MiQ STANDARD

for Methane Emissions Performance of Natural Gas Systems

Main Document – LNG

v2.0

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1 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[1] and SYSTEMIQ[2] to reduce methane emissions from the global oil and gas industries through a market-based gas certification system.

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;

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

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

2 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

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

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

potent greenhouse gas with a short-term climate impact over 80 times that of carbon dioxide[1].[3] 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 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.

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[3] 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.

3 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, 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 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).

4 Terms

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-level	Detectable to a component of an equipment group, 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].
Equipment group	The components that make up a process within a Facility (i.e. boil off gas compressor, flare, acid gas removal unit)

Equipment-level	Detectable to a specific equipment group
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 (CO2) 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.
Materiality	For methane emissions inventories, the aggregate of sources that account for a minimum of 90% of total methane emissions from the Facility
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 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.
LNG Voyage	The actual Laden Voyage (including loading and unloading) and either the actual Ballast Voyage or an assumed Ballast Voyage from the unloading port back to the original loading port on the same LNG Carrier.
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 assist the operator to narrow the location of the emission event to a single localized area of the Facility for mitigation and Causal Examination 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-emission event, due usually to abnormal process conditions, which can significantly affect the total emissions of a Facility.
Throughput	For LNG liquefaction, the total quantity of LNG produced at a LNG Liquefaction Facility prior to loading. For LNG regasification, the total quantity of LNG delivered to the LNG Regasification Facility minus the quantity vented, flared or used in the process during 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.

5 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.

6 Participant Roles

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	· define and managing all aspects of the development of the Standard · publish 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	· engage with the Auditing Body to prepare for assessment; · provide 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)*

7 Facility Criteria

7.1 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*.

7.2 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 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. Mandatory requirements are required for all grades.

	Score Requirements[4]		
Grade	**Methane Intensity**	**Company Practices**	**Monitoring Technology Deployment**
A	<=0.020%	6	12
B	<=0.040%	4	8
C	<=0.080%	2	
D	<=0.20%	-	-
E	<=0.4%	-	-
F	<=0.8%	-	-

8 Document Flow

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

[4] All mandatory requirements for each of the Standard elements must be met *along* with each element's threshold for an operator to be eligible for a given Grade.

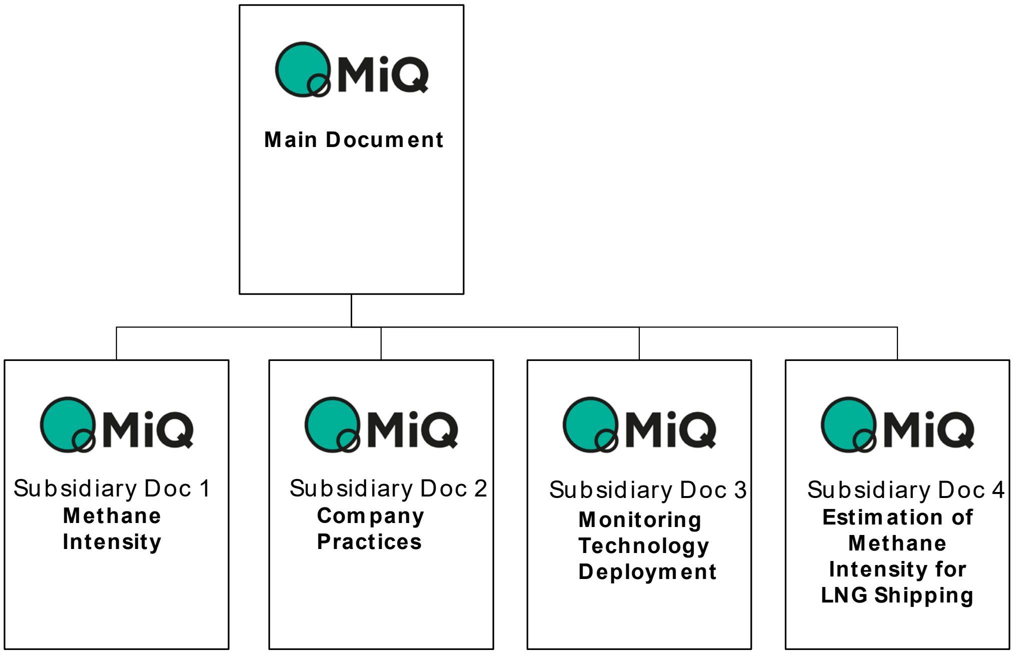

Figure 1: Document hierarchy

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: 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
	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
V2.0	2024-12	Main Document	Updated the definitions of Component-level, LNG Voyage, Site and Throughput Included the following new terms: Equipment group, Equipment-level and Materiality Updated Table 2: Grading System with revised methane intensity thresholds for each MiQ Grade and revised points structure for Company Practices and Monitoring Technology Deployment
		Methane Intensity	Added language separating requirements for material and non-material methane emission sources in *Section 3.2: Emission Sources* Included additional requirements for the quantification of emission rates and the determination of emission durations for events that are reconciled with the Operator's source-level methane emissions inventory. Updated the definitions of calculation methods in *Table 2: Types of calculation methods*

