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Leak Detection on Petroleum Pipelines

Class # 2210.1

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Introduction

Early interest in pipeline leak detection was probably born of a desire to prevent interruption of fluid delivery in early open conduits carrying water from its source at high elevation to its destination in the valley. As technology improved and wooden, then lead, pipes carried water under head pressure, the consistent behavior of the flow stream at the delivery point provided evidence of good pipeline integrity. Stepping forward many years, fluids have expanded in types and number, as has the cost of fluid loss in terms of its commercial value, damage resulting from its release, and cost of remediation. Hydrocarbons of many forms are transported safely and efficiently by pipelines compared to railroads or trucks over long and short distances. However, on occasions sufficiently rare that they are not expected, leaks occur. Risk analyzers combine the probability of a leak event with the consequences of the event to determine the appropriate course of action to prevent the leak event and to mitigate damages should one occur. The more courageous among us, who believe they have little need for leak detection technology, have occasionally found their risk analysis short-sighted at high cost in dollars, company reputation and increased government oversight.

Why Leak Detection?

Reasons for preventing a leak are self-explanatory. Leaks always result in downtime for repairs, thus interrupting production. In many cases, there is a potentially higher cost in safety hazards and cleanup in the case of hydrocarbon liquids. Consequently, the primary importance of leak detection is often in mitigating risk of a catastrophic event and/or minimizing remediation costs rather than simply the value of lost fluid. While industry standards of due diligence have evolved in recent years, they do not tend to advance standards of appropriate leak detection performance. Instead, they tend to support the lowest common denominator approach to appropriate technology. Each pipeline, its contents, and operating regime differs from other situations, but generally falls under some guideline or regulation. Government regulations are now beginning to dictate a minimum commitment standard of pipeline safety including leak detection where it is needed to increase safety.

History of Leak Detection

Early methods of leak detection on pipelines involved simple pressure and flow measurements with evaluation performed by manual means. Telemetry was verbal over telephone lines. Familiarity with normal pipeline behavior was critical in recognizing anomalies indicative of a leak. Direct observation such as flying or driving the right-of-way (ROW) looking for unhealthy vegetation was, and still is, a major method of verifying pipeline integrity.

The evolution of transducers evolved quickly, first to support manual readings, then to transmit results to data collection devices. Over time, automated methods of monitoring and collecting pipeline data also evolved quickly. Early methods involved tone generators that produced a tone of duration proportional to the variable being monitored. These tones in turn were transmitted to a central location where data could be interpreted and/or displayed. As familiarity with hydraulic behavior along the pipelines grew, the now common over/short behavior of some lines needed explanation regarding the causes. Algorithms were developed to deal with these common behaviors and procedures for evaluating evidence of a possible leak followed.

Performance

From the former API 1155 (Evaluation Methodology for Software Based Leak Detection Systems), we have four (4) results by which modern leak detection performance is graded. These are as follows:

1. The system correctly indicates that there is no leak,
2. The system correctly indicates that there is a leak,
3. The system incorrectly indicates that there is a leak (false alarm), and
4. The system incorrectly indicates that there is no leak (failure to detect).

Significant efforts can be expended to achieve only the first two (2) conditions. Four (4) metrics exist to describe the abilities of a particular leak detection system's performance. These parameters are heavily influenced by the leak detection product's inherent strengths and weaknesses as well as the pipeline's instrumentation complement and fluid properties. These metrics are as follows:

1. Sensitivity – combination of the size of a detectible leak and the time required to detect it (often informally used to describe the smallest detectible leak),
2. Reliability – a measure of the system's ability to accurately assess whether a leak exists or not,
3. Accuracy – the ability of a system to estimate leak parameters such as leak flow rate, total volume lost, and leak location, and
4. Robustness – the ability of a system to continue to function in unusual hydraulic conditions or when data is compromised.

Leak Detection Tools

The purpose of leak detection systems has evolved along with advancements in technology and improved capability. Early meter-based systems, such as simple over/short tabulations, were expected to give the pipeline controller insight into the pipeline's recent hydraulic behavior to enable him/her to form a subjective opinion regarding pipeline integrity. As tools became more sophisticated and trustworthy, many companies chose to eliminate the controller's subjective evaluation from the process and rely on the leak detection system's algorithms. However, the limitations associated with the algorithms, combined with compromises in instrumentation availability and/or quality, often led to false alarms. The natural solution is increasing alarm thresholds and/or persistence criteria so transient conditions that momentarily share hydraulic characteristics with those of a leak do not trigger an alarm. Where the controller has good familiarity with pipeline operation, there is no substitute for alarm settings that draw the attention of the controller to hydraulic anomalies in order to apply operational experience in determining pipeline integrity. This allows more sensitive operation with potentially shorter detection times, especially when leak detection systems employ sophisticated linepack analysis techniques before issuing an alarm.

Meter-Based Technology

Flow meter-based technology has evolved from simple meter comparisons (instantaneous or accumulated flow) to use more sophisticated algorithms performing linepack analysis in order to properly allocate any observed flow imbalance to a change in pipeline inventory. Meter-based systems eventually became known in the industry as Computational Pipeline Monitoring or CPM. This name originally applied only to methods that employed computational algorithms to replace the need for manual calculations. However, other proven technologies, such as acoustic pressure wave detection, have been added to that definition.

