FINAL
GTI Project Number 22420

Leak Detection Body of Knowledge – Recommended Practice

Reporting Period:
August 01, 2018 through October 31, 2020

Report Issued:
January 29, 2021

Agreement Number:
693JK31810005

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1 Special Notes

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2 Introduction

Natural gas pipeline operators rely on leak detection instruments to monitor and operate their pipelines safely and reliably so that there are no adverse effects on the public, employees, the environment, or the pipeline assets. The RP presented here is intended to outline the key factors that must be considered when establishing and maintaining an onshore natural gas external leak detection system including sections for selecting systems, establishing performance targets/performance metrics, reporting requirements, data/measurement quality management, and control center responses.

2.1 Objectives and Guiding Principles

This RP is intended to be used in conjunction with other industry-specified documents such as that American Petroleum Institute (API) RP 1175 “Pipeline Leak Detection – Program Management”. This RP builds on existing requirements of 49 CFR § 192.706 – “Transmission lines: Leakage surveys” and is not intended to replace requirements of any other standards or regulations. Method classifications and performance determination procedures presented in this RP are intended to be general enough to allow flexibility as new external leak detection instruments are developed and placed within a method category. Further, the structures within the certification organization framework presented in this RP are intended to provide a functional foundation and suggested procedures for test protocol development. Decisions made as part of a leak detection program (LDP) rely on a thorough assessment and analysis of leak detection instruments as they apply to onshore, external leak detection of transmission pipelines and integration with the leak detection objectives of the operator.

The sections of this RP will cover:

- Leak detection equipment selection criteria for external leak detection of onshore transmission pipelines;
- A universal metric for measuring performance of onshore transmission pipeline external leak detection instrumentation.

The sections of this RP do not include the following:

- Detailed technical design of leak detection systems;
- Supervisory control and data acquisition (SCADA) system design (as this is already covered in other API documents, for example API 1113, API 1164, API 1165, or API 1167);
- Specific risk-based approaches for pipeline leak detection (as this is already covered in API 1175);
- Field response (as this is covered in a pipeline operator's emergency response plan);

- Presentation of information to Pipeline Controllers (covered in API 1165);
- A definition of the relationship between emergency flow restriction devices (EFRDs) (as they are mitigation systems);
- Procedures for measuring mass emission rate from individual or aggregated sources (as this RP is intended for leak detection systems only).

3 Scope

This RP presents a framework for establishing and maintaining an LDP for onshore natural gas transmission pipelines that are jurisdictional to the U.S. Department of Transportation (specifically, 49 CFR Part 192) [1]. Although specifically developed for natural gas transmission pipelines, the approaches covered in this RP may be broadly applicable to other natural gas pipelines and associated sets of asset categories or facilities.

This RP represents industry best practices for selecting and evaluating performance of natural gas transmission pipeline external leak detection systems (LDSs). All forms of leak detection used by a pipeline operator should be managed in a coordinated manner. The overall goal of this RP is to assist operators with detection of leaks quickly and with certainty and therefore minimizing negative consequences.

Onshore intrastate and interstate gas pipeline networks are defined in this RP as the mechanism of gas transport from processing plants in producing regions to those areas with high natural gas demand at higher pressures (typically 200 to 1,500 psi) country wide. Components of intrastate and interstate pipelines may consist of the transmission pipes themselves; compressors, metering, and control stations; pipe valves; SCADA systems; and gas storage. The scope of this RP will focus on transmission pipelines and their associated valves within the intrastate and interstate natural gas pipeline system.

4 Normative References

The following reference documents are important for the application of this document.

4.1 Regulatory Documents and Governmental Guidance

- United States Senate (2020): Protecting our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act. [2]

- DOT PHMSA (2019): Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments. 49 CFR Parts 191 and 192. [1]
- PHMSA Report from C-FER Technologies (2019): Framework for Verifying and Validating the Performance and Viability of Leak Detection Systems for Liquid and Natural Gas Lines. [3]
- USEPA (2019): Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2017. [4]
- ITRC (2018): Evaluation of Innovative Methane Detection Technologies. [5]
- CPUC Report (2017): Safety & Enforcement Division, Natural Gas Leakage Abatement, Summary of Best Practices, Working Group Activities and Revised Staff Recommendations. [6]
- ANSI/ISA 18.2 (2016): Management of Alarm Systems for the Process Industries. [7]
- API RP 1175 (2015): Leak Detection Program Management. [8]
- DOE ARPA-E (2014): Methane Observation Networks with Innovative Technology to Obtain Reductions. [9]
- API RP 1165 (2007): RP for Pipeline SCADA Displays. [10]

4.2 Research Articles and Papers

- Keyes et al. (2020): An enhanced procedure for urban mobile methane leak detection. [11]
- Bell et al. (2020): Evaluation of next generation emission measurement technologies under repeatable test protocols. [12]
- Zimmerle et al. (2020): Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions. [13]
- Sherwin et al. (2020): Single-blind test of airplane-based hyperspectral methane detection via controlled releases. [14]
- Ravikumar et al. (2020): Repeated leak detection and repair surveys reduce methane emissions over scale of years. [15]

- Wang et al. (2020): Machine vision for natural gas methane emissions detection using an infrared camera. [16]
- Fox et al. (2019): A review of close-range and screening technologies for mitigating fugitive methane emissions in upstream oil and gas. [17]
- Fox et al. (2019): A Methane Emissions Reduction Equivalence Framework for Alternative Leak Detection Repair Programs. [18]
- Ravikumar et al. (2019): Single-blind inter-comparison of methane detection technologies – results from the Stanford/EDF Mobile Monitoring Challenge. [19]
- Ulrich et al. (2019): Natural Gas Emissions from Underground Pipelines and Implications for Leak Detection. [20]
- Alvarez et al. (2018): Assessment of methane emissions from the U.S. oil and gas supply chain. [21]
- Feitz et al. (2018): The Ginninderra CH4 and CO2 Release Experiment: An Evaluation of Gas Detection and Quantification Techniques. [22]
- Ravikumar et al. (2018): “Good versus Good Enough?” Empirical Tests of Methane Leak Detection Sensitivity of a Commercial Infrared Camera. [23]
- Schwietzke et al. (2018): Aerially-Guided Leak Detection and Repair: A Pilot Study for Evaluating the Potential of Methane Emission Detection and Cost Effectiveness. [24]
- Tannant et al. (2018): Evaluation of a Drone and Laser-Based Methane Sensor for Detection of Fugitive Methane Emissions. [25]
- Weller et al. (2018): Vehicle-Based Methane Surveys for Finding Natural Gas Leaks and Estimating Their Size: Validation and Uncertainty. [26]
- Yang et al. (2018): Natural Gas Fugitive Leak Detection Using an Unmanned Aerial Vehicle: Measurement System Description and Mass Balance Approach. [27]
- Zimmerle et al. (2018): Current and Near-term Technology Options to Detect Leakage of Hydrocarbons, Water, and Gas from Flowlines. [28]

- Bell et al. (2017): Comparison of methane emission estimates from multiple measurement techniques at natural gas production pads. [29]
- Ravikumar et al. (2017): Are optical gas imaging techniques effective for methane leak detection? [30]
- Tandy, W. D. (2017): Practical Design Guidelines for Fugitive Gas Detection from Unmanned Aerial Vehicles. [31]
- Vaughn et al. (2017): Comparing facility-level methane emission rate estimates at natural gas gathering and boosting stations. [32]
- Zavala et al. (2017): Super-emitters in natural gas infrastructure are caused by abnormal process conditions. [33]
- Brandt et al (2016): Methane Leaks from Natural Gas Systems Follow Extreme Distributions. [34]
- GTI (2016): Improving Methane Emission Estimates Phase III - Cast Iron and Unprotected Steel Pipes. [35]
- Henrie et al. (2016): Pipeline Leak Detection Handbook. [36]
- Kemp et al. (2016): Comparing natural gas leakage detection technologies using an open-source virtual gas field simulator. [37]
- SWRI (2015): Testing of methane detection systems – Phase 2. [38]
- Zimmerle et al. (2015): Methane Emissions from the Natural Gas Transmission and Storage System in the United States. [39]

5 Terms, Definitions, Acronyms, and Abbreviations

5.1 Terms and Definitions

For the purposes of this document, the following terms and definitions apply

Aggregate-Level Survey Method

- Encompasses all instrumentation used for equipment-by-equipment or facility-by-facility style (sometimes called downwind) surveys.

Area Under the Curve (AUC)

- A single value that summarizes performance across a range of detection thresholds and can be viewed as the area under the ROC curve. The AUC value provides a means of comparison between instruments that underwent the same testing protocol. The higher the AUC, the better the instrument's ability to distinguish between true positives, false positives, true negatives and false negatives. AUC values closer 1.0 indicate better performance, with normal values between 0.5 and 1.0. AUC values between 0.0 and 0.5 indicate that the technology is performing in an opposite manner than intended.

Component-Level Survey Method

- Encompasses all instrumentation and platforms used in a component-by-component type of leak detection survey. These systems need to be placed in direct contact with components or on/near the surface directly above a buried asset.

Controlled Gas Release System

- Instrumentation and equipment used to adjust leak flow rates through a combination of pressure regulators, choked-flow orifices, and/or release valves such that a wide range of leak sizes can be produced and maintained at a constant flow rate.

Deployment Platforms

- Equipment where the methane sensor is mounted or placed for deployment such as a handheld device, a drone, an aircraft, a vehicle, or a satellite.

Evaluators

- Instrument certification experts (e.g., individuals performing instrument certification)

External Leak Detection Systems (LDSs)

- Applications that use technology to detect presence of methane or physical changes in environment due to a leak external of the pipeline outer shell. External technology differs from internal technology in its ability to detect the presence of leaks external to the pipeline integrity shell.

False Positive

- A positive indication of a leak by the detection instrument when a leak is actually not present or a leak cannot be found.

False Negative

- A negative indication of a leak by the detection instrument when a leak is actually present.

Instrument Types

- Specific types of methane detection sensors used in transmission pipeline external leak detection

Leak Alarm Threshold

- How the instrument alarms are tuned to recognize that an indication of methane registers as a leak or not. Leak alarm threshold is the **methane concentration** at which an emission is classified as a leak. For example, if a leak alarm threshold of 100 ppm is used, if a leak surveyor obtains a concentration reading of more than 100 ppm during leak survey then a leak indication is found. The person will have to investigate the leak indication in order to verify the location of the leak.

Leak Detection Method

- Classification of a survey, sampling or monitoring methodology used to detect leaks.

Leak Detection Program (LDP)

- Top-level term that encompasses all the various LDSs (which may include multiple techniques) employed by the pipeline operator and identifies all methods used to detect leaks and the policies, processes, and the human element.

Leak Indication

- Alarm or other notification from a leak detection system that suggests the presence of a leak

Leak Margin

- Defines the **flow rate** (as opposed to concentration in leak alarm threshold) above which is considered an actual leak vs. a non-detect from the instrument, i.e., the flow rate at which an emission is considered a leak. For example, if the leak margin is 2 scfh, then an emission with size 1 scfh is not a leak, an emission of 6 scfh is a leak. Leak margin can be helpful for operators to prioritize bigger emissions in their leak surveys.

Method Class

- Methodologies used to detect leaks on transmission pipelines such as component-level inspections, downwind measurements or continuous monitoring.

Probabilistic Approach

- Performance is rated on an instrument systems ability to delineate between false positives and false negatives according to the desired use case for that system and is therefore focused on leak detection methods used in addition to individual methane sensor performance. Validation using probabilistic approaches include testing how one utilizes instrument analytics, algorithms, and data outputs to improve the probability of a positive result. Probabilistic approaches go beyond "Pass/Fail" for analyzers to techniques that explore system performance for combinations of instruments, instruments with advanced analytics and data processing features, chosen instrument settings, and frequency of deployment are all considered.

Receiver Operating Characteristic Curve (ROC)

- A measure for evaluating a binary classifier's performance. A leak detection instrument can be considered a binary classifier as its main purpose is to distinguish between two conditions: registering a "leak" or registering "no-leak". Conducting an ROC analysis can provide a systematic approach for quantifying the leak detection ability of a technology across a range of leak thresholds.

Stationary Continuous Monitoring Method

- Leak detection sensor arrays or permanently mounted monitors gathering continuous data over longer timeframes.

Technology Classes

- Categorizations of sensor types such as ranged lasers or in-plume lasers.

Technology Performers

- Technology developers wishing to certify an instrument

True Negative

- A negative indication of a leak by the detection instrument when a leak is actually not present.

True Positive

- A positive indication of a leak by the detection instrument when a leak is actually present.

5.2 Acronyms and Abbreviations

For the purpose of this document, the following abbreviated terms apply.

API	American Petroleum Institute
CIPS	Correlated Interference Polarization Spectroscopy
CNT	Carbon Nanotube
CFR	Code of Federal Regulations
CRDS	Cavity Ringdown Spectroscopy
DIAL	Differential Absorption LiDAR
EFRD	Emergency Flow Restriction Device
FID	Flame Ionization Detector
GPS	Global Positioning System
LDAR	Leak Detection and Repair
LiDAR	Light Detection and Ranging
LDP	Leak Detection Program
LDS	Leak Detection System
MOS	Metal Oxide Sensor
NDIR	Nondispersive Infrared
OAICOS	Off Axis Integrated Cavity Output Spectroscopy

OGI	Optical Gas Imaging
OPFTIR	Open Path Fourier Transform Infrared
OPLAS	Open Path Absorption Spectrometer
PID	Photoionization Detector
ROC	Receiver Operating Characteristics
RP	Recommended Practice
SCADA	Supervisory Control And Data Acquisition
TDLAS	Tunable Diode Laser Absorption Spectroscopy
TCF	Trillion Cubic Feet
WMS	Wave Modulation Spectroscopy

6 Leak Detection System Management Processes

Leak detection sensors should be embedded within a robust LDS as recommended in API RP 1175 [8] and should consider such factors as company goals for leak detection (e.g. surveying for large leaks vs. component-level emission rates); be appropriate for weather conditions as necessary (such as temperature extremes), comply with local regulatory requirements, and address specific site requirements (such as risk associated with pipeline proximity to sensitive areas). Effective leak detection requires appropriate sensor platforms and sampling methods for any meaningful leak detection to occur. A high-performing sensor deployed in an unsuitable way may not detect leaks or may be too resource-intensive to implement into operations.

Establishing an LDS is dependent on a clear understanding of the desired company objectives. The following are the top 3 external LDS objectives considered most common for natural gas transmission pipelines:

- **Objective 1:** The LDS should include one or more methane sensors capable of detecting gas concentrations above a pre-defined detection limit or difference from baseline concentration, while minimizing false positives. Several factors can affect false positives such as:
    - Leak detection threshold
    - Sensitivity of follow-up, handheld equipment (e.g. when a mobile survey

instrument is more sensitive than the handheld instrument used to verify the leak indications).

    - Presence of biogas in the area
    - Changing weather conditions (during initial survey and follow-up)

- **Objective 2:** LDSs should include one or more methane sensors capable of conducting leak surveys of large areas, over multiple types of terrain in search of high emitting sources from below-ground pipes.
- **Objective 3:** LDSs should achieve compliance with both local and national regulations.

