CANADA'S OIL & NATURAL GAS PRODUCERS

Best Management Practice

Pipeline Leak Detection Programs

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The Canadian Association of Petroleum Producers (CAPP) represents companies, large and small, that explore for, develop and produce natural gas and crude oil throughout Canada. CAPP's member companies produce about 80 per cent of Canada's natural gas and crude oil. CAPP's associate members provide a wide range of services that support the upstream crude oil and natural gas industry. Together CAPP's members and associate members are an important part of a national industry with revenues from crude oil and natural gas production of about $110 billion a year. CAPP's mission, on behalf of the Canadian upstream crude oil and natural gas industry, is to advocate for and enable economic competitiveness and safe, environmentally and socially responsible performance.

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1 Overview

This best management practice (BMP) intends to guide operators of upstream pipelines in the selection, operation and maintenance of pipeline leak detection programs (LDP). It was developed by the CAPP Pipeline Technical Committee to address leak detection as part of upstream operators' focus on performance improvement through companies' pipeline integrity programs. This BMP is a proactive step by industry to detect leaks quicker, reduce the environmental impacts from leaks and improve pipeline performance, particularly in high-risk areas.

Note that pipeline LDP does not and cannot eliminate leaks. However, it can potentially reduce the impact of leaks due to earlier detection and remedial action. The overall reduction in leak occurrence is the job of pipeline integrity management.

This BMP is complementary to CSA Z662 (Oil and Gas Pipeline Systems), the governing standard for pipeline systems in Canada, and other regulations, codes and standards. These are listed in Section 3 of this document. It also provides a summary of additional resources that address leak detection.

The purpose of this BMP is to provide a guide to pipeline LDP best management practices that can be applied in the broadest range of applications, noting there is diversity in the practical problems that will be encountered in pipeline leak detection.

Canada's pipeline system includes a large number of existing and new pipelines that are continuously being added to the inventory. Pipeline leak detection is therefore dynamic and evolving like the underlying pipeline system.

This BMP applies nationally in jurisdictions where CAPP members operate. Alberta's pipeline system, the most extensive and diverse in Canada, is used as an illustrative example only.

The diversity of types of pipelines, products, operational details and operating company characteristics means that no simple set of rules can apply universally. Each situation must be evaluated independently to identify the characteristics which influence pipeline LDP implementation. It is the intent of this BMP to guide the choice of LDP.

This document references CSA Z662-15, the current edition of this standard at the time of writing. Please refer to the most recent edition of this standard as it becomes available.

This document, as well as other BMPs, are available free of charge on CAPP's website at www.capp.ca.

2 Pipeline performance

The current pipeline inventory in Canada is approximately 825,000 km, consisting of about 250,000 km of gathering lines (four to 12 inches), 25,000 km of feeder lines, 100,000 km of large diameter transmission lines (four to 48 inches) and 450,000 km of local distribution lines (one-half to six inches), according to Natural Resources Canada. Much of this pipeline inventory – about 426,000 km – is located in Alberta and is regulated by the Alberta Energy Regulator (AER).

Data from the AER serves as an illustrative example for how pipeline performance has continuously improved: over the past 10 years, the length of pipelines in Alberta grew by 11 per cent while the number of pipeline incidents dropped by 48 per cent, driving the pipeline failure rate to 0.98 incidents per 1,000 km of pipeline in 2017 compared to 2.08 incidents in 2008. This decrease is due to improved requirements, industry education, improvements to inspection programs and a greater focus on pipeline safety within industry.

Nonetheless, operators recognize that pipeline performance must continue improving. This includes focus on detecting leaks more quickly, reducing the potential for pipeline releases and mitigating release volumes. LDP is an integral part in this process.

Current pipeline performance data can be viewed on the websites of most regulators in Canada.

3 Regulations, codes and standards

While numerous regulations, codes and standards relate to pipeline LDP, none provides a comprehensive definition of requirements. Below is a summary of the most relevant.

CSA Z662: Governing standard for pipeline design, construction, operation and maintenance in all Canadian jurisdictions. Annex E is the main part of this standard that addresses recommended practices for liquid hydrocarbon pipeline leak detection. Other sections in this standard that address leak detection include clauses 4.20 and 10.3. As a best practice, leak detection practices detailed in CSA Z662 should be applied generally. Note that this BMP is intended to also address products other than liquid hydrocarbons.

