A Policymaker's Guide to Implementing Leak Detection and Repair for Methane Mitigation

Core Principles for using Optical Gas Imaging, Survey Design, and Compliance Reporting

CLEAN AIR TASK FORCE

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Acknowledgements

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About Clean Air Task Force

CATF is a global nonprofit organization working to safeguard against the worst impacts of climate change by catalyzing the rapid development and deployment of low-carbon energy and other climate-protecting technologies while advocating for enabling policies. CATF's Methane Pollution Prevention (MPP) program focuses on advancing the necessary policy changes to rapidly cut methane emissions from the oil and gas, coal, waste, and agriculture sectors. CATF has offices in Boston, Washington D.C., and Brussels, with staff working virtually around the world. For more information, visit www.catf.us.

The OGI images and footage documented in this report were captured using two FLIR GF320 cameras operated by CATF staff.

Cover photo credits: Mohammed Aminu, Africa Methane Policy Manager, Clean Air Task Force (CATF)

Table of Contents

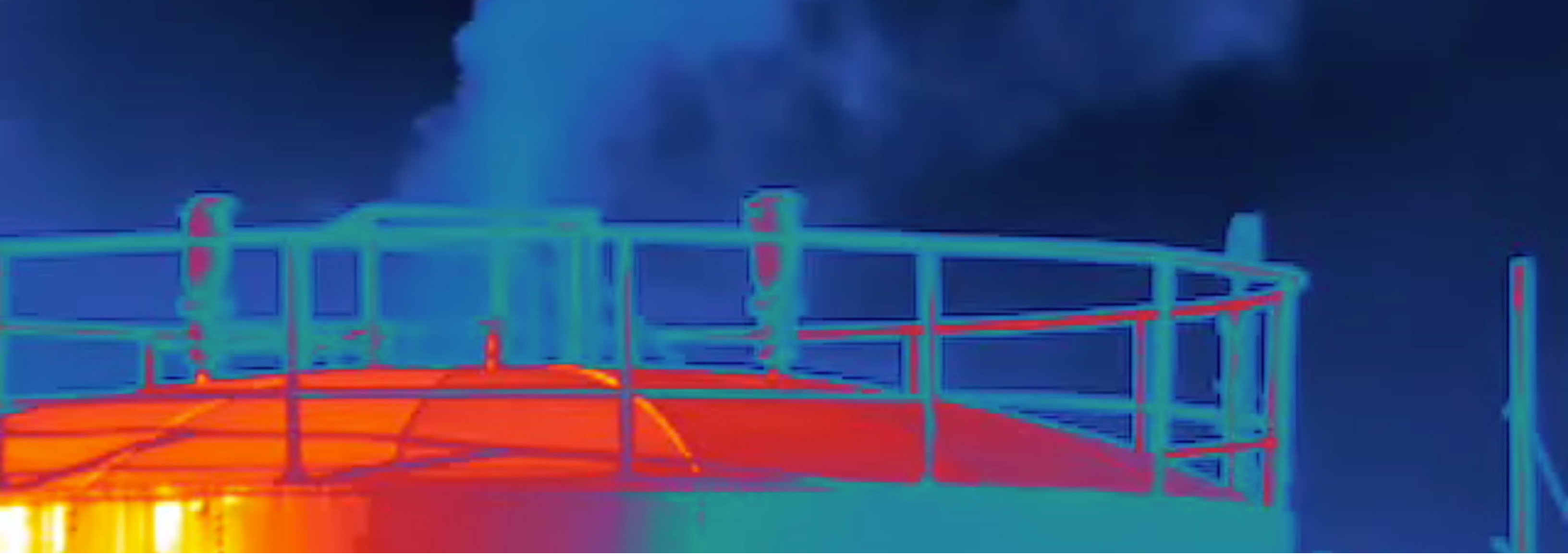
List of Tables, Figures, and Boxes

Abbreviations

AVO	Audio, Visual, and Olfactory
CMS	Continuous Monitoring System
DOR	Delay of Repair
FSRU	Floating Storage Regasification Unit
LDAR	Leak Detection and Repair
LiDAR	Light Detection and Ranging
MDL	Minimum Detection Limit
MRV	Measurement, Reporting, and Verification
OGI	Optical Gas Imaging
OGMP	Oil and Gas Methane Partnership
PFD	Process Flow Diagram
PIG	Pipeline Inspection Gauge
P&ID	Piping and Instrumentation Diagrams
POD	Probability of Detection
PPE	Personal Protective Equipment
PRV	Pressure Relief Valve
QOGI	Quantitative Optical Gas Imaging
TDLAS	Tunable Diode Laser Absorption Spectrometer
U.S. EPA	United States Environmental Protection Agency
UAV	Unmanned Aerial Vehicles
VOC	Volatile Organic Compounds

Glossary

Critical Components	Component whose repair would require the shutdown of a critical process unit if component was shut down or disabled. A critical process unit is a process unit that must remain in service, except during regularly scheduled maintenance, because shutdown of the unit could affect the safety and/or reliability of the natural gas supply system.
Detection	Identification of the presence of methane gas without determining its size (e.g., a visual detection with an OGI camera).
Flaring	Controlled burning of natural gas in a flare. Flares are a source of methane emissions because not all of the gas is completely burned, so some methane escapes uncombusted from the flare tip (also known as "methane slip"), and methane may be directly vented if flare is unlit for any period of time.
Fugitive Emissions (Leaks)	Unintentional release of methane gas from components across the oil and gas infrastructure. Note: The term “fugitives” is sometimes used to refer to all methane emissions from a site. However, in this report, we use the terms “fugitives” and “leaks” interchangeably to refer to the unintentional release of methane.
LDAR Inspection	Site visit conducted by a regulator to ensure compliance with existing LDAR regulation.
LDAR Program	A structured action plan that translates regulatory requirements into operational procedures. It defines roles and responsibilities, processes, data management, and quality assurance to ensure compliance with the LDAR regulation.
LDAR Regulation	Mandatory rules that define what is required by operators, including covered sources of leaks, monitoring frequency, approved detection methods, repair timelines, and reporting obligations.
LDAR Survey	A field inspection process where operators use approved detection methods to identify leaks, document findings, and initiate repairs in accordance with regulatory requirements.
Measurement	The process of determining the concentration of methane gas in a plume (e.g., parts per million) at specific points in space.
Methane Slip	Methane slip occurs when methane escape unburned through the exhaust of a combustion device, such as flares, compressor engines, turbines, furnaces, boilers, and burners. This results from incomplete combustion which can occur due to inefficiencies or unideal operating conditions (i.e., poor fuel-air mixing). Similarly, in flare systems, the same inefficiencies allow methane and other gases to slip through the flare tip unburned or partially combusted and being released directly to the atmosphere.
Quantification	The calculation of the actual or estimated emission rate, which is the total volume of methane being emitted from a point source over time (e.g., grams per hour of methane emitted), often by using weather or process data at the time of detection.
Super-Emitter	Events releasing 100 kg or more of methane per hour.[1]
Venting	Intentional release of methane gas from equipment or processes designed to periodically vent gas for operational safety, such as pressure relief devices or pneumatic controllers.



Executive Summary

The oil and gas sector is responsible for roughly one-quarter of global anthropogenic methane emissions,[2] making it a high-priority target for effective mitigation efforts. A significant share of these emissions come from persistent, unnoticed leaks from routine on-site operations and equipment failures, which add up to one of the sector's largest sources of methane. Systematically identifying and addressing these leaks through Leak Detection and Repair (LDAR) programs are among the most effective mitigation strategies for reducing these emissions. Well implemented LDAR programs can reduce methane emissions from leaks by nearly 80%.

In practice, there is often a lack of knowledge and clarity on how to design and implement LDAR programs, among both the operators responsible for conducting field surveys and the regulators mandating and evaluating them. Variability in field methods, inconsistent documentation, and lack of standardization often lead to uncertainty about survey quality and hinder mitigation efforts. While foundational technical resources exist (e.g., U.S. EPA's Method 21 and Appendix K), they do not fully meet the needs of regulators seeking to evaluate compliance or operators seeking to effectively conduct surveys. There is a clear need for resources that are technically sound, up-to-date, and practical for real world use.

This report aims to fill that gap and support more effective LDAR implementation by providing practical, step-by-step guidance informed by CATF's field experience with Optical Gas Imaging (OGI) cameras and aligned with existing, well-regarded international best practices. While LDAR programs that combine multiple advanced methane detection technologies may be more effective and efficient if implemented properly, this report focuses primarily on implementation of LDAR with OGI cameras. OGI cameras remain one of the most effective and tested tools for LDAR. However, there is room to improve implementation of LDAR programs, even with this mature technology, as the effectiveness of LDAR programs depends entirely on their implementation.

The primary audience for this report is regulators as they develop and enforce LDAR programs within their jurisdictions. It can also be used as a resource by oil and gas operators or third party LDAR service providers as they plan for, conduct, and report on these LDAR programs. Finally, civil society organizations can also use the report to better understand and evaluate what is required by operators and regulators (see Table ES 1).

Table ES 1: Intended Use of Report Sections by Operators and Regulators

Report Sections	Intended Use		
	Regulators	**Operators**	**Civil Society**
1. Regulatory Framework for LDAR	Understand the foundational elements of LDAR regulations to support effective LDAR implementation and evaluation.	Understand regulatory objectives, applicability, and compliance obligations.	Understand the components of an LDAR regulation for advocacy purposes.
2. Leak Detection Technologies	Understand detection capabilities and limitations and evaluate the adequacy of technologies when writing LDAR standards and in evaluating submitted surveys.	Understand available measurement and detection technologies and select appropriate technologies.	Understand technologies for detecting emissions when evaluating public company reports.
3. Guidance for Planning and Implementing LDAR Surveys	While regulators do not conduct LDAR surveys, it is important for them to understand the steps involved in order to ensure that field execution aligns with compliance requirements.	Plan surveys, ensure systematic coverage, prioritize high-risk equipment, and follow best practices for safe, and effective leak detection.	Understand the LDAR survey process when conducting 3rd party surveys or when evaluating company reports.
4. Typology of Common Leak Types and Repair Considerations	Review operator reports for consistency and completeness and verify that leak classifications are accurate.	Identify and classify different leak types, prioritize repair actions, and standardize documentation for reporting.	Understand common leak types and terminology used in company LDAR reports.
5. Considerations for Reporting and Evaluation	Create LDAR reporting templates and interpret and evaluate submitted LDAR reports, verify accuracy and completeness, and make informed decisions regarding compliance and enforcement.	Document survey results clearly, communicate findings to regulators, and ensure records support compliance.	Understand reporting requirements to evaluate company reports when they are made publicly available.

In Section 1, we describe the key components of an LDAR regulation. Then, we review the technologies that can be used for standard LDAR implementation (Section 2) and other technologies that can be used in tiered LDAR programs or super-emitter programs (Appendix A).

Next, we describe how operators should plan and carry out LDAR surveys (Section 3). The steps for carrying out LDAR surveys are summarized in Table ES 2.

Table ES 2: Steps for Carrying out LDAR Surveys with OGI

1	**Survey planning**	Before beginning the survey, all involved stakeholders should align on a plan to ensure the survey is conducted efficiently, safely, and in accordance with the LDAR regulation.
2	**Facility entry and site verification**	At the facility entrance, the LDAR inspection team should begin documenting site conditions and review facility boundaries.
3	**Component examination**	The LDAR surveyor should thoroughly inspect each regulated component using the chosen detection technology (in this case, the OGI camera).
4	**Leak identification and documentation**	Once a leak is identified during component examination, the operator must clearly document it.
5	**Survey continuation**	Maintain survey integrity as the team moves through the facility.
6	**Post-survey verification**	Verify that all components listed in the LDAR route map or other site coverage approach have been surveyed.
7	**Repair**	Effective repair strategies must balance immediate action with engineering best practices to ensure a quick fix does not inadvertently create greater safety risks.
8	**Re-survey to confirm repairs**	Leaking components should be re-surveyed within 15 days of their repair or according to applicable regulatory compliance requirements. A re-survey of components using the same method and protocols as the original survey is important to verify the effectiveness of corrective actions and ensure any emissions sources have been successfully mitigated.
9	**Data review and reporting**	Within a few days of the initial survey, the LDAR survey team should review and consolidate the survey data.

We present a typology of leaks that describes the main sources of leaks, the cause of emissions identified, description of emissions observations, and OGI images of each leak type (Section 4). This typology is summarized in Table ES 3.

Table ES 3: Summary of Leak Typology

Typical Component Category	Potential Causes of Emissions
Valves	Stem packing degradation, seating failure, improper positioning (stuck open), or cracked valve
Flanges and bolted connections	Gasket failure, corroded or loosened connectors, compromised infrastructure, or improper assembly.
Seals, packing, and dynamic Interfaces	Compressor seal or packing degradation, equipment malfunction, or stuffing box leaks
Process piping and structural components	Corroded pipeline, erosion in elbows, stress cracks
Instrumentation and controls	Loose or broken gauge, improper installation or tuning, or component degradation
Tanks, storage equipment, and pits	Open or unsecured thief hatches, open vents, or structural degradation
Pressure release device	Poor tuning, sealing failure, or component degradation
Emission control equipment	Flare failure or malfunction, pilot failure, insufficient capacity/ malfunction/poor tuning of vapor recovery units (VRUs)
Actuated device	Component degradation, improper tuning, or controller failure
Vents, open-ended lines, and intermittent sources	Improper operational practices, uncapped open-ended lines, compromised infrastructure, or component degradation
Threaded and mechanical fittings	Component degradation, loosened threading, seal failure, or misalignment or improper installation

Finally, we describe how operators must report on their LDAR activities and how regulators can ensure that LDAR is implemented effectively (Section 5).

Accompanying this report are videos of leaks, model reporting templates, an overview of various types of technologies used for LDAR, and other supplementary materials that can be useful to operators and regulators, found at https://www.catf.us/resource/leak-detection-and-repair

By offering clear and standardized guidance for both in-field surveys and the reporting process, this guide aims to strengthen LDAR practices and enhance the effectiveness and credibility of LDAR programs. In doing so, it will contribute not only to improved regulatory compliance, but also to meaningful, measurable reductions in methane emissions.

Introduction

The oil and gas sector represents a major opportunity for rapid, cost-effective methane mitigation, which has driven increased policy attention and industry engagement worldwide. Since the launch of the Global Methane Pledge in 2021, the European Union, Nigeria, Colombia, and more than a dozen nations have adopted, drafted, or are in the process of developing dedicated plans and regulations to cut methane emissions from the sector.[3] Complementing these regulatory efforts, voluntary initiatives such as the Oil and Gas Methane Partnership (OGMP) 2.0, have established measurement and reporting standards for methane emissions. These efforts are further strengthened through initiatives like the Oil and Gas Decarbonization Charter and the International Methane Emissions Observatory (IMEO), which provide important infrastructure for global accountability by increasing access to global emissions data and driving industry-wide commitments for abatement. Together, these efforts reflect growing recognition that methane emissions from oil and gas are both addressable and central to near-term climate change mitigation.

Despite this momentum, emissions from the sector are projected to decline only marginally in the near term, falling short of what is required to meet global methane targets and climate goals.[4] This gap between ambition and outcomes is partly attributable to persistent implementation barriers that continue to limit mitigation progress across countries.

Leak Detection and Repair (LDAR) program implementation sits at the center of this challenge. An LDAR program is a structured action plan that translates LDAR regulations into operational procedures. It involves conducting LDAR surveys, which are field inspections to identify, document, and repair gas leaks from equipment and infrastructure, commonly referred to as fugitive emissions. These emissions, which result in a loss of containment, are distinct from venting, which refers to the intentional release of methane from equipment or process activities. LDAR is conducted both as a regulatory compliance activity, required under many national or subnational methane regulations, and as part of voluntary methane management programs.

When well-designed, LDAR programs can deliver substantial emissions reductions while also supporting operational safety and regulatory accountability. The U.S. EPA estimated that quarterly LDAR can reduce fugitive emissions by an average of 77%.[5] In practice, however, several hurdles undermine successful LDAR implementation: field methods lack standardization, documentation is inconsistent, resources are limited, and technical requirements are interpreted differently across operators, which can significantly lower the emissions reduced.[6]

When conducting LDAR surveys, using Optical Gas Imaging (OGI) cameras is considered best practice for detecting leaks in real time and prioritizing repairs, because it can relatively easily and quickly pinpoint specific emissions sources. Other technologies, like handheld detectors, aerial surveys, and fixed-point sensors, can extend coverage, improve sensitivity, and provide more continuous data streams. These other technologies are advancing quickly, with detection abilities improving and costs decreasing. We discuss the various types of technologies more in Section 2 and in Appendix A. While many technologies are complementary to OGI, as of the writing of this report, none can *fully* replace OGI cameras for the detection of leaks in LDAR programs. In addition, the specific technology or set of technologies used in a country will depend on these technical specifications as well as the cost and accessibility of the given technology in that country.