7 Selection of Leak Detection Methods, Platforms, and Instrumentation

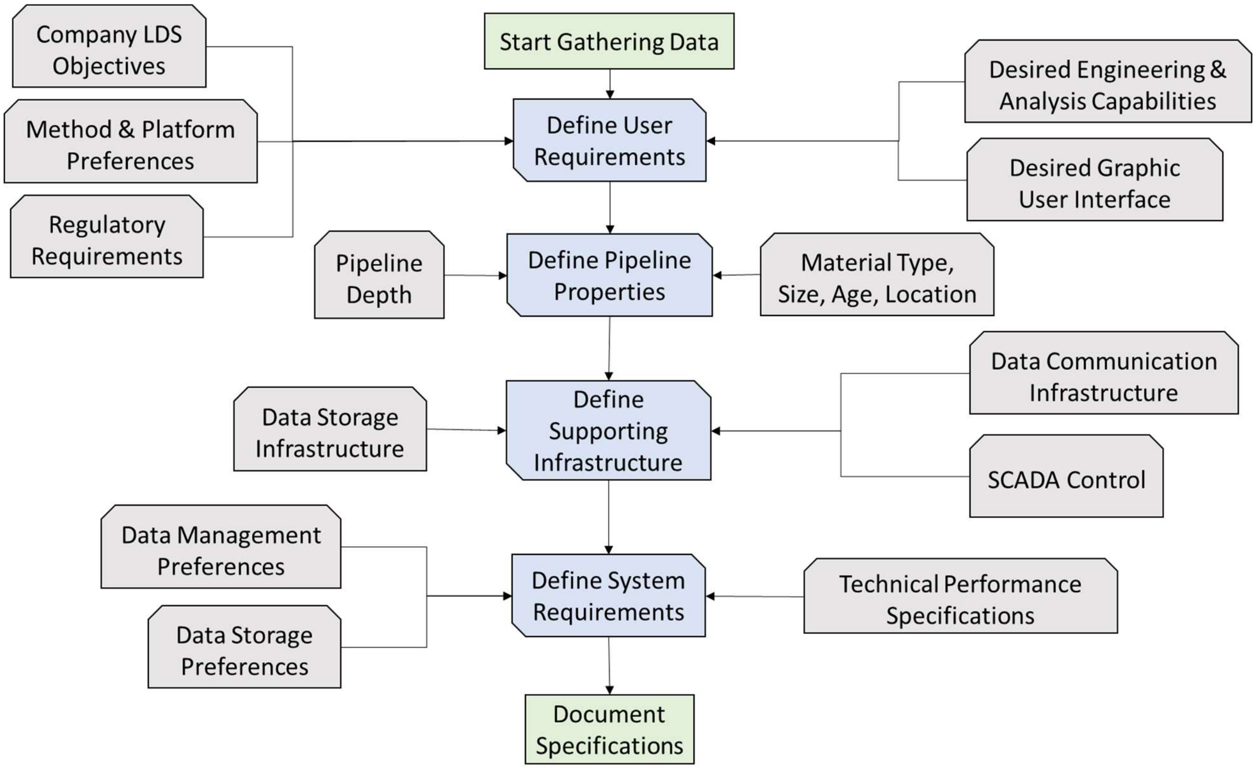
7.1 Selection Process Overview

Selection of leak detection instrument systems will be reliant on operator requirements, physical properties of the pipeline, constraints with supporting infrastructure, and/or desired system specifications. The distinctiveness of each pipeline, the surrounding environment, operator policies, and regulatory landscape should guide the final selection of the most appropriate leak detection instrument. Establishing the full range of functional and technical performance requirements for the use case of the instrument will be necessary and will involve data gathering and specification development. Selection of leak detection systems should be based on an objective assessment of technology-neutral, quantitative metrics and directly related to stakeholder goals.

Instrument user requirements should be identified and matched with desired sampling methods and platforms. This will inform the evaluation metrics once an instrument system is selected for certification.

Figure 1 provides a flow chart outline for the instrument selection process. It summarizes high-level performance indicators needed to evaluate instruments, remain compliant with regulations, as well as align with policies and internal requirements of pipeline operators. Each of the boxes within the flow chart will be described in detail in the sections that follow.

Figure 1. Flow chart of the instrument selection process



7.2 Aligning Instrument Selection with Company LDS Objectives

A clear understanding of company objectives is necessary and should be agnostic to instrumentation or platform in order to expand the number and type of potentially successful leak detection instruments. Any leak detection instrument chosen should be embedded within a robust LDS as recommended in API RP 1175 [8] and should strongly consider company goals for leak detection, compliance with regulatory requirements, and an understanding of specific site requirements (such as risk associated with pipeline proximity to sensitive areas). Examples of LDS objectives include (but are not limited to) the following:

- Detection of emissions to immediately repair hazardous leaks;
- Prioritization of non-hazardous leak repair;
- Development of company specific emission factors;
- Assess performance-based comparisons of various leak mitigation technologies;
- Location of leak sources at spatial resolutions that allow direct identification of a leaking

components;
- Compliance with a specific regulation or voluntary program.

7.3 Aligning Instrument Selection with Regulatory Requirements and RPs

Incorporating applicable leak detection regulations (both existing and pending) into the leak selection process is necessary to ensure technologies chosen will meet regulatory requirements. The federal regulatory authority that oversees fugitive emissions from natural gas transmission leaks is the Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) [1]. States that have been delegated regulatory authority from PHMSA typically implement applicable regulations through an environmental department, public utility commission (PUC), and/or other similar agencies [36].

States may also adopt their own regulations that exceed federal requirements. Local governments or districts may also adopt their own fugitive emissions regulations and/or have delegated authority to implement federal or state requirements.

7.4 Aligning Instrument Selection with Desired Engineering & Analysis Capabilities and User Interface

Once identification of regulatory requirements and company objectives are complete, user requirements should be gathered from the perspective of analysts, controllers, and leak detection engineers. Understanding how users will interact with leak detection instrumentation and resulting data will help in the eventual selection of an instrument that meets performance requirements associated with leak detection limits, monitoring procedures, data communication, data management, and instrument maintenance requirements.

7.5 Aligning Instrument Selection with Desired Sampling Methodology and Sensor Platform

Understanding desired sampling method preferences is key in identification of a technology that will ultimately perform to intended expectations. Companies should become familiar with typical leak detection methods, effective platforms for mounting sensors, and commonly used methane measurement instrumentation. Table 1 can be used as a guide to determine which technology classes and instrument types are best suited to a particular sampling or surveying need. Note that instrument types suitable for one type of method or platform may also be coupled with other instrument types to support a wholistic leak detection strategy. A description of advantages and disadvantages related to instrument types outlined in Table 1 are available in the Appendix.

Table 1. Aligning Methods, Platforms, and Technologies

External LDS Platforms	Technology Classes	Commonly Used Instrument Types
Above Ground Stationary	Ranged Laser	OPFTIR, TDLAS
	In-Plume Laser	WMS, CRDS, ICOS, TDLAS, MCS
	In-Plume Point Sensor	CNT
	Catalytic Combustion/Pellistor	Catalytic Pellistor
	Metal Oxide Senor	MOS
	Nondispersive IR	NDIR
Vehicle Mounted Sensors	Ranged Laser	TDLAS
	In-Plume Laser	WMS, CRDS, OA-ICOS
	Etalons	CIPS
	IR Imaging	OGI
Foot Patrol (Handheld) Sensors	Ranged Laser	TDLAS
	In-Plume Laser	Miniature OPLAS
	Etalons	CIPS (ex. DPIR, OMD)
	Nondispersive IR	NDIR
	Flame Ionization (FI)	FID
	Photo Ionization	PID
	Thermal Conductivity	Thermal Conductivity
	IR Imaging	OGI
	Catalytic Combustion/Pellistor	Catalytic Pellistor
Unmanned Rotary (Drone) Mounted Sensors	Ranged Laser	TDLAS, LiDAR
	In-Plume Laser	Miniature OPLAS
Manned Rotary (Helicopter) Mounted Sensors	Ranged Laser	TDLAS, DIAL
Unmanned Fixed Wing (Drone) Mounted Sensors	In-Plume Laser	TDLAS, OA-ICOS, WMS, Miniature OPLAS
Manned Fixed Wing (Drone) Mounted Sensors	Ranged Laser	DIAL
	In-Plume Laser	CRDS, OA-ICOS, WMS
	IR Imaging	Imaging Spectrometer (Hyperspectral)
Satellite	IR Imaging	Imaging Spectrometer (Hyperspectral)

7.6 Aligning Instrument Selection with Requirements of Individual Pipelines

Once underlying user requirements are effectively defined, the unique physical requirements specific to the pipeline being monitored should be obtained. Because not all leak detection instruments are applicable to all physical environments, it is necessary to define pipeline physical details and various operating states. If a pipeline operates in an inaccessible region, this may change the type of measurement platform from vehicle or foot patrol to aircraft. This means that instrumentation should be adjusted to leak detection on air-based platforms.

7.7 Aligning Instrument Selection with Supporting Operator Infrastructure

Desired technical specifications of any telecommunication systems, SCADA systems, data analysis models, geodatabases, and data storage systems that may interact with leak detection instrumentation should be defined. Any limitations of existing infrastructure should be understood before selection and eventual evaluation of the technology occurs. If telecommunication infrastructure does not support data transfer requirements of an identified technology, the technology may not meet some of its intended performance metrics. Other leak detection instrument systems may require dedicated analysts that may not be transferrable to some operations.

7.8 Aligning Instrument Selection with Hardware/Software Requirements

A description of how an instrument should operate within its surrounding environmental conditions should be developed in adherence with regulatory parameters and aligned with company objectives. The following list of specification types should be considered at a minimum.

- *Power Requirements:* Ability to operate in remote locations. Battery life and operational voltage should also be considered.
- *Hardware Specifications:* Size and weight of the instrument that may cause deployment constraints. Ease of use, maintenance requirements, operating temperature and humidity, system cost, and desired ancillary instrumentation such as a meteorological station should be defined.
- *Detection Capabilities:* Detection capability is a composite measure of the size of a leak that that an instrument is capable of detecting and the time required to issue an alarm in the event a leak of that size occurs. Typical detection specification types include whether the instrument

detects in units of % gas or ppm, the detection range (ex. 5-100% gas or 0-50,000 ppm-m), and the detection distance (ex. how close or how far from the source the instrument needs to be to operate effectively).

- *Data Quality Features:* Desired data quality features, frequency of calibration requirements, diagnostic self-testing capability, testability while in service, alarming ability, false positive rate, adjustable thresholds, and user interface for data analysis.
- *Data Communication Capabilities:* Data transmission from instrument to operations. Wireless or cellular capacity and/or remote access software (ex. phones or tablets).
- *Safety Features:* Class 1/Division 2 safety features as appropriate. Review claims of "designed" to meet Class 1/Div 2, vs "certified." Instruments positioned close to sources may require a certification of Class 1/Div 2 at a minimum. For ranged laser instruments, eye safety features should be evaluated depending on the intended method and platform for the instrument.

7.9 Aligning Instrument Selection with Platform and Specification Type

Instrument performance is directly dependent on the particular specifications of the sensor, as well as its chosen platform and so should be understood. Certain instrument types are specialized and may only perform well on specific platforms. Instrument developers may also customize the instrument design according to specific needs of the platform and desired sampling method.

Therefore, it is recommended to collect performance information via questionnaire on leak detection instrumentation and the qualifications of technology development companies prior to acquisition of instruments so vendor performance may be matched with company expectations. Sample questions are included in Annex B.

7.10 Periodic Review of Selection Process

It is important to periodically evaluate instrument selection procedures to ensure compliance with the leak detection strategy. Examples that may trigger a review include the following:

- Population or environmental changes have occurred around a monitored pipeline thus warranting a different type of technology or platform for leak detection.
- Leak detection requirements from a regulatory body change, or company strategies change that require different or enhanced leak detection instrumentation.

- Performance enhancements resulting from new, commercially available technology may warrant a refresh of instrumentation in certain situations.
- New assets are built, existing assets are modified, or pipeline service has changed that warrants an extension or modification to the types of instrumentation or platforms used for leak detection monitoring.

A periodic review may also be performed on a timed cycle (such as a five-year cycle, for example) with the purpose of keeping the technology selection process updated with current information. The updated instrument selection process may then be re-applied to new conditions.

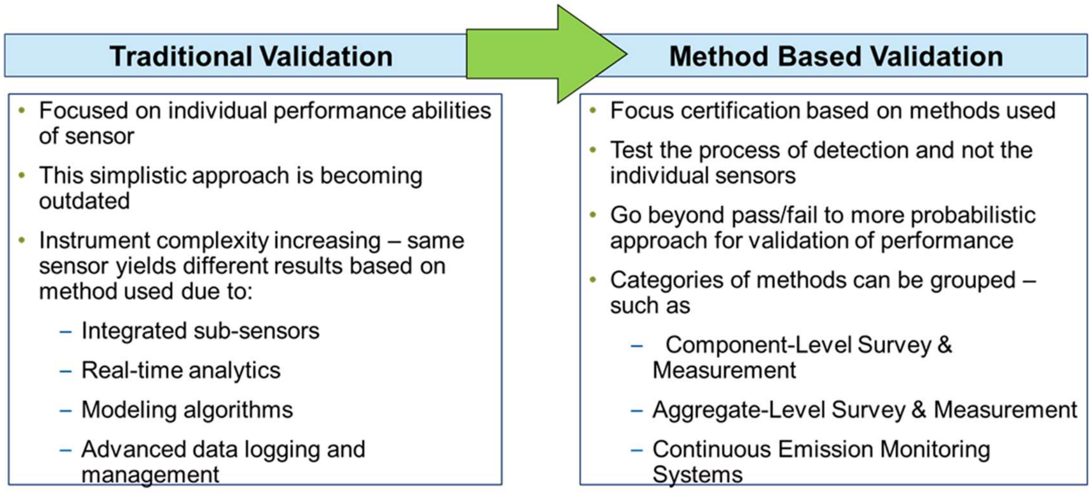
8 Framework for Certification Organizations

8.1 General

This RP establishes a framework that can be used by an independent certification organization to develop validation procedures for leak detection instrument systems used on transmission pipelines. The framework is designed to provide general guidance for a certification organization to provide comprehensive yet flexible, and efficient approaches to instrument system certification. This RP will focus on the process of validating and certifying leak detection instruments, or systems of instruments deployed under pre-defined sampling methods and platforms.

Evaluation of the instrument system performance requires more advanced test methodologies and facilities than simply validating sensor performance in a lab (Figure 2) and should advance beyond “Pass/Fail” for analyzers to techniques that incorporate probabilistic approaches such that combinations of instruments, instruments with advanced analytics and data processing features, chosen instrument settings, and frequency of deployment can be considered in the performance evaluation.

Figure 2. Comparison of traditional instrument validation with whole method-based validation



Traditional Validation

- Focused on individual performance abilities of sensor
- This simplistic approach is becoming outdated
- Instrument complexity increasing – same sensor yields different results based on method used due to:
  - Integrated sub-sensors
  - Real-time analytics
  - Modeling algorithms
  - Advanced data logging and management

Method Based Validation

- Focus certification based on methods used
- Test the process of detection and not the individual sensors
- Go beyond pass/fail to more probabilistic approach for validation of performance
- Categories of methods can be grouped – such as
  - Component-Level Survey & Measurement
  - Aggregate-Level Survey & Measurement
  - Continuous Emission Monitoring Systems

This section of the RP will identify and define appropriate performance criteria for both performers (technology developers wishing to certify an instrument) as well as evaluators (instrument certification experts). By basing performance testing on a suggested probabilistic approach, leak detection instrument evaluation may be performed on many different types of leak detection instruments regardless of their configuration.

8.2 Scope of Certification Organization Framework

Method classifications and performance determination procedures are intended to be general enough to allow flexibility as new leak detection instruments are developed and placed within a method category. Neither the inclusion of methods, the definition of classes, or the probabilistic approaches for defining performance are intended to be completely prescriptive or exhaustive. The structures within the certification organization framework presented in this RP are intended to provide a functional foundation and suggested procedures for test protocol development. Certification guidelines will be developed for external leak detection instruments suited for onshore intrastate and interstate transmission pipeline systems. Offshore systems located in sub-marine environments require specific and separate approaches to leak detection and are beyond the scope of the RP. The methods described in this RP are intended to validate instruments suited for the detection of leaks only and not intended for validation of mass emission rates from individual or aggregated sources.