National Energy Board Onshore Pipeline Regulations (OPR): Provide regulatory requirements for oil and natural gas companies, including leak detection.

Alberta Pipeline Regulation 91/2005 (Pipeline Rules): Invoke CSA Z662 as a mandatory standard and impose various LDP requirements. They require Annex E only for liquid hydrocarbon pipelines. Other Canadian jurisdictions have similar regulatory frameworks invoking CSA Z662 requirements.

AER Directive 56: Energy development applications and schedules requires leak detection for liquid hydrocarbon pipelines only.

AER Bulletin 2016-22: Highlights the importance of leak detection for multiphase (oil-well effluent) and oilfield water pipelines. The required AER standard is an “effective” leak detection system.

B.C. Oil & Gas Activities Application Manual: Requires leak detection for liquid hydrocarbon pipelines. Optional for other users.

Saskatchewan Pipeline Regulations 2000: Invoke CSA Z662 as the general authority and require minimum leak detection according to Annex E for liquid hydrocarbon pipelines. Explicitly exclude multiphase pipelines. Note that Saskatchewan regulations use the term “spillage” instead of “leak.”

Manitoba Oil & Gas Act and Regulation: Invoke CSA Z662 generally but contain no specific provisions for leak detection requirements.

United States regulations and standards have no formal authority in Canadian jurisdictions but are worth mentioning due to the fact that many Canadian operators have pipelines in the U.S.

49 CFR 195: Federal regulation governing the transport of hazardous liquids by pipeline.

API 1130: Deals with computational pipeline monitoring for liquids.

API 1149: Deals with variable uncertainties in pipelines and their effects on leak detection performance

API 1175: Establishes a framework for leak detection program management for hazardous liquid pipelines. It can serve as a template or reference for operators wishing to implement a leak detection program or strategy.

Detailed comparisons of U.S. and Canadian standards have been published that are helpful in developing best practices (see PHMSA 2008).

4 Principles

The AER Strategic Plan 2017-20 (AER 2017) identifies four key principles that can be applied to LDP. While these principles were developed by the AER, CAPP member companies support the application of these principles to LDP in jurisdictions where they operate.

Principles:

Protective: LDP is protective of human health, safety and the environment. LDP is also protective of the commercial interests of the pipeline. LDP reduces risk exposure and can be viewed as part of an overall corporate risk-management strategy

Effective: LDP must be effective, which implies that LDP will achieve stated performance objectives. LDP will be effective in reducing the size and impact of pipeline leaks through early detection and prompt response.

Efficient: LDP should be efficient in targeting high-consequence incidents first. This implies a risk assessment that may be as simple as identifying the high-consequence areas and addressing these as priority areas (see CAPP BMP Guide for Designated Pipeline Sections in High-impact Areas). More comprehensive risk assessment may be justified for refined risk-based decision-making.

Credible: LDP should be credible and demonstrate the effectiveness, particularly in reducing the impact of high-consequence incidents. Credible LDP is critical to demonstrate publicly how operators continuously improve environmental and safety performance.

5 LDP performance criteria

The appropriate performance criteria to be applied in any given LDP implementation will vary depending on the physical characteristics of the pipeline and its operating conditions.

CSA Z662 Annex E provides minimum performance criteria and a practice for leak detection based on computational methods and direct leak-detection methods. Other leak-detection practices should be defined and implemented at the discretion of individual operators, based on their unique circumstances. Also, best practice should implement the minimum practical leak detection duration and volume without introducing excessive uncertainty and consequent errors and false alarms.

The achievable performance will depend on physical constraints, including hydraulics (e.g., multiphase flow, slugging, slack line, etc.), operation (e.g., unsteady, intermittent, shut-in, batch etc.) and fluid characteristics (e.g., HVP).

LDP should primarily focus on liquid pipelines and identifying high-consequence areas (HCA) – areas where risk is highest and where the potential environmental impact or impact on public safety can be greatest. HCAs should be given higher priority and performance, which may include installation of a secondary LDP for the specific area.

For liquid pipelines, HCAs can include surface water (lakes, streams, rivers) and wetlands where mobility of release liquids can affect large areas with sensitive environments, and high population-density areas close to a pipeline.

6 Leak detection methods

A leak-detection program can comprise one or more methods. Where practicable, pipeline operators should compare the results of one method of leak detection with the results of other applicable methods.