The regulatory landscape governing LDAR is expanding rapidly. New and updated regulatory frameworks include requirements for operators to increase survey rigor and training requirements, reduce repair timelines, and improve reporting transparency. They also increasingly require regulators to assess technically complex surveys and interpret diverse data streams, often with limited capacity and resources. Foundational resources to guide LDAR implementation are available, including the United States Environmental Protection Agency's (U.S. EPA) Method 21[7] and Appendix K,[8] as well as international initiatives like the Global Methane Initiative.[9] However, additional guidance is needed to support consistent, high-quality implementation and evaluation. Furthermore, regulations are more effective when LDAR programs are implemented alongside rigorous equipment and work practice standards, such as restrictions on venting and flaring, which ensures a more comprehensive reduction in a facility's overall emissions.

This report bridges the gap between the text of LDAR regulations and on-the-ground implementation by providing structured guidance on **implementing an LDAR program for regulatory compliance**, with regulators as the primary audience and operators and civil society as the secondary audiences. This report focuses on implementing an LDAR program with an OGI camera, but we recognize that in the future it may be possible to complement the OGI camera, in whole or in part, with other advanced technologies. However, much of the Guidance for Planning and Implementing LDAR Surveys (Section 3) and the Typology of Common Leak Types and Repair Considerations (Section 4) will remain relevant, regardless of the detection technology used.

While the report is oriented toward regulatory applications, the descriptions of LDAR surveys, leak identification, and technical considerations are also applicable to voluntary LDAR surveys. The report focuses on the use of OGI cameras but also provides descriptions of alternative detection technologies and key considerations for each in Appendix A. Regulators and operators should adapt the report to the context of their operations, applicable regulations, and available resources.

SECTION 1

Regulatory Framework for Leak Detection and Repaid (LDAR)

LDAR programs are a core component of a comprehensive methane regulation in the oil and gas sector.[10] They are essential tools for driving deep reductions in emissions and improving operational performance. To be effective, these programs must include clear standards for survey frequency, repair timelines, and reporting requirements. Table 1 shows the leading policies globally that provide a standardized method for identifying, mitigating, and documenting fugitive emissions throughout the oil and gas supply chain. (*For a guide to leading policies in regulating methane emissions in the oil and gas industry*, see CATF's Leading Methane Abatement Policies for Oil and Gas Operations.[11])

Table 1: Key Elements of a Regulatory LDAR Program, the Importance of Each, and Best-in-Class LDAR Regulations

Regulatory Element	Description	Best-in-Class Guidelines	Jurisdiction with Precedent
Program applicability	The types of oil and gas facilities that must conduct LDAR.	LDAR requirements must apply to all oil and gas infrastructure and facilities, including pipelines, process equipment, and components (e.g., valves, connectors, flanges, and open-ended lines).	U.S.[12], EU[13]
Technology	The technology and/or technical requirements of the technology that must be used to conduct surveys.	Operators must conduct leak detection using specially designed instruments (OGI or U.S. EPA Reference Method 21, a method used to detect volatile organic compound (VOC) leaks from process equipment).	U.S.[14]
Survey frequency	The frequency with which surveys must be conducted.	LDAR surveys must be conducted quarterly (i.e., every three months).[i]	Colorado, Pennsylvania, Ohio, Wyoming, Nigeria[15]

[i] As we discuss below, approaches that combine regular OGI camera survey with continuous monitoring or frequent aerial surveys may achieve greater emission reductions than OGI surveys alone, but in this report, we focus on maximizing the effectiveness of OGI surveys.

Regulatory Element	Description	Best-in-Class Guidelines	Jurisdiction with Precedent
Repair time	How long the operator has between the detection of a leak and when the leak must be repaired.	Initial repair attempts for detected leaks must be completed within five days. For "critical components" where a repair requires a full process shutdown, operators must minimize the leak immediately and finalize the repair during the next scheduled maintenance window or within one year.	California, Nigeria,[16] EU[17]
Re-survey	A second survey to ensure that the leak was successfully repaired.	Repaired or replaced components must be re-inspected within 15 days of the repair. This verification ensures that the leak has been successfully repaired.	U.S., Nigeria,[18] EU[19]
Plan/Program	Requirements for operators to make and submit plans for how they will carry out the LDAR requirements.	Regulations should require operators to develop and submit a company- or business unit-wide LDAR plan, detailing how it will meet requirements, including the required number of surveys per facility, the technology it plans to use, repair protocols, and training for staff. Operators should also prepare site-level plans to document issues at any site that will deviate from the company- or business unit-wide plan. By comparing these plans to the LDAR reports submitted, the regulator can more quickly and efficiently evaluate company compliance (see Section 5).	U.S., EU[20]
Record-keeping	Requirement for the operator to retain records of leak surveys and leaks detected and repaired.	Operators must maintain detailed records documenting the results of surveys for a set period of time (5 years per U.S. EPA); identification of the number of leaks per component; dates of surveys, repairs, and re-re-surveys to verify the repairs; as well as a list of components that presented problems and monitoring plans for these components.	Colorado, Canada,[21] EU[22]
Reporting	Requirement for operators to submit reports to the regulator, which the regulator must review to verify compliance.	Annual reports must be submitted to the regulator with documentation of the total number of facilities inspected, the total number of surveys, the total number of leaks identified by component and facility type, the total number of leaks repaired, and the total number of leaks pending repair (see Section 5 for more detail on reporting requirements).	Colorado, Nigeria,[23] EU[24]

In addition to the regulator components above, regulators can approve the use of alternative technologies and survey frequencies (or adopt approved lists from other jurisdictions), provided the operator demonstrates that the technology meets or exceeds the emissions reduction associated with OGI. For example, under the updated Clean Air Act Section 111 standards ("OOOOb/c"), the U.S. EPA introduced a hybrid compliance framework that allows operators to use alternative screening methods. This approach combines aerial or site-level surveys with ground-based methods to provide flexibility and enhance detection efficiency.[25] In this program, sites that are subjected to quarterly OGI surveys may opt for alternative periodic screening approaches using approved remote sensing technologies, as shown in Table 2. Even in the case where remote sensing technologies are used, OGI is often essential to pinpoint specific leaking components, to follow-up to ensure repair was effective, and to ensure process safety and efficiency.

Table 2: Minimum Detection Threshold of Screening Technologies Set by U.S. EPA[26]

Minimum screening frequency	Minimum detection threshold of screening technology* (kg/hr)
Quarterly	≤1
Bimonthly	≤2
Bimonthly + Annual OGI	≤10
Monthly	≤5
Monthly + Annual OGI	≤15

**Based on a probability of detection of 90%*

A comparable but more prescriptive approach is observed in the European Union under the European Methane Regulation (EU) 2024/1787, which mandates comprehensive LDAR programs across all oil and gas operations. Operators are required to conduct regular surveys using Best Available Techniques, adhere to defined detection thresholds, and repair identified leaks within strict timelines (typically within 5–15 days). The regulation also differentiates between survey types and survey frequencies, requiring systematic and recurring monitoring of all relevant components, thereby ensuring consistent detection sensitivity and rapid mitigation of emissions.

Box 1: Super-Emitter Programs

Programs designed to identify and repair super-emitter sources (i.e., very large emission sources typically greater than 100 kg/h) are complementary to, but distinct from, LDAR programs. Super-emitter programs rely on satellite, aerial, or other remote sensing measurement methods capable of detecting large emission sources. An LDAR program can sometimes detect these large emission events, but typical, ground-based LDAR surveys may miss a large, short-duration event that occurs between scheduled visits. On the other hand, depending on weather conditions (specifically clouds and fog) and topology of a region, satellites may be unable to consistently detect emission sources.

The use of satellites and other remote sensing tools for regulatory policy can be attractive due to the growing stream of publicly (and privately) available data from these sources. But the implementation of these programs through both regulatory policy and voluntary action is still in its infancy. Satellite detected methane plumes represent real and significant emission sources, and while some sleuthing can be required to find these leaks, addressing these emissions represents a significant opportunity to reduce pollution and decrease waste of valuable product. The Oil and Gas Climate Alliance published a "Satellite Methane Detection Response Playbook" to help operators better respond to satellite methane detections.

Super-emitter programs can be incorporated into broader methane regulations. For example, the state of California developed a Satellite Methane Project to provide data that is integrated into the oil and gas methane regulation.[27] The U.S. EPA finalized (but later paused) a super-emitter program. The U.S. EPA program included the following steps as finalized (compliance with the U.S. EPA Super Emitter Program is currently delayed until January 2027):[28]

- The U.S. EPA certifies third parties to use approved technologies to detect emissions.
- If the certified third party detects emissions above 100 kg/hr, it reports that detection to the U.S. EPA.
- The U.S. EPA evaluates the reported detection for accuracy and completeness of information and then notifies relevant operators.
- The operator must then begin an investigation within 5 days. The investigation includes:
    - reviewing maintenance activities, monitoring data from control devices, any fugitive surveys performed, and/or
    - screening of the entire facility with appropriate instrument (OGI, U.S. EPA Method 21, or approved alternative test method).
- The operator must respond to the U.S. EPA within 15 days with details of the emission source and confirmation of repair.

Box 1: Super-Emitter Programs, continued

The United Nations Environmental Programme's (UNEP) Methane Alert and Response System (MARS) can also be considered a super-emitter program, although in this case it is a voluntary program rather than a mandatory one. This program has 4 key steps:[29]

- Detect and Attribute: UNEP's International Methane Emissions Observatory (IMEO) uses data from satellites to detect very large emission sources and attributes to particular company or facility.
- Notify and Engage: UNEP notifies relevant governments and/or companies about large emissions events.
- Stakeholders Take Action: Governments and companies determine the best ways to respond and are encouraged to notify IMEO about actions taken to mitigate emissions.
- Track, Collaborate, and Learn: IMEO continues to monitor the area to ensure that emissions do not continue, and data is made publicly available.

It is important to clearly outline the goals of a super-emitter program and understand the limitation of instruments in different jurisdictions before attempting to design a new program. For instance, if half of a country's production is located onshore and the other half is located offshore, operators in the onshore production basins will be treated differently by this policy because many super-emitter remote sensing instruments struggle with detection of emissions offshore. The same limitations could be presented due to local weather conditions, like cloudy areas, and other geographic features, like mountains or jungles. For a more in-depth discussion on the considerations of the limitations of satellite instruments for use in regulatory policy, as well as other examples of jurisdictions that have developed regulatory policy, consult these two reports:

- EMBER and Clean Air Task Force "The geography factor: How environmental conditions shape methane monitoring from space"
- UC Berkeley "Hunting Methane Using Satellites: A Guide for Policymakers"

SECTION 2

Leak Detection Technologies

Methane detection technologies have been widely used in the past several decades by operators and regulators to manage operational risks (i.e., safety, operational control, emissions management) and better understand the emission profiles of various oil and gas equipment and facilities. These technologies range from satellites for global monitoring of large emission events to portable gas analyzers and OGI cameras for component-level detection, with their application depending on the user's specific goals and environmental parameters. Consequently, the integration of these technologies into a regulatory framework requires an understanding of their specific resolutions and operational constraints. This section includes a description of OGI technology, which serves as the primary LDAR implementation technology in this report. While we acknowledge the diverse range of available sensors and detection methods, a technical analysis of technologies other than handheld OGI for LDAR is out of the scope of this report.

An important consideration when leveraging technology solutions for LDAR is understanding the difference between levels of data gathering, which include detection, measurement, and quantification in addition to the frequency with which they can be deployed.[ii] Detection is the identification of the presence of methane gas without determining the size of the plume (e.g., a visual detection with an OGI camera) and is the foundational step in LDAR. Measurement involves determining the concentration of methane gas in a plume (e.g., parts per million) at specific points in space. Finally, quantification is the most complex step as it requires translating the gas concentration into an emission rate and determining the magnitude of the source. This involves calculating the total mass or volume of methane being released into the atmosphere over time typically expressed in units like kilograms per hour (kg/hr) or grams per hour (g/hr). Under U.S. EPA regulation, a concentration reading exceeding 500 ppm is defined as a leak and converted to flow rate (kg/hr) using correlation equations for quantification.[30]

Minimum Detection Limit (MDL) is another important metric to evaluate when creating a functional LDAR regulation that leverages multiple technologies, as it determines what is actionable (what the program can address) versus what is legally invisible (volume of emissions allowed to escape). MDL is not a static number; rather, it is a dynamic minimum threshold for a specific compound, derived from a sensor's Probability of Detection (POD) curve, which identifies the lowest possible quantity of the compound that can be reliably detected under varying environmental conditions, such as wind speed, humidity, etc. It is necessary to specify a POD when referencing detection limits for monitoring methods and technologies as lowest emission rate detected fluctuates under different field conditions; for example, U.S. EPA assesses technologies based on their ability to achieve a 90% POD.[31] A regulatory program that permits a technology with a limited detection resolution (like satellites) will naturally miss the myriad of smaller leaks that a device with a higher detection sensitivity (like portable gas analyzers and OGI cameras) would easily observe.

[ii] While often discussed together, Leak Detection and Repair (LDAR) and Monitoring and/or Measurement, Reporting and Verification (MRV or MMRV) serve distinct but complementary roles in methane management. MRV frameworks are designed to provide a more transparent account of a company's total methane emissions by reconciling top-down and bottom-up inventories. While MRV can help identify the scale of methane emissions from a facility and guide mitigation efforts, LDAR programs are critical for pinpointing the emission sources and triggering immediate repair leading to direct emissions reduction.

LDAR regulation usually mandates a higher sensitivity tool like OGI because the goal is to eliminate all detectable leaks, regardless of size. Conversely, if a regulation only requires a technology with a limited detection sensitivity, it creates a gap where emissions from many small sources go unaddressed because they individually fall below the sensor's detection limit and create a false impression of low emissions. However, in most cases there is a direct relationship between detection sensitivity of technologies and survey frequency: a technology with limited sensitivity can be deployed more frequently than a technology with a higher detection sensitivity. This is especially critical when implementing a tiered approach into a regulatory framework allowing the integration of alternative screening methods for LDAR. For example, lower sensitivity tools and methods allow for frequent, rapid screening to catch large emissions events, while higher sensitivity tools can be mandated for periodic surveys to find and repair many leaks caused by component degradation or mechanical issues.[32]

While the landscape of methane detection technologies has expanded in today's market, this report focuses exclusively on conducting LDAR with handheld OGI. Handheld OGI cameras remain the industry gold standard for LDAR programs because they offer the precision necessary to pinpoint emission sources required for repairs. Additional information regarding alternative technologies for LDAR is included in Appendix A for further reference.

Considerations for LDAR with OGI

This section examines the technical capabilities and performance characteristics of OGI to assess its effectiveness for LDAR. OGI is a mature, proven technology that has been used for more than a decade to detect and mitigate fugitive emissions from oil and gas operations (see Box 2). The U.S. EPA and other regulatory agencies have long relied on OGI monitoring for its proven ability to detect emissions from a wide range of equipment and its ability to pinpoint emission sources that can be prioritized for mitigation.[33] OGI also has important, but limited, ability to quantify emissions (see Box 3).

Box 2: OGI - How it Works

OGI detects methane by measuring the infrared radiation passing through a gas. Methane absorbs infrared energy in the 3.2 - 3.4 micrometer waveband. OGI cameras use a spectral filter and a cooled mid-wave infrared detector to visualize methane.

Successful OGI detection depends on four primary factors: the presence of a gas that absorbs infrared energy, a camera equipped with the correct spectral filter, plume movement, and thermal contrast (or delta T) between the gas and the background. When a methane or hydrocarbon plume is present, the camera absorbs the background infrared radiation, creating a thermal contrast that allows the user to see the otherwise invisible gas on the display. While these cameras have higher sensitivity and are capable of detecting leaks in the 1-4 grams per hour range with a delta T as low as 2 degrees Celsius, they are still sensitive to environmental interferences.[34] To ensure effective detection under varied field conditions, regulations like EPA OOOOb establish more conservative standards, mandating a minimum 6 degree-Celsius thermal contrast and a minimum detection limit of 19 grams per hour to account for environmental interferences like wind and low thermal contrast.[35]

The performance of OGI technology is highly dependent on the expertise of the operator and meteorological conditions like high wind speeds, dust, precipitation, or heavy fog which can rapidly disperse a plume or block the transmission of the infrared energy. Research has found that operators with significant field experience (e.g., more than 700 surveys) can detect up to twice as many leaks compared to those with less experience.[36] As such, the effectiveness of an LDAR program is highly sensitive to the quality and rigor of the survey. If OGI surveys are conducted poorly (examples of this are discussed in Section 3), the actual emissions reductions are lower. Most critically, substandard surveys risk missing large emission events that can often account for a large portion of a facility's emissions.[37] Consequently, any LDAR regulation or program with OGI must prioritize consistent and in-depth technician training by experienced, accredited instructors and periodic requirements for certification to ensure high accuracy of detection.[38] Furthermore, many regulators have begun addressing this gap between theoretical and actual emissions reductions caused by inconsistent survey quality by allowing hybrid approaches that incorporate alternative technologies.[39] These integrated programs that combine high-frequency screening with ground-level OGI may achieve emission reductions that match or exceed traditional standards that only allow handheld OGI.[40]

Figure 1: OGI Camera Example

Box 3: OGI and QOGI[41]

While OGI is primarily a qualitative detection tool, most models include quantification capabilities, providing modeling software allowing users to estimate the flow rate of the detected leak using multiple technical inputs based on field conditions. QOGI estimates are also influenced by gas composition, emission intermittency, and other assumptions embedded in the software model. While it can streamline data collection for regulatory reporting, this function is highly sensitive to environmental factors such as wind speed, imaging distance, thermal contrast (temperature difference between the gas and the background), cloud cover, and operator experience. Studies analyzing the effectiveness of (quantitative optical gas imaging) have reported that errors and uncertainty in individual emissions can be significantly high, in the +/-50% range. However, the uncertainty in measurements can be reduced to +/-18% by averaging multiple readings of the same emission source.[42] In practice, QOGI is generally considered a screening tool (e.g. to get a sense of a flow rate while considering a regulatory threshold) or estimation tool rather than a substitute for direct measurement methods, particularly for small or variable emissions.