8.3 Classifying Leak Detection Instruments and Platforms into Method Classes

Commonly used instrument types should be categorized into instrument classes. Then, further categorized by commonly deployed platforms. Platforms can then be used to delineate common sample method classes. Table 2 describes three common methods for external leak detection for onshore transmission pipelines:

- Component-Level Survey and Measurement
- Aggregate-Level Survey and Measurement
- Stationary Continuous Monitoring Systems

The classes of methods combine technologies, platforms, work practices, and analytics for use in an LDP. Certification testing in a given method class should be completed using generalized protocols for that class – understanding that there may be permutations and refined protocols to evaluate specific performance indicators within each method.

Table 2. Categorizing Technology Classes by Deployment Platform

Method Class	Deployment Platform	Technology Class	Example Instrument Types
Component-Level Survey and Measurement	Handheld and Vehicle-Mounted	Ranged Laser	TDLAS
		In-Plume Laser	Miniature OPLAS
		Etalons	CIPS
		Nondispersive IR	NDIR
		Flame Ionization (FI)	FID
		Photo Ionization	PID
		Thermal Conductivity	Thermal Conductivity
		IR Imaging	OGI
		Catalytic Combustion/Pellistor	Catalytic Pellistor
Aggregate-Level Survey and Measurement	Vehicle-Mounted	Ranged Laser	TDLAS
		In-Plume Laser	WMS, CRDS, OA-ICOS
		IR Imaging	OGI
	Unmanned Rotary (Drone) Mounted	Ranged Laser	TDLAS, LiDAR
		In-Plume Laser	Miniature OPLAS
	Manned Rotary (Helicopter) Mounted	Ranged Laser	TDLAS, DIAL
	Unmanned Fixed-Wing (Drone) Mounted	In-Plume Laser	TDLAS, OA-ICOS, WMS, Miniature OPLAS
		Ranged Laser	DIAL
		In-Plume Laser	CRDS, OA-ICOS, WMS

Method Class	Deployment Platform	Technology Class	Example Instrument Types
	Manned Fixed-Wing (Airplane) Mounted	IR Imaging	Imaging Spectrometer (i.e., Hyperspectral)
	Satellite Mounted	IR Imaging	Imaging Spectrometer (i.e., Hyperspectral)
Stationary Continuous Monitoring Systems	Semi-Permanent (Tripod or Truck) or Permanent (Tower)	Ranged Laser	OPFTIR, TDLAS
		In-Plume Laser	WMS, CRDS, ICOS, TDLAS, MCS
		In-Plume Point Sensor	CNT
		Catalytic Combustion/Pellistor	Catalytic Pellistor
		Metal Oxide Senor	MOS
		Nondispersive IR	NDIR
		IR Imaging	Imaging Spectrometer (i.e., Hyperspectral)

8.4 Infrastructure Framework for Certification Organizations

Validation testing and instrument certification should be offered by an independent organization that is helpful and informative for the end user of the leak detection system. The types of certifications that may be offered include (but are not limited to) leak detection capability, method class, environmental performance, and human/system interface certifications.

Leak detection system validation and certification requires a specific type of facility infrastructure to ensure integrity of the certification. This includes properly performed controlled testing for the development and promulgation of clear, reproducible leak detection performance protocols administered to accurately simulate leaks from natural gas transmission pipelines.

8.4.1 Controlled Gas Release Systems

Any facility performing controlled releases of gas must have the proper permits in place to release measured amounts of natural gas from a source where the concentration of constituents/species are closely monitored (i.e, percentage of methane, ethane, and other gases). The facility should possess the ability to adjust leak flow rates through a combination of devices that can produce and maintain a wide range of leak sizes at a constant flow rate with a known level of uncertainty/precision.

Once a leak rate is set, the flow rate should be readable and verifiable at the point of release with devices such as flow meters and/or laminar flow elements for above and below ground simulated sources. Laminar flow elements should be capable of measuring pressure drops such that below ground leak rates can be calculated at the subsurface point of release.

Some leak detection technologies may have minimum detection limits that are higher than permit limitations at the testing facility for a gas release. The certification organization should be responsible for understanding, maintaining, and posting ranges for pertinent testing by communicating with technology developers.

8.4.2 Environmental Evaluation Systems to Perform Environmental Certifications

It is recommended that certification organizations install one or more meteorological weather stations capable of collecting wind speed, wind direction, temperature, and humidity at a minimum. This data will be important as meteorological conditions could be a factor impacting the ability of an instrument to detect a leak, depending on the method chosen and the platform used. Any controlled gas release area should be located a reasonable distance from other known sources of methane that could cause interference during performance testing.

As stationary leak detection sensor arrays become more sophisticated and affordable, it is conceivable that stationary continuous sensor networks could be situated along right-of-way (ROW) segments of high risk/high consequence natural gas transmission lines in the near future. Although at the time that this framework was assembled, continuous leak detection monitors were not widely used, it is recommended that certification organizations be prepared to conduct performance testing of instruments deployed under the stationary continuous monitoring method in addition to the two other more widely used method classes of instruments.

Under this method, leak detection instrumentation would be deployed in outdoor environments where instruments could remain for extended periods of time such that an instrument’s ability to withstand environmental elements such as extreme temperatures, humidity, and dust may be evaluated and documented. The installation location of the stationary instrument may be unclear or unknown so it will be important to test a full range of environmental tolerances and document limitations so the instrument can ultimately be matched with the proper environment.

Evaluating environmental tolerance ranges are best performed in laboratory settings where variances of temperature, humidity, and dust can be controlled. This means that in addition to performing a controlled release in an outdoor setting, the certification organization should be capable of performing performance testing in temperature-controlled chambers such that the upper and lower bounds of temperature and humidity can be evaluated.

8.4.3 Calibration Evaluation

Leak detection instrument systems should have vendor established methods of calibration to verify and maintain performance on a regular basis. The effectiveness of each established calibration method should be evaluated by the certification organization. Proper calibration techniques and intervals should be communicated to the certification organization by the vendor to ensure proper operation of the system during certification testing. The certification organization may also verify the effectiveness of the calibration interval by performing tests within and beyond the recommended calibration interval to determine whether the interval is sufficiently reliable.

Certification organizations should also possess the necessary tools for a technology performer to conduct calibration testing on handheld leak detection instruments brought in for performance testing. A calibration (or reference) compound (such as methane) will typically be used to adjust the leak detection instrument reading to a known value that is approximately equal to the leak indication concentration. The leak indication concentration is the methane concentration of the leak source that indicates a leak is present. As a result, the leak indication concentration is the instrument reading based on the reference compound.

Calibration precision should be tested on handheld instruments by observing the degree of agreement between measurements of the same known value and expressed as the relative percentage of the average difference between the instrument reading and the known concentration. Of equal importance is the instrument's ability to flag an indication when the methane concentration exceeds the leak definition threshold. For example, if a leak indication concentration is 1.0 ppm methane, then any source emission that results in a concentration that yields an instrument reading of 1.0 ppm (calibrated with methane) would be classified as a detection on the instrument. [40] The percentage that the instrument agrees with the classification from the known concentration can be evaluated as well.

For each compound measured during certification, the performer should demonstrate that calibration gas contains a composition that results in a concentration reading approximately equal to the applicable leak definition. If calibration gas mixtures are used, they should be analyzed and certified by the manufacturer to be within 2 percent accuracy, with the shelf life specified. This will help technology performers with handheld instruments establish calibration protocols that align with compliance requirements outlined in Method 21. [40]

Calibration gases may be prepared according to any accepted gaseous preparation procedure that will yield a mixture accurate to within 2 percent. [40] Prepared calibration gases (i.e., mixtures prepared that day and not obtained from an already certified gas cylinder) should be replaced each day of use unless it is demonstrated that degradation does not occur during storage. Additionally, calibrations may be performed using a compound other than the reference compound. In this case, a conversion factor should be determined for the alternative compound such that the resulting meter readings during calibration can be converted to reference compound results. [40]

Leak detection instruments deployed under the aggregated-level survey method are typically complex and thus could require laboratory grade calibration which may be unreasonable to perform on site. In this case, the performer should provide calibration results as well as the date and time of the most recent calibration. Time since last calibration should be no more than 3 days. However, since calibration frequency requirements can vary dramatically depending on instrument type, it is up to the evaluator to determine if the length of time since last calibration will be sufficient enough for performance testing to provide a reliable result. It is important that each instrument involved in testing be calibrated to vendor specifications (not just the methane analyzer). This includes but not limited to GPS equipment, meteorological equipment, optical gas imaging (OGI) cameras, sample cannisters, communication systems, and power systems.

8.4.4 Aerial Platform Evaluations

The certification organization should have infrastructure in place to evaluate leak detection instruments that use aerial platforms such as rotary and/or fixed-wing drones, manned helicopters and planes and should consider FAA regulations, airspace clearances from local aviation authorities, site safety risk assessments, equipment preparation (such as landing areas), notifications, and personnel safety training applicable to working on or near active aircraft.

8.5 Leak Detection Instrument Certification Using a Probabilistic Approach

Leak detection instrument validation using a probabilistic approach involves examination of false negatives (FNs) and false positives (FPs). Prior to instrument performance testing, the evaluator should choose a leak margin in order to define the two outcomes of detect vs. non-detect. A leak margin set to zero means that at 0 standard cubic feet per hour (scfh), no leak is considered present, and greater than 0 scfh, a leak is considered present.

The performer should determine the leak detection threshold value of each instrument undergoing testing. This is the number that the instrument uses to register an indication that a leak is present. Units used to define leak detection within the instrument is of little importance.

A method class is identified (component-level, aggregated-level, or continuous) for the test and instrument calibration or a self-test is performed on-site during the day of the controlled release, or calibration results are provided to the evaluator for more complex instruments.

Based on the method class being tested, the evaluator determines the number of controlled releases, the length of time for each gas release (as well as air freshening times between each release), and the range of flow rates for the test. Chosen flow rates are then categorized into bins. For example, the evaluator may determine that 25 controlled releases be performed at varying flow rates ranging from 0-20 scfh with controlled releases spread evenly among five bins. An example is shown in Table 3 below and is meant entirely for demonstration purposes since leaks on transmission pipelines may be 100s of scfh.

Table 3. Example Leak Range Bins

Bin Number	Leak Test Rate (scfh)
1	0 - 4
2	4 - 8
3	8 - 12
4	12 - 16
5	16 - 20

The number of controlled releases, flow rate ranges, and bins for each experiment should be chosen with care and should reflect the methods and platforms being tested during the controlled release.

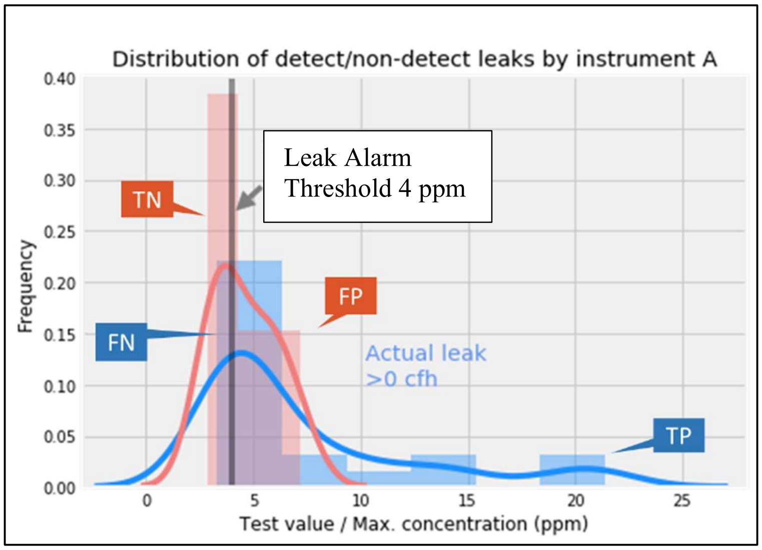
During each controlled release, data collected should include Leak ID, known flow rate, time of release, whether or not each instrument being tested detected the leak or registered a non-detect and the time (indicated by yes or no), the maximum concentration readings of each measurement, prevailing wind speeds, and wind direction. An example dataset is shown in Table 4 below.

Table 4. Example Controlled Release Dataset

Leak ID	Known Flow Rate	Detection Inst. A	Detection Inst. B	Meas. A PPM	Meas. B PPM
1	0	Yes	No	6.2	2.5
2	1	No	No	3.33	2.99
3	3	Yes	Yes	4.32	3.86
4	4	No	Yes	3.92	4.1
5	0	No	Yes	3.4	3.52
6	6	Yes	Yes	5.57	5.32
7	8	Yes	Yes	6.23	5.75
8	5	Yes	No	5.32	3.34
9	12	Yes	Yes	10.44	9.62
10	11	Yes	Yes	8.23	7.41

Data collected from controlled releases should be used to calculate detection probability for each bin, the distribution of max concentration readings registered by the instrument, and distributions of detect vs. non-detect. Leak margin and leak alarm threshold can be incorporated into concentration distributions. True positives (TPs) and FNs can be colored separately from true negatives (TNs) and FPs to better visualize the separation. An example of this visualization is shown in (Figure 3).

Figure 3. Example Distribution of Detect vs. Non-Detect of Leaks



True positive rate (TPR) and false positive rate (FPR) should also be calculated from the data. TPR is calculated from the true positives divided by the sum of true positives plus false negatives.

$$\text{Equation - } TPR = \frac{TP}{TP+FN}$$

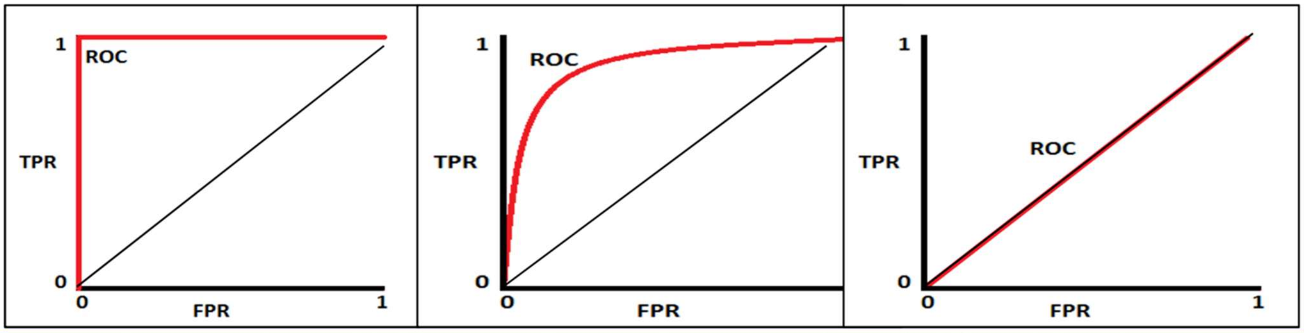
FPR is Calculated from the false positives divided by the sum of the false positives plus true negatives.

$$\text{Equation - } FPR = \frac{FP}{FP+}$$

TPR and FPR can be combined with receiver operating characteristics (ROC) curve and Area Under the Curve (AUC) techniques to develop a single number indicative of the performance of the system. This approach presents instrument performance as a range of tradeoffs between TPR and FPR, as well as provides a way to quantify results (detect vs. non-detect) across a range of leak thresholds potentially used by the operator.

The AUC provides a quantitative means of summarizing system performance into a single number. The higher the AUC, the better the instrument has distinguished between TPs and TNs. A perfect AUC curve will have an AUC of 1.0 (Figure 4 - left). The far-right graph in Figure 4 shows an AUC score of 0.5. This result means that the instrument registered random assignments of detect vs. non-detect. In other words, the instrument possessed no ability to discriminate between TPs and FPs. The AUC score can actually go below 0.5, which would mean the instrument was giving the opposite results from what was expected – that is, it consistently registered FN and FP instead of TN and TP. Typically, however, distributions will overlap which introduces some error. This result will typically fall somewhere between 0.5 and 1.0 as shown in the middle graph in Figure 4 which has an AUC of 0.7.