		Updated the minimum emission calculation requirements in *Table 3* for numerous emission sources Added the following emission sources to *Table 3*: Nitrogen removal units, LNG storage vessel venting, Emergency shutdown venting, and LNG loading and unloading
	Company Practices	Removed GP-1 and updated relevant requirements within UMEP-1 Revised and reclassified *Reporting Methane Emissions observations and incidents* as GP-1 Revised and reclassified *Estimating and measuring methane emissions* as GP-2 Revised and reclassified *Continual improvement* as GP-3 Removed GP-4.1 Removed GP-5: *Low-carbon energy supply* Revised UMEP-1 to include staff training requirements and inspection requirements for AVO inspections and updated staff LDAR-method competency requirements Revised UMEP-2: *Source-level detection plan* requirements Removed UMEP-3, UMEP-4 and UMEP-5 Removed IMEP-1: *Venting – Loading/Unloading* and replaced with IMEP-1: *Venting and Flaring* to include both mandatory and improved company practices related to venting and flaring at LNG Facilities Removed IMEP-2: *Venting – Facility Blowdowns* Revised and reclassified *Venting – Pneumatic Devices as IMEP-2* Separated company practices related to compressor venting into IMEP-3: *Venting – Reciprocating Compressors* and *IMEP-4: Venting – Centrifugal Compressors*

		Removed IMEP-5: *Flaring* and included flaring company practices within new IMEP-1 Removed IMEP-6 *Combustion Equipment*
	Monitoring Technology Deployment	Updated Table 2: Technology Performance Criteria by explicitly requiring AVO inspections at various frequencies for point thresholds, revising Source Level inspection frequency requirements, revising and adding numerous new options to meet Facility Scale inspection requirements Added Section 3.2.3 for details of AVO inspections required by the Standard Revised language in Section 3.2.4: *Equivalency Determinations* Updated language in Section 5.2: *Interconnection with Company Practices*

References

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MiQ STANDARD

for Greenhouse Gas Emissions Performance of Natural Gas Systems

Subsidiary Document 1: Methane Intensity – LNG

v2.0

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

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 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 Components of 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 Source Level

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 all material methane emissions from LNG Facilities in an accurate, credible, and replicable way that is consistent with existing frameworks for reporting and disclosure. All material methane 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. The minimum level of facility-specific data increases for sources likely to be material within an LNG facility. Emission sources deemed not to be a material emission source or have associated risk of being a material emission source may be calculated with less specific methods with documented justification.

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 Reconciliation Process

An Operator's accounting methodology must also include the 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. All methods used to detect emissions events 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 are 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 without discrimination.
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.

For emission rate quantification, the operator's protocol must incorporate the following logic:

1. If a technology has the ability to estimate an emission rate, the operator must default to the technology's algorithm unless the operator justifies that an engineering calculation is more representative of the event
2. If the technology cannot calculate an emission rate and necessary inputs to an engineering calculation cannot be estimated, the operator must use an emission factor representative of the event type.

For the determination of the duration and annualization of emission event types, the operator must incorporate the following logic:

1. Utilize monitored process parameters from properly functioning sensors and sound engineering principles to determine the duration of a specific emission event type
2. In the absence of monitored process parameters, utilize previous inspection results, as conducted according to the requirements of *Subsidiary Document 2* and *Subsidiary Document 3*, that can reasonably confirm an emission event was not previously occurring in either an intermittent or a persistent manner. For additive emission event types that emit intermittently and may not reliably be detected by a "snapshot[5]" survey, the operator must make efforts to characterize the intermittency and annualize emissions from the event type.
3. If there is no data that can reliably confirm the absence of an emission event type then assume the emission event persisted for the entire period in between inspections of the same method..

In the first year of adherence to this Standard, 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 survey with a MDL of ≤25 kg/hr[6], at least 6 Facility Scale monitoring surveys with an MDL of ≤200 kg/hr across the previous 1 year, or 3 months of continuous monitoring results from the operator's Facility that can be shown to be representative of its entire methane emissions footprint.