Technology Complementarity

Recognizing that no single technology is universally applicable for the purposes of LDAR, effective regulation should allow operators to integrate various technologies, provided they follow technical guidance and meet established equivalency standards. A robust framework can offer technological optionality, which allows for the optimal tool to be determined by the specific asset being inspected. For example, aerial technologies are efficient at basin-wide surveys for detecting tank battery emissions. Meanwhile portable, ground-based technologies can be indispensable for indoor compressor stations or pipeline interfaces where aerial visibility is obstructed and for pinpointing specific leaking components. Regulators and operators can leverage these strengths by adopting hybrid LDAR programs which use a tiered approach similar to the EPA's compliance matrix referenced in the previous section. In this framework, high-frequency, site-level screening (such as satellite or aerial flyovers) is paired with targeted, on-site surveys with OGI or other handheld devices to efficiently and quickly find and repair different types of emissions. This tiered approach also allows operators to balance the expense of deploying different technologies against the potential economic recovery of captured gas while meeting regulatory requirements.

SECTION 3

Guidance for Planning and Implementing Effective LDAR Programs

The primary objective of an LDAR survey is to ensure that unintentional fugitive emissions are identified and mitigated in a manner that is both safe and effective. In addition, LDAR surveys should be conducted as part of regular site maintenance and can reveal other emissions sources like unlit flares and malfunctioning equipment. If LDAR is seen as a simple compliance "check-the-box" exercise to satisfy a regulatory requirement or to demonstrate nominal adherence to best practice, it risks overlooking systemic issues and recurring sources of emissions. In this section, we discuss the necessary elements to ensure that LDAR programs are implemented effectively to ensure maximum methane mitigation.

LDAR surveys are often discussed and evaluated primarily in terms of the instruments deployed or the methodologies applied. However, evidence shows that survey effectiveness is strongly influenced by the human element.[43] Experienced surveyors dynamically adapt their survey speed, inspect components from multiple viewpoints, and apply judgment-based adjustments that significantly improve leak detection rates. These adaptations allow the survey to make optimal use of detection equipment and to identify emissions that would otherwise remain undetected. OGI detections can be improved using advanced algorithms that enhance gas plume signals, but these cannot fully replace the need for a well-trained and experienced surveyor for LDAR.[44]

Building on this understanding, an LDAR survey should be considered a comprehensive early-warning check of a facility and its operational integrity.

Beyond identifying fugitive emissions, LDAR surveys provide an opportunity to observe operating practices, equipment condition, and deviations from expected or safe configurations. While OGI equipment is central to detecting emissions, it is not the only tool required for an effective survey. Audio, Visual, and Olfactory (AVO) inspections, supported by the use of intrinsically safe digital cameras and tablets/phones (for data-input), are essential for documenting signs of damage, malfunction, or improper operation (e.g., missing bolts, open hatches, misaligned components) and are key for rapid and necessary repairs. These observations often provide critical context for emissions detected by OGI and may reveal underlying causes that require corrective action.

Conducting the Field Survey: Step-by-Step Process

The following steps outline a structured workflow for conducting an LDAR field survey using OGI. These steps are based on best practices drawn from EPA's Appendix K,[45] EPA's Guidance for Conducting LDAR Surveys,[46] CATF's experience performing OGI field surveys[47] and other reputable sources for LDAR development and implementation. While the exact order and details of the workflow may vary depending on facility type, regulatory jurisdiction, and site conditions, the sequence below reflects the foundational components of an effective LDAR field survey.

Step 1: Survey planning

Proper survey planning ensures that operators and team members understand survey requirements, including scope, methodology, frequency, and conditions, so they have the necessary equipment and safety information to perform their work effectively. As noted in Section 1, a strong regulatory framework should require companies to develop and submit company- or business unit-wide plans for LDAR surveys and site-level plans to describe specifics of the LDAR plan at a particular site. Thus, during this Survey Planning step, the site operator should refer to those plans.

1. **Clearly define team roles and responsibilities.** Effective LDAR surveys require multiple team members with distinct expertise working in coordination. Clearly defining roles and responsibilities prior to the survey is critical for improving survey quality and field safety. Key roles include:

    - **LDAR surveyor:** Personnel trained and certified by an accredited center or third-party contractors responsible for operating the OGI equipment and conducting the survey (i.e. a certified thermographer). Surveyors follow established protocols and best practices, including examining components from multiple viewpoints, adjusting survey speed (or dwell time) and distance, and applying professional judgment to maximize detection probability.

    - **On-site personnel:** Facility operators and technicians with detailed knowledge of processes, equipment, and current operating conditions. They provide essential context to interpret detected emissions and, in turn, benefit from near real-time feedback on the condition of the assets they operate.

    - **Compliance manager:** Personnel responsible for understanding applicable regulations, internal requirements, and reporting obligations. They ensure that survey results are documented appropriately, integrated into compliance workflows, and translated into actionable mitigation plans.

    The LDAR survey team should consist of at least two people: an LDAR surveyor equipped with an OGI camera and on-site personnel supporting the activity by tagging leaks, updating leak reports, etc. Effective LDAR surveys require a foundation of mutual trust and transparency between the LDAR surveyor and on-site personnel to ensure OGI inspections are comprehensive and objective.

2. **Review company- or business-wide LDAR plan.** All survey team members should review this overarching framework to identify all regulated components and confirm monitoring frequency and methodology to perform the survey. The plan should have been developed prior to the opening meeting described below in accordance with LDAR regulations.

3. **Conduct an opening meeting to review the site-specific LDAR plan.** All team members should attend an opening conference prior to the survey. The key elements of the conference include:

    - **Review site coverage approach.** Route maps are a common method for ensuring comprehensive site coverage. A route map consists of a visual plan of the path the LDAR survey team will follow through the facility to ensure that every required component is inspected. This route map can be created in accordance with the site layout by reviewing appropriate facility and process diagrams. Figure 2 below is an illustrated and simplified example of a survey route map with path to follow ensuring every component is viewed from multiple angles while preventing the survey from missing blind spots in the facility. Operators should confirm that the map matches the actual site layout and note discrepancies. Alternatively, visual cues (e.g., equipment tags, markers, or process diagrams), satellite imagery, or flow charts may be used to plan the optimal and comprehensive survey path. In addition to the site map and visual cues, the survey team should discuss which areas of the site might be on stand-by, under maintenance, or depressurized at the time of the survey.

    - **Review equipment checklist.** An equipment checklist should be prepared and verified in advance. At a minimum, this should include the primary leak detection instrument (the OGI camera), complementary VOC detection devices such as flame ionization or photoionization detectors (optional), and a digital camera for documentation. The survey team should also review and follow site protocols when using equipment within classified hazardous areas. This may require OGI cameras to be either certified as intrinsically safe or authorized for use under a Hot Work Permit, ensuring that combustible gas concentrations are monitored and remain below explosive limits during the operation of the device. Each participant must also be equipped with appropriate personal protective equipment (PPE), including hard hats, personal gas monitors, steel-toed boots, fire-resistant clothing, etc.

- **Conduct daily camera verification check.**[48] At minimum, this includes:
    - Confirm the OGI camera software loads successfully without error messages, batteries (primary and spare) are charged, and there is sufficient memory storage space and/or spare SD card
    - Verify the camera can focus properly at both the shortest and longest distances expected during the survey
    - Demonstrate that the camera produces a live IR image using a known emissions source
    - Confirm the camera's delta-T (i.e., the difference in temperature between the process gas being emitted and surrounding background.)
    - Check all functions/modes operate correctly when they will be used

- **Review safety considerations.** Operators must be briefed on site-specific hazards, PPE requirements, camera and equipment safety, fatigue (i.e., eye strain and fatigue, as well as physical and mental fatigue),[49] break schedules, and emergency procedures.

  While this report identifies common hazards, it does not provide an exhaustive safety manual and should not replace site-specific safety protocols or mandatory regulatory requirements. Operators must perform their own comprehensive risk assessments to ensure the safety of personnel during detection and repair activities.

- **Check weather and operating conditions.** Weather and environmental conditions have a significant impact on the effectiveness of OGI. Favorable OGI survey conditions are highly dependent on regional climate and local weather, so the surveyor must assess the environmental variables (e.g., wind speed, ambient temperature) to ensure the regulatory detection limit is maintained.[iii] The weather conditions that are favorable or unfavorable to an OGI survey will be different in different geographies, and the LDAR Surveyor should evaluate weather conditions based on this geographic-specific understanding. To ensure conditions remain acceptable for survey effectiveness, there should be procedures for monitoring and documenting weather conditions at least once every two hours while on site.

- **Leverage satellite data.** When available, operators and regulators should review historical satellite data for the site to identify heightened methane concentrations or "super-emitter" detections in the area. Satellite data may be publicly available but not within a company's existing records, so an additional check for available external data is warranted.

[iii] Conducting LDAR surveys on offshore facilities require specialized site-specific and area-specific protocols to manage complex infrastructure, challenging logistics, and weather conditions. Given the additional constraints of offshore platforms, operators and regulators should begin planning months in advance to meet necessary regulatory and company-specific requirements.

Figure 2: Illustrated Examples of Route Maps

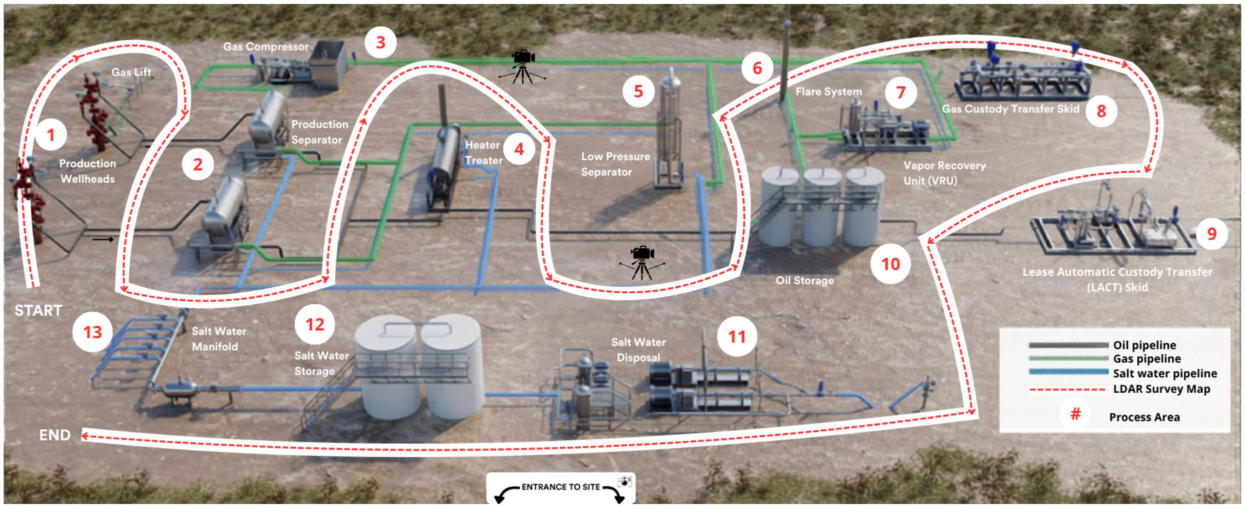


Figure 2a

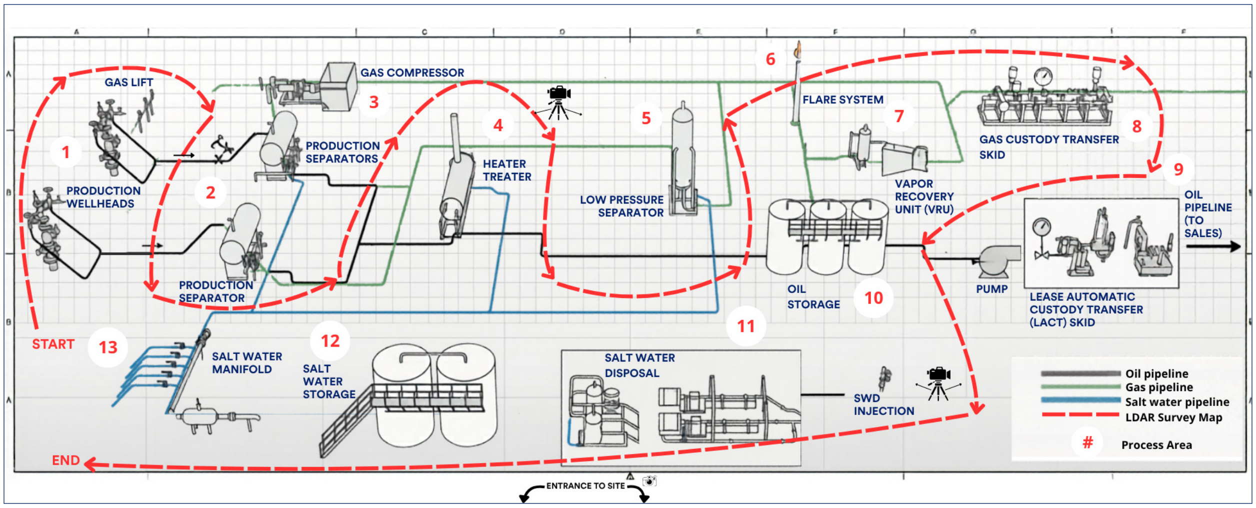


Figure 2b

The route map examples shown above use both a 3D site rendering (Figure 2a) and a technical line diagram (Figure 2b) to clearly illustrate the survey path for a comprehensive LDAR inspection and observation of all process areas at a well pad. By demarcating oil, water, and gas pipelines as well as labeling equipment and process areas, the map can be used to inform the surveyor of the facility's layout. It can also allow operators to identify high-risk zones or construction areas that require more safety considerations. When conducting the inspection, the surveyor should begin at the designated starting point, entrance to the site, or at high-pressure inlets and follow the indicated arrows, stopping at every process area (marked on the map or every 1-2 meters) to examine components for leaks. Each component should be examined from at least two angles while following the survey path. The survey is complete once all components shown on the route map have been examined and the surveyor returns to the site entrance or designated end location.

Image Source: https://gaso.com/blog/reducing-methane-emissions-in-upstream-oil-and-gas-processes

Survey Planning: Common Pitfalls and How to Avoid Them

- **Lack of trained personnel or on-site personnel.** Survey quality drops significantly when surveyors have not received formal OGI training or lack substantial field experience. It is critical that surveyors complete a training program from an accredited center or instructor that includes classroom lectures and field experience on OGI camera and other technologies, monitoring techniques, best practices, and regulatory requirements related to leak detection.[50] Typically, a senior OGI camera operator has 1,400 survey hours over the entirety of their career, including at least 40 survey hours in the last 12 months.[51] Research has shown that detection performance increases markedly among surveyors who have completed more than 551 surveys.[52]

- **Insufficient understanding of the capabilities and limitations of the selected detection technology.** In many LDAR programs, only a single detection technology may be available or permitted. In these cases, it is essential for operators to fully understand the attributes, strengths, and limitations of the technology they are using (see Section 2 for more information). Failure to recognize these aspects can lead to missed leaks, misinterpretation of results, or false confidence in the survey's completeness.

- **Incomplete desktop study to comprehensively identify and categorize all the components and potential emission sources.** Route maps, site maps, process flow diagrams (PFDs), heat and materials balances, and piping and instrumentation diagrams (P&ID) must be used to create an inventory of all potential emission sources prior to the survey during the planning phase and how to survey them. Using these technical documents will avoid oversimplifying the site's complexity and lower the chances of components being missed, particularly when piping overlaps, equipment is stacked, or process connections are not visually obvious. These documents (i.e., route maps and P&IDs) should be annotated during the LDAR survey to indicate where leaks were detected.

- **Lack of historical data management.** If historical LDAR survey data is stored in a way that is not easily accessible for future survey planning and trend analysis, it becomes difficult to track the overall condition of a facility over time and identify components that fail repeatedly after being repaired. A centralized digital library, with historical OGI video snippets, survey notes, can be a helpful reference to review when planning for the next survey.