Figure 4. Types of ROC curves



Adapted from – Narkhede (2018) [41].

This approach can be used to gauge performance of a single instrument for which a minimum AUC score could determine a pass or fail measure of performance, or this approach could be used to compare the performance of one instrument to another.

8.6 Framework for Performance Certification by Method Class

Topics to be considered by the certification organization for evaluation and certification procedures for systems by method class will be explored in this section. The information in this section can serve as a foundation for the topics that should be considered by evaluators during development of standardized repeatable performance test procedures while still maintaining the rigor needed for each individual instrument undergoing performance testing.

Commonly used instrument types may be categorized according to Table 2 into the following three method classes:

- Component-level survey and measurement
- Aggregate-level survey and measurement, and

- Stationary continuous monitoring systems

The component-level survey method class of instruments/systems encompasses all instrumentation and platforms used in a component-by-component type of leak detection survey. The aggregate-level survey method encompasses all instrumentation used for equipment-by-equipment or facility-by-facility style (sometimes called downwind) surveys. Further, the stationary continuous monitoring method takes the aggregated-level survey a step further with leak detection sensor arrays or permanently mounted monitors gathering continuous data over longer timeframes.

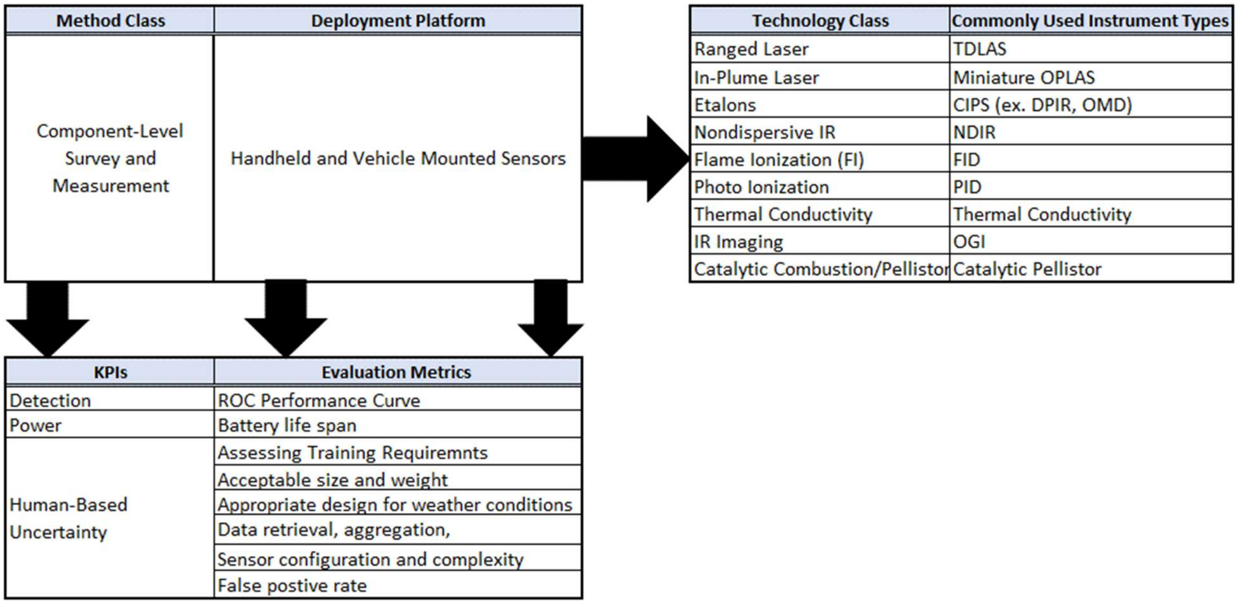
Each technology within a given method class may require a slightly different evaluation/certification technique. However, each method class will have instrument deployment protocols that are similar. For example, handheld lasers, etalons, optical imagers, and non-dispersive infrared instruments deployed under EPA Method 21 [40] and/or guidelines for handheld optical gas imagers deployed under the EPA Alternative Work Practice [42] could all be considered within the component-level survey and measurement method class. Likewise, technology classes that deploy on platforms using sample methods such as the EPA Other Test Method 33 (OTM33) [43], OTM33A [44], fly-over survey protocols, or drive-by leak detection guidelines could be placed within the aggregate-level survey and measurement method class. Monitoring protocols related to above-ground stationary systems such as sensor arrays could be tested within the stationary continuous monitoring system method class. These similarities offer opportunities for a certification organization to streamline certification protocols.

8.6.1 Component-Level Survey and Measurement Methods Certification Protocol Considerations

Component-level leak detection may be accomplished using portable (i.e. handheld or vehicle-based) instruments to detect leaks from individual leaking components (such as pressure relief valves or flanges) or by being placed on or near the surface directly above a buried pipeline (as opposed to aggregate-level vehicle-based systems). Instrument classes commonly used for this leak detection method include handheld ranged lasers, in-plume lasers, etalons, non-dispersive infrared, flame and photo ionization devices, thermal conductivity sensors, infrared and acoustic imagers, as well as catalytic combustion devices. Figure 5 summarizes key performance indicators

(KPIs) that a certification organization may consider when attempting to validate leak detection instrumentation in the component-level method class.

Figure 5. Platforms, Technologies, and KPIs: Component-Level Survey Method



Method Class	Deployment Platform
Component-Level Survey and Measurement	Handheld and Vehicle Mounted Sensors

Technology Class	Commonly Used Instrument Types
Ranged Laser	TDLAS
In-Plume Laser	Miniature OPLAS
Etalons	CIPS (ex. DPIR, OMD)
Nondispersive IR	NDIR
Flame Ionization (FI)	FID
Photo Ionization	PID
Thermal Conductivity	Thermal Conductivity
IR Imaging	OGI
Catalytic Combustion/Pellistor	Catalytic Pellistor

KPIs	Evaluation Metrics
Detection	ROC Performance Curve
Power	Battery life span
Human-Based Uncertainty	Assessing Training Requiremnts
	Acceptable size and weight
	Appropriate design for weather conditions
	Data retrieval, aggregation,
	Sensor configuration and complexity
	False postive rate

At the component-level, instrument types primarily include handheld or vehicle-mounted devices falling into the technology classes and types shown in Figure 5. In addition to detection evaluation involving ROC and AUC techniques, other KPIs should be evaluated including the power and level of uncertainty associated with different operators. The level of uncertainty associated with different operators of the instrument is crucial for this method class. Although some vehicle-based systems exist in this method class, leak detection instruments used for this method are predominantly handheld so a clearly written and all-inclusive standard operating procedure should be included to minimize uncertainty introduced from different operating procedures. A properly designed method based on an instrument that performs well will minimize this uncertainty.

8.6.1.1 Instrument Calibration for Component-Level Survey Method

During calibration, the instrument should be assembled and started according to the instructions provided by the manufacturer for the recommended warm-up period and preliminary adjustments. Methane analyzers should be have a calibration check by introducing a calibration-grade gas mixture to the analyzer and recording the observed meter reading [40]. A response time test should be performed prior to validation according to EPA Method 21 [40]. The performer should demonstrate that the leak detection instrument should be readable to +/- 2.5% of the specified leak definition concentration to remain in compliance with Method 21 at the end of the calibration [40].

Optical gas imaging technology undergoing performance testing can be calibrated through the detection of a reference compound where a chambered vessel is filled with the reference gas of known concentrations and mounted onto the lens of the OGI camera. A video overlay allows the user to adjust camera settings to align the gain and level amounts to match with the desired concentration thus allowing the camera to be calibrated. Alternatively, the raw pixel intensity from the OGI camera's detector can be used in a laboratory setting developed with gas and reference cells against a temperature-controlled background. In this pixel intensity approach, the OGI camera images are processed with a pixel intensity analyzer or software algorithm that gathers and evaluates the raw pixel data from the detector and are used to construct a quality control chart that defines the quality control criteria [45].

8.6.1.2 Controlled Release Set-Up for the Component-Level Survey Method

The evaluator should determine the number of controlled releases, the length of time for each gas release (as well as air replenishment times between each release), and the range of flow rates for the test. Chosen flow rates should be then categorized into bins to assure a minimal statistical acceptance when conducting the probability analysis later. Although it is up to the evaluator to make the final determination, the following minimal criteria should be considered when performing the controlled releases under this method:

- A minimum of 30 controlled releases,
- A minimum length of 10 minutes per release
- A minimum of 0-20 scfh flow rate range
- A minimum number of 5 flow rate bins – assuring a good distribution of release rates will fall into each bin

8.6.1.3 Data Collection for the Component-Level Survey Method

Data collected during the controlled release should include at least Leak ID, known flow rate, time of release, whether or not each instrument being tested detected the leak or registered a non-detect and the time, the maximum concentration readings of each measurement (or a single value that can be compared against the leak detection threshold), prevailing wind speeds, and wind direction.

There are primarily two permutations to how data can be collected under the component-level survey method. The first consists of using a stem-and-probe style leak detection instrument where portable methane analyzers are fitted with wand attachments and are used for walking surveys or mounted to the front of vehicles and driven over buried assets. This style of instrument can include both closed-path, pump systems or open-path systems. The second permutation of this method involves the use of point-and-detect style leak detection instruments where handheld lasers or optical gas imagers are used to detect a leaking component from a short distance away. The following sections provide an overview of leak detection sampling methods related to each permutation.

8.6.1.4 Component-Level Leak Detection Methods for Handheld Stem-and-Probe Instruments

Handheld stem-and-probe style instruments that are typically used for component-level leak detection involve leak surveyors following Method 21 by placing the sample probe inlet at the surface of a component where leakage is likely to occur [40]. The probe is then moved along the interface periphery while observing the instrument readout. If an increased meter reading is observed, the interface where leakage is indicated is slowly sampled until a maximum meter reading is obtained. The probe inlet is left at the location where a maximum reading is obtained for approximately two times the instrument response time. If the maximum observed meter reading is greater than the leak indication definition, the results are recorded.

Vehicle-based component-level systems work in a similar fashion. The detector or sampling inlet is attached to a vehicle and driven directly above a buried asset. If a concentration is detected above the leak indication concentration, a leak is recorded and investigated further to verify/pinpoint location.

Component-level survey and measurement methods require close proximity to the leaking source. Instruments should be intrinsically safe for operation in explosive atmospheres as defined by the National Electrical Code of the National Fire Protection Association and the Occupational Safety and Health Administration (OSHA) for operation in any explosive atmospheres that may be encountered in its use. This should include Class 1, Division 1 conditions, and/or Class 2, Division

1 conditions. Additionally, leak detection instruments should not be operated with any safety device (such as an exhaust flame arrestor) removed. [46]

8.6.1.5 Component-Level Leak Detection Methods for Point-and-Detect Style Instruments

Point-and-detect style instruments can also be used for component-level leak detection. However, instruments in this category are not used to precisely determine methane concentrations. This is due to leaks of different sizes potentially having the same reported path integrated concentration – depending on the distance of the surveyor. Rather, the usefulness lies in the qualitative capabilities to help identify and locate a leak. In general, point-and-detect instruments can be designed as 1) an infrared laser which emanates outward from the handheld instrument, reflects off a surface, and travels back to a detector that measures infrared absorbance along the laser path, or 2) an optical imager which utilizes an infrared camera to detect component-level leaks by means of thermographic imaging.

8.6.1.6 Infrared Lasers

In order for infrared lasers to properly detect a gas leak, three conditions must be met. First, the gas plume concentration and size must be greater than the minimum sensitivity of the instrument. Second, the infrared beam must pass through the plume. And third, the background target (i.e., ground, building, etc.) has to reflect the infrared beam back.

However, the most important aspect to using infrared lasers will be the proper control (sweeping rate) and aiming of the infrared beam. Performing a survey too quickly or improperly could result in an incomplete scan of the area thus increasing the risk of FNs. The following protocol should be considered when performing leak detection during performance testing:

- When scanning a buried pipeline where the pipe location is known, the beam should be pointed out 15 to 20 feet. This allows for the beam footprint on the ground to be large enough to provide good coverage, and control over the path of the beam.
- Wide, sweeping motions around the pipeline location should be conducted by working the beam up the line in an “S” or “Z” pattern.
- A sweeping motion is typically used to scan service taps and valves while approaching and targeting probable gas vent locations such as cracks in the ground, vegetation damage, etc. Meter areas are then scanned, and the process repeats back down the pipeline with a rescan

using the same pattern.

- If the range is too far or ground elevation causes the beam to miss contact with the ground creating dark zones, then the surveyor should move closer until readings are obtained.
- When scanning an area where the pipeline location is not known, an “X” pattern is typically used to thoroughly scan the area.
- Typical vent areas such as surface separations, along any structural foundations, or locations where valves may be placed are targeted and closely inspected.
- If it is unclear as to whether a leak is located underground or on a surface structure, the surveyor tries to keep the wind to their back and stand approximately 5 to 10 feet from the plume if possible. The settings on the instrument are then adjusted to get the strongest return and the laser is first aimed low on the ground while working the beam upward. It is important to note that in some point-and-detect infrared lasers, spotter lasers can be located several inches above the actual infrared laser beam.

8.6.1.7 Optical Gas Imagers (OGI)

Optical Gas Imaging (OGI) cameras use spectral wavelength filtering and cold-filtering technology to visualize infrared absorption of gases. The success of OGI detection is qualitative in nature and depends on a variety of factors. OGI relies on the reflective surface in the background - the greater the background energy differential, the easier the camera will be able to visualize the gas leak and pinpoint its source. For example, plumes can be seen against the sky because it provides a “cool” background against the “warm” gas. On the other hand, the ground is a poor background because it is “warm” due to thermal radiation. This is partly why OGI is not well-suited to detects leaks migrating up from underground sources.

Rain and/or strong winds should to be considered. Rain can make detection difficult, but wind can help visualize the plume because it makes the gas move. However, as winds increase and gas is dispersed more rapidly, plumes become more difficult to detect. Due to the environmental variants and the background energy differential variations, an OGI camera alone cannot determine the specific type or amount of gas escaping through a leak – just that a leak may be present. This means that one can only “see” the plume by creating a radiant contrast between the plume cloud and the background.