[5] Snapshot survey methods include, but are not limited to, AVO inspections, handheld OGI inspections, aerial pass overs with any type of sensor, and drone-based inspections

[6] At 90% probability of detection, confirmed via independent single-blind testing

4 Recordkeeping

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: 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: Types of Calculation methods

Calculation method type	**Clarification**
Direct Measurement	Any method which is able to calculate a methane emissions rate for the particular source for the time period of measurement. The method of conversion from a measured parameter to a methane emissions rate must be disclosed. Methods of conversion may include the conversion of a concentration measurement from a remote sensing technology to a methane emissions rate using an algorithm based on environmental parameters, or the conversion of a natural gas flow measurement to a methane emissions rate by multiplying the natural gas flow rate by the concentration of methane in the natural gas.

Engineering Calculation	Utilizing process simulation software to model methane emissions emitting from a physical or chemical process, or a calculation using sound engineering principles to estimate emissions from methane emissions releases.
Measurement-based Emission Factors	Emission factors derived from direct measurement campaigns of specific equipment types undertaken at the Facility or of equipment types similar to the equipment at the Facility. Emission factors may be derived from a statistically-representative sample of the equipment type of a Facility for some emission sources that is outlined in Table 3.
Other Emission Factor	Emission factors derived from sound engineering principles describing the emitting process . These emission factors may be derived from Facility-specific inputs or general knowledge of an emitting process. The requirements for emission factors for each source are outlined in Table 3.d

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: Minimum calculation requirements

Emission Source [7]	**Minimum Emission Calculation Requirements[8]**	**Examples of Accepted Methodologies**
Flares	Continuously metered waste gas flow rate with measured fuel 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]
Catalytic and thermal oxidizers	Estimated waste gas flow rate using measured parameters or engineering principles with measured fuel gas composition and a representative destruction efficiency	API Compendium 5.2 [2]
Internal combustion engines/drivers	Facility-specific measurements for a statistically-representative sample of each type of internal combustion unit **or** a published emission-factor based on measurements for the type of internal combustion unit	API Compendium 4.5.2; OGMP TGD Incomplete combustion (L3-L4) [5]; NGER 2.3.5 (Method 2) [8]; 40 CFR 98.233(z)[9]
Turbine generators/drivers	Published emission-factor for the type of combustion unit.	API Compendium 4.5.2 [2]; OGMP TGD Incomplete combustion (L3-L4) [5]; NGER

[7] 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.

[8] Emission sources that constitute a material portion of an operator's methane emissions inventory must be calculated per *at least* the minimum emission calculation requirements in Table 3. Sources not deemed to be material may use an emission factor-based method coupled with an actual activity or equipment count. Refer to Terms section of *Main Document* for the definition of a material emission source, under term *Materiality*.

[9] Any reference to 40 CFR 98.233(z) refers to the revisions made to Subpart W that becomes effective in January 2025 [10]

		2.3.5 (Method 2) [8]; 40 CFR 98.233(z)
Glycol dehydrator vents	Process simulation modelling with Facility-specific inputs	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	Process simulation modelling with Facility-specific inputs **or** at least 2 measurements annually of inlet and outlet CH4 concentrations with volumetric flow measurement of natural gas throughput	API Compendium 6.5.2 [2]; OGMP TGD Purging and venting (L3) [5]; GHGI[10] [9]; 40 CFR 98.233 (d) [6]; NGER 3.39F (Method 1) [8]
Nitrogen removal units	Process simulation modelling with Facility-specific inputs **or** at least 2 measurements annually of inlet and outlet CH4 concentrations with volumetric flow measurement of natural gas throughput	
Liquid hydrocarbon storage vessel venting	Engineering Calculations or process simulation modelling using Facility-specific inputs	API Compendium 6.5.3 [2]; 40 CFR 98.233(j) [6]; NGER 3.3.9F (Method 1) [8]
LNG storage vessel venting	Engineering calculations or process simulation modelling using Facility-specific inputs including tank pressures and vent pressure control setpoints	OGMP TGD Purging and Venting (L4)
LNG Loading/ Unloading	Engineering calculations using facility-specific transfer rates and empirically-derived emission factors based on transfer pipe material and connection type	API Compendium 6.7.2 [2]
Pneumatic devices and pumps	Published emission-factor based on measurements for the type of pneumatic device	API Compendium 5.6 [2]; OGMP TGD Pneumatics (L3-

[10] 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.

		L4) [5]; 40 CFR 98.233(a) [6]; NGER 3.3.9F (Method 1) [8]
Facility blowdowns (any equipment type)	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];
Emergency shutdown venting	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];
Equipment leaks	Leak surveys with a compliant Source-Level inspection technology and a published emission factor based on measurements for the leaking component type	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]
Centrifugal compressor venting	Facility-specific measurements for a statistically-representative sample of the type of centrifugal compressor vent	API Compendium 6.5.4.2 [2]; OGMP TGD Centrifugal compressors (L3-L4)[5]; GHGI[6] [7]; 40 CFR 98.233(o)[6]
Reciprocating compressor venting	Facility-specific measurements for a statistically-representative sample of the type of reciprocating compressor vent	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	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 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[11] and natural gas, emissions are allocated to natural gas on an energy basis ("Energy-allocated"). Operators should make best efforts to attribute individual inventory adjustments made via *Section 3.3: Emissions Reconciliation* to individual sources. The methodology for calculating methane intensity associated with LNG operations is as follows:

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

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

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

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

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)

An Operator must then calculate its Methane Intensity as:

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

Where:

[11] 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}.