Step 2: Facility entry and site verification

Facility entry and site verification ensures the LDAR team begins the survey safely, efficiently, and under conditions that support reliable emissions detection. At the entrance of the facility, the team should:

1. **Record arrival information.** Key things to record include:[53]
   - Facility name
   - Date
   - Time of arrival
   - Weather conditions, including ambient temperature, wind speed, relative humidity, and sky conditions. For surveys that take over four hours, operators should record weather conditions every two hours.[54] Review the wind direction using the windsock on-site (if any) and refer to it to identify down and upwind locations, and most suitable screening vantage points.

2. **Take a digital photograph of the facility entrance** to confirm correct site identification and ensure accurate attribution.

3. **Review and validate facility boundaries.** Conduct a high-level review of the facility boundaries and verify consistency with the LDAR route map. Facility limits are typically defined by physical markers such as fencelines or bund walls. In the absence of clearly defined boundaries, the survey scope shall include:
   - The main operational areas of the facility (e.g., wellheads, processing units).
   - All connected above-ground lines and equipment up to the point where pipelines go underground (e.g., gathering lines).
   - Any discrepancies between the actual site layout and the LDAR route map should be noted.
   - Quick OGI scan of the facility boundary to note any large methane plumes for safety considerations.

Facility Entry and Site Verification: Common Pitfalls and How to Avoid Them

- **Lack of prior authorization from facility operators for LDAR survey.** Facilities may require formal access procedures, including site-specific orientation or work permit requests, before inspecting certain operational areas. Engaging with facility management in advance can help ensure that operational schedules do not conflict with survey activities.

- **Inconsistent tagging protocol or insufficient tags.** Having physical weatherproof, high-visibility tags with unique identification numbers can make repair or maintenance later much more efficient. LDAR surveys may also often expose leaks that require following formal lockout/tagout procedures to safely de-energize equipment for repair. The lack of proper tagging protocol leads to significant delays, repeat surveys, and potential regulatory non-compliance. Thus, the LDAR survey team should ensure that they have a large enough supply of tags before beginning component examination.

Step 3: Component examination

This step involves inspecting each regulated emission source thoroughly using OGI. It ensures that each component is observed under conditions that support effective detection, with sufficient time and appropriate technique to meet regulatory expectations for survey quality. For each potential emission source, operators should:

1. **Observe components from at least two different angles** to improve plume visibility and contrast using a tripod for stability or telescopic lens for better visualization.[55] The initial screening of components can be performed using regular or enhanced mode (called High Sensitivity Mode in some camera models). Enhanced mode, if available in the selected OGI camera, is useful to highlight movement in low-contrast environments. Figure 3 shows the difference between normal and enhanced modes. The enhanced mode increases the sensitivity of the camera by comparing consecutive frames in real-time and subtracting the static background, highlighting only the pixels that are changing, which may be the movement of a gas plume. When using these background subtraction enhancement features, sufficient stabilization using a tripod is required for accurate detection and visibility of emissions. Both normal and enhanced modes are useful to understand the scene and sources of emissions.

Figure 3: Difference Between Normal and Enhanced Operating Modes for an OGI Camera

A. **B.** **C.**

A is a normal photograph of the component. B is the same component filmed in normal mode (OGI camera), and C is the same component recorded in enhanced mode with visible gas plume.

2. **Spend sufficient time observing each scene.** Avoid quick scans and ensure survey speed is appropriate for the scene. Survey speed refers to the dwell time required by EPA Appendix K, which specifies the minimum amount of time an operator must observe each potential leak source to ensure effective detection. EPA mandates a minimum dwell time of 2 seconds per component in the OGI camera's field of view for each angle.[56] Thus, the time spent observing each scene is dependent on the number of components in the field of view:

   - **For a simple scene** that contains 10 or fewer components in the field of view, the operator should spend 15-20 seconds per scene (or 2 seconds per component based on U.S. EPA requirements) before changing the angle, distance, or focus.[57]

   - **For more complex or congested scenes** with over 10 components in the field of view, the operator should divide the scene into manageable subsections, reduce the distance, or change the angles to reduce the number of components in the field of view. Operators should spend at least 2 seconds per component in the field of view for each angle and allocate more time per component based on site configuration and additional difficulties (e.g., reflective material for insulation making the survey challenging or long weeds partially obscuring the scene).[58]

     If there are environmental factors that interfere with component examination (e.g., wind speed, humidity, refraction due to heat, pollen, flying insects, etc.), adjusting the viewing distance is a way to simplify the scene and make it easier to analyze.

   - **Operators must restart the observation time** every time they change the OGI camera operating modes or viewing angles.[59]

3. **Spend more time observing components as needed.** Additional time may be needed to assess whether each component is leaking or not leaking. OGI operators should apply their training and knowledge to make judgments on whether increasing the observation time is necessary in order to distinguish between methane plumes, heat, water vapor, or other releases of gasses with a high delta T.[60]

In this step, the survey team must perform audio, visual, and olfactory (AVO) inspections to identify potential safety hazards that require immediate adherence to safety protocols. For example, in midstream and downstream gas facilities, where gas is intentionally odorized for leak detection, if the survey team smell gas, it should be treated as a possible safety concern and survey the area with a gas monitor to verify gas concentrations remain below safety limits.

Component Examination: Common Pitfalls and How to Avoid Them

- **Dispersed gas plumes because of changing or high wind speed.** Wind speed is one of the most critical factors during component surveys. As wind increases, gas plumes disperse more quickly, making leaks harder to see and easier to miss. For this reason, OGI surveys should only be conducted within a defined maximum wind speed. If winds exceed this limit, the survey may need to be postponed or conducted at a shorter viewing distance to maintain detection sensitivity. In addition to wind, several other environmental factors can interfere with an operator's ability to visualize gas leaks:

  - Steam, fog, mist, or rain undermines detection and visualization
    - Conducting LDAR with OGI at LNG facilities can present similar technical challenges, as the extremely low temperature of the gas leaks often causes local water condensation. This atmospheric moisture can obscure or distort the infrared plume visualization, making it difficult for the thermographer to accurately distinguish between methane and cryogenic fog.
  - Solar glare or reflections, which can mask or distort gas plumes
  - High levels of dust or particulate matter in the air
  - Hot or cluttered backgrounds, which reduce contrast and make leaks harder to distinguish

  Adjustments must be made if the conditions fall outside the acceptable limits for a survey. This may include reducing the distance between the camera and the equipment being inspected or delaying the survey until conditions improve. The viewing distance for each survey day should be documented.

Component Examination: Common Pitfalls and How to Avoid Them, continued

- **Inadequate surveying of components in close proximity.** Components located near a documented emission source may not be properly surveyed due to plume interference, which can obscure detection. A common mitigation approach is to stabilize the camera (e.g., using a tripod) and adjust viewing angles to ensure all potential sources within the scene are adequately assessed.

- **Failure to properly manage safety risks when identifying severely degraded components or high-risk emission.** If operators do encounter this, they should:

  - Follow established safety protocols immediately
  - Notify on-site personnel without delay
  - Suspend survey activities in the affected area to ensure personnel safety

- **Operator fatigue (i.e., eye strain and fatigue as well as physical and mental fatigue) during surveys.** Failure to plan for regular breaks can decrease survey quality and reduce operator effectiveness to detect leaks. The U.S. EPA's Appendix K recommends that:[61]

  - The operator does not survey continuously for a period of more than 30 minutes without taking a break of at least 5 minutes
  - During the 5-minute break, operators can do other survey tasks, like documentation, so long as they are not actively imaging components

  Two camera operators are recommended if surveying continuously for 30 minutes is desired.

Step 4: Leak identification and documentation

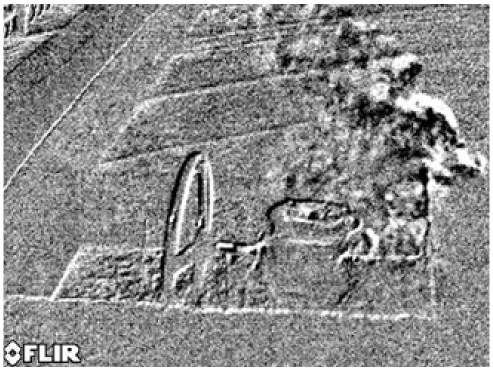
Once a leak is identified during component examination, the operator must clearly document it. This step ensures that leaks are consistently recorded with sufficient visual evidence and contextual information to enable effective repair and follow-up. While quantification can be helpful to prioritize mitigation, the primary objective of any robust program is reliable detection and timely repair of leaks, which can be accomplished with or without quantification (see Box 4). Operators should.[62]

1. **Record the leak using the OGI camera in thermal imaging mode.** The recording should last at least 10 seconds and clearly show the leaking component, the gas plume, and sufficient context to confirm the source of the emissions. See Figure 4 as an example of a leak recorded using an OGI camera versus a regular camera.

Figure 4: Methane Emissions Detected From a Valve

A.

B.



A shows a valve with a regular camera the emissions; B shows the same valve using an OGI camera.

2. **Take a digital photograph or a short video clip of the leaking component** to document equipment condition and provide visual context. Some OGI cameras are equipped with both infrared (thermal) and visual (visible light) recording capabilities. When a leak is observed, surveyors should capture thermal and digital footage to enable maintenance teams to precisely identify leaking components within complex infrastructure.

3. **(Optional) Conduct measurements for leak quantification** (see Box 4).

4. **Log the leak in the survey record.** The date, time, location of the leak, and identification of the component associated with the leak (including a unique identification number for the leaking component) must be recorded. The minimal content of this survey record may be defined by the regulation in the given jurisdiction (see Section 5), but the operator may keep more detailed records for their own operational purposes. The unique identification number for the leaking component is essential to track patterns of leaking components over time, particularly to determine whether leaks are reoccurring at previously repaired components (and thus whether a more robust repair is required).

   To help identify the root cause of the leaks, operators should record supplemental information such as operating conditions, visible damage, abnormal sounds or vibrations. See Table 2 for examples of emission sources that are commonly identified during an LDAR survey.

   Refer to the **Typology of Common Leak Types and Repair Considerations** for more information on the type of leaks and potential root causes.

Table 2: Commonly Identified Emission Sources During an LDAR Survey

Emission Sources	Examples
Valves	Valve stem packing
Actuated devices	Actuator diaphragm leaks
Flanges and bolted connections	Bolt corrosion leaks, blind flange leaks
Threaded and mechanical fittings	Instrument connection leaks, gauge fitting leaks
Seals, packing, and dynamic interfaces	Pump shaft seal leaks, rod packing leaks, compressor seal leaks
Tanks, storage equipment, and pits	Thief hatch seal leak, tank roof or structure-related leaks
Pressure relief and safety devices	Pressure relief valve (PRV) leaks, PRV discharge piping leaks, emergency shutdown system leaks
Process piping and structural components	Pipe wall or equipment corrosion leaks, weld seam leaks, elbow leaks, expansion joints or flexible connector leaks
Instrumentation and controls	Sample line leaks, control panel leaks
Emission control equipment	Vapor recovery unit leaks, combustor or flare header leaks, knockout drum leaks
Openings, vents, and intermittent sources	Open-ended line leaks, manual vent valve leaks, blowdown valve leaks, wellhead casing leaks, emissions from pits holding waste extraction fluids

In addition to these leak sources, the LDAR survey should also include venting and/or potentially unlit and poorly combusting flaring stacks that may result in excessive emissions. It is important to note that flares and other combustion stacks as well as the pilot system must still be regularly tested to ensure they meet regulatory and international best standards for pollution control. While the main target of LDAR is, by definition, leaks, finding and remediating these venting and flaring sources should be treated as a key element to effective LDAR. For example, the LDAR surveyor may discover a piece of equipment that is malfunctioning and venting more than designed, prompting the site operator to investigate and, if necessary, plan appropriate remediation. The LDAR surveyor should also view the flare stack to determine whether the flare is operating properly. It should note whether the flare is 1) lit and appearing to combust efficiently, 2) lit but with clear poor combustion and residual unburnt methane trailing, or 3) unlit. In these cases of venting or flaring observations, it is best practice to document the suspected excess venting and report it to the regulator if required. See Section 5 for an example of how operators can report these venting and flaring emissions detected during an LDAR survey.

5. **Identify and document the suspected root cause of the emissions.**

6. **Physically tag the leaking component**, where accessible and safe. This can help repair crews locate the leak and prevent omissions. Figure 5 shows an example of a physically tagged leaking component.

Figure 5: LDAR Survey Tag Example[63]

Leak Identification and Documentation: Common Pitfalls and How to Avoid Them

- **Mischaracterization of leaks or incorrect root-cause identification.** Poor investigation practices can result in misclassification of a leak or misidentification of its root cause. This can lead to ineffective or unnecessary repairs. See the **Typology of Common Leak Types and Repair Considerations** section for more details on the types of leaks, causes, and possible solutions.

- **Rushing the documentation process during a survey.** Rushing can cause surveyors to overlook leak sources, especially after detecting a larger emission downstream. Surveyors must backtrack to previously documented positions to verify that no components were missed before identifying the dominant source.

- **Poor or nonexistent data management systems.** A dedicated LDAR management software enables more robust data handling, data integrity, traceability, and long-term usability. However, in many jurisdictions this software is not available, so at the very least, operators must use a standard template spreadsheet to document sufficient information about the detected leak to ensure information is communicated to appropriate personnel (compliance managers, repair teams, etc.) and submitted as part of annual reports to regulators (see Section 5 for more details on the regulatory reporting process).

Leak Identification and Documentation: Common Pitfalls and How to Avoid Them, continued

- **Improper evaluation of malfunctioning designed-to-vent equipment.** Certain components, such as pneumatic controllers and pressure relief devices, are often engineered to release gas as part of their normal function. While some regulations, like the European Methane Regulation, phase out designed-to-vent equipment in oil and gas facilities, many other regions still allow these devices. Therefore, it is important for surveyors to understand whether a release of gas is part of normal operations or is the result of a malfunction that could impact personnel and process safety. In both cases, the surveyor must document the emissions in the log. This documentation allows the operating or engineering team to conduct a root cause analysis to determine if the emissions are in fact normal or if the equipment is venting excessively and requires mitigation. If the surveyor fails to document such cases, it may result in prolonged and unnecessary emissions.

- **Not tagging leaks that have been immediately repaired.** When a leak is detected and repaired during the same site visit, operators should still tag and report the leak so that the component can be re-surveyed to confirm that the repair is successful. For more information about immediate repairs, see **Step 7: Repair.**

Box 4: Leak Quantification with QOGI

While accurate emission rate quantification is not an essential part of LDAR, it can support post-repair verification and regulatory compliance. The following steps can help reduce uncertainties in QOGI modeled estimates and inaccurate reporting.

1. Once a leak is identified, stabilize the camera using a tripod while pointing at the plume to stabilize camera and reduce noise into the quantification software.
2. Document or manually input in the software current such as emission characteristics (e.g., color of emission plume (in Greyscale), distance to the target component, gas being measured (select methane for natural gas), type of leak (point or diffuse), and weather data (e.g., wind speed, ambient temperature, etc.).
3. Confirm that there is sufficient thermal contrast, delta T, between the gas and the background (typically > 2°C).
4. Record the plume in QOGI mode for 15-30 seconds to allow the software to analyze gas velocity over time.
5. Repeat the process from multiple perspectives to reduce background interference. Averaging the emission rates from different angles reduces variability introduced by wind speed and direction, providing a more accurate flow rate for the leak.

An important note is that QOGI software allows for both real-time quantification on-site and post-survey analysis of recorded thermal videos. QOGI is only one of several technologies available for quantifying flow rate of the detected leaks. Operators may use alternative tools, such as Hi-Flow Samplers, which provide volumetric measurements that can be more precise for certain components than the estimates derived from QOGI.

- **Quantifying leaks in high-wind environments.** Gas plumes can disperse or flattens too rapidly not allowing the gas to form a cloud in high-wind environments (typically > 9 m/s) making it difficult to accurately calculate the plume's volume or velocity. Since the quantification software relies on analyzing the physical size of the plume, high winds can result in high uncertainty in the leak rate.[64]

- **Having insufficient thermal contrast.** Attempting to quantify emissions during days with heavy overcast or when the gas temperature is identical to the background (uniform background or low delta T) causes the plume to become "invisible" to the software, which leads to high error margins.

- **Using incorrect distance measurements.** If the distance to the leaking component is estimated incorrectly, the software will miscalculate the volume of the gas. Using a laser rangefinder or similar measurement devices to input precise distances into the quantification software can improve estimate accuracy.

Step 5: Survey continuation

This step focuses on maintaining survey integrity as the team moves through the facility.

1. **After documenting a leak, resume the survey.** Ensure that residual gas plumes (i.e., lingering clouds of gas that can drift over to nearby components) do not interfere with detection of nearby components, as plume interference can lead to false positives. If plume interference occurs, adjust the survey angle, increase distance, or allow time for dispersion before continuing.