This section intends to complement the section in CSA Z662 that describes leak detection systems. It describes leak detection methods and technologies that are currently available for a variety of uses. The decision of which of these to implement as part of a comprehensive LDP depends on a variety of factors related to the pipeline, including commodity transported, operating characteristics and environment setting.

The tables below are meant to serve as a guide for operators for which method or methods may be most appropriate to an operator's pipeline or pipeline system. Further detailed guidance and requirements for leak detection systems can be found in CSA Z662 or the documents referenced in Section 3 of this BMP.

The tables below provide a wide range of possible pipeline leak detection methods, recognizing, however, that no single leak detection method is applicable to all pipeline situations.

The tables do not rank the possible leak detection methods. Each situation requires an evaluation of the applicability of the methods used to determine the correct choice.

Some of the technologies are in the development stage and further testing and operational experience is required. Many of the technologies have limited operational experience. For many technologies the only source of performance data is from the vendors.

It is also noted that internal leak detection systems based on computational pipeline monitoring (CPM), the most widely used method for liquid hydrocarbon pipelines, is the only class of LDP technology methods for which industry recommended practice exist (API 1130). Other technologies do not have the benefit of a standard and/or recommended practice that defines design, testing or operational principles. This is seen as a key requirement for further development and application of alternative leak detection technologies.

Table 1: Gas sensor technology

Internal vs External	Leak Detection Method	Description	Applicable Commodity Type	Pros	Cons/Limitations
External	Infrared (FLIR)	Use of thermal imaging to detect leaks	NG – Sweet NG – Sour Potentially applicable to liquid lines with temperature (>40 degrees C). Need to confirm temperature limitations with vendor.	May observe a significant section of pipeline from an elevated location. Particularly effective when located on an aircraft.	Foliage (line of sight). Low-lying area. Sensitivity based on volume (limitation to technology).
External	Flame ionization (FILD)	Measures HC concentration	NG - Sweet NG - Sour OE (with gas phase)	Can detect leaks at low concentrations. Can be used while walking the pipeline right of way. Can be truck mounted	Need to test in winter (may pick up rogue emissions from swamp gas resulting in false pipeline leak alarms). Wind. Foliage. Low-lying areas. Need light ends for this work - high gas/condensate cut required.
External	Laser gas detection	Aircraft mounted device to test for methane; testing the atmosphere	NG - Sweet NG - Sour OE (with gas phase) Can be reconfigured for other gases.	High sensitivity. Covers a long section of pipe in a short period of time.	Limited by atmospheric conditions (high winds).

Table 2: Visual Surveillance

Internal vs External	Leak Detection Method	Description	Applicable Commodity Type	Pros	Cons/Limitations
External	Visual Checks	Check for vegetation distress, bubbling in wet areas	All commodity types	Simple, can be done by operations with minimal equipment. Inexpensive in equipment cost.	Requires the leak to persist for long enough to come to surface or cause vegetation distress. Can have a large spill size as a result (depending on the scenario). Expensive due to manpower required to frequently walk the pipeline right of way and document results. Limited to time of year. Limited by topography, such as low-lying areas. May be difficult to see small effects over time and leak size may escalate as a result. Photo comparison is needed. Vegetation distress observed more on lines with liquid hydrocarbon and/or salinated water. Not overly effective for sweet shallow gas unless area is wet.
External	Aerial inspections	Visual inspections to spot spills (could include the use of drones)	All commodity types	Easy to detect crude oil visually. Can gain visual close to the ground (ROW); safety.	Very reactive - spill can be large by the time it is detected. Effectiveness may be limited depending on the technology used. Time-dependent - time of leak and time of inspection Drone - have to have line of sight, cannot use on military base; may lose some of the "human input" that using a helicopter enables. Drones may be restricted in pipeline right of ways close to airports and military installations.