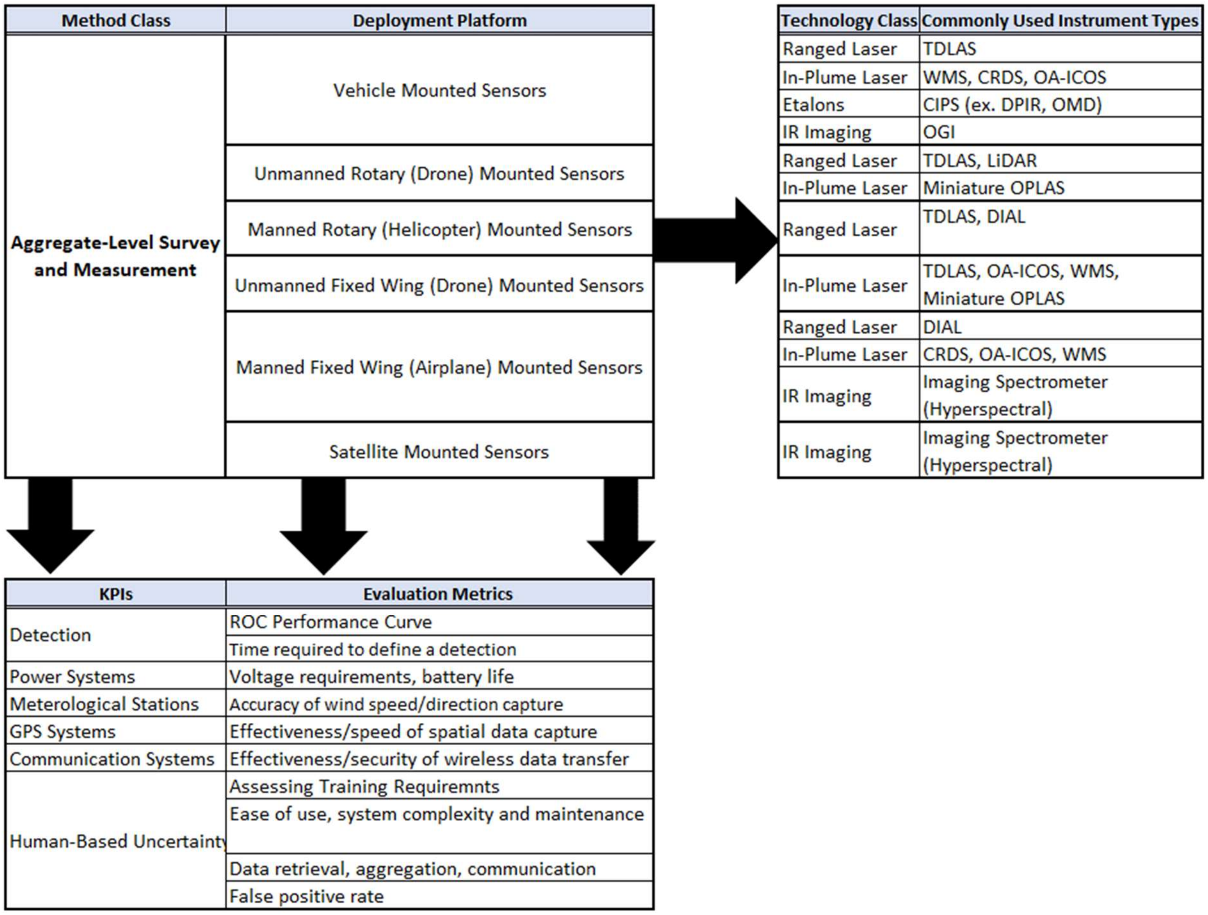
Conducting leak detection with an OGI requires careful attention to several parameters that work in concert and can ultimately effect detection capability. An example of OGI Performance protocols can be found in Appendix K of the USEPA Technical Support Document regarding Optical Gas Imaging Protocols from 40FCR Part 60 [47].

8.6.2 Aggregate-Level Survey and Measurement Methods Certification Protocol Considerations

Aggregate-level survey methods relate to the general practice of using ground-based, air-based, or space-based platforms to acquire information on natural gas transmission pipeline leaks located in proximity to the driving route, flight path, or satellite viewing area respectively. Leak indications ranging from near-field inspection of small leaks to facility-wide emission screening can be executed with this method. As such, aggregate-level leak detection is typically not performed for component-by-component surveys. Instead, they typically evaluate groups of components or larger segments of pipe for detection and localization of leaks.

It is also important to note that some leak detection instruments used in component-level survey methods may also be deployed for aggregate-level surveys by deployment on modified platforms. For example, a handheld OGI tool that appeared in the component-level survey method could also be deployed on a vehicle or drone as an “aggregate OGI” but it typically will not have the same component-by-component accuracy or precision in this deployment method. Technology classes commonly used for this leak detection method include ranged lasers, in-plume lasers, etalons, and infrared imagers (Figure 6).

Figure 6. Platforms, Technologies, and KPIs: Aggregate-Level Survey Methods



Method Class	Deployment Platform
Aggregate-Level Survey and Measurement	Vehicle Mounted Sensors
	Unmanned Rotary (Drone) Mounted Sensors
	Manned Rotary (Helicopter) Mounted Sensors
	Unmanned Fixed Wing (Drone) Mounted Sensors
	Manned Fixed Wing (Airplane) Mounted Sensors
	Satellite Mounted Sensors

Technology Class	Commonly Used Instrument Types
Ranged Laser	TDLAS
In-Plume Laser	WMS, CRDS, OA-ICOS
Etalons	CIPS (ex. DPIR, OMD)
IR Imaging	OGI
Ranged Laser	TDLAS, LiDAR
In-Plume Laser	Miniature OPLAS
Ranged Laser	TDLAS, DIAL
In-Plume Laser	TDLAS, OA-ICOS, WMS, Miniature OPLAS
Ranged Laser	DIAL
In-Plume Laser	CRDS, OA-ICOS, WMS
IR Imaging	Imaging Spectrometer (Hyperspectral)
IR Imaging	Imaging Spectrometer (Hyperspectral)

KPIs	Evaluation Metrics
Detection	ROC Performance Curve
	Time required to define a detection
Power Systems	Voltage requirements, battery life
Meterological Stations	Accuracy of wind speed/direction capture
GPS Systems	Effectiveness/speed of spatial data capture
Communication Systems	Effectiveness/security of wireless data transfer
Human-Based Uncertainty	Assessing Training Requiremnts
	Ease of use, system complexity and maintenance
	Data retrieval, aggregation, communication
	False positive rate

Performers that use the aggregated-level survey method will typically deploy complex leak detection systems, which can include tiered processes, multiple pieces of equipment, and customized platforms. For example, in addition to a methane analyzer, a leak detection system that supports this method may include GPS, an on-board meteorological station, power charging station, batteries, inverters, equipment for reducing vibration, and/or communication systems. Auxiliary system malfunctions during performance testing could lead to errors and a reduced efficiency in leak detection. Therefore, additional KPIs and other evaluation metrics in addition to leak detection should be considered as shown in Figure 6.

8.6.2.1 Instrument Calibration for the Aggregate-Level Survey Method

Since instruments deployed under this method are typically complex and thus could require laboratory grade calibration, the performer should provide calibration results as well as the date and time of the most recent calibration. Since calibration frequency requirements can vary dramatically depending on instrument type, it is up to the evaluator to determine if the length of time since the last calibration may be sufficient enough for performance testing to provide a reliable result. It is important that each instrument involved in testing be calibrated (not just the methane analyzer). This includes but not limited to GPS equipment, meteorological equipment, OGI cameras, sample cannisters, communication systems, and power systems.

8.6.2.2 Controlled Release Set-Up for the Aggregate-Level Survey Method

The evaluator should determine the number of controlled releases, the length of time for each gas release (as well as air replenishment times between each release), and the range of flow rates for the test. Chosen flow rates should be then categorized into bins. This is to assure a minimal statistical acceptance when conducting the probability analysis later. Although it is up to the evaluator to make the final determination, it is recommended to establish the following minimal criteria when performing the controlled releases under this method:

- A minimum of 30 controlled releases,
- A minimum length of 30 minutes per release
- A minimum of 5 passes for each controlled release rate (drive-by or fly-over)
- A minimum of 0-100 scfh flow rate range for vehicles and small, low-speed aircraft such as rotary drones
- A minimum of 150 to 250 scfh flow rate range for high altitude, high speed aircraft and satellites
- A minimum number of 5 flow rate bins – assure a good distribution of release rates will fall into each bin

8.6.2.3 Data Collection for the Aggregate-Level Survey Method

Data collected should include at a minimum Leak ID, known flow rate, time of release, whether or not each instrument being tested detected the leak or registered a non-detect and the time, the maximum concentration readings of each measurement (or a single value that can be compared against the leak detection threshold), prevailing wind speeds, and wind direction. In theory, the aggregated-level survey method can be accomplished using stop-and-go observations or in-motion transect approaches as well as deploy a variety of instrumentation, platforms, and data processing schemes.

Performers that utilize the aggregated-level survey method will ultimately produce concentration measurements that are a function of encountered meteorology, plume obstructions, and background concentrations. This speaks to the general need for repeat measurements, conducted potentially at different times of day with different starting locations and traveling directions. Survey route lengths should be kept to limited duration so that atmospheric conditions during each individual survey are as similar as possible. Additionally, potential for interference from mobile sources, nearby methane sources, and far away methane sources should be considered during performance testing [43].

8.6.2.4 Meteorology and Obstructions

The importance of meteorological conditions throughout performance testing and the role that auxiliary instruments can play in leak detection under this method should be clearly understood. For example, if a release is not detected on subsequent transects under similar meteorological conditions, it may be a FN, or it may indicate that the plume was transient in nature. As the atmospheric boundary layer increases and wind speeds decrease, ground-level detection of near-field sources becomes more difficult so detection routes in closer proximity to controlled releases should be favored [43].

Fixed-wing and rotary aircraft platforms tend to demonstrate increased likelihood of error under elevated wind conditions (excess of 15 mph). This is because aircraft surveying at 400-750 ft above ground level (AGL) will experience FNs due to rapid dispersion of plumes. To minimize risk, higher leak rates could be investigated (e.g. 150 – 250 scfh) [43].

During aggregate-level survey testing, particular attention should be given to potential non-target sources and wind field obstructions that could affect detection accuracy of instruments undergoing testing. A necessary condition for successful leak detection is that the plume be transported to the driving or flying path for in-plume instruments or transect through the infrared laser beam for ranged-laser instruments. Even when favorable wind conditions exist, near-field obstructions such as hedges, trees, buildings, and fences can lower the efficacy of detection by adding dispersive elements and thus increasing the risk of FNs. For underground pipeline leak surveys, the ground itself can be an obstruction, diverting and/or dispersing emissions along underground channels that could change depending on moisture content of the soil.

As a result, leak detection using this method incorporates a suite of instrumentation that plays an integrated part of the overall sampling platform. For example, auxiliary data from optical images can assist in documenting the identity or state of a source and also provide information on the presence of potential interfering non-target sources or flow obstructions. Therefore, a “detect” could be obtained from any one instrument, or a combination of instruments mounted to or included in the survey platform.

As such, the performer informs the evaluator of how many passes are required to properly characterize the source – which could also involve mapping upwind and downwind of the suspected source to help identify source location and reduce the occurrence of FNs and FPs.

8.6.2.5 Near-Field and Far-Field Sources

Contributions from both near-field and far-field sources can be present in the plume generating “off plume” background data that can result in an increased risk of FPs. Typically, background methane is canceled by subtraction of off-plume concentrations from the survey data [44]. The closer the background source is to the testing site, the higher risk of an instrument registering FPs unless care is taken by the performer to account for and subtract off-site sources.

With knowledge of prevailing wind direction and real-time methane concentration, rough triangulation is typically performed that provides direction to the leak source. Additionally, the performer can further confirm the origin of the detection through use of optical imagery.

Larger methane sources such as landfills, animal feeding operations, or other energy development operations should be located far enough away from the controlled release site so that their contribution can be considered a relatively uniform baseline offset to the ambient background. Methane signals from far away sources tend to be highly dispersed and typically do not vary with changes in wind direction as sharply as the proximate controlled release source under study. Typically, these sources contribute less than 100 ppb of the overall methane background signal [43]. However, since these background signals will overlap with controlled release signals, they will inherently become part of the analysis so care should be taken to not mistakenly register them as a detection during testing.

There are primarily two permutations to how data can be collected under the aggregate-level survey method. The first consists of using a *stop-and-go* approach to leak detection where ground-based mobile platforms such as vehicles are stopped for a period of time so that a sample can be obtained, and a determination made as to whether or not a leak exists. The second permutation of this method involves the use of *successive transects* where leaks are detected while the platform is in motion – either driving by or flying by the source of the leak. The following sections provide an overview of leak detection sampling methods related to each permutation.

8.6.2.6 Aggregated-Level Survey using Stop-and-Go Sampling

If the method requires that the vehicle is stopped during sampling, a 20 minute sampling period (+/- 5 minutes) is recommended since 20 minutes is considered long enough to allow representative sampling but short enough to typically capture a representative "snapshot" of the ever changing atmospheric transport conditions [44]. A very short sampling time period (a few minutes) may not capture the plume due to shifting wind conditions and thus increase the risk of FNs. This method is typically performed by positioning the sampling vehicle at a determined downwind observing location. Methane concentrations and corresponding wind angles are recorded for each 20-minute minimum stationary observation [44].

8.6.2.7 Aggregated-Level Survey using Successive Transects

This method describes a fully mobile procedure where data is collected in a series of transects such as driving or flying over a section of gas transmission pipeline and usually involves an initial pass to screen for leaks with a follow-up survey to narrow down and localize areas of suspected leak activity.

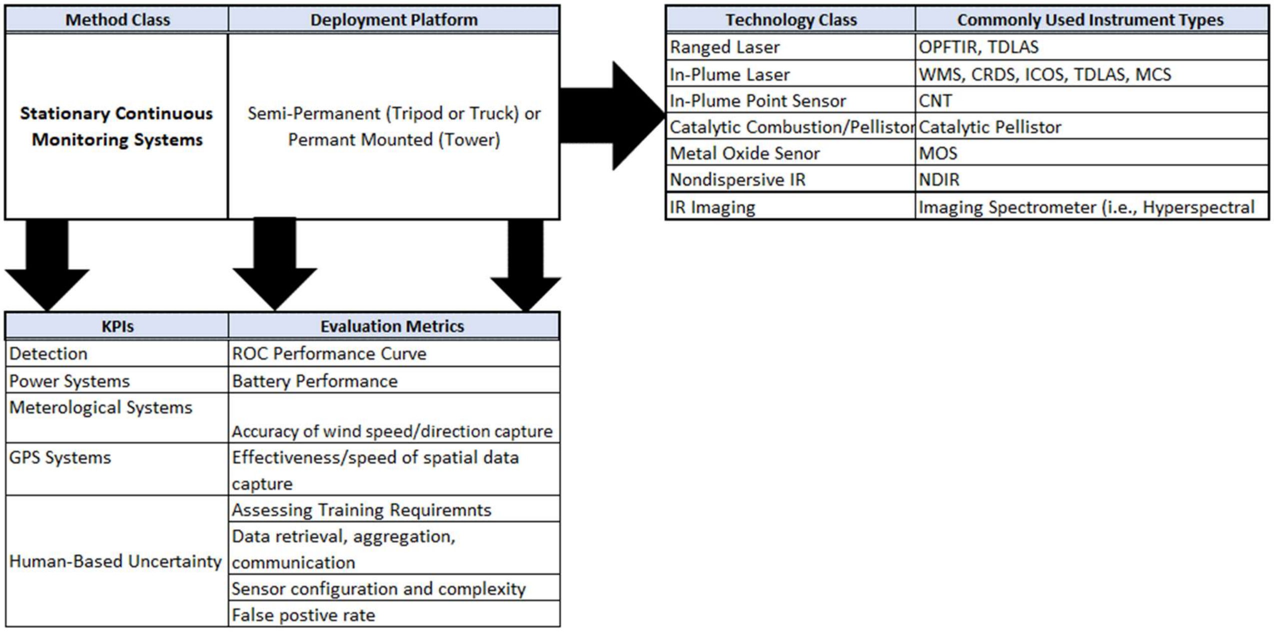
Initial screening is typically performed by driving, flying, or conducting satellite scans of large pipeline segments to establish initial indications of gas leaks as well as establish predominate wind direction. If a leak is indicated, a second component to the survey is triggered where the suspected area of the leak is circumnavigated with smaller-scale transects by flying or driving around the source to verify a leak is present as well as capture upwind and downwind conditions. In this way, the origin of the leak can be established and the potential for non-target source interferences can (in many cases) be eliminated. This method can be a challenge with ground-based vehicle platforms as driving access around remote sites may be limited.

It is anticipated that satellite-mounted leak detection will work in much the same manner – that is an initial indication will be detected by a satellite sensor, followed up with either an air-based or vehicle-based platform for a closer look at the potential leak source. Or, satellite based alarms could trigger a further investigation using stationary continuous monitoring mesh networks working in concert with the satellites.