2. **For units where no emissions are detected** (e.g., wells, separator units), explicitly record "no emissions detected" in the log and the reason for no detections, e.g. no leaks identified, equipment or section not pressurized/not operating, etc.

Step 6: Post-survey verification

At the completion of the field survey and prior to the debrief:

1. **Verify that all components** listed in the LDAR route map have been surveyed.

2. **Confirm that additional potential emission sources** identified during the survey (e.g., decommissioned pipelines, newly installed equipment and lines not yet included in the LDAR program) have been inspected and documented.

3. **Review survey logs** and add any missing information.

4. **Record relevant observations,** including equipment or camera issues, environmental conditions, interferences, digital artifacts, other general site observations that may affect data interpretation.

Post-Survey Verification: Common Pitfalls and How to Avoid Them

- **Assuming no detection equates to no emissions.** The absence of detected leaks does not guarantee the absence of emissions. Safety protocols and operational rules must always be followed. LDAR activities do not replace or override established safety requirements.

Step 7: Repair

The repair step is the most critical phase of the LDAR cycle as it leads to successful mitigation. Effective repair strategies must balance immediate action with engineering best practices to ensure a quick fix does not inadvertently create greater safety risks. Strategies to address leaks can vary significantly based on the component's location and severity of the leak, ranging from simple mechanical adjustments to complex maintenance actions that may require specialized parts, scaffolding for difficult-to-reach areas, or a facility shutdown.

This report is not intended to prescribe specific repair procedures, tools, or methods and recognizes that repair methods must be determined by operators in accordance with site-specific conditions, safety protocols, and regulatory requirements.

It is important for repair planning to integrate OGI findings with operational knowledge, engineering standards, and site safety procedures. Depending on the characteristics of the leak, repair actions could include those listed in Table 3. Refer to Table 4 for more information on repair considerations for different types of leaks.

Table 3: Examples of Repair Actions

Repair Actions	Examples
Mechanical adjustment	Adjustments to restore sealing
Component replacement	Replacing worn, damaged, or degraded components like gaskets, seals, packing, fittings, or valves
Operational adjustment	Changing operating conditions (i.e., pressure, temperature) to reduce emissions or process routing changes
Shutdown-dependent repair	Depressurizing or isolating equipment or processes for repair during planned maintenance or turnarounds
Engineering evaluation	Repairs requiring design review, further testing, and material integrity assessment for structural or recurring leaks
Monitoring actions	Leaks or emissions that are tracked and monitored under applicable regulatory requirements and thresholds like emissions from pneumatic devices

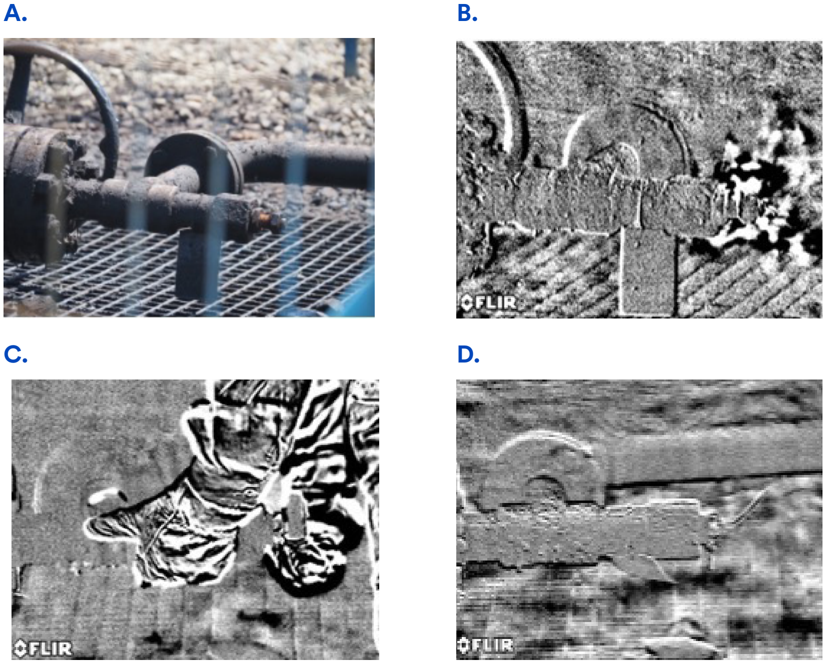
Repair timelines and procedures

There are three potential timelines for repair, which are discussed below: immediate, regularly scheduled, and deferred. In all cases, it is essential that the operator tags the repaired components to make the re-survey process (described in Step 8) efficient.

1. **Immediate field repairs.** If the site personnel performing the survey (or accompanying the surveyor) has relevant safety training and tools, minor leaks can be immediately repaired on-site. Immediate repairs must be documented and tagged for re-survey (see Step 4 for more information on leak documentation, and Step 8 for more information on re-survey). Common minor repairs include tightening a flange bolt or a threaded connection. However, if a 3rd party LDAR surveyor is conducting the survey, it may not be possible to attempt even these minor repairs immediately.

2. **Regularly scheduled repairs.** If surveyors lack the appropriate equipment or if safety conditions are not met, no repair should be attempted during the survey. Instead, the leak must be tagged and documented for repair and immediately communicated to appropriate facility operators so they can initiate risk assessment process and execution of repairs under controlled, safe conditions. Repair must be attempted and completed within the timelines set in the jurisdiction's regulations (e.g. within 5 days of detection) unless it is a critical component or unsafe to repair.

Figure 6: Methane Emissions Detected From a Loose Connection Seal (OGI) and Immediate Field Repair Performed



A shows a loose connection seal captured using a regular camera, where emissions are invisible; B shows the same connection seal captured using an OGI camera, where emissions are visible; C shows immediate repairs being performed; D shows emissions mitigated.

3. **Deferred repairs.** If the cause of the leaking component is structural (e.g., a cracked valve) or the leak persists after an initial repair attempt, it must be scheduled for a full repair. Some deferred repairs may require de-pressurizing or de-energizing equipment, which requires a temporary shutdown, potentially delaying the repair further. In such cases, the leaks must be documented and reported on the Delay of Repair (DOR) list with a technical explanation for why the repair is delayed and when it will be completed, provided it occurs within the next scheduled maintenance period. Such cases of deferred repair are typically allowed in regulations and described as "critical components" or "unsafe to repair" components. In cases where the operator determines that a leaking component falls into one of these categories, it must include this in its reporting to the regulator.[65] Immediate repairs for some types of leaks may not be possible if replacement parts or equipment are not stocked on-site. Planning for repairs, including procurement and labor scheduling, should begin as soon as the leak is identified to avoid unnecessary delays.

Repair: Common Pitfalls and How to Avoid Them

- **Attempting immediate repair under unsafe conditions.** A dangerous pitfall in an LDAR survey is the impulse to perform an immediate repair, or "first attempt", when operational conditions are unsafe for manual intervention. A first repair attempt should never be forced if the surveyor lacks the specific tools, PPE, or mechanical training required for the specific assets because an improper adjustment can turn a minor leak into an emergency incident.

- **Excessive delay in repair.** Leaks documented in the DOR list can persist for years if operators fail to initiate the procurement of parts immediately or fail to track the leak until the next facility shutdown. Leaks placed in the DOR list without a technical or engineering justification can result in unnecessarily prolonged emissions. Without a proactive plan to address deferred repairs, the DOR list becomes ineffective, stalling necessary mitigation efforts and undermining the integrity of the LDAR program.

Repair: Common Pitfalls and How to Avoid Them, continued

- **Failure to document initial repair attempts.** Regulators may require proof that a repair attempt was made within a specific timeframe.
- **Applying substandard repairs.** Using improper or non-rated bolts, tape, or makeshift collection systems (i.e., buckets collecting condensate from open-ended pipes) is not a repair. These types of actions, which are not in accordance with engineering best practices, can often increase safety risks.
- **Neglecting root cause analysis.** If the same component (e.g., flange) leaks every month, simply tightening is not sufficient as a repair attempt. The operators should examine the issue further for vibration issues, thermal expansion, or improper gasket installation.
- **Removing a tag immediately after a repair is completed.** Tags should remain on a repaired component until after a re-survey to ensure that the re-survey team can quickly and efficiently find the correct component to confirm successful repair.

Steps 1-6 should be repeated until they have surveyed the entire facility (or the agreed-upon section of the facility).

Step 8: Re-survey to confirm repair

Leaking components should be re-surveyed within 15 days of their repair or according to applicable regulatory compliance requirements. A re-survey of components using the same method and protocols as the original survey is important to verify the effectiveness of corrective actions and ensure any emissions sources have been successfully mitigated.

Re-Survey and Confirm Repair: Common Pitfalls and How to Avoid Them

- **Inadequate tracking of repairs and follow-up actions.** Effective LDAR programs require systematic tracking of repairs, re-surveys, and verification of repairs. Proper data management also allows for cross-survey and cross-asset comparisons, which support performance benchmarking.
- **Inadequate re-survey of the component/equipment.** After a repair is completed, the exact location of the emission source may shift to a different area of the component. The re-survey method must include multiple viewing angles to verify that the leak has not migrated to another part of the component. Failure to perform a thorough re-survey may result in undetected emissions.

Step 9: Data review and reporting

Within a few days of the initial survey:

1. **Review all collected survey data**, including OGI footage, digital photographs, and field observations.
2. **Consolidate and reconcile findings** into a single, comprehensive LDAR report in accordance with program or regulatory requirements. See **Considerations for Reporting and Evaluation** for more information on reporting considerations and templates.
3. **Ensure the same team that conducted the survey reviews and validates the data** for consistency and accurate interpretation.

SECTION 4

Typology of Common Leak Types and Repair Considerations

LDAR programs cover all emissions caused by the loss of gas, excluding normal operational emissions or safe emergency disposal. Leakages can happen from the tubing, valves, connections, flanges, open-ended lines, storage tanks, and other process and operation components.

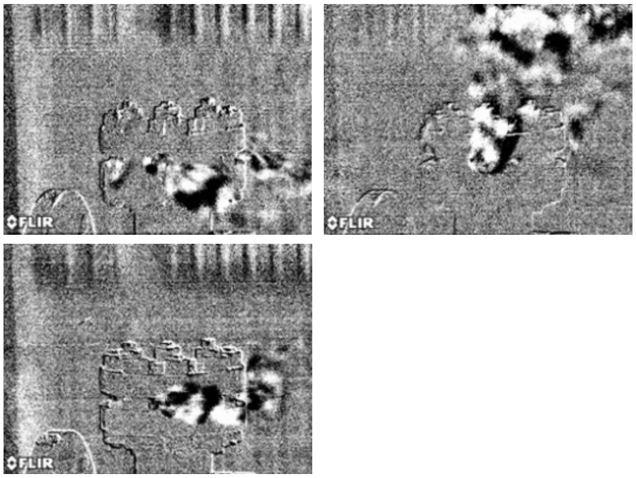
Some emissions are directly linked to operational practices, such as missed protocol steps, poor procedures, or temporary modifications that compromise equipment integrity (e.g., a thief hatch that was left open or a gauge that was unscrewed for inspection and not properly re-sealed). In these cases, the loss of gas containment results from human error or oversight. Conversely, emissions can also occur independently of operational practices, arising from normal equipment degradation such as corrosion, seal failure, or general wear and tear such as a corroded thief hatch emitting due to material failure. Distinguishing between these categories of leaks is important for targeting corrective actions and understanding that not all leaks are the result of faulty components. Implementing an LDAR program improves operational practices by detecting emissions early, minimizing product loss, as well as health, climate, and process safety risks.

A shared and consistent understanding of emission and leak types is essential for the effective implementation of LDAR programs. In this section, we first define a few key terms that are used to describe leaks, then we present a typology of common leaks that can be used by operators and regulators, and finally we discuss additional important considerations. This shared understanding of leaks—in terms of what they look like in the field, the types of equipment they are coming from, their root causes, and potential repairs—is critical to allow productive communication between regulators and operators throughout the regulatory process.

Figure 7: Methane Emissions Detected From a Loose Connection Seal (OGI)

A.

B.



A shows a loose bolted connection captured using a regular camera, where emissions are invisible; B shows the same connection captured using an OGI camera, where emissions are visible.

Leak Typology

Developing an effective LDAR regulation and program requires a deeper understanding of why and where emissions occur, including common emission sources and facility characteristics or process conditions that contribute to fugitive emissions.

A key challenge lies in the fact that emissions are not interpreted uniformly across stakeholders. The definition of what constitutes a "leak" can vary depending on operational, safety, or regulatory perspectives. For example:

- An open thief hatch on a storage tank may not be considered a leak by on-site operators, as it may be used to bypass vapor control systems to reduce the accumulation of VOCs and methane in the tank headspace to facilitate manual gauging of the tank by the next technician. This practice compromises the integrity of the primary containment system required to control hazardous VOCs and methane and poses safety risks. From an on-site process perspective, this source would typically be classified as venting. However, during an LDAR survey or an inspection by a regulator, the same open hatch may be categorized as a leak per regulatory classification or engineering standards, triggering follow-up requirements.

- A compressor stack venting depressurized gas may be viewed as venting-by-design from a compliance standpoint, whereas on-site personnel are often best positioned to determine whether the emission is the result of normal operation or a malfunction requiring corrective action.

These examples illustrate that emission source classification depends not only on physical observations but also on operational context and intent. The emissions should be investigated to understand the root cause beyond just the identification of the faulty equipment. Similarly, if emissions are detected at multiple LDAR surveys, a thorough investigation should be conducted.

Many fugitive emission sources are straightforward, and the root cause can be identified within a few moments of detection. For instance, holes in tight storage vessels, corroded pipelines, and missing components can lead to immediate characterization and reporting.

As a result, the classification of emission sources is critical to accurately identify emissions, determine their regulatory status, and implement effective mitigation measures. Numerous terms are used to describe emission sources and root causes, with many categories partially overlapping.

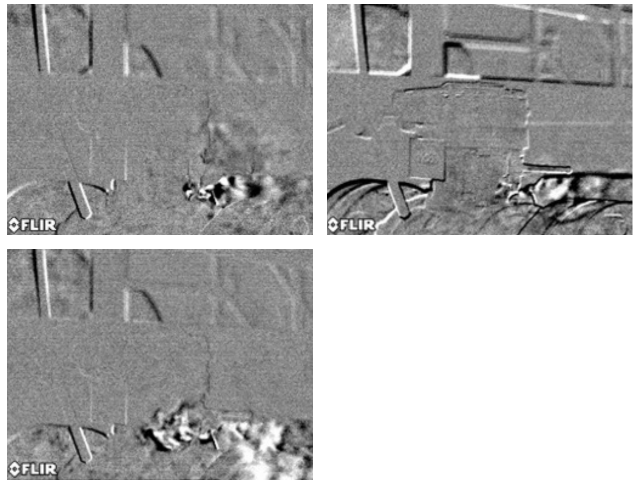
Spatial characteristics

- **Point source:** Emissions are localized and stationary, with the origin of the emission easily identifiable (e.g., storage tank vent) (Figure 8).
- **Diffuse source:** Emissions are spread out over an area, making it difficult to pinpoint a single localized source (e.g., wastewater pond) (Figure 9).

Figure 8: Example of Point Source – Methane Emissions Detected From a Poorly Sealed Manual Vent (OGI)

A.

B.

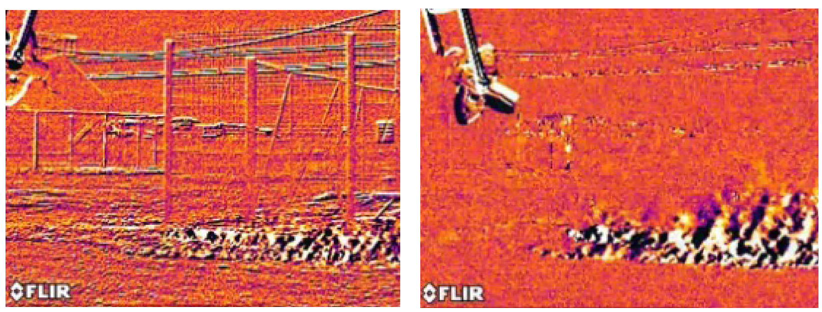


A is a photograph of the manual vent with a regular camera, where emissions are invisible to the human eye; B shows the same manual captured using an OGI camera, where emissions are visible.

Figure 9: Example of Diffuse-Source Emissions – Methane Emissions Detected From a Ruptured Gathering Line (OGI)

A.

B.



A shows the ground of the well pad with a regular camera, where emissions are invisible to the human eye; B shows emissions coming out of the ground using an OGI camera.[iv]

[iv] OGI technology can have limitations when used for detecting emissions from buried gas lines because it only detects gas after it escapes into the air, and underground leaks often don't reach the surface in sufficient concentrations. In addition, OGI relies on a visible contrast between a gas plume and a clear background; with buried leaks, any gas that does emerge is too diffuse and lacks a consistent background, making the plume difficult for an operator to distinguish reliably.