Table 3: Tracer and use of sensory

Internal vs External	Leak Detection Method	Description	Applicable Commodity Type	Pros	Cons/Limitations
External	Mercaptans	Smell test Use of tracers Use of dyes in freshwater systems - use of produced water systems	NG - Sweet NG - Sour (liquid lines would have to be drained and filled with gas)	Inexpensive. Can be useful when the location of a suspected leak cannot be found. Proven effective for buried pipelines in frozen ground when used with dogs.	Wind can make it difficult to identify actual location. Reactive approach to leak detection in upstream. Used in systems where moving a few 100m3/d.
External	Chloride probe in water crossing	Groundwater probe	Lines containing chlorinated water		Have to learn concentration ranges over seasons. Location of problem presents challenges. May need Department of Fisheries and Oceans approval.
External	Polymer Absorptive Technology (PAS)	Hydrocarbon detection due to resistance change in a polymer when in contact with hydrocarbon	Hydrocarbon pipelines	Probes installed near pipeline can be used to detect hydrocarbon leaks in high-consequence areas. Applicable to above-ground pipeline installations.	Difficult to install on existing buried pipelines. Emerging technology.

Table 4: Computational methods

Internal vs External	Leak Detection Method	Description	Applicable Commodity Type	Pros	Cons/Limitations
Internal	Automated compu-tational methods	The use of sophisticated software products such as statistical models or RTTMs to detect and alarm on possible leaks.	All commodity types. Single phase.	Detect leaks in a timely manner. Removes some of the subjectivity from other human-based methods. Allows monitoring of large pipeline segments or networks from a single control room. Typically sensitive to relatively small changes within the system.	Requires SCADA infrastructure to bring data back to software. Requires substantial instrumentation. Costly to implement. Requires tuning and adjustment during initial installation with continuous improvement/monitoring over time. Can be prone to false alarms in certain operating scenarios and if not tuned properly.

Table 5: Line balance

Internal vs External	Leak Detection Method	Description	Applicable Commodity Type	Pros	Cons/Limitations
Internal	Bypass lines around valves, combined with a flow detector inside the bypass line.	Recycle volume indication of a leak.	All commodity types Single phase	Process control approach requiring modifications to existing equipment. Can be alarmed.	Very facility/equipment specific. Cannot detect where actual leak is. Range of detection and production composition would have to be consistent. Good for bursts or large pressure drops.
Internal	Basic line balance calculations metering Volume, flow tempera-ture, pressure (loss) and mass monitoring	Use of meters and flow computer at input and output of pipeline to determine if the product entering the line is leaving the line at the delivery end (in – out).	All commodity types. Single phase. Easier to apply to flooded liquid lines. (Coriolis meters - crude, LVP)	24/7 monitoring (dependent on the system). Quick detection means quick response. Coriolis Meters - good for mass balance of blends and continuous improvement of model. Provides linear mass reading even with products and flow rates.	Relies heavily on the accuracy and reliability of measurement devices. Improved detection with SCADA but can be an expensive initial startup. Tolerances need to be set appropriately and tuned to minimize false alarms and nuisance alarms Requires a baseline period. Customized instrumentation approach. Pinhole leaks difficult to detect. Does not compensate for line pack on pipeline startup. Does not function well on longer batched pipelines with products of significantly different densities. Can be expensive.

Table 6: Imagery technology

Internal vs External	Leak Detection Method	Description	Applicable Commodity Type	Pros	Cons/Limitations
External	Use of Fixed Cameras Video Surveillance		All commodity types (may have restrictions with gas)	Incorporated with aerial or ground surveillance as well as infrared.	Pictures are static. Surveillance may be limited to a fixed position.
External	Satellite Imagery	1. Visual 2. Spectral shift		No terrestrial infrastructure required.	Direct line of visual required. Costly, depending on interval of orbit. Experimental.

Table 7: Other

Internal vs External	Leak Detection Method	Description	Applicable Commodity Type	Pros	Cons/Limitations
External	Fibre optic cable system	Temperature Acoustic Strain	All commodity types. Single phase and multi-phase.	Good for short lengths of pipeline (due to cost). Multipurpose approach, temperatures and acoustic. SCADA capable, with low power for remote locations. Geotechnical events can be detected as well. Temperature is sensed via fiber cable characteristics change. No additional sensors required.	Difficult to install on existing lines. Expensive for longer lines due to fiber cost and range limitation of laser. Temperature cables - if using for water systems, need to ensure temperature difference between ground and water is different or it won't be detected.
External	Acoustic emission	Uses acoustics to detect a small leak in the pipeline Smart-ball technology (reads acoustic signature as it travels) Pipeline sensors	All commodity types	Can find leaks in a pipeline where the leak location cannot be readily identified.	Requires the tool to travel in the pipeline. Only detects leaks during the time tool is travelling in the pipeline. Monitoring therefore not continuous. Cannot be used for corrosion detection.
Internal	Operational systems checks	Low pressure alarms Tank level sensors (OE) Production and pressure trending (check charts) Pressure point analysis (pressure monitoring) Valve positioners	All commodity types	Can be done by operations on a frequent basis Centralized data collection centers with live data may be needed, but data collection sheets can be used.	Best supports the identification of larger leaks. Intended to be used in conjunction with other methods. Fluid accumulation can cause false readings. Heavily reliant on operator experience, system dependent and doesn't directly indicate a leak but provides a warning there may be a problem and further investigation is required.