8.6.3 Stationary Continuous Monitoring Systems Certification Protocol Considerations

Stationary continuous monitoring system method class protocols are intended for testing leak detection instruments being deployed as a permanent fixture to detect emission sources. Each technology may have a slightly different method definition such as location and number of sensors, proximity requirements to suspected emission points, or field of view. However, in principle, the deployment strategy of the methods is similar and therefore, the testing metrics will be similar. Technology classes commonly used for this leak detection method include ranged lasers, in-plume lasers, in-plume point sensors, pellistors, metal oxide sensors, and non-dispersive infrared lasers (Figure 7).

Figure 7. Platforms, Technologies, & KPIs: Stationary Continuous Monitoring Systems



Method Class	Deployment Platform
Stationary Continuous Monitoring Systems	Semi-Permanent (Tripod or Truck) or Permant Mounted (Tower)

Technology Class	Commonly Used Instrument Types
Ranged Laser	OPFTIR, TDLAS
In-Plume Laser	WMS, CRDS, ICOS, TDLAS, MCS
In-Plume Point Sensor	CNT
Catalytic Combustion/Pellistor	Catalytic Pellistor
Metal Oxide Senor	MOS
Nondispersive IR	NDIR
IR Imaging	Imaging Spectrometer (i.e., Hyperspectral

KPIs	Evaluation Metrics
Detection	ROC Performance Curve
Power Systems	Battery Performance
Meterological Systems	Accuracy of wind speed/direction capture
GPS Systems	Effectiveness/speed of spatial data capture
Human-Based Uncertainty	Assessing Training Requiremnts
	Data retrieval, aggregation, communication
	Sensor configuration and complexity
	False postive rate

Beyond detection probability and performance at varying environmental conditions, leak detection instruments deployed under the stationary continuous monitoring method class may require the ability to provide their own power, have small footprints to fit in tight areas, and have the capacity to aggregate, transmit, and even store vast amounts of data over the long term. Figure 7 shows additional KPIs and evaluation metrics that should be considered when validating systems in this method class.

8.6.3.1 Instrument Calibration for the Stationary Continuous Monitoring Method

Since instruments deployed under this method are typically complex and could require laboratory grade calibration, the performer will provide calibration results as well as the date and time of the most recent calibration. Since calibration frequency requirements can vary dramatically depending on instrument type, it is up to the evaluator to determine if the length of time since last calibration is sufficient for performance testing to provide a reliable result. Each instrument involved in testing should be calibrated (not just the methane analyzer). This includes but not limited to meteorological equipment, OGI cameras, communication systems, and/or power systems. It is up to the evaluator to determine if calibration results are appropriate for the leak detection system undergoing performance testing.

8.6.3.2 Controlled Release Set-Up for the Stationary Continuous Monitoring Method

The evaluator should determine the number of controlled releases, the length of time for each gas release (as well as air replenishing times between each release), and the range of flow rates for the test. Chosen flow rates should be then categorized into bins to assure a minimal statistical acceptance when conducting the probability analysis later. Unlike the other 2 methods, the continuous stationary monitoring method deploys leak detection instruments into outdoor environments where instruments could remain for extended periods of time. Therefore, ability to withstand environmental elements such as extreme temperatures, humidity, and dust, should also be evaluated and documented. The final placement of a leak detection system may be unknown so it will be important to test a full range environmental tolerances and document limitations so the instrument can ultimately be matched with the proper environment.

Evaluating environmental tolerance ranges are best performed in laboratory settings where variances of temperature, humidity, and dust can be controlled. This means that in addition to performing a controlled release in an outdoor setting, the certification organization should perform chamber studies to evaluate instrument performance at the upper and lower bounds of temperature and humidity. Although it is up to the evaluator to make the final determination, it is recommended to establish the following minimal criteria when performing the controlled releases under this method:

Outdoor Controlled Release – Uncontrolled Environmental Conditions

- A minimum of 30 controlled releases
- A minimum length of 10 minutes per release
- A minimum of 0-20 scfh flow rate range
- A minimum number of 5 flow rate bins – assuring a good distribution of release rates will fall into each bin

Indoor Controlled Release – Controlled Environmental Conditions

- A set controlled release at or above the instrument detection threshold value
- A minimum 30 minute sampling at "ideal temperature."
- A minimum 30 minute sampling at the upper temperature limit of the instrument. Some performers will have this number, while others may wish to determine this number.
- A minimum 30 minute sampling at the lower temperature limit of the instrument. Some performers will have this number, while others may wish to determine this number.
- 30 minute sampling at "ideal humidity."
- 30 minute sampling at the upper humidity limit of the instrument. This number varies depending on instrument type.
- 30 minute sampling at the lower humidity limit of the instrument. Although it is rare for 0% humidity to impact leak detection instruments, the evaluator may wish to perform this test for thoroughness.
- Testing for tolerance to dust over the long-term can be accomplished with an observational inspection to identify components at risk of dust encroachment. This includes exposed wiring (on both the detector and auxiliary equipment), optical assemblies and/or photovoltaics that must remain free of debris to properly operate, and any moving parts or grease packed bearings that could be impacted over time.

8.6.3.3 Data Collection for the Stationary Continuous Monitoring Method

During an outdoor controlled release, data should be collected that includes Leak ID, known flow rate, time of release, whether or not each instrument being tested detected the leak or registered a non-detect and the time, the maximum concentration readings of each measurement (or a single value that can be compared against the leak detection threshold), prevailing wind speeds, and wind direction. For the indoor temperature and humidity tests, data should be collected that includes the Leak ID, the known flow rate, the known temperature or humidity settings, the length of sampling time, start time, whether or not each instrument being tested detected the leak or registered a non-detect and time, and the maximum concentration readings of each measurement. For outdoor performance testing, instruments are typically mounted on tripods or poles in a similar configuration as would be utilized in field conditions. The number of detects and non-detects should be recorded as gases are released at pre-determined rates.

8.6.3.4 Meteorology and Obstructions

Like the aggregated-level survey method, performers that utilize the stationary continuous monitoring survey method will yield detections that are a function of encountered meteorology, plume obstructions, and background concentrations. Additionally, potential for interference from mobile sources, nearby methane sources, and far away methane sources should be considered during performance testing. For example, if a release is not detected, it may be a FN, or it may indicate that the plume traveled in a different direction.

8.6.3.5 Near-Field and Far-Field Sources

Potential non-target sources and wind field obstructions that could affect detection accuracy of instruments should be avoided when possible. Even when favorable wind conditions exist, near-field obstructions such as hedges, trees, buildings, and fences can lower the efficacy of detection by adding dispersive elements and thus increasing the risk of FNs. For underground pipeline leak monitoring, the ground itself can be an obstruction, diverting and/or dispersing emissions along underground channels that could change depending on moisture content of the soil.

Leak detection using this method can either incorporate a mesh network by which a plume will intersect a sensor regardless of direction thus reducing FNs, and/or the leak detection instruments can integrate meteorological sensors such that off-site sources can be subtracted from the data set to reduce the likelihood of FPs.

8.7 Certification Organization Documentation Requirements

During and/or after leak detection instrument performance testing, all data collected, and all actions taken should be documented. Any abnormal operating conditions of facility equipment, sensor instrumentation, or platforms, as well as actions taken to mitigate any issues encountered during validation should be documented per the established procedures. A standard form should be provided to assist with documenting data, events and timelines.

9 Framework for Human-System Interface Certification

9.1 General

The purpose of this section is to address human factors as they relate to external pipeline leak detection. This includes the incorporation of the human element in the context of technology-based leak detection systems as well as how design, implementation, and maintenance activities associated with physical, mental, and workload aspects of how pipeline operators interact with leak detection technologies in the working environment. In particular, the focus will be on integrating human elements with instrument performance and how measurable performance metrics can be developed that minimize risk of human error. In other words, a set of performance metrics will be derived at the interaction point between the technology side of leak detection and the people who must make decisions about which technology to select for the job, as well as must interpret data outputs of that technology.

9.2 Background

There is growing attention regarding the human element of leak detection and the role people play in instrument performance – from selecting the appropriate leak detection instrument for the job, to tuning the instrument properly, to operator response of leak alarms. Operators must interpret leak alarms and determine from experience and/or training if alarms are a result of a valid leak or a false alarm. Furthermore, the root cause of a “non-performing” instrument may not be the instrument at all, but rather that the wrong instrument was installed for the job. Leak detection is often a human issue because a human must 1) select which instrument to use in leak surveys or to install for continuous monitoring, and 2) initiate an investigation when a leak alarm is triggered.

Training is an important factor as well as a holistic leak detection approach by companies that optimize instrument tuning and sensitivity with false positives.

9.3 Incorporating the Human Element into Instrument Performance Metrics

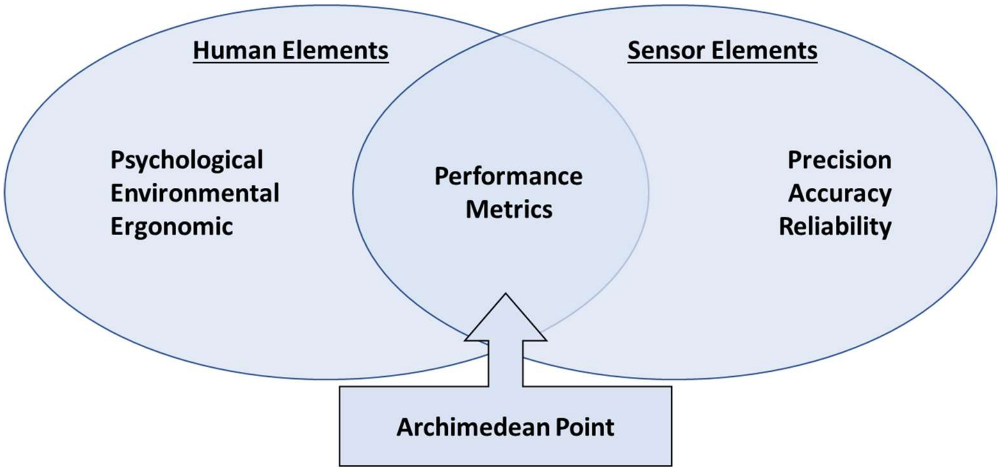
Leak detection instruments are designed to obtain data during a survey or monitoring event via one or more input channels (lasers, pumps, optical imagers etc.) that combine through various means (interferometers, algorithms etc.) to create a reading (concentration, % gas LEL etc.). The reading is then compared to a threshold at which time an alarm or warning is issued if the calculated result has met or exceeded a pre-determined threshold [36].

The human/technology interaction that occurs with these systems includes monitoring and responding to changing environmental conditions, events, and alarms, as well as various leak detection information dashboards. Figure 8 below demonstrates the overlap of human and technological elements of a leak detection system.

The Sensor Elements side of

Figure ***8*** consists of the ability of the instrument to precisely and accurately detect leaks, along with reliability which includes continuous performance without a significant amount of maintenance. The human element side consists of varying levels of reaction to the leak detection instrument which can be categorized as psychological (e.g. desensitization from too many false alarms), environmental (e.g. instrument not designed for deployed use case), or ergonomic (e.g. cumbersome instrument leads to incomplete or inaccurate leak detection). The interface between human and sensor elements is referred to as the "Archimedean Point" [36]. This is the point where human aspects interact with technical aspects of a leak detection sensor. In order to establish a set of performance metrics that encompass both human and technology elements, one must first establish where these two elements intersect, and performance metrics should be defined at this point of intersection.

Figure 8. Performance Metrics at the Intersection of Human & Sensor



Leak detection systems with successful leak capability and method class certifications may not be easily deployable by companies in the field. One possible way to avoid this scenario would be for the certification organization to offer a certification for the human-system interface. To perform such a certification, a set of performance metrics should be derived to evaluate performance of the systems at the interaction point between the technology and the people who must interpret data outputs of that technology.

9.4 Performance Testing Based on Human Reactions to Technology Issues

Table 5 summarizes the types of interactions that humans are anticipated to have in response to commonly encountered technology precision/accuracy/reliability issues. Performance testing procedures should be developed with these elements in mind to minimize risk of missed leaks, poor decision making, and incomplete or incorrect leak survey data due to human reactions to technology issues.

Table 5. Performance Testing: Human-System Interface

Human Element	Technology Element (combination of precision, accuracy, reliability)	Human Reaction to Technology Element	Focus of Performance Testing Archimedean Point
Psychological	Overly sensitive instrument creates FPs	De-sensitivity to alarms leading to increased risk of missing leaks	FPR, Instrument sensitivity

	Complex output of data, noisy data	Misses valid leak alarms increasing the potential for missing valid leaks	Dashboard and data visualization – how leak alarms are presented to operator; Validity of training programs
	Data communication overload	Information overload leading to mental fatigue that hinders decision making process increasing potential for missing leaks	Data delivery, management and storage features of the instrument
	Multiple instruments operating at once – not integrated	Must review and manage inputs from multiple locations leading to high workloads and increased potential of missing leaks	Data management and alarm system has ability to be easily integrated with other systems
Environmental	Sensor not designed for all areas of intended use, platform not designed to access intended areas of use	Area appears inaccessible or unsafe causing hesitancy leading to incomplete or inaccurate survey thus increasing the potential of missing a leak	Technology platform is suited to commons areas of leak detection
	Sensor not designed for all weather conditions, no warning of being used outside normal operating ranges (ex. humidity too high, or too cold, or too hot)	Unaware of limitations and surveys with potentially malfunctioning sensor leading to inaccurate data and FNs	Dashboard warnings; integrated thermometers/barometers; Clear labels; User training
Ergonomic	Leak survey instrument too heavy	Leads to rushing of survey or incomplete data collection due to fatigue thus increasing the potential for FNs	Instrument weight and ease of use aligned with method

9.5 Aligning Instrument Selection with Intended Use

A clear understanding of leak detection program objectives, the regulatory requirements of sampling areas, the proper platforms needed for sampling, the means in which data will be managed and stored, and defining the leak detection instrument performance expectations must be understood prior to deploying a new leak detection instrument in the field to maximize leak detection success.

9.6 Leak Detection Thresholds that Balance False Positives and False Negatives

Minimizing negative impacts from FPs involves balancing the distraction of too many FPs with the benefits of increased leak detection sensitivity. Technology, communication, and modeling constraints exist that prevent one from achieving a perfect instrument capable of detecting all leaks with no false positives. Therefore, when validating an instrument, the restrictions and constraints that exist within the instrument should be fully understood so that an optimized balance may be designed. Once a leak detection instrument is selected, it should be optimized to capture leaks possible while minimizing FPs.

The generation of FPs can be categorized into the following general areas:

- *instrument driven* FPs are generated from such elements as sensor, telecommunication and/or leak algorithm errors.
- *environment driven* FPs occur from the surrounding environment such as nearby sources and/or episodic venting.
- *human driven* FPs can result from incorrect sensor use or platform mounting, tuning instrument sensitivity settings too high, and/or inappropriate training of sensor functionalities, calibration.

FPs should be completely addressed during the instrument development and validation periods. Table 6 below summarizes the types of qualitative and quantitative performance metrics that can be tested to address FPs.