Temporal characteristics

- **Continuous:** Emissions are continuous and uninterrupted at a relatively steady rate over a 24-hour period (e.g., malfunctioning compressor seal).
- **Intermittent/single event:** Emissions are released intermittently, triggered by specific operational activities or changes in process conditions (e.g., unlit flare or pressure relief valve emissions) (Figure 10).

Figure 10: Example of Intermittent/Single-Event Emissions

A. **B.**

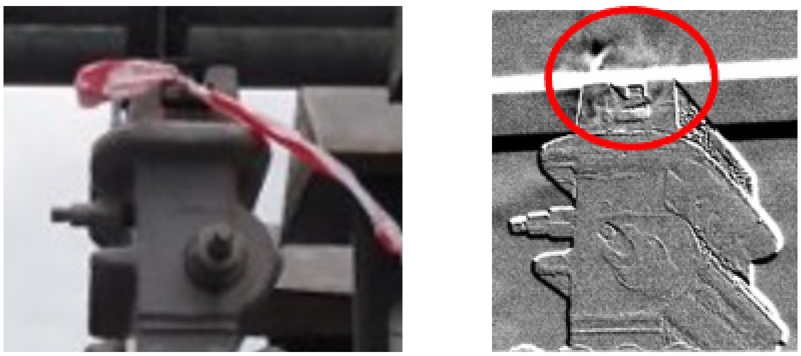
A shows methane emissions detected from an unlit flare, captured with an OGI camera and a regular camera; B shows the same flare combusting the gas.[66]

Leak source characteristics

- **Equipment malfunction:** Emissions resulting from mechanical failure or gradual degradation of a leak-tight component (e.g., corroded flange gasket) (Figure 11).
- **Operational upsets:** Emissions resulting from poorly configured process controllers, system error, or operating outside of designed parameters (e.g., valve stuck in "open" position) (Figure 12).

Figure 11: Example of Equipment Leak – Methane Emissions Detected From a Malfunctioning Valve on a Metering Skid

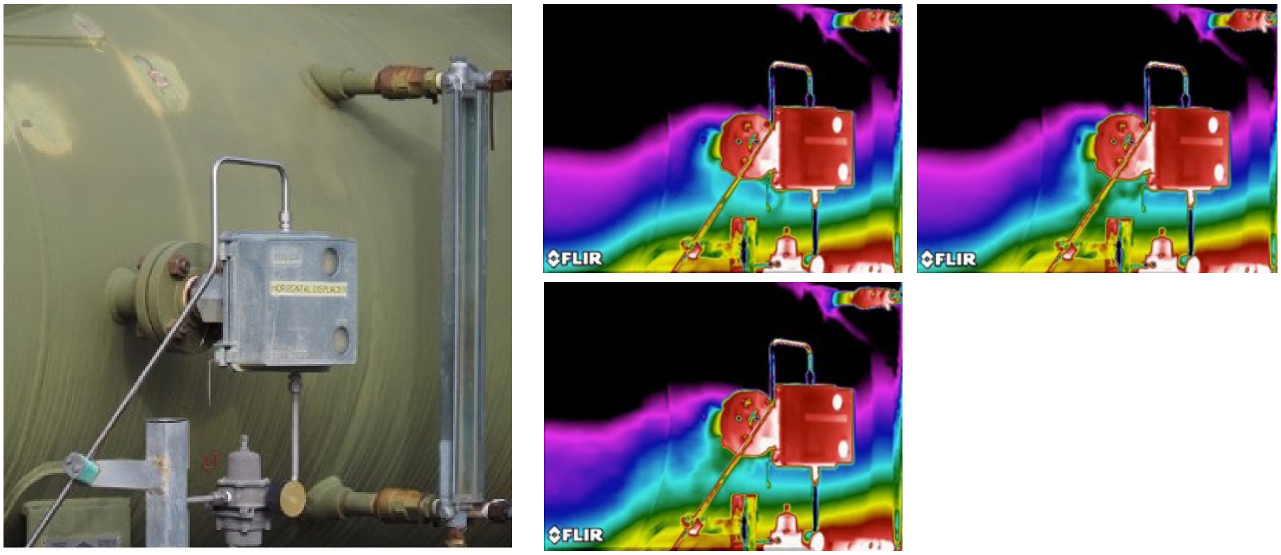
A. **B.**



A shows a valve appearing to be functioning normally without emissions captured during an OGI campaign; B shows the OGI footage which reveals the valve is malfunctioning and leaking methane. Note: the red ribbon visible in the digital image was used in the interim by the operator (in the absence of detailed leak tag) to identify leaking component for subsequent repair. Recognizing this as not the recommended best practice for tagging leaks, CATF collaborated with the regional regulator and operator to develop comprehensive LDAR policy designed to transition field practices toward globally recognized standards.

Figure 12: Example of Operational Emissions – Methane Emissions Detected From a Liquid Level Controller Excessively Venting

A. **B.**



A shows the liquid level controller with a regular camera, where emissions are invisible; B shows the same liquid level controller captured using an OGI camera, where emissions are visible in green. The equipment should be venting less during normal operations.

Leak Types and Repair Considerations

Repair considerations vary depending on the type of leak, the equipment involved, and the operational and safety context. Leak types can be grouped into categories when planning for appropriate responses and repairs. The leak categories include:

- **Routine leaks.** These leaks typically occur on standard components and can often be repaired using established maintenance practices without significant operational disruption. Examples include valve packing leaks, instrument tubing leaks, threaded connection leaks.
- **Process-critical or safety-related leaks.** These leaks involve equipment that plays a critical role in process control. Repairs may require temporary shutdowns or adherence to specific safety protocols. Examples include pressure relief device leaks, compressor seal leaks, tank thief hatch leaks, large diameter flange leaks, heater or fired equipment leaks.
- **Structural or access-limited leaks.** These leaks originate from components that are physically hard to reach or require specialized access equipment (in some jurisdictions they are called “difficult to monitor components”). Examples include elevated piping or equipment, tank roofs, pipe racks, offshore, or remote facilities.

Certain leak types may be associated with repairs that require additional safety controls, engineering reviews, or permitting processes. Regulators should consider various factors related to facility layout and operating conditions when setting repair timelines in their LDAR regulations, including:

- **Hot work** activities that may generate ignition sources.
- **Working at height** repairs that require elevated access, scaffolding, or fall protection.
- **Confined space entry** repairs that involve enclosed structures, equipment housed inside of buildings, or tanks.
- **Live process work** repairs that are conducted on pressurized or flowing systems.
- **Lockout/tagout and isolation** repairs that require energy control and system depressurization.

These considerations are not exhaustive and may vary by operator, facility type, and regulatory requirements. Additional classifications may be applied depending on regulatory frameworks, monitoring technologies, or operational practices.

Summary of Leak Typology and Repair Considerations

Table 4 categorizes leaks from different components, equipment, and processes in oil and gas facilities and provides insights into repair considerations for each category. It also highlights leaks from procedural oversight, such as human-error (i.e., unlatched hatches) and those stemming from complex operational issues like mechanical failures, component degradation, and fatigue.

It is important to note that many emissions identified during a survey will likely fall into multiple categories due to the interconnected nature of these process systems, for instance, a single leak at a wellhead may simultaneously involve valve stem corrosion, seal degradation, and loose bolted connections. Finally, Table 4 offers some insights into relative risks for emissions from different equipment and processes, and potential safety and environmental consequences if emissions are left unaddressed. These technical insights, combined with OGI footage from past OGI data collection campaigns conducted by CATF, serve as a practical reference for identifying emissions during field visits or LDAR surveys, and for establishing a standardized framework that connects field operators, LDAR surveyors, regulators, and company management. Please refer to Appendix B for more details on observations from past CATF OGI campaigns.

Table 4: Summary of Leak Typology and Repair Considerations

Typical Component Category	Potential Cause of Emissions	Potential Repair or Mitigation Action	Potential Effects of No Mitigation	OGI Videos from Field Campaigns (Appendix B)
Valves	Leaks can be caused by structural failure or cracks, seal degradation, stem corrosions, lack of lubrication, procedural oversight, etc. (Found in all oil and gas facilities)	Mechanical adjustment; component replacement; engineering review	Prolonged emissions; loss of process isolation; fire/safety hazard	■ Open Wellhead Valve ■ Open Wellhead Valve ■ Open Sampling Valve ■ Open Wellhead Valve and Repair ■ Degraded Valve Component ■ Broken Valve - Loose Gasket ■ Broken Valve
Actuated devices	Leaks can be caused by diaphragm rupture or failure, poorly tuned or fatigued pneumatic controller, improper pressure settings, etc. Leaks can also occur from malfunctioning or stuck separator dump valves which can lead to emission from tanks or downstream of the process. (Found in all oil and gas facilities)	Component replacement; mechanical adjustment (re-calibration); engineering review.	Continuous methane venting; failure of “fail-safe” functionality; process safety risk.	■ Actuated Controller Emissions ■ Actuated Controller Emissions ■ Actuator Valve Leaks ■ Controller Emissions ■ Actuator Valve Emissions

Typical Component Category	Potential Cause of Emissions	Potential Repair or Mitigation Action	Potential Effects of No Mitigation	OGI Videos from Field Campaigns (Appendix B)
Flanges and bolted connections	Leaks can be caused by gasket failure, material degradation, loosened bolts, improper installation, etc. (Found across all oil and gas facilities)	Mechanical adjustment (re-torquing); component replacement; engineering review.	Intermittent or continuous fugitive emissions; potential for gasket blowout (major safety risk).	■ Flanged Connection Leak ■ Flanged Connection Leaks ■ Flanged Connection Leak ■ Flanged Connection Leak ■ Flanged Connection Leak
Threaded and mechanical fittings	Leaks can be caused by vibration-induced loosening, misaligned threading, or seal-tape/compound failure. (Found across all oil and gas facilities)	Component replacement (fittings); mechanical adjustment (tightening); engineering review.	Small persistent leaks that can increase quickly with pressure surges or other operational changes.	■ Sample Tubing Leak
Seals, packing, and dynamic interfaces	Leaks can be caused by loss of lubrication barrier, shaft misalignment, gland packing fatigue, rod packing failure, etc. (Found in upstream and midstream facilities)	Component replacement; mechanical adjustment; frequent maintenance.	Contamination; accelerated wear on rotating equipment (health and process safety risk); product loss.	■ Compressor Seal Leak ■ Wellhead Stuffing Box Leak ■ Wellhead Stuffing Box Leak
Tanks, storage equipment, and pits	Leaks can occur from unlatched or seals on thief hatches, vent valve failure, structural degradation, persistent venting from waste extraction fluid, underground storage, or condensate pits, etc. (Found in upstream and midstream facilities)	Component or equipment replacement (cleaning or replacing seals on thief hatches); mechanical adjustment (closing thief hatch); engineering review (pressure set-point adjustments).	Significant VOC exposure (health, climate, and process safety risks), fire hazard; loss of product; contamination of environment	■ Tank Leak – Open Thief Hatch ■ Tank Leak - Open Thief Hatch ■ Tank Leak - Open Thief Hatch ■ Underground Condensate Tank Leaks – Open Roof ■ Tank Thief Hatch Leak Repair ■ Tank Failed Thief Hatch Repair ■ Tank Leak - Collapsed Roof ■ Tank Leak - Damaged Exterior

Typical Component Category	Potential Cause of Emissions	Potential Repair or Mitigation Action	Potential Effects of No Mitigation	OGI Videos from Field Campaigns (Appendix B)
Pressure relief and safety devices	Leaks can be caused by spring fatigue, improper valve sealing due to debris or scale buildup, seal degradation, etc. (Found across all oil and gas facilities)	Mechanical adjustment; component replacement; engineering review of device set point.	Process instability; critical safety risk caused by failure to provide full containment during an overpressure event.	▪ Pressure Relief Valve (PRV) Leak ▪ Fire Safety Valve Leak - Broken Tank Valve ▪ Pressure Safety Valve (PSV) Leak ▪ Pressure Safety Valve (PSV) Leak
Process Piping and structural components	Leaks can be caused by material failure from internal/external corrosion (pitting), erosion in elbows, or stress cracks (thermal-/vibration-induced). (Found across all oil and gas facilities)	Component/equipment replacement; mechanical adjustment (composite wrapping[67]); engineering review on material and process integrity.	Catastrophic loss of containment; environmental contamination; major safety risk.	▪ Ruptured Pipeline Leaks ▪ Ruptured Pipeline Leaks
Instrumentation and controls	Leaks can be caused by sample valves left open, small-diameter tubing manifold leaks due to misaligned connections, control panel leaks due to malfunctioning seals, improper tuning, or loose bolts caused by operational stress and vibration, etc. (Found across all oil and gas facilities)	Component replacement (i.e., cracked tubing), mechanical adjustments (closing sample valves); engineering review (adjusting operating set points)	Persistent localized emissions (fire hazard); process instability due to inaccurate process data (process safety risk)	▪ Gauge Leak - Loose Fitting ▪ Gauge Leak - Loose Fitting ▪ Broken Gauge Leak ▪ Broken Gauge Leak Repair
Emission control equipment	Leaks can be caused by abnormally emitting flare headers (unlit flares, inefficient flaring), malfunctioning vapor recovery unit (compressor seal failure), knockout drum leaks, etc. (Found in upstream and midstream facilities)	Component replacement (i.e., flare pilot system); frequent maintenance (VRU compressor)	Significant volumes of emissions released into the atmosphere causing health, climate, and process-safety risks in and around the facility.	▪ Flare Failure - Unlit Flare Leaks ▪ Enclosed Flare Failure - Unlit Flare Leaks

Typical Component Category	Potential Cause of Emissions	Potential Repair or Mitigation Action	Potential Effects of No Mitigation	OGI Videos from Field Campaigns (Appendix B)
Openings, vents, and intermittent sources	Leaks caused by uncapped or unplugged open-ended lines, malfunctioning isolation or blowdown valves, compromised cement casings causing gas to migrate near wellheads, emissions caused by poor engineering or operational practices, etc. (Found in upstream and midstream facilities)	Component replacement or repair; installation of secondary seals (plugs, caps, or blind flanges to double block and bleed); mechanical adjustment; engineering review (material integrity and process stabilization)	Increased safety hazards near wellheads; high volumes of emissions released into the atmosphere causing health, climate, and process-safety risks in and around the facility, environment and groundwater contamination.	■ PIG Trap Leak ■ PIG Trap Leaks ■ PIG Trap - Vent Emissions ■ Open-ended Pipe Leak ■ Non-Engineered Collection Leaks ■ Compressor Blowdown Emissions ■ Flanged Connection Leak ■ Open-ended Pipe Leak ■ Wellhead Leak - Cracked Casing ■ Wellhead Leak - Production Casing Failure

SECTION 5

Considerations for Reporting and Evaluation

Reporting must be included as part of a regulatory LDAR program, with reports submitted by operators to the regulator on an annual basis. Through this process, operators communicate to their relevant regulator about actions taken throughout the year to comply with regulatory requirements. This reporting is subsequently reviewed by regulators to ensure compliance and take follow-up actions when needed. Effective reporting therefore requires not only that operators provide all relevant information, but also that the process be streamlined and efficient for both operators and regulators.

As noted in the **Regulatory Framework for LDAR** section, in the initial stages of regulatory LDAR program implementation, it is best practice for regulations to require operators to submit a Company-Wide Implementation Plan as well as Site-Level Implementation Plans (where needed). The regulator should keep these submissions on file for all operators and refer to them as needed when evaluating annual LDAR reports.

This section provides information to regulators on the key elements of reporting templates and tips for evaluation, enforcement considerations, and best practices for conducting site audits to support effective verification. It explains to operators what sort of data a regulator may request and why this data is important. Civil society can also use this information to evaluate company reports when they are publicly available.

Reporting Template

It is best practice for the regulator to establish an LDAR reporting template that they share with all operators in their jurisdiction. In most cases, this template will be a spreadsheet in which all reporting elements are clearly specified and described. Such a template removes ambiguity about reporting requirements for operators and makes the review process for the regulator easier.

Facility Reporting: In this section of the reporting template, the operator must report information on each facility that was subject to LDAR in the year. It allows the regulator to have a high-level overview of compliance/non-compliance with LDAR requirements. It should collect all relevant facility-level information, including:

LDAR Facility Data Log
Name and ID of Facility
Geographic Coordinates
Number of surveys conducted in calendar year
Survey Method
Number of leaks found
Number of leaks repaired
Number of leaks recurring (previously repaired)
Number of leaks outstanding (on delayed repair list)
Any deviations from Company-Wide or Site-Level Implementation

For the following sections, reporting details can be divided into "Mandatory" and "Optional". Mandatory fields are necessary to determine whether the operator has complied with the requirements in the LDAR regulation. Optional elements are useful in the regulator's evaluation of the report but are not required.

Survey Reporting: This section requires details of each survey, including date, surveyor, weather conditions, and instrumentation used. This information allows regulators to evaluate survey quality, including detection limits and uncertainties, helping distinguish between true absence of emissions and survey limitations that may have prevented detection. Operators should submit information using a standardized template with the data points listed below, along with raw survey data (either scanned handwritten notes or copies of electronic records).