- *ME* is the annual Methane Emissions from Facility (metric tons) attributed to natural gas throughput.
- 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

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[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

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MiQ STANDARD

for Methane Emissions Performance of Natural Gas Systems

Subsidiary Document 2: Company Practices – LNG

v2.0

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

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 LNG Voyages.

3 Facility 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:

h) **Mandatory**: Must be demonstrated by the LNG Operator in order to qualify for the Standard; or

i) **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 Performance Criteria

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 [12] categorized according to their character ('Mandatory' or 'Improved').

Table 1: General Company Practices (GP)

Practice	Character	Points
(GP 1) Reporting Methane Emissions observations and incidents • A reporting system is accessible for all relevant staff to report unintended methane emissions events; **and** • The Operator adheres to a written procedure detailing the information that must be submitted for all unintended methane emissions events; **and** • The Operator adheres to a written chain of command procedure that details the internal notification of emissions events • The Operator adheres to a written procedure that defines who must be notified depending on the magnitude of an unintended methane emissions event	Mandatory	**-**

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

Practice	Character	Points
(GP 2) Estimating and measuring Methane Emissions The Operator maintains a written plan detailing: • The source-level quantification methods for all emissions sources that are compliant with the minimum requirements in **Table 3** of MiQ's methane intensity subsidiary document; **and** • The process for quantifying the impact of emission events identified from all inspections required by the *Monitoring Technology Deployment Subsidiary Document*[13] • For emissions sources quantified by extrapolations of a measured sample, a description of the methodology and a justification of its representativeness	Mandatory	**-**
(GP 3) Continual improvement Methane management is integrated into an LNG Operator's company culture, as evidenced by: • A written policy minimizing venting; **and** • A Health, Safety & Environment (HSE) communication plan communicated to all staff that includes methane emissions reduction best practices for the operator's material methane emissions sources; **and** • Demonstrated knowledge of best practices to minimize methane emissions by the Facility's operations staff; **and** • A key performance indicator (KPI) for methane emissions that is tracked and has progress communicated to site management at least annually	Mandatory	**-**

3.2 Performance Criteria for Managing and Reducing Unintended Methane Emissions

[13] These quantification methods must be compliant with the requirements set forth in Section 3.3 of the *Methane Intensity Subsidiary Document*

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
Relevant staff receive training that:
• Emphasizes the sources of emissions and operating conditions that cause the highest potential for unintended emissions**; and**
• Includes actions to take when an unintended emission is identified including the follow-up, repair and repair verification**; and**
• Includes Audial, Visual, and Olfactory (AVO) inspections[14] as part of unit rounds with specific instructions to inspect at minimum:
    ○ Whether or not pneumatic devices are operating by design, based on manufacturer specifications**; and**
    ○ Whether or not liquid dump valves are operating by design**; and**
    ○ Connections along closed vent systems routing gas to process, flare or a control device for signs of emissions**; and**
    ○ Covers to process equipment for any cracks, holes, gaps or broken components that are or could cause emissions**; and**
    ○ Atmospheric vent systems for any abnormal streams being routed to vent**; and**
    ○ Control device bypasses for any leak-by**; and**
    ○ The status of the pilot for control devices and flares, and whether each is operating properly.
	Mandatory	-

[14] AVO inspections are described from a monitoring perspective in Section 3.2.3 of *Subsidiary Document 3: Monitoring Technology Deployment*

Practice	Character	Point
• Details how to log information related to unintended emissions to support repair efforts and investigation of the cause • Is required at least annually Leak Detection and Repair (LDAR) method-specific proficiency is demonstrated for: • Method 21-compliant [1] surveys – LNG Operator's personnel responsible for carrying out inspections demonstrate proficiency in the proper use of instruments, instrument calibration, inspection methods and regulatory requirements including leak definitions, follow-up and repair tasks; **and/or** • Optical Gas Imaging (OGI) – LNG Operator's personnel responsible for use of OGI cameras demonstrate proficiency in the 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 present proof that the third party is proficient in the LDAR-method as stated above; **and** In the event an alternative LDAR technology is used, the personnel responsible for carrying out inspections demonstrate proficiency in the proper use of instruments, instrument calibration, and proper inspection methods based on manufacturer recommendations		
(UMEP 2) Source Level[15] Detection Plan Source Level Detection, or LDAR, plan outlines at a minimum: • specific equipment / components included in LDAR survey (must reference process valves, connectors, compressor seals, open-ended lines, meters, pressure relief valves, regulators, and pneumatic controllers); **and** • leak definition for each inspection technology; **and** • that identified leaks constituting 90% or greater of total fugitive emissions are prioritized for repair • for prioritized leaks	Mandatory	-