Table 6. Performance Metrics for Reducing FPs

Metric Category	Issue leading to FPs	Performance Testing Metric
Instrument	Sensor Errors	Detection limit testing at a controlled gas release facility
	Telecommunication Uncertainty	Testing on instruments ability to send data and alarms
	Modeling or Leak Algorithm Errors	Alarm threshold testing at a controlled gas release facility

Environmental	Episodic Venting (Pneumatics, Blowdowns)	In-field testing to determine instrument capability of discerning between patterns of nearby episodic emissions vs a leak
		Validation of operator training programs to discern difference of background emissions and awareness of scheduled maintenance/blowdowns at the facility
	Nearby Sources	Instruments ability to detect upwind sources
		Validation operator training to understand nearby sources and patterns of emissions at nearby facilities
		Adjustable tuning capabilities of the instrument
Human	Type of leak detection instrument in use is not appropriate for the job	Instrument validated using the intended configuration for eventual deployment rather than in a laboratory setting
	Type of platform chosen for the instrument is not appropriate for the sensor and/or for the job	Sensor is validated on its intended platform (example tripod, or vehicle mounted)
		Platform capabilities is validated in parallel with the sensor
	Instrument sensitivity set too high by user	Establish detectable leak size target realistically aligned with instrument capabilities and regulatory requirements at intended area of use
	Inadequate training on instrument use, sensor sensitive, platform mounting, or calibration	Validation of operator training programs for more complex and sensitive methane sensors

9.7 Company Policies that Incorporate Human Elements to LDPs

Company policies should provide clear direction on how the leak detection system integrates humans and technology and guide performance goals such as operator leak alarm acknowledgement procedures, analysis and response times, as well as the maximum number of acceptable FPs optimized to the size of leaks and acceptable sensitivity specifications of the instrument.

Regulatory requirements on human interaction should be reviewed such as the PHMSA Pipeline Safety: Control Room Management/Human Factors Rule [48] that requires several distinct actions such as implementing measures to prevent fatigue and the development of alarm management plans. Oil and gas companies have developed and institutionalized the following standards and best practices that take human interactions into consideration:

- ANSI/ISA 18.2-2009 [7] details alarm management standards and best practices;
- API RP 1165 [10] discusses the establishment of a human factors management plan;
- API 1175 [8] addresses tuning and threshold settings aimed at pipeline operator responsiveness by increasing the reliability of instrument alarming.

These documents are designed to provide structure regarding the identification, selection, display, response, and maintenance of leak alarms. Thus, those who are monitoring leak alarms can do so in an effective and efficient manner.

9.8 Training

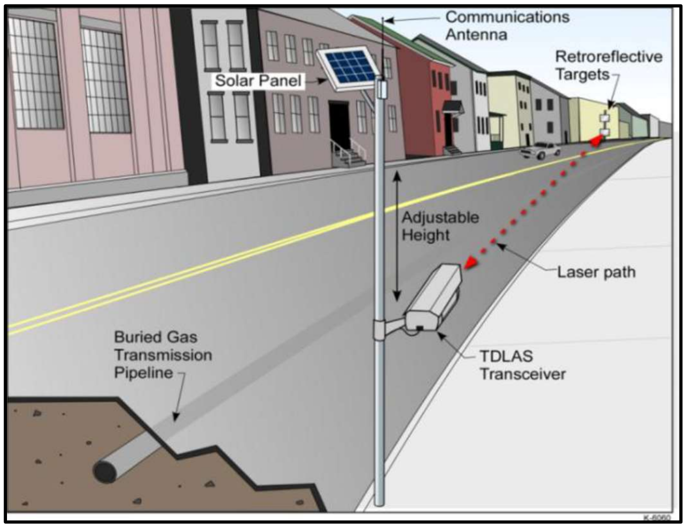
Training should be performed throughout the leak detection process. Leak detection instruments require a trained eye to understand factors such as calibration drift or other abnormalities in operation. Operators should understand the functionality of telecommunication systems, instrument software/modeling algorithms, and be able to detect patterns of emissions from nearby sources. If self-powered, features such as photovoltaics, batteries, or other ancillary power equipment can have indirect effects on the instruments ability to perform and therefore should be understood and monitored.

10 Annex A (Informative): Technology Class Descriptions

10.1 Technology Class 1: Ranged Laser

Methane measurement instrumentation within this technology class have the capability to sense path-integrated concentrations of methane along a laser line of sight by sensing the attenuation of the laser light absorbed by the target gas over the distance traveled by the beam (Figure 9). The two most common methods, tunable diode laser absorption spectroscopy (TDLAS) and differential absorption light detection and ranging (or differential absorption LiDAR - DIAL) both require laser emitters and detectors that yield fast (sub-hertz response rates) and sensitive (5 ppm-m for handheld units) results.

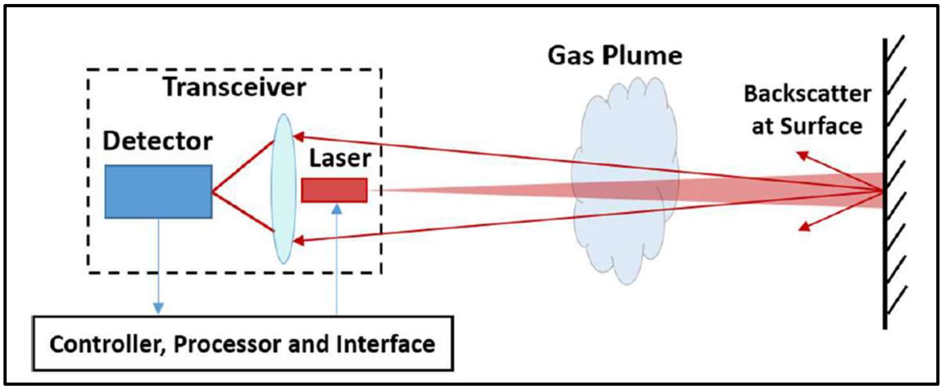
Figure 9. Example of Laser-Ranged Technology Class



10.1.1 Tunable Diode Laser Absorption Spectroscopy (TDLAS)

TDLAS is a type of spectroscopy used by Ranged Laser instruments that have been operational for decades. However, in the 1990s, instruments were miniaturized and taken from the lab to field applications. TDLAS systems operate on the same principle as other spectrometer-based systems including a laser that can be tuned to different wavelengths at high frequency. In this way, sampling occurs at the wavelength of known absorption (on-line) for a particular species (such as methane). It then immediately shifts off that wavelength to an area of little absorption (off-line). The two signals are subtracted to determine the net effect for the species of interest. With additional noise reduction techniques (as used in wave modulation spectroscopy), these systems can be used with very little reflected laser light (such as a wall) instead of highly reflective optics (such as a retroreflector, Figure 10)

Figure 10. Basic Premise of TDLAS Sensor Operation [24]



TDLAS spectroscopy-based instruments are widely used across many methods and platforms for leak detection. They typically have high selectivity for methane, a fast-response rate, and are sensitive to 5 ppm-m for handheld units. The handheld version is suitable for walking investigations and for checking areas that are inaccessible but are within line-of-sight. Due to the range of detection and portability of the handheld sensors, TDLAS instruments have been integrated onto vehicle-mounted, unmanned rotary, and manned rotary platforms for leak surveys TDLAS sensors also have stationary variants used for continuously tracking emissions of below-ground pipelines and above-ground sources.

10.1.2 Conventional Light Detection and Ranging (LiDAR) and Differential Absorption LiDAR (DIAL)

Typical LiDAR systems collect pulsed laser energy scattered from molecules to monitor gas and aerosol concentrations. A LiDAR instrument principally consists of a laser, a scanner, and a specialized GPS receiver. Near infrared fiber lasers enable long range detection with relatively high sensitivity and can be deployed on a range of mobile platforms to survey multiple sites per day. LiDAR sensors are commonly mounted on unmanned rotary platforms. Differential absorption LiDAR is based on the same principal as traditional LiDAR, but operates at two wavelengths - one wavelength is on-resonance and one wavelength is off-resonance of the molecular absorption of the gas being measured. Because the on-resonance wavelength is more strongly absorbed by a GHG gases such as methane, the difference between both signals is proportional to its number density. Thus, this technology could provide users with quantities of gases being released at a particular location and pinpoint their sources. Technological advancements in DIAL systems have greatly increased the measurement capabilities of both ground-based and airborne platforms for measurements of methane with this technology. By using LiDAR, the DIAL technique can make remote range-resolved, single-ended distribution measurements of a targeted compound within the atmosphere (in this case methane) with no disruption to normal site operational activities. DIAL provides three-dimensional mapping of emission concentrations and, when combined with wind information, enables quantification of emission rates

10.1.3 Open Path Fourier Transform Infrared (OP-FTIR)

OP-FTIR instruments utilize a spectroscopy application that measures absorbance or emission pattern spectra. The technology can be used to measure absorption loss along an optical path in ambient air. Often these systems can be tuned to obtain concentrations of many individual species simultaneously if actively operated with a laser and paired with a retroreflector. The laser is focused on the retroreflector, which allows the light to travel specifically to the reflector and back to the spectrometer mounted on the system. The use of the reflector essentially creates a very large cavity in ambient air and can be used to speciate many different hydrocarbons. Given the relatively bulky size and weight of typical OP-FTIR systems, platforms are typically limited to stationary monitoring.

10.2 Technology Class 2: In-Plume Laser

In-plume gas sensors are a technology class that draws air samples across the active element of the sensor (usually housed within the sensor casing) and produces a measurement of gas concentration encountered by the sensor. For this technology class, the sensor must be transported through the emission plume to gather a reading, or the sample must be transported from the plume to the sensor. This is the largest technology class and includes instrument types such as Cavity Ringdown Spectroscopy (CRDS), Wavelength Modulation Spectroscopy (WMS), Integrated Cavity Output Spectroscopy (ICOS), Miniature Open Path Laser Spectroscopy, and in-plume applications of Tunable Diode Laser Absorption Spectroscopy based instruments.

10.2.1 Cavity Ring-Down Spectroscopy (CRDS)

CRDS is a specific in-plume application of spectroscopy that uses a high-speed laser tuned to a specific frequency, and a cavity housing with highly reflective mirrors to measure the absorption of gas many times within a few microseconds. A pulse of light from the laser is introduced into the cavity and permitted to bounce back and forth on the mirrors until it disappears (called a ring-down). The way the light disappears is influenced by two factors - the reflectivity of the mirrors, and the amount of light absorbed by the gas in the cavity. Once the effect of light leaking out through the mirrors is subtracted, the ring-down can be used to precisely determine concentrations of species in the gas sample. This technique greatly increases sensitivity (down to parts per billion or even parts per trillion). CRDS sensors can be used on vehicle-mounted platforms to detect leaks along natural gas transmission pipelines. Several utilities have deployed these systems for compliance-based leak surveys which involves driving on pre-selected routes multiple times to collect data which is then processed to generate maps of leak indications. Follow-up surveys are required (usually on foot) to verify initial leak indications.

10.2.2 Wavelength Modulation Spectroscopy (WMS)

WMS is a specific in-plume application of TDLAS that uses a single-mode tunable near-infrared laser, which operates at ambient temperature, allowing for low power consumption. Instead of using a cavity, the laser pulse passes through open ambient air. WMS provides very rapid measurements allowing instruments to output data at up to 40 Hz. Pressure and temperature induced effects along with changes in laser power and mirror reflectivity are handled within the software of the system. These sensors are a popular selection among the scientific community and have been implemented as stationary methane monitors and on vehicle platforms to conduct mobile surveys.

10.2.3 Integrated Cavity Output Spectroscopy (ICOS) and Off-Axis ICOS (OA-ICOS)

ICOS (sometimes called cavity-enhanced absorption spectroscopy - CEAS) records the integrated intensity behind one of the cavity mirrors, while the laser is repeatedly swept across one or several cavity modes. Off-axis ICOS (OA-ICOS) improves on the conventional technique by coupling the laser light into the cavity from an angle with respect to the main axis to eliminate interaction with high density of transverse modes. OA-ICOS advances the principles of CRDS by utilizing a slightly different alignment of the laser (off-axis) to specifically handle cavity vibrations. The configuration therefore is less susceptible to temperature changes and optical alignment, making the instrument more robust and less costly than conventional CRDS instruments.

10.2.4 Miniature Open Path Laser Absorption Spectroscopy (OPLAS)

OPLAS-based instruments were originally designed by NASA Jet Propulsion Lab (JPL) to find methane on Mars as a part of the NASA Mars Rover program. The newer, miniature version of the OPLAS is now being used to detect and localize leak sources. Drone-mounted OPLAS instruments are light weight and possesses the capability of detecting methane down to 10 ppb sensitivity. This technology provides greater sensitivity than typical field-deployable measurement devices of similar size and weight and has therefore been used to detect gas leaks using handheld platforms or unmanned aerial platforms. The system utilizes multiple mirrors and a laser that is coupled to the appropriate wavelengths for measuring concentrations of a target trace gas (in this case, methane). The system is configured to detect a portion of the emitted light impinging on the detector to generate a corresponding signal. The electronic system then adjusts the wavelength range of the emitted light from the laser in order to measure the gas concentration. The system is called an “Open Path” system because the laser is exposed to the atmosphere via a porous housing – even though the laser is technically contained within a structure. The instrument is considered sensitive (10 ppb), lightweight (< 150 g), and fast (< 0.5 seconds) and is capable of locating leaks as well as determining the strength of a leak.

10.3 Technology Class 3: Etalons

Etalons (also known as Fabry-Pérot Interferometers) are typically made of a transparent plate with two reflecting surfaces, or two parallel highly reflecting mirrors. (Precisely, the former is an etalon and the latter is an interferometer, but the terminology is often used inconsistently.) The transmission spectrum is utilized as a function of a wavelength to exhibit peaks corresponding to resonances of the etalon. Fabry–Pérot Etalons can be used to prolong the interaction length in laser absorption spectrometry, particularly cavity ring-down, techniques. Recent advances in fabrication techniques allow the creation of very precise tunable Etalons, thus creating instrument types that can achieve high sensitivity gas detection at high speeds without the use of lasers or long light paths.

10.3.1 Correlated Interference Polarization Spectroscopy (CIPS)

CIPS is a patented optical method for detection of ultra-low concentrations of various gases - and coupled with Etalon technology, is the functional core of portable methane measurement instruments typically used for walking investigations of gas pipeline networks or used on vehicle platforms during mobile surveys. Typical instruments are portable and are usually handheld or affixed to the front of vehicles for leak detection surveys.

10.4 Technology Class 4: Catalytic Combustion / Pellistor

Catalytic combustion technology is the primary sensor used in combustible gas indicator (CGI) instruments. Catalytic detectors are not methane specific. Rather, they respond to the oxidation of a gas, which produces a known amount of heat that varies with gas concentration. The sensor contains an active heating coil that is embedded in a catalyst, where a reaction takes place as combustible gases undergo an exothermic reaction which in turn causes a change in resistance. This change is compared to a reference heating coil that does not react to the gas, providing a stable background that can be subtracted.

10.5 Technology Class 5: Nondispersive Infrared (NDIR)

The main components of NDIR instruments are an infrared (IR) source (lamp), a sample chamber or light tube, a light filter, and an IR detector. The IR light is directed through the sample chamber towards the detector. In parallel, there is another chamber with an enclosed reference gas, typically nitrogen. The gas in the sample chamber causes absorption of specific wavelengths according to the Beer–Lambert law, and the attenuation of these wavelengths is measured by the detector to determine the gas concentration. The detector has an optical filter in front of it that eliminates all light except the wavelength that the selected gas molecules can absorb. Without the use of a cavity or other technique such as a retroreflector to increase the measurement pathway, the methane near-infrared “fingerprint” (absorption spectrum) cannot be detected until concentrations reach into the ppm range. NDIR sensors therefore fall into a different category of methane sensors that have higher detection limits, measure at slower speeds, but have lower power draws, are smaller, and cheaper than other IR sensors with higher resolution. NDIR sensors are typically deployed as continuous monitoring systems and are installed close to potential above-ground leak sources at natural gas facilities. Typical sensors possess a detection range of 0-100% LEL. Monitoring underground pipelines with these sensors is not currently viable due to the low sensitivity. Cost and sensitivity of point sensors must be improved before they can be implemented for monitoring long stretches of underground pipelines. However, these sensors may offer an inexpensive monitoring solution for portions of pipeline that emerge above ground at pigging or metering stations.