LDAR Survey Data Log	Reporting Requirement
Name and ID of Facility	Mandatory
Survey Date	Mandatory
Duration of Survey (hours)	Optional
Internal or Third Party Survey	Optional
Third Party Service Provider (if applicable)	Optional
LDAR Technician Name	Mandatory
Training/ Expertise of Inspector	Optional
Facility Type	Mandatory
Ambient Temperature (Celsius)	Mandatory
Barometric Pressure (KPa)	Mandatory
Wind Speed (m/s)	Mandatory
Precipitation	Mandatory
Maximum Survey Distance	Optional
Facility Status (Active/Idle/?)	Mandatory
Detection Method	Mandatory
Detection Instrument Make	Mandatory
Detection Instrument Model	Mandatory
Date of last detection instrument calibration/maintenance	Optional
Quantification Method	Optional
Quantification Instrument Make	Optional
Quantification Instrument Model	Optional
Date of last quantification instrument calibration/maintenance	Optional
Note on survey limitations due to weather or other conditions	Optional

Leak Reporting: In this part of the template, the operator must report on the details of each leak found in the year.

- Report details of leak

LDAR Survey Leak Observation Log	Reporting Requirement
Leaking Component ID	Mandatory
Leaking Component Type[v]	Mandatory
Leaking Component Process Block	Optional
Leaking Component Service Type	Optional
Distance of Camera from Leak	Optional
Repeat of Previously Repaired Leak (Y/N)	Optional
Picture/Video of Leak	Optional
Leak Flow Rate	Optional (if using QOGI)

- Report details of repair

LDAR Survey Leak Repair Log	Reporting Requirement
Leak Repaired (Yes/No)	Mandatory
Date of Successful Repair	Mandatory
Successful Repair Made Same Day? (Y/N)	Mandatory
Repair Confirmation Method	Mandatory
Repair Method Applied	Mandatory
Basis for Repair Delay (if applicable)	Mandatory
Efforts to minimize leak until next turnaround (if applicable)	Mandatory
Repair at Next Turnaround (if applicable)	Mandatory
Anticipated Date of Next Turnaround (if applicable)	Mandatory

- Report on other equipment surveyed (as noted in Section 3, the primary purpose of the LDAR survey is to detect and repair leaks. However, the LDAR surveyor and site operator should also use the survey to assess equipment venting and flaring to determine whether they are aligned with engineering design parameters or indicate system malfunction or operational upset):

LDAR Survey Equipment Observation Log	Reporting Requirement
Number of Flares Observed	Mandatory
Flare Observation	Mandatory
Number of Natural Gas Driven Pneumatic Devices Observed	Mandatory
Natural Gas Driven Pneumatic Device Observation	Mandatory
Number of Natural Gas Driven Pneumatic Devices Observed	Mandatory
Storage Tanks Observation	Mandatory

- Other comments (including a note of survey conducted with no leaks detected).

[v] See Table 3 for description of common leak emission sources.

Evaluation of Company Reports

The regulator should establish routines and processes to thoroughly and efficiently evaluate all operator LDAR reports. This may include a checklist such as the following:

1. Is the annual LDAR report consistent with the Company-Wide Implementation Plan and the Site-Level Implementation Plan? If not, has the company provided justification for this discrepancy?
2. Is there any missing information?
3. Did the operator use appropriate technology to conduct surveys?
4. Did the operator conduct the appropriate number of surveys at each site? If not, has the company explained why?
5. Did the operator follow the required repair timelines for all detected leaks? If not, has the company explained why?
   - Many leaks will reoccur because the operator fixed the immediate cause of the leak but not the root cause of the issue. Therefore, the regulator should take this into account when evaluating company reports, as root cause repairs might exceed regulatory repair timelines.
6. Are there any leaks that have been on the Delay of Repair list for an extended time? If so, why? Has the facility had any shutdowns to allow for the repair? If not, when is the next shutdown planned?

Enforcement

When reported data shows an operator is not in full compliance with LDAR requirements, the regulator may consider enforcement actions. In these cases, the regulator can adjust the severity of an enforcement action based on the severity of the infraction and whether it is a first time or repeat offender. Below are examples of enforcement actions from low to high impact:

- **Resubmit report:** If the regulator believes that the operator unintentionally reported incorrect or unclear information, it can require that the operator resubmit the report with corrected data.
- **Corrective action:** The regulator can give the operator a notice that it must increase the frequency of LDAR surveys or accelerate repair schedules to avoid additional enforcement actions.
- **Fines/penalties:** The regulator can issue a fine or penalty if the company has repeatedly violated LDAR requirements.
- **Suspension of operating permit:** In extreme cases of non-compliance, the regulator may have the authority to suspend a company's operating permit.

Site Audits

While desk audits of the operator LDAR reports are an essential part of the implementation of a regulatory LDAR program, they can be supplemented by site visits to verify and validate company reports. In most cases, regulator capacity to conduct such site visits is extremely limited, but even a few site visits per year can greatly enhance the implementation of the LDAR program. Site visits allow regulators to verify the accuracy of operator reports and strengthen technical expertise within the regulatory agency, while compelling operators to remain up-to-date with their repair deadlines. Best practices for regulator site visits include:

- Site visits should occur with as little advance notice to the operator as possible, ensuring the regulator sees the site in an unbiased manner. In some cases, it might be necessary to give operator advanced notice of inspection for safety and security reasons, but this notice period should be as limited as practical.

- The regulator should verify that company reports match site records (e.g., verify that equipment on the "delayed repair" list is appropriately tagged).

- If the regulator has access to an OGI camera, it should be brought on site to conduct an LDAR Inspection. This could be a camera owned by the regulator, or the regulator could hire a 3rd party camera operator company to accompany them on the site visit. However, if an OGI camera is unavailable, a site visit will still be useful.
  - For site visits with an OGI camera, the regulator can independently inspect the site for leaks. If the regulator discovers a leak, it does not necessarily mean that the operator is in violation of the LDAR program requirements, as the leak could have commenced after the last OGI survey of the site. Nevertheless, the leak discovered by the regulator should be documented for the operator and repaired within the appropriate repair timeline. In addition, emissions detected during regulatory inspections are a point of concern that the regulator should flag to be addressed by the operator.
- Regulator site visits can be timed to occur while the operator is conducting the LDAR survey. If the regulator does not have funding for its own OGI camera, joining a scheduled LDAR survey can be advantageous. In addition, if the regulator visits during the LDAR survey, it can observe the operator conducting the LDAR survey to ensure they are implementing the program correctly.

SECTION 6

Conclusion

LDAR is an essential part of a methane mitigation program within the oil and gas industry. Consequently, it must be incorporated into mandatory regulatory requirements in jurisdictions that wish to achieve significant reductions in methane emissions. OGI cameras remain one of the foundational and precedential tools for modern LDAR programs, providing real-time, visual insights on emissions at the component level. Given this capability, it is imperative for regulators to incorporate the ground-level OGI-based LDAR into mandatory frameworks to ensure that climate commitments are achieved with actionable data and proven mitigation methods.

However, the effectiveness of LDAR can vary significantly depending on how it is implemented and the depth of shared understanding between stakeholders. Rather than simply a “check the box” exercise, LDAR must be a rigorous, systematic effort that minimizes methane emissions while enhancing operational efficiency and site safety. By establishing a shared technical understanding of emission sources and leak characteristics among regulators, operators, and LDAR surveyors, this standardized framework ensures that LDAR is a unified effort.

With these technical insights into OGI’s capabilities and limitations, regulators can confidently require operators in their jurisdictions to implement LDAR programs. Simultaneously, operators can plan and implement LDAR programs with the certainty that their efforts will be supported and understood by regulators. Through this increased shared understanding of LDAR program requirements, both operators and regulators can ensure that LDAR mitigates methane to the greatest extent possible.

Appendix A: Technology Overview

Methane detectors are typically designed to identify the presence of methane gas, measure its concentrations in the atmosphere, or quantify volumetric flowrates from process streams or emissions (or a combination of all three). These detectors use a range of different instruments, such as infrared imaging, laser-based spectroscopy, ultrasound mapping and can be handheld or mounted on different platforms, including satellite, aircrafts, drones, vehicles, or fixed-point towers. The following section covers these technologies and different deployment strategies to provide a deeper understanding of their detection capabilities, sensitivities, and limitations.

Handheld devices such as OGI cameras, Tunable Diode Laser Absorption Spectrometer (TDLAS) systems, and ultrasound imaging cameras are a few of the technologies available today to detect methane leaks from oil and gas operations.[68] These handheld devices allow for ground-based, equipment- and component-level methane leak detection. Detecting emissions at the equipment- and component-level is essential for LDAR programs, as it provides immediate information on the source of the leak and actionable data to inform the repair process. These handheld tools can also provide a greater understanding of leak characteristics, including flow rates, concentrations, and precise location data critical for prioritizing repairs on leaks that present risks to safety of operation. TDLAS and ultrasound imaging cameras provide an alternative to OGI by detecting methane concentrations at parts-per-billion (ppb) levels or detecting high-pressure leaks in environments with low thermal contrast. Ultrasound equipment, on the other hand, has challenges detecting emissions in areas near lout equipment, such as compressors. Handheld devices are typically highly sensitive, but are limited with regards to safety, accessibility, and labor intensity compared to remote-sensing technologies.

Other technologies can both detect and measure methane emissions at facility or sub-facility level by mounting similar detection instruments on different platforms. These technologies serve dual purposes: complementing handheld devices in comprehensive, tiered LDAR programs. For this reason, programs using the technologies described below must still include another technology, often OGI cameras, to verify the detection, pinpoint the precise leak sources, and provide documentation for successful repair. These technologies can also enable "super-emitter" detection and targeted mitigation activities.

Space-borne (or satellite) sensors have capabilities ranging from basin-wide to facility-level coverage.[69] Area flux satellites provide daily global coverage but have a low spatial resolution (~5.5×7 km).[70] They are designed to assess regional trends in emissions to track whether emissions have decreased or increased over periods of years, rather than pinpoint individual leaking equipment. Point-source satellites can provide down to 30×30 m spatial resolution, allowing facility or sub-facility level emission attribution.[71] While satellites offer regular observation intervals, their accuracy can be hindered by cloud cover, physical obstructions, or adverse weather.[72]

Aerial instruments with methane sensors (aircrafts and drones) equipped with high precision sensors provide a middle ground between satellite and ground-inspections. They can provide coverage ranging from basin to sub-facility level, depending on the flight altitude and the sensitivity of the sensor. Drones or unmanned aerial vehicles (UAVs) can be particularly effective for accessing hard-to-reach facilities and process areas like offshore facilities, flare tips, or tank tops where manual inspections may be physically challenging or pose safety risks to personnel. They also can provide facility- or component-level concentrations below 1 kg/hr.[73] For both space-borne and aerial sensors, there are trade-offs between spatial coverage and detection sensitivity, which are important to consider.

Vehicle-mounted sensors provide methods for rapidly screening accessible infrastructure or for fenceline surveys while maintaining moderate detection thresholds. Similar to aerial instruments, these vehicle-mounted units offer higher spatial resolution compared to satellites and more mobility than fixed sensors in complex or high-risk environments.

Fixed-point sensors or cameras can be installed on or near leak prone equipment (such as tank batteries or compressors) or along a facility fenceline. This category also includes tower-based line sensor systems, which uses eye-safe laser beams to sweep across a wide area (i.e., multiple well pads) from a central location.[74] These sensors are capable of detecting persistent and intermittent fugitive emissions (often in the parts per million range) that are frequently missed by periodic surveying methods.[75] Some of the technology vendors provide an ongoing stream of data identifying the time a leak starts to allow operators to initiate repair in a timely manner and gain deeper insights into the performance of leak-prone components. However, the efficacy of fixed sensors is limited due to their reliance on certain weather conditions (e.g., the wind blowing at a certain speed and in a certain direction to observe emissions). These systems are sometimes referred to as continuous monitoring systems (CMS), but they are not truly monitoring "continuously". In addition, these technologies require sophisticated atmospheric dispersion models and wind data to triangulate a potential leak source. While the results from a CMS include high detection sensitivity and temporal resolution, it typically offers only moderate spatial resolution because the system cannot always accurately pinpoint the exact location of the emission without a supplemental follow-up surveys. Though these fixed-point sensors are convenient for operators, they require the same rigorous field testing that handheld devices require and ultimately might not qualify for some regulatory LDAR requirements.

Appendix B: Leak Typology

Component Category	Cause of Emissions Identified	Description of Observations (Case Study) *These examples are based on on-site observations and discussions with field personnel, and are intended for illustrative purposes only, acknowledging that field interpretations and the constraints of OGI technology may lead to inaccuracies.*	OGI Footage (GF320) (Links to Vimeo)	OGI Footage Caption (Description of Facility: Segment)
Valves	Open Valve	Based on previous OGI survey experience and discussions with on-site personnel, we found that fugitive emissions from valves aren't always a result of total mechanical failure. In many cases, emissions were linked to procedural oversights, such as valves being left open for convenience in between routine gauging and sampling activities, or subtle mechanical wear between maintenance cycles that prevents a tight seal. Even when a valve is functionally closed, emissions have been observed due to degradation of seals, worn packing, or stem interfaces. During some campaigns, when operators observed a live gas plume through the OGI camera, many attempted on-the-spot repair by trying to secure a valve that had been left partially or fully open. This experience highlighted the need for a two-step mitigation approach. First, an immediate response of closing the valve and verifying the seal serves as an effective first step. Second, these findings should also trigger a review of operational procedures to ensure valves are consistently and correctly sealed after maintenance or sampling. Refer to OGI footage captured during previous campaigns of observed emissions from open valves and associated repair attempts in oil and gas facilities.	Open Wellhead Valve	This footage showing a leaking wellhead valve was captured at an oil wellpad. These types of emissions can be seen across the upstream segment in oil and gas wellpads.
			Open Wellhead Valve	This footage showing a leaking wellhead valve was captured at an oil wellpad. These types of emissions can be seen across the upstream segment in oil and gas wellpads.
			Open Sampling Valve	This footage shows emissions from a sampling valve left open at a gas facility.
			Open Wellhead Valve and Repair	This footage is composed of two videos captured at an oil wellpad. On the first video, the valve is open and emissions can be seen from the open line. On the second video, the valve has been closed and no emissions are visible.
	Loose, degraded or broken valve	Our field campaigns have revealed that even when the equipment appears structurally sound, subtle degradation or loose bolts caused by thermal expansion, vibration, and general wear can create small pathways for gas to leak. When these small, persistent leaks are caught during a survey, a quick mechanical adjustment, like tightening a flange or a bolt, can often stop the emission immediately, provided that safety and operational protocols allow for immediate adjustments; otherwise, a formal repair must be scheduled for the next maintenance or shutdown period. Refer to OGI footage to see examples of emissions from component degradation and loosened bolts on valves.	Degraded Valve Component	This footage shows emissions from the flanges of a valve. It was captured at a valve station, on a gas line. This type of emissions is frequent across upstream, midstream, and downstream gas networks.
			Broken Valve - Loose Gasket	This footage shows emissions from a loose valve. It was captured on the oil gathering line on an oil wellpad. This type of emissions is frequent across upstream, midstream, and downstream gas networks.
			Broken Valve	This footage shows emissions from a damaged valve. It was captured at an oil wellpad. The valve does not close.

Component Category	Cause of Emissions Identified	Description of Observations (Case Study) *These examples are based on on-site observations and discussions with field personnel, and are intended for illustrative purposes only, acknowledging that field interpretations and the constraints of OGI technology may lead to inaccuracies.*	OGI Footage (GF320) (Links to Vimeo)	OGI Footage Caption (Description of Facility: Segment)
Flanges and Bolted Connections	Mechanical Adjustment	During several campaigns, our OGI team and on-site operators have identified emissions often stem from a gradual loss of tightness at connections, such as bolted flanges and threaded fittings, rather than major equipment failures. While the piping remains structurally intact, the cumulative effects of thermal expansion, vibration, and corrosion naturally cause bolts to lose preload and gaskets to degrade over time. Many of these types of leaks can be repaired through immediate on-site intervention, where simply tightening a bolt or fitting can restore the seal, provided safety and operational protocols allow for immediate repair. However, if tightening fails to stop the emission, it can indicate that the gasket or seal has internally failed and requires a planned replacement. To ensure a permanent fix, a follow-up OGI inspection is always conducted to verify that the leak has been fully mitigated under actual process conditions. Refer to OGI footage to see examples of emissions from flanges and bolted connections.	Flanged Connection Leak	This footage shows multiple leaks from the flanges of connections. It was captured on an oil gathering line at a wellpad.
			Flanged Connection Leaks	This footage shows multiple leaks from the flanges of connections. It was captured at a valve station of a gas line.
			Flanged Connection Leak	This footage shows emissions from misaligned or degraded flanges at a processing facility.
			Flanged Connection Leak	This footage shows emissions from misaligned or degraded flanges at a processing facility.
			Flanged Connection Leak	This footage shows multiple leaks from the flanges of connections. It was captured at a valve station of a gas line.
Seals, Packing, and Dynamic Interfaces	Compressor seal degradation	Some observations at compressor stations showed emissions from compressor seals that often stemmed from the gradual degradation of sealing interfaces due to corrosion and mechanical wear. These leaks typically occurred due to compromised internal components, causing gas to leak from primary containment systems. Effective mitigation may require component replacement, frequent maintenance, or upgrading to materials specifically engineered to withstand the chemical and thermal stress of the process.	Compressor Seal Leak	This footage shows leaks from a compressor unit. It was captured at a field compressor station in an oil and gas field. This type of emissions can be seen at every compressor unit both upstream and midstream.
	Stuffing Box Leaks	Based on previous campaign experience, some emissions observed from wellpad occur at the stuffing box signaling degradation or malfunction in components like gland packing, flange seals, or internal gaskets. While the wellhead often remains operational, the continuous stress of mechanical wear/stress, corrosion, and thermal cycling eventually compromises these interfaces, creating pathways for unintended emissions. These types of emissions caused by significantly degraded components demand immediate attention to prevent environmental contamination and potential structural failure. Effective mitigation may require a planned replacement of the damaged components and engineering review to repair damaged infrastructure to restore sealing.	Wellhead Stuffing Box Leak	This footage showing a leaking wellhead stuffing box was captured at an oil wellpad. These types of emissions can be seen across the upstream segment in oil and gas wellpads.
			Wellhead Stuffing Box Leak	This footage showing a leaking wellhead stuffing box was captured at an oil wellpad. These types of emissions can be seen across the upstream segment in oil and gas wellpads.