[15] Source Level inspections are described from a monitoring perspective in Section 3.2.2 of *Subsidiary Document 3: Monitoring Technology Deployment*

Practice	Character	Point
○ First attempt at repair is conducted within 5 days of detection; **and** ○ Final attempt at repair or replacement and repair verification completed within thirty (30) days of detection; **and** • procedure for adding prioritized leaking equipment / components to a delay or repair list if the leaking equipment / component cannot be repaired in the required timeframe due to a safety or technical reason[16]; **and** • requirement to complete repair for prioritized leaking equipment / components on the delay of repair list during or before the next scheduled unit shutdown, or within one year, whichever comes sooner; **and** • requirement for replacement parts to be sufficiently stocked if reasonably available by the supplier		

3.3 Performance Criteria 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 and Flaring		

[16] Safety or technical considerations include the safety of personnel near the leak, an environmental impact related to repairing the leak that is more adverse than allowing the leak to persist until the next scheduled shutdown, the unavailability of replacement parts, and a regional deterioration of gas supply likely to lead to crisis [3]

<table>
<tr><th>Practice</th><th>Character</th><th>Point</th></tr>
<tr><td>IMEP 1.1 – Venting

Operators must maintain a written plan:
• Requiring the minimization of blowdown events through maintenance planning and/or engineering and design solutions; and
• Which defines allowable scenarios for venting natural gas directly to the atmosphere without the use of a control device; and
• Which defines the magnitude of allowable scenarios for venting natural gas directly to the atmosphere without the use of a control device</td><td>Mandatory</td><td>-</td></tr>
<tr><td>IMEP 1.2 – Flaring Scenarios

LNG Operators that operate a flare must have measurable and actionable plans in place to reduce flaring volumes; and

LNG Operators may only flare:
• During incidents that endanger personnel or public safety; and
• During periods of maintenance or repair in which; and process equipment must be cleared to safely perform work; and
• During periods of commissioning; and
• During the purging of inert vessels and subsequent filling of LNG; and
• To control sources of methane emissions during normal operations that would otherwise be vented; and

For all other reasons the Operator must route natural gas back to process, or use the natural gas that would be flared as an onsite fuel source</td><td>Mandatory</td><td>-</td></tr>
<tr><td>IMEP 1.3 Flare Controls</td><td>Mandatory</td><td>-</td></tr>
<tr><td>LNG Operators that operate a flare must maintain a written flaring plan which includes:
• Definitions of allowable flaring scenarios
• Definitions for the beginning and end of each flaring scenario
• Tracking requirements for flaring events</td><td></td><td></td></tr>
</table>

Practice	Character	Point
LNG Operators must assure a constant flame during operation and operation to a flare's design destruction efficiency by: • Operating the flare with a continuously lit pilot that is continuously monitored • Implementing an alarm that is sent to the control room as soon as practicable for when the flame is unlit • Implementing a response plan when an alarm is sent to the control room for returning the flare to normal operation • Defining the minimum net heating value of waste gas in the combustion zone • Defining the minimum allowable flow rate of the flare		
IMEP 1.4 Reducing venting	Improved	
In addition, the percent of potentially vented natural gas[17] that are recovered and sent back to process, recovered and used as an onsite fuel source or flared in compliance with *IMEP-2 and IMEP-3* exceeds: • 50% of potentially vented natural gas • 75% of potentially vented natural gas • 90% of potentially vented natural gas		3 4 5
(IMEP 2) Venting – Pneumatic Devices Operators must: • Maintain an accurate inventory of pumps and controllers that is checked annually, at a minimum; **and**	Mandatory	-

[17] Potentially vented emissions are the sum of the mass of natural gas vented to atmosphere, the mass of natural gas recovered and sent back to process or used as an onsite fuel source, and the mass of natural gas flared in compliance with IMEP-2 and IMEP-3, during the reference 12-month period. The mass of natural gas vented is the sum of natural gas emissions from reciprocating compressor vents, centrifugal compressor vents, LNG storage vessel vents, acid gas removal vents, nitrogen removal vents, pneumatic device vents, LNG loading and unloading process vents, emergency shutdown venting events, and all Facility blowdowns.