Table 7 continued

Internal vs External	Leak Detection Method	Description	Applicable Commodity Type	Pros	Cons/Limitations
Internal	Liner vent checks	Test for leak between the liner and pipeline	All commodity types	Allows for early detection of a problem.	Distance between liner vents can make this very practical or impractical Difficult to interpret as gas migration would be expected in a lined gas pipeline Subjective approach - dependent on service conditions (baseline might be different depending on the line).
Internal	Shut-in tests (pressure bleed-off). Also known as in-service leak test or stand-up pressure test.	Pressure bleed off	All commodity types	Easy for on-site personnel to detect.	Need to shut-in production (will vary depending on pressure response). Test duration needs to be sufficient for compressible fluids. Difficult to determine actual failure location. Thermal effects - sensitivity can be lost.

7 Instrumentation, operation and maintenance

This section highlights main points referenced in CSA Z662. For greater detail, see CSA Z662.

Instrumentation and Measurement: Critical data used to drive a computational leak detection method (i.e., flow rate, temperature and pressure) should be calibrated/proved on a regular basis. Measurement equipment should be matched to the performance requirements of the leak detection system (i.e., leak detection or custody transfer accuracy).

Critical instruments and processes: Data sources and processes used for LDP must be reliable. It is the responsibility of the operating company to determine critical processes, instruments and data.

Alarms and analysis: The operating company shall monitor the reliability of the leak detection system and balance the occurrence of invalid leak alarms with consideration of the impact on the sensitivity of the system.

Calibration and maintenance of instruments: Critical instruments shall be calibrated to maintain their outputs to meet the performance required by the leak detection system. Operating companies should develop a plan that specifies the frequency and rationale for calibration of critical instruments.

LDP maintenance: Changes to the LDP or to instrumentation should be evaluated to determine if system testing is necessary to confirm that the LDP performance has not been degraded by the changes or new configuration.

Function monitoring: Leak detection software is a critical process and should include features that monitor and report any degradation or loss of function.

8 Testing, monitoring and training

Testing, monitoring and training are critical to the success of LDP. CSA Z662 provides detail on all these elements. While this BMP is intended to complement CSA Z662, the section below highlights in general terms the main elements referenced in the standard. For greater detail, see CSA Z662.

Testing: LDP should be tested to demonstrate that design thresholds are met and to establish a baseline of achieved performance. LDP should be tested at least annually.

Testing methods: LDP should be tested to alarm state with actual or simulated service fluid removal or with a procedure that upsets the pipeline hydraulics and simulated a leak. Test methods and parameters should be repeatable. The testing procedure and the results are to be recorded for historical reference.

Leak detection manual: Operators should develop, implement and regularly update a leak detection manual. A manual may be developed for each particular pipeline or it may be applicable to a number of pipelines. Detailed manual contents are listed in CSA Z662.

Improving LDP performance: To be effective in continuously improving performance, the sensitivity, accuracy, reliability and robustness of the performance metrics used in LDP should be quantified and periodically evaluated. Performance assessment should be done at least annually with results documented.

Audits: LDP should be reviewed and audited periodically to determine whether they are in accordance with established requirements and should be revised as necessary. Internal audits should be conducted periodically by the operating company or designated representative.

LDP Training: Continuous employee training is critical to the implementation and effective functioning of LDP. To accomplish this, an operating company should develop a policy for pipeline operator or controller training, testing and retraining.

Record Control: Documentation required by CSA Z662 should be considered to be records of the pipeline company and should be retained for the periods specified in CSA Z662.

9 Revisions to CSA Z662

Revisions to CSA Z662 in 2019 are expected to include changes to leak detection requirements contained in clause 10 and Annex E. The impact of any changes on pipeline operators' LDP management programs must be assessed if and when CSA Z662 changes are implemented and appropriate modifications made to the LDP.