not consumed in the main and auxiliary engines/generators, reliquefaction, steam dump and gas combustion inputs are based off of estimated daily percentage of use of cargo capacity. If desired, operators may overwrite these inputs and methodologies following the principles and submittal of required information in Section 3.4.

Table 4: Voyage Inputs from the MiQ Voyage Model

MiQ LNG Voyage Model Input Sheet: Voyage information		ENTER DATA IN THIS COLUMN	ENTER DATA IN THIS COLUMN
Item	**Unit**	**Input value – Ballast Voyage**	**Input value – Laden Voyage**
Departure point / loading port			
Arrival point / unloading port			
Total duration of each voyage (including Idle Days)	days (or part days)		
Idle Days* (included in total duration of each voyage above)	days (or part days)		
Distance travelled for each voyage	nautical miles		
Quantity of LNG cargo delivered at unloading port	tonnes LNG	*N/A*	
Methane content of LNG cargo delivered at unloading port	%, mass fraction	*N/A*	
Loading operation duration of Laden Voyage	days (or part days)	*N/A*	
Unloading operation duration of Laden Voyage	days (or part days)	*N/A*	

** Idle Days is the total number of days or part days that the vessel is at berth or at anchor, but excluding loading and unloading operations.*

Table 5: Methane Slip & Specific Fuel Efficiency Factors by Engine Type from the MiQ Voyage Model

Methane slip and specific fuel factors by engine type

	Methane slip (g/kWh)			
Engine Load (%)	LPDF MS 4 stroke	LPDF SS 2 stroke	HPDF SS 2 stroke	Steam turbine
0%	61.25	6.06	0.30	0.04
25%	25.30	4.21	0.28	0.04
50%	10.45	2.93	0.25	0.04
90%	5.50	2.50	0.20	0.04
	LNG Specific Fuel Factor (g LNG/kWh)			
	156	148	135	285

The LNG specific fuel factors LNG and methane slip factors for each engine type used in the MiQ LNG Voyage Model are sourced from IMO [2] and are presented in Table 5. Engine load curves were estimated from published peer-reviewed material where possible and were applied to the IMO [2] methane slip factors to provide more granular differentiation of emissions results for part-loaded engines (for example, when LNG Carriers are operating at reduced speeds on a voyage). The resulting methane slip curves are summarised in Table 4. For simplicity, specific fuel factors are assumed to be constant across all loads. As discussed in Chapter 2 of IMO [2], this assumption holds true for steam turbines but not for internal combustion engines, and IMO [3] proposes applying a parabolic relationship for specific fuel factors and engine load. However, having investigated this relationship, it is not considered to have a significant impact on the specific fuel factor and therefore on methane emissions, and as a result the simplifying assumption has been kept for practicality in the MiQ LNG Voyage Model. If desired, operators may overwrite these inputs and methodologies following the principles and submittal of required information in Section 3.4.

Table 5: LNG Composition Inputs

LNG Composition	
Constituent/Characteristic	**Mole Fraction** Mole fraction
C1	0.954926
C2	0.042352
C3	0.002017
iC4	0.000202
nC4	0.000202
iC5	0.000101
nC5	0.000101
C6+	0.000101
N2	0
MW (t LNG/t-mol LNG)	16.68
CC (# carbon atoms/mol LNG)	1.05