Practice	Character	Point
• Ensure that all pneumatic devices are included in the Source-level Detection Plan.		
(IMEP 3) Venting – Reciprocating Compressors Operator must: • Ensure that all reciprocating compressors are included in the Source-Level Detection Plan • Replace natural gas reciprocating compressor rod packing components on a fixed schedule based on operating time, unless the operator follows IMEP-4.1; **and** • Implement policies to minimize emissions from compressor gas starters.	Mandatory	-
(IMEP 3.1) For Operators with reciprocating compressor venting as greater than or equal to 10 percent of their total source-level emissions inventory, the operator must • Route at least 50% of calculated emissions back to process or for use as an onsite fuel source; **or** Measure a representative sample of at least 50% of the compressor inventory and confirm a leak rate of less than 2 cubic feet per minute. If a leak rate above 2 cubic feet per minute is measured, the Operator has 180 days to repair the compressor rod packing.	Improved	2
(IMEP 4) Venting – Centrifugal Compressors Operator must: • Ensure that all reciprocating compressors are included in the Source-Level Detection Plan • Implement policies to minimize emissions from compressor gas starters.	Mandatory	-
(IMEP 4.1) For Operators with reciprocating compressor venting as greater than or equal to 10 percent of their total source-level emissions inventory, the operator must	Improved	2

Practice	Character	Point
• Convert at least 50% of wet seal degassing systems to dry seal systems; **or** • Route at least 50% of calculated emissions back to process or for use as an onsite fuel source; **or** • measure at least 50% of its wet-seal degassing compressor inventory and confirm a leak rate of less than 10 scfm. If a leak rate above 2 cubic feet per minute is measured, the Operator has 180 days to repair the compressor rod packing.		

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] Commission Regulation (EC) 2024/1787. Retrieved from: https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=OJ:L_202401787

MiQ STANDARD

for Methane Emissions Performance of Natural Gas Systems

Subsidiary Document 3: Monitoring Technology Deployment – LNG

v2.0

MiQ

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.

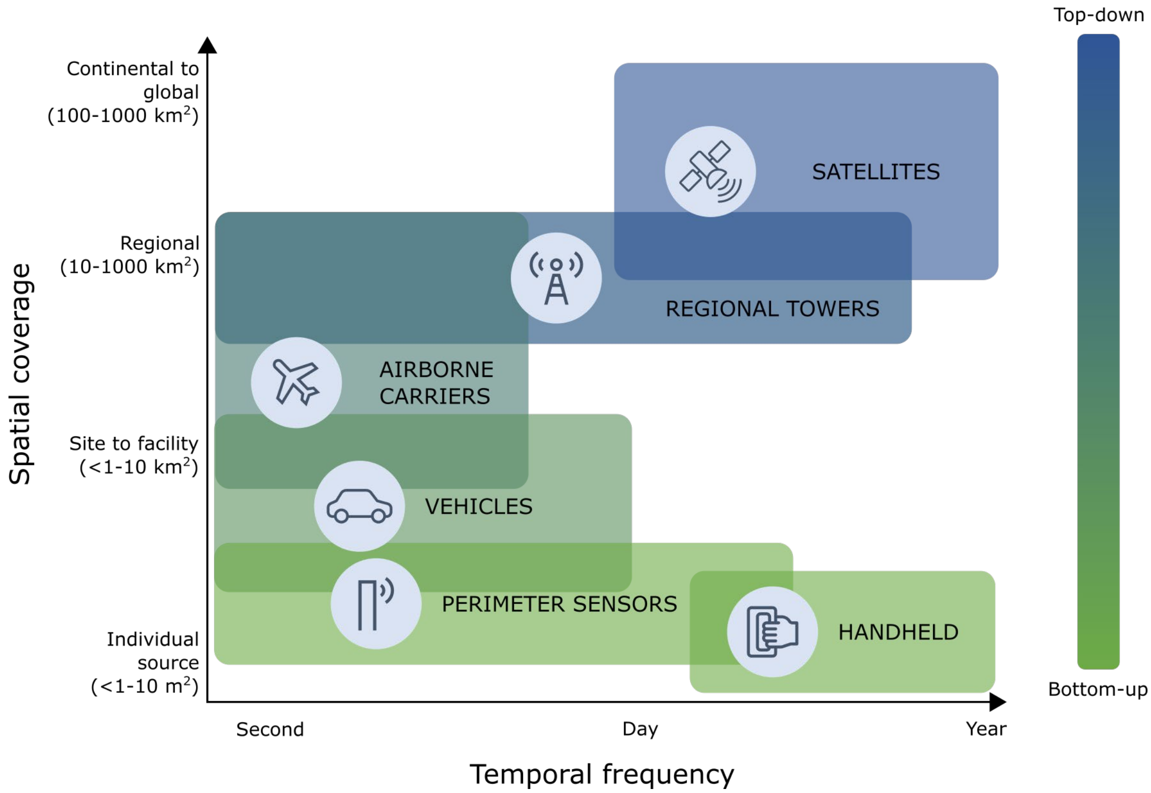

Figure 1: Methane monitoring technology across a variety of spatial and temporal scales (adapted from the National Academies of Science, Engineering, and Medicine, 2018 [1])

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*][18] These studies indicate that under-representation of abnormally high emission sources, commonly referred to as Super-Emitters, is one cause of this divergence[4][19]. 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.