10.6 Technology Class 6: Infrared Imaging

IR imaging systems, in general, are not methane specific. Rather, they utilize cameras to filter IR wavelengths absorbed by gas plumes. Most optical gas imagers (OGI) are tuned to specific, narrow, bands of wavelengths, typically in the mid- or short-IR region, and have frame rates of 1-10 Hz, while newer classes of hyperspectral imagers cover a wider range of wavelengths, albeit at slower frame rates.

10.6.1 Optical Gas Imaging (OGI)

OGI is a camera that detects infrared radiation (heat or spectra) and converts it into an electronic signal that is processed to produce an image or video, on which one can perform temperature calculations and chemical species analysis. Heat sensed by an OGI can be very precise, however, chemical species analysis is less so, and processing is still being developed to quantify concentrations and leak rates. While OGI cameras image plumes with contrast created by absorption of IR light, most practical deployments rely heavily on the temperature difference between the gas plume and the background. While significant temperature differences are common in above-ground equipment – often because the cold sky can be utilized as a background – gas leaking from underground pipelines is most often at the same temperature as the ground, thus reducing the contrast between plume and background to nearly zero. For this reason, underground leak detection is typically restricted to “cooled” cameras with high sensitivity, deployed at as low an angle as possible, with a large leak plume that is transported rapidly from the leak point to the surface reducing the temperature equilibration with the surrounding soil to image the plume against contrasting background temperatures.

10.6.2 Hyperspectral Imaging

The goal of hyperspectral imaging is to obtain the spectrum for each pixel in the image of a scene, with the purpose of finding objects, identifying materials, or detecting processes. Whereas the human eye sees color of visible light in mostly three bands (long wavelengths - perceived as red, medium wavelengths - perceived as green, and short wavelengths - perceived as blue), spectral imaging divides the spectrum into many more bands. This technique of dividing images into bands can be extended beyond the visible. In hyperspectral imaging, the recorded spectra have fine wavelength resolution and cover a wide range of wavelengths. Hyperspectral imaging measures continuous spectral bands, as opposed to multispectral imaging which measures spaced spectral bands. Certain objects leave unique fingerprints in the electromagnetic spectrum. Known as spectral signatures, these fingerprints enable identification of the materials that make up a scanned object. For example, a change in spectral signature from methane stress on plants or a change in soil chemistry could be indirect indications of a leak from buried pipelines.

10.7 Technology Class 7: Flame Ionization (FI)

Flame ionization detectors (FID) do not detect specific compounds or molecules. Rather, they combust chemicals to produce ions that are subsequently detected as an electrical current. The sample is directed into a flame (usually hydrogen or a hydrogen/nitrogen mixture), which is combusted – and the resulting ions are measured with electrodes just beyond the flame. These instruments are usually paired with a laboratory grade gas chromatographs in order to identify individual compounds. When used as a stand-alone instrument, the detection is not specific to methane, but rather detects bulk hydrocarbons.

10.8 Technology Class 8: Photoionization (PI)

The photoionization detector (PID) is an efficient and inexpensive detector for many gas and vapor analytes. A PID produces instantaneous readings, operates continuously, and is commonly used as a detector for gas chromatography or as a hand-held portable instrument. Like the FIDs, PIDs are not methane specific, but rather use high-energy photons to break molecules into positively charged ions within the detector. As compounds enter the detector, they are bombarded by high-energy UV photons and are ionized when they absorb the UV light, resulting in ejection of electrons and the formation of positively charged ions. The ions produce an electric current, which is the signal output of the detector. The greater the concentration of the component, the more ions are produced, and the greater the current.

10.9 Technology Class 9: Metal Oxide Sensing (MOS)

Metal oxide sensors (MOS) are another non-methane specific sensor that utilizes a metal oxide semiconductor (e.g., SnO2, ZnO2, TiO2) as the sensing material. The metal oxide, in the form of granular micro-crystals, is heated to a high temperature at which oxygen in the air is adsorbed to the crystal surface. The sensor has a certain resistance in clean air, which is reduced under the presence of a gas to which the MOS is sensitive (e.g. methane).

10.10 Technology Class 10: Thermal Conductivity

Thermal conductivity instruments incorporate non-methane specific sensors that measure gases with thermal conductivities that are different from a known reference gas (usually air). Typically, thermal conductivity sensors have two heated filaments: a filament that is sealed with a reference gas and an exposed filament. When gas passes through the exposed filament, a rise or drop in temperature occurs, resulting in a resistance change in the electric circuit, which can be measured as a signal and correlated with the amount of gas. This sensor type is favored for its large gas detection range of 0-100%. However, one of the factors limiting the accuracy of the sensor is the inability to distinguish between multiple gases when a mixture is present around the sensor. This is caused by the non-linear relationship between concentration and output signals for some gases. Therefore, thermal conductivity sensors are commonly used as a secondary sensor in combination with another sensor. The idea is to have the thermal conductivity sensor read high concentrations of methane (typically > 5% volume) while the other sensor reads lower concentrations.

11 Annex (Informative): Sample Questions for Technology Developers

The following is a sample questionnaire included as an example and is not intended to be exhaustive:

- *Summarize the Preferred Monitoring Platform and Method:* The operator should provide leak detection technology vendors with an overview of their leak detection needs such as a high-level description of the facility or area for which the technology is being considered (e.g. Metering and Regulating Station, buried pipeline), the preferred platform and method for the instrument (such as handheld instrumentation for walking surveys, vehicle-based platforms for large tracts of pipe, stationary, continuous leak detection), ancillary system requirements (e.g. self-powering with solar, integrated meteorological station.), data communication requirements (e.g. SCADA compatible, wireless), and security needs (e.g. protected dashboards, enhanced wireless networks).

- *Request Information on Instrument Performance:* Leak detection instrument specifications should be requested according to the needs of the monitoring effort. Some examples of important instrument performance specifications are as follows:
    - Gases detected, accuracy, precision, detection range and distance, detection lag, power requirements and operational voltage, datalogging/communication features, dashboard features, size and weight, and hazardous area rating.

  Instrument specifications should be based on claims supported by relevant data. Specification sheets received by technology providers should be supplemented with evidence to support their claims. This could include data from controlled field tests or pilot projects, data from laboratory or bench-scale tests, and/or data from modeling.

- *Additional Information Needed for a Wholistic Cost Estimate:* When requesting a cost estimate, ensure inclusion of all ancillary system costs for a fully functional system (such as dashboards, SCADA incorporation, solar power systems, mounting hardware, wands and attachments, wireless network data communication etc.). Additionally, it is helpful to request an itemized cost breakdown for all optional accuracy/precision upgrades as well as optional ancillary systems as these are not always apparent or advertised with off-the-shelf instruments.
- *Request Business Proficiency Information:* Request operational and financial information about the vendor to ensure necessary commercial and business-related proficiencies to support the monitoring and/or survey requirements. This could include questions about current vendor operations, financial history, number if instruments available for deployment, and/or customer references.
- *Request a Hands-On Instrument Demonstration:* Request an in-person demonstration prior to purchase - preferably at a testing center where a leak can be simulated. Ensure that staff who will be using the instrument are in attendance to ask questions.

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12 Appendix – Technology Summary Tables

Table 7. Summary Table of Component-Level Instrument Type Advantages and Disadvantages

Method Class	Instrument Type	Technology Class	Deployment Platform	Advantages	Disadvantages
Component-Level	**Tunable Diode Laser Absorption Spectroscopy (TDLAS)**	Ranged Laser	Handheld and Vehicle Mounted	• Small, lightweight capable of being handheld • Methane specific • Relatively fast response • Can detect from distances of 30m or more	• Reports a path-integrated concentration (ppm-m) • Relies on light reflected from a surface • Can be impacted by obstructions
	Miniature Open Path Absorption Spectrometer (OPLAS)	In-Plume Laser	Handheld and Vehicle Mounted	• Methane specific • Small and lightweight • Low detection limit (ppb)	• Limited measurement range • May be affected by wind and rain
	Correlated Interference Polarization Spectroscopy (CIPS)	Etalons	Handheld and Vehicle Mounted	• Low detection limit (low ppm) • Methane specific • Intrinsically safe • Low maintenance	• More expensive than catalytic sensors • Requires warm-up • Sensitive to dust and water • Requires extra sensor to measure high concentration

Method Class	Instrument Type	Technology Class	Deployment Platform	Advantages	Disadvantages
	Nondispersive Infrared (NDIR) Sensors	NDIR	Handheld and Vehicle Mounted	• Methane specific • Immune to poisoning • Low power requirements • Class 1 Div. 1 certification capabilities • Low maintenance	• High minimum detection limit (%LEL) • More expensive than catalytic sensors • Requires warm-up • Sensitivity affected by dust and water (snow, ice)
	Flame Ionization Detector (FID)	Flame Ionization	Handheld and Vehicle Mounted	• Relatively low detection limit (~1 ppm) • Relatively fast response (~3 sec)	• Not selective to methane • Requires external hydrogen as fuel • High concentration will cause flame out
	Photo Ionization Detector (PID)	Photo Ionization	Handheld and Vehicle Mounted	• Low detection limit (sub-ppm) • Detects multiple VOCs	• Non-specific to methane; quenching effect by other VOCs • Sensitive to dust and humidity
	Thermal Conductivity Sensor	Thermal Conductivity	Handheld and Vehicle Mounted	• Very low cost • Fast response • Small and light	• Low sensitivity (1-100% vol) • Temperature change, dust, and moisture may cause false detection • Requires other sensors for low concentrations

Method Class	Instrument Type	Technology Class	Deployment Platform	Advantages	Disadvantages
	Optical Gas Imaging (OGI)	IR Imaging	Handheld and Vehicle Mounted	• Surveys large area rapidly • Ranged detection • Flow rate quantification (not verified) • Ability to view leak and assist with localization	• Not methane specific • Detection limit is quite high (1 scfh from 6 meters) • Costly • Not for underground leaks

Table 8. Summary Table of Aggregate-Level Instrument Type Advantages and Disadvantages

Method Class	Instrument Type	Technology Class	Deployment Platform	Advantages	Disadvantages
Aggregate-Level	**TDLAS**	Ranged Laser	Vehicle-Mounted; Rotary (Manned and Unmanned); and Fixed-Wing (Manned and Unmanned)	• Small, lightweight capable of being handheld • Methane specific • Relatively fast response • Can detect from distances of 30m or more	• Reports a path-integrated concentration (ppm-m) • Relies on light reflected from a surface • Can be impacted by obstructions
	Cavity-Type Infrared Spectroscopy (e.g. CRDS, OA-ICOS, WMS, Mid-IR based)	In-Plume Laser	Vehicle-Mounted; Unmanned Fixed-Wing; Manned Fixed-Wing	• Low detection limit (1-2 ppb) • High precision (< 1 ppb) • High frequency measurements • Good software system	• Start-up time (Some are 5-30 min) • Can be delicate • Costly • Bulky (Some are 50+ lbs.) • Limited measurement range • Requires skilled operators

Method Class	Instrument Type	Technology Class	Deployment Platform	Advantages	Disadvantages
	Optical Gas Imaging (OGI)	IR Imaging	Vehicle-Mounted	• Surveys large area rapidly • Ranged detection • Flow rate quantification (not verified)	• Not methane specific • Detection limit is quite high (1 scfh from 6 meters) • Costly • Not for underground leaks
	Light Detection and Ranging (LIDAR)	Ranged Laser	Rotary (Manned and Unmanned); and Fixed-Wing (Manned and Unmanned)	• Relatively high sensitivity • Optical view to assist with localization • Surveys large areas rapidly • Flow rate quantification	• High equipment cost • Available as a service • Can be bulky • Collects high levels of data in 3D space • Needs advanced analytics • Requires skilled operators
	Miniature OPLAS	In-Plume Laser	Unmanned Rotary	• Methane specific • Small and lightweight • Low detection limit (ppb)	• Limited measurement range • May be affected by wind and rain
	Differential Absorption LIDAR (DIAL)	Ranged Laser	Manned Rotary; Manned Fixed Wing	• Optical view to assist with localization • Surveys large areas rapidly • Flow rate quantification	• High minimum detection limit • High equipment costs • Available as a service • Can be bulky • Collects high levels of data in 3D space • Needs advanced analytics • Requires skilled operators

Method Class	Instrument Type	Technology Class	Deployment Platform	Advantages	Disadvantages
	Imaging Spectrometer	IR Imaging	Manned Fixed Wing; Satellite	• Wide coverage • Locates emission sources • (Satellite) Global and complete spatial coverage	• Bulky • Limited to sun-lit, snow-free scenes • (Satellite) Sparse spatial resolution

Table 9. Summary Table of Stationary Continuous Monitoring System Instrument Type Advantages and Disadvantages

Method Class	Instrument Type	Technology Class	Deployment Platform	Advantages	Disadvantages
Stationary Continuous Monitoring Systems	**Open Path Fourier Transform Infrared (OPFTIR)**	Ranged Laser	Semi-Permanent (Tripod or Truck) or Permanent (Tower)	• Capable of simultaneously measuring many gas species • Covers a long path (line-of-sight)	• Follow up survey needed to confirm leak location • May require a reflector • May require sunlight as light source • Laser position may be rendered ineffective if dominant wind direction changed drastically • Costly
	TDLAS	Ranged Laser	Semi-Permanent (Tripod or Truck) or Permanent (Tower)	• High sensitivity (1 ppm*m) • Can run on solar power • Covers a long path (line-of-sight)	• Follow up survey needed to confirm leak location • May require a reflector • Laser position may be rendered ineffective if dominant wind direction changed drastically

Method Class	Instrument Type	Technology Class	Deployment Platform	Advantages	Disadvantages
	Cavity-Type Infrared Spectroscopy (e.g. CRDS, OA-ICOS, WMS)	In-Plume Laser	Semi-Permanent (Tripod or Truck) or Permanent (Tower)	• Low detection limit (1-2 ppb) • High precision (< 1 ppb) • High frequency measurements • Good software system	• Start-up time (5-30 min) • Can be delicate • Costly • Bulky (50+ lbs.) • Limited measurement range • Requires skilled operators
	Carbon Nanotube (CNT)	In-Plume Point Sensor	Semi-Permanent (Tripod or Truck) or Permanent (Tower)	• Low-powered • Low cost • Detects multiple gases • Relatively high sensitivity (5 - 50 ppm)	• Will get poisoned periodically (requires active material replacement) • Still in development (not commercially available)
	Catalytic Combustion Sensor (Pellistor)	Catalytic Combustion/Pellistor	Semi-Permanent (Tripod or Truck) or Permanent (Tower)	• Sensitive (1 -10,000 ppm) • Low cost • Portable	• Catalysts can get poisoned by sulfur or silicon • Requires oxygen for detection • Non-linear at higher concentration (> 100% LEL)
	Metal Oxide Sensor (MOS)	MOS	Semi-Permanent (Tripod or Truck) or Permanent (Tower)	• Very low cost • Low power consumption • Fast response • Small and light	• Low sensitivity (1-25% LEL) • Low resolution • Temperature dependent • Can be damaged by water

Method Class	Instrument Type	Technology Class	Deployment Platform	Advantages	Disadvantages
	Nondispersive Infrared (NDIR) Sensors	NDIR	Semi-Permanent (Tripod or Truck) or Permanent (Tower)	• Methane specific • Immune to poisoning • Low power requirements • Class 1 Div. 1 certified • Low maintenance	• High detection limit (%LEL) • More expensive than catalytic sensors • Requires warm-up • Sensitivity affected by dust and water (snow, ice)
	Imaging Spectrometer	IR Imaging	Semi-Permanent (Tripod or Truck) or Permanent (Tower)	• Ability to locate leak source • Can quantify leak rate • Well suited for facilities with known potential emission sources	• Can be costly • Not suitable for underground assets (no thermal contrast between gas and ground)