Component Category	Cause of Emissions Identified	Description of Observations (Case Study) *These examples are based on on-site observations and discussions with field personnel, and are intended for illustrative purposes only, acknowledging that field interpretations and the constraints of OGI technology may lead to inaccuracies.*	OGI Footage (GF320) (Links to Vimeo)	OGI Footage Caption (Description of Facility: Segment)
Process piping and structural components	Corroded Pipeline	When observing pipelines that are either above or underground, several surveys of these lines indicated that can get damaged and crack due to internal and external corrosion, pressure, and/or poor maintenance. Even when a pipeline appeared intact during a visual walk-through, these structural vulnerabilities can create high-risk pathways for significant, and sometimes hazardous, gas leaks. Addressing these integrity issues requires specialized engineering or operational review and interventions, such as the full replacement of compromised pipe segments. Effective mitigation should also include a broader review of flow dynamics to prevent recurrent mechanical fatigue and ensure long-term containment.	Ruptured Pipeline Leaks	This footage shows a cracked underground gas line at a gas compressor station.
			Ruptured Pipeline Leaks	This footage shows a cracked underground gathering line at an oil wellpad.
Instrumentation and Controls	Loose or Broken Gauge	Emissions observed from instrumentation such as pressure and temperature gauges during past campaigns often originated at connection points due to improper tightening, degraded seals, or mechanical wear from frequent adjustments (from operators trying to record gauge readings). While these instruments appeared functional and provided process readings, a misalignment in the threaded or sealed interface, or a broken gauge resulted in unintended gas leaks. Operators on-site attempted re-tightening the gauge to restore the seal, which can be an effective first repair attempt. This must be followed by a secondary OGI verification to ensure the leak is resolved; however, if the leakage persists, the gauge seal or the entire unit may require replacement.	Gauge Leak - Loose Fitting	This footage shows a loose gauge presenting emissions from a wellhead. This kind of emissions can be seen across all up, mid, and downstream oil and gas infrastructure.
			Gauge Leak - Loose Fitting	This footage shows a loose gauge with emissions from a gas pipeline at a metering station. This kind of emissions can be seen across all up, mid, and downstream oil and gas infrastructure.
			Broken Gauge Leak	This footage showing a damaged gauge with emissions was captured on the gathering line at a wellpad. This kind of emissions can be seen across all up, mid, and downstream oil and gas infrastructure.
			Broken Gauge Leak Repair	This footage showing a damaged gauge with emissions was captured on the gathering line at a wellpad. The second part of the video shows an immediate repair being performed, and no emissions subsequently. This kind of emissions can be seen across all up, mid, and downstream oil and gas infrastructure.

Component Category	Cause of Emissions Identified	Description of Observations (Case Study) *These examples are based on on-site observations and discussions with field personnel, and are intended for illustrative purposes only, acknowledging that field interpretations and the constraints of OGI technology may lead to inaccuracies.*	OGI Footage (GF320) (Links to Vimeo)	OGI Footage Caption (Description of Facility: Segment)
Tanks, storage equipment, and pits	Open thief hatches and open vents	Our OGI campaigns across various regions around the world identified significant emissions from open thief hatches on tanks or manways, often resulting from operational oversight or mechanical wear. Since these lids are frequently opened for gauging, sampling, or tank inspections, they are prone to being left unlatched or improperly seated, leading to significant venting despite the tank appearing structurally sound. Beyond human error, fugitive emissions can occur when the internal seals or gaskets degrade over time, creating a gap that allows gas to leak even when the hatch is visually closed. Practical mitigation can start with a simple operational check to ensure the lid is properly latched, followed by an OGI verification to confirm the seal is holding. If a leak persists after closing of the thief hatch, it may require further repair or component replacement to a complete seal. In more severe cases, where a hatch is entirely missing or structural components have major damage, a repair may require installing a new hatch or major roof repair to restore the containment for the tank.	Tank Leak - Open Thief Hatch	This footage showing emissions from an open thief hatch on top of a crude oil storage, was taken at an oil storage facility. This kind of emissions can be seen across the upstream oil segment.
			Tank Leak - Open Thief Hatch	This footage showing emissions from a damaged thief hatch on top of a crude oil storage, was taken at an oil storage facility. This kind of emissions can be seen across the upstream oil segment.
			Tank Leak - Open Thief Hatch	This footage shows emissions from open thief hatch from oil storage tanks.
			Underground Condensate Tank Leaks - Open Roof	This footage shows emissions from open condensate pits from an oil facility.
			Tank Thief Hatch Leak Repair	This footage shows an operator closing the thief hatch on an oil storage tank preventing further methane emissions.
			Tank Failed Thief Hatch Repair	This footage showing emissions from an open thief hatch on top of a crude oil storage, was taken at an oil storage facility. The worker went to close the hatch, but emissions remained, indicating a loss of containment of the gas. This kind of emissions can be seen across the upstream oil segment.
	Structural Degradation	Other emissions observed from tanks were a result of holes or breaches in the roof or shell of the tank stemming from severe corrosion, localized structural damage, or internal roof collapse. Because these emissions signal a compromise in the tank's shell, mitigation must be tailored to the severity of the damage to ensure the vessel can safely maintain its operating pressure and containment. While minor perforations might be addressed faster through additional reinforcement, severe degradation can require immediate engineering review to prevent total structural failure and catastrophic emissions.	Tank Leak - Collapsed Roof	This footage showing emissions from a damaged crude oil storage tank, was taken at an oil storage facility. This kind of emissions can be seen across the upstream oil segment.
			Tank Leak - Damaged Exterior	This footage showing emissions from a damaged crude oil storage tank, was taken at an oil storage facility. This kind of emissions can be seen across the upstream oil segment.

Component Category	Cause of Emissions Identified	Description of Observations (Case Study) *These examples are based on on-site observations and discussions with field personnel, and are intended for illustrative purposes only, acknowledging that field interpretations and the constraints of OGI technology may lead to inaccuracies.*	OGI Footage (GF320) (Links to Vimeo)	OGI Footage Caption (Description of Facility: Segment)
Pressure Release Device	Poor tuning or component degradation	Pressure release valves (PRVs) are devices designed to protect process equipment, such as tanks and separators, from overpressure. During our field campaigns, we documented several instances of persistent emissions observed from PRVs across different oil and gas facilities. In some cases, when the device is not tuned correctly (i.e., incorrect set points), more methane can be released from the equipment. In some facilities, these set points are intentionally kept lower due to a lack of confidence in the vessel's capacity to handle different process conditions or the valve's own mechanical reliability, resulting in chronic emissions. In other cases, the observed emissions were a result of component malfunction or broken valve. Methane leaks can be effectively reduced by correctly tuning and calibrating the device to ensure it remains tightly sealed until the set operating pressure is reached. If emissions persist despite proper tuning, further investigation may be required for component repair or valve replacement. Frequent monitoring can be critical to verify that the device operates within its specified range, preventing unintended leaks while maintaining the safety function of these devices.	Pressure Relief Valve (PRV) Leak	This footage showing emissions from a poorly tuned pressure release valve, was taken at an oil storage facility. PRVs and other pressure release devices can be found across the upstream oil and gas segment, as well as some midstream facilities like gas storage.
			Fire Safety Valve Leak - Broken Tank Valve	This footage shows emissions from an open fire safety tank valve.
			Pressure Safety Valve (PSV) Leak	This footage shows continuous emissions from a pressure safety valve at a processing facility.
			Pressure Safety Valve (PSV) Leak	This footage showing emissions from a broken pressure release valve, was taken at an oil storage facility. PRVs and other pressure release devices can be found across the upstream oil and gas segment, as well as some midstream facilities like gas storage.
Emission Control Equipment	Flare Failure or Malfunction	Flares are commonly across upstream, midstream, and some downstream oil and gas facilities to reduce harmful gases from being releasing into the atmosphere. During our OGI campaigns, CATF thermographers have routinely observed many malfunctioning flares releasing significant amount of methane and other harmful gases into the atmosphere. Whether a flare is completely unlit or simply operating with poor combustion efficiency, it will continue to leak significant volumes of these gases into the atmosphere without immediate intervention. An effective mitigation may require repairing or upgrading the ignition system or flare tip ensuring reliable and efficient flare operation. In many cases, an internal inquiry or review can be necessary to determine if operational changes have affected the gas composition or flow rates beyond the flare's design capacity causing unintended leaks. Regular monitoring, testing, and maintenance of the pilot system and flare operation are essential to maintaining and quickly restoring the flare's primary function as a environmental emissions control device.	Flare Failure - Unlit Flare Leaks	This footage shows emissions from an unlit open flare at an upstream oil facility.
			Enclosed Flare Failure - Unlit Flare Leaks	This footage shows emissions from an enclosed flare at a compressor station.

Component Category	Cause of Emissions Identified	Description of Observations (Case Study) *These examples are based on on-site observations and discussions with field personnel, and are intended for illustrative purposes only, acknowledging that field interpretations and the constraints of OGI technology may lead to inaccuracies.*	OGI Footage (GF320) (Links to Vimeo)	OGI Footage Caption (Description of Facility: Segment)
Actuated device	Component Degradation or Controller Failure	Our past field observations revealed chronic unintended emissions from pneumatic devices (i.e., controller and pumps) resulting from component degradation from mechanical stress or wear or drifting from set points. These leaks can stem from poor tuning, where the device fails to close/seal completely under most process conditions, or from physical damage like internal corrosion and worn-out seals. While some of these devices are designed to vent small amounts of gas during normal operation, mechanical fatigue and wear can lead to continuous, high-volume leaks. Mitigation of these emissions can require recalibrating, mechanical repair, or replacement of damaged internal components or device to ensure that the device can operate within the intended operational parameters. Regular monitoring and maintenance can help reduce emissions from these devices in the long-term.	Actuated Controller Emissions	This footage shows emissions from a controller at a gas well. This type of emissions can be found at all segments of both the oil and gas industries.
			Actuated Controller Emissions	This footage shows continuous emissions from a pneumatic controller at an oil and gas facility.
			Actuator Valve Leaks	This footage is showing emissions from an actuated valve on a metering skid on an oil processing facility.
			Controller Emissions	This footage shows continuous emissions from a pneumatic controller at an oil and gas facility.
			Actuator Valve Emissions	This footage shows emissions from an actuator valve at compression station. This type of emissions can be found at all segments of both the oil and gas industries.
Vents, Open-Ended Lines, and Intermittent Sources	Pig Trap/ Door: Worn/ Corroded Seal	During some field visits with OGI, our thermography team observed significant emissions from pig launchers and receivers stemming from closure doors failing to maintain a gas-tight barrier when the trap or pipeline is pressurized. This loss of gas containment could be a result of component degradation or mechanical wear, requiring further investigation into repair requirements or component replacement to restore complete sealing for mitigation.	PIG Trap Leak	This footage shows emissions from a leaky PIG trap on a gas pipeline. This type of emissions can be found from any manway or openings on upstream and midstream sites.
			PIG Trap Leaks	This footage shows emissions from a leaky PIG trap on a gas pipeline. This type of emissions can be found from any manway or openings on upstream and midstream sites.
			PIG Trap - Vent Emissions	This footage shows emissions from a manual vent on top of a PIG trap at a regulation station on a midstream gas pipeline. This type of emissions can be seen on the upstream and midstream segments of both oil and gas infrastructures.

Component Category	Cause of Emissions Identified	Description of Observations (Case Study) *These examples are based on on-site observations and discussions with field personnel, and are intended for illustrative purposes only, acknowledging that field interpretations and the constraints of OGI technology may lead to inaccuracies.*	OGI Footage (GF320) (Links to Vimeo)	OGI Footage Caption (Description of Facility: Segment)
Vents, Open-Ended Lines, and Intermittent Sources	Process Vents: Open or Poorly Closed	Our thermography team has documented many instances of open vents or continuous unintentional emissions from process vents in the oil and gas facilities. In many cases, the emissions were a result of pipeline maintenance or pigging operating when emissions are not routed to a control device and instead are vented through open vents or vents that are subsequently left partially open or fail to seal properly upon closure. While these vents may be designed for emergency-controlled releases, an improperly closed valve can lead to continuous, high-volume leaking long after the operational activity is complete causing major health, process, and climate risks. Mitigation may require additional checks to ensure the vent valve is fully rotated to the closed position and verifying via OGI to confirm the leak has stopped. In cases where the valve is fully functional, but the leak persists, the internal components may be compromised by debris or wear, requiring further investigation into repair requirements for mitigation.	Open-ended Pipe Leak	This footage shows emissions open-ended pipes at a gas facility.
	Bad Operational Practices	Our past OGI campaigns have also revealed many emissions resulting from bad operational practices like temporary modifications or improvised solutions or workarounds (i.e., using buckets to collect condensate from discharge lines). These practices often create significant unintended emissions and leaks bypassing any emission control systems on-site. Effective mitigation often requires a shift from relying on these temporary fixes to implementing a robust engineered solution that aligns with the internationally recognized engineering and operational best practices. Addressing these emissions may involve a formal review of field procedures and site conditions to replace leak-prone improvised workarounds with standardized, low-emission solutions.	Wellhead Leak	This footage shows an improvised heating system installed inside a wellhead at an oil well.
			Non-Engineered Collection Leaks	This footage shows emissions from a rudimentary collection system of condensate from a discharge line. These types of workarounds and improvised solutions have been seen across the upstream, midstream, and downstream segments.
			Compressor Blowdown Emissions	This video shows significant emissions from a process vent at a gas compressor station potentially due to equipment malfunction or poor operational practices during blowdown process.
			Flanged Connection Leak	This footage shows emissions from a flanged connection that only was bolted in 2 locations for maintenance at a processing facility.
			Open-ended Pipe Leak	This footage shows emissions from an open -ended pipe that was disconnected for maintenance at a processing facility.

Component Category	Cause of Emissions Identified	Description of Observations (Case Study) *These examples are based on on-site observations and discussions with field personnel, and are intended for illustrative purposes only, acknowledging that field interpretations and the constraints of OGI technology may lead to inaccuracies.*	OGI Footage (GF320) (Links to Vimeo)	OGI Footage Caption (Description of Facility: Segment)
Vents, Open-Ended Lines, and Intermittent Sources	Wellhead Casing Leaks	Previous OGI campaigns observations also include significant emissions around wellheads stemming from structural cracks or gaps in the subsurface casing, allowing pressurized gas to accumulate and leak compromising operations and causing major health and climate risks. These emissions may be result of component degradation or mechanical wear which would require immediate intervention to restore the protective barriers and safeguard the operations. Effective mitigation can involve mechanical adjustments, such as tightening flange bolts or repacking the stuffing box, and component replacement to restore sealing and re-establish a gas-tight boundary. Depending on the severity of the structural integrity issues or equipment malfunction, methane mitigation may require immediate engineering review and intervention to repair or replace major equipment. It is critical for very repair to be followed by a verification scan to confirm mitigation of emissions.	Wellhead Leak - Cracked Casing	This footage shows emissions escaping from cracks in the casing and concrete foundation at an oil wellpad.
			Wellhead Leak - Production Casing Failure	This footage was taken at an upstream gas facility with several gas wells.
Threaded and mechanical fittings	Component Degradation or Misalignment	Past campaigns have shown leaks from threaded and mechanical fittings which may be caused by vibration-induced loosening, misaligned threading, or seal-tape/compound failure. Mitigation can often involve component replacement (e.g., fittings, sealing tape) or mechanical adjustment (e.g., tightening).	Sample Tubing Leak	This footage shows emissions from poorly fitted sampling connection at a processing facility

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