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[18] 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.

[19] 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.

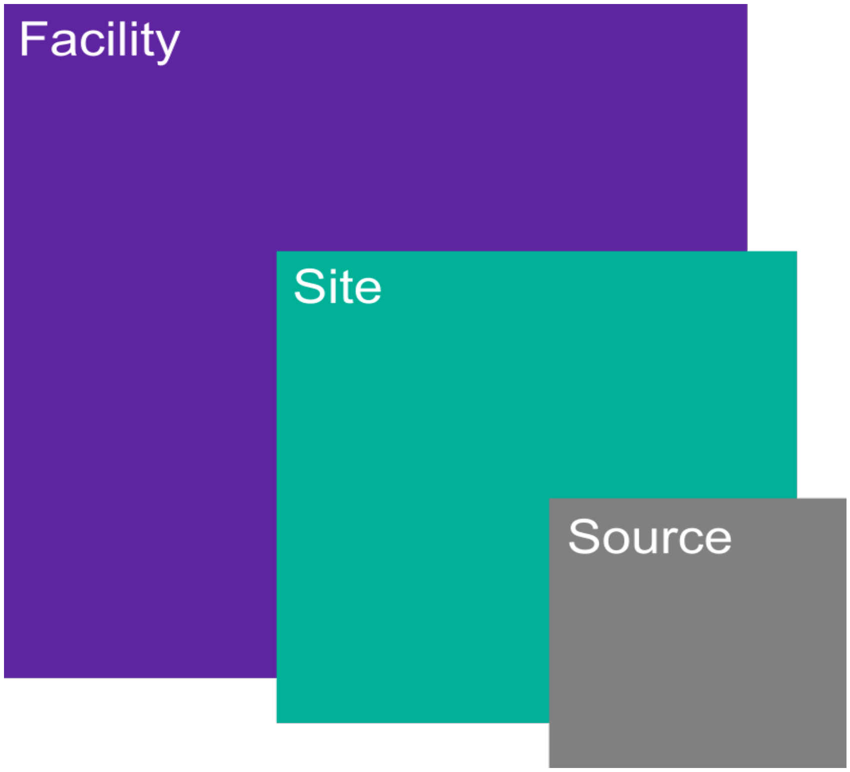

Figure 2: Spatial scales utilized within the Standard, referencing the definitions of Facility, Site, and Source as outlined in the *Main Document*, see there for reference.

2 Scope

This subsidiary document outlines requirements for Monitoring Technology Deployment for detection of Unintended methane emission Sources at a Liquefaction or Regasification Facility. For the avoidance of doubt, the requirements of Monitoring Technology Deployment do not apply to 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 Facility Performance Criteria

The primary objective of Monitoring Technology Deployment is to:

a) 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:

b) to provide assurance of the calculated Methane Intensity using reconciliation (see *Subsidiary Document 1: Methane Intensity)*

c) to implement better operating practices and equipment design for reduced methane emissions; and

d) to encourage LNG Operators to work towards Measurement of emission sources at their Facilities.

3.1 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[20].

[20] 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.

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[21] must be applicable for the specific Facility and validated by the Auditor.

3.2 Criteria

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 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.

[21] 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.

Table 2: Technology Performance Criteria

Unit round / AVO inspection[22]	**Source Level inspection**[23]	**Facility Scale Inspection**	**Points**
6x over 100% of Facility	2x over 100% of Facility	1x over 100% of Facility, @ MDL[24] of ≤10 kg/hr[25]; **or** 2x over 100% of Facility, @ MDL of ≤25 kg/hr; **or** 1x over 100% of Facility, @ MDL of ≤25 kg/hr **and** 12x over 100% of Facility @ MDL of ≤200 kg/hr	12
4x over 100% of Facility	2x over 100% of sites	1x over 100% of Facility, @ MDL of ≤ 25 kg/hr**; or** 12x over 100% of Faclility, @ MDL of ≤200kg/hr	8
4x over 100% of Facility	1x over 100% of sites	N/A	0

3.2.1 Facility Scale Inspection

The intention of a Facility Scale inspection is to provide assurance that potential abnormally high emissions are being monitored while more efficiently screening for unintended emissions sources that

[22] AVO inspections must be conducted in accordance with the relevant details in UMEP-1 of *Subsidiary Document 2: Company Practices and records must be kept and recorded in accordance with Section 4 of this Subsidiary Document*

[23] Source-level inspections must be conducted in accordance with the relevant details of UMEP-1 and UMEP-2 of *Subsidiary Document 2: Company Practices and records must be kept and recorded in accordance with Section*

[24] MDL is minimum detection limit of the technology as demonstrated by independent single-blind testing. The probability of detection for the stated MDL must be at 90%

[25] Facility Scale inspection methods must also be able to attribute detections to the equipment level

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 or above the frequency designated in Table 2 above
- must meet the designated MDL of 25kg/hr[26] 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[27]
- 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 investigated to determine if the source exceeds the expected rate and ascertain if the event requires follow-up or mitigation.

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[26] 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].

[27] Inspection technologies determined to have a MDL of <10 kg/hr must also be able to attribute detections to the equipment-level

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 plan. The operator must have a Source Level detection plan consistent with the requirements in UMEP-2 of *Subsidiary Document 2: Company Practices*.

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

- Spatial resolution must be sufficiently low to reliably attribute emission sources to the 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).

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 AVO Inspections

As part of the operators' unit rounds, audio, visual, and olfactory (AVO) inspections are required to help identify and mitigate large emission events caused by abnormal operations by a trained operator instead of a monitoring technology. AVO inspections must be conducted consistent with the training requirements in UMEP-1 of *Subsidiary Document 2: Company Practices*.

3.2.4 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 determinations can only define different frequencies, coverages and detection thresholds of a combination of Source Level inspection methods and Facility Scale inspection methods. AVO inspections must be conducted per the requirements in Table 2 and *Subsidiary Document 2* along with the methods defined in an operator's equivalency determination.

4 Recordkeeping and Reporting

LNG Operators are required to record information related to 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. Table 3 outlines the minimum recordkeeping requirements for Monitoring Technology Deployment. LNG Operators must have adequate Company Practices in place which underpin accurate recordkeeping and reporting structures.

4.1 Minimum Recordkeeping and Reporting Requirements

Table 3: Minimum recordkeeping requirements for Facility Scale, Source Level and AVO inspections

Recordkeeping element	Details

Detection Technology Specifications[28]	• 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
	  ○ Third party used to conduct testing
	  ○ Confirmation of single-blind nature of testing
	  ○ Operating conditions of equipment used for testing
	  ○ Variables tested that could affect the sensitivity of the technology and the ranges tested (i.e. humidity, temperature, wind speed, groundcover, obstruction, solar irradiation)
	  ○ Calibration protocols used during testing
	  ○ If operator uses technology for quantification, characterization of emission rate uncertainty

Work Practice Specifications	• Frequency of surveys and routes taken[29]
	• Alarm criteria, including the alarm threshold used for each type of event[30]
	• Deployment specifications for individual Sites to replicate location and environmental criteria determined during controlled released testing[31]
	  ○ If a third party is contracted for the survey, this should also include contractor or data service provider information.
	  ○ To include details for both Facility Level and Source Level inspections

[28] Not applicable to AVO inspections

[29] Not required for stationary sensors

[30] Not applicable to AVO inspections

[31] Not applicable to AVO 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 inspection recordkeeping form	For each emission source, includes component, equipment and/or site ID and type, date of all repair efforts, repair validation date, success of repair or replacement, and (if applicable) a reason for delay to repair or replace and the date rectified.
Monitoring locations	Includes a list of monitoring locations visited for each survey
QA/QC	Chain of custody sign off on data collected for accuracy, 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 ○ 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 Monitoring Data Usage

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 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 the types of emitting events and equipment types . See *Section 3.3 Emissions Reconciliation* for detailed requirements on quantifying and characterizing methane emissions that are identified by inspections related to this Subsidiary Document or a third party.

5.2 Interconnection with Company Practices

Unintended methane emission events identified through inspections related to this Subsidiary Document or by a third party must be reported following GP 1 of *Subsidiary Document 2: Company Practices.* Relevant staff and contractors must be trained to perform AVO inspections and Source Level inspections per UMEP 1 of *Subsidiary Document 2.* Source Level inspections, follow up and repair must be conducted in accordance with UMEP 2 of *Subsidiary Document 2*.

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MiQ STANDARD

for Greenhouse Gas Emissions Performance of Natural Gas Systems

LNG Shipping Model

v2.0

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[32]).

Table 1. Inputs relating to LNG Carriers

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

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

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

4 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.

5 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.

6 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.

7 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 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.

8 Methane and Carbon Dioxide Intensity

Total methane emissions for the 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 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 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	Input value (ENTER DATA IN THIS COLUMN)
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

Item	Unit	ENTER DATA IN THIS COLUMN Input value – Ballast Voyage	ENTER DATA IN THIS COLUMN 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