Meter-based CPM is the dominant method employed on long transmission lines. It does not require instruments between major stations, though detection times are adversely affected by linepack uncertainty over long distances between instruments. This method requires meters at all entry and exit points. Achievable sensitivity is determined by the aggregate accuracy of all meters serving as boundaries for a given pipe segment. Alarm threshold must tolerate expected flow/volume imbalances as the line unpacks during normal operation. Algorithms that can correlate flow imbalance with inventory changes provide better immunity from false alarms at configured sensitivity levels. Practical sensitivity thresholds also improve with meter accuracy as illustrated in Figure 1 - *Influence of Meter Quality on Performance.*

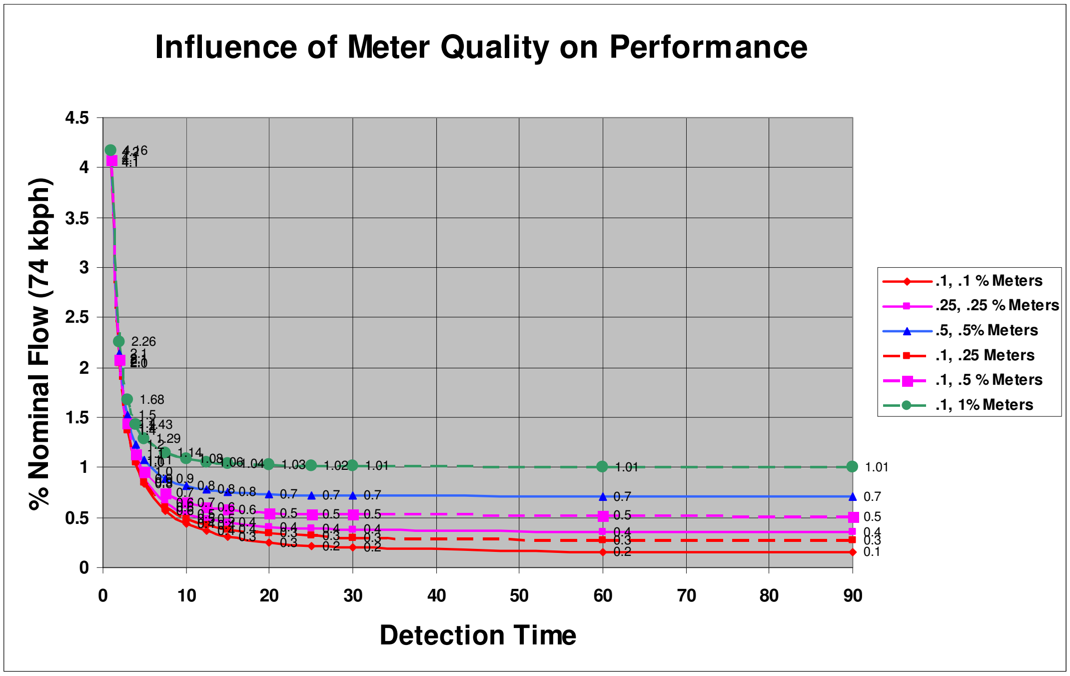

Figure 1 – Influence of Meter Quality on Performance

The major limitation in meter-based CPM is due to transient changes in linepack during normal pipeline operation. Control actions such as valve operation, changing injection rates or delivery paths can cause the line to unpack just as a leak might do. This contributes to a short-term uncertainty in the inventory of the line as the line re-stabilizes after the transient dissipates. Such transients need to be either tolerated, or understood by the leak detection system. Systems involving Real-Time Transient Models (RTTM) understand the expected transient behaviors and can perform short-term assessments regarding the influence of the transient on the linepack, thus avoiding any assumption that a predictable linepack disturbance may be a leak. Over an extended observation interval, the hydraulic effect of transient behaviors is dwarfed by aggregate fluid throughput, thus allowing good sensitivity without having to consider transient behavior to such a degree as is necessary over short time periods. In any case, persistence is a leak characteristic not shared by transient behavior.

Instrument Quality

Instrument quality determines the performance of any leak detection system dependent on the instrument. Instrument placement is critical to avoid erroneous readings due to flow stream inconsistencies or isolation of the instrument under unusual configuration of valves and flow paths. Instrument error can contribute to leak alarms that are false with respect to pipeline integrity, but legitimate with respect to consideration of hydraulic data that may be evidence of a leak. It is not unusual for a controller to recognize instrument error in a particular reading while other readings remain normal.

Measurement Uncertainty

Measurements are only taken at particular points along the line where acquisition of data is convenient. Each measurement has its own uncertainty due to analog to digital conversion resolution, instrument placement, accuracy, and repeatability. However, these uncertainties may not be significant compared to the uncertainties in estimates of pressures, temperatures and fluid characteristics between measurement points.

Pipeline operators are very familiar with the packing and unpacking hydraulic behaviors of their pipelines. These conditions are transient in nature and must reverse at some point in time to return to an earlier condition. This behavior can be caused by startups and shutdowns during which entry and exit flows are legitimately imbalanced. In the case of unpacking, pressures drop and potentially suggest a leak may exist. Most leak detection systems would see the outgoing flow being greater than incoming flow as a reason for the unpacking and avoid a false leak alarm. In the case of packing, there is greater incoming flow than outgoing flow which would be indicative of a leak if pressures do not rise. Fortunately, most systems will recognize increasing pressure as an indication the packing is legitimate. The most sophisticated systems can evaluate evidence of a leak accurately even during transient conditions.

On some pipelines, there are thermal conditions such that fluid density increases significantly as heat is lost to the environment during transit. This affects the volume occupied by each quantity of fluid originally injected into the line in a way that makes it appear that more fluid is entering the line than leaving it when measured by volume. Under this condition, there will be a gradient of temperature and density along the line that reflects the heat lost and resulting temperature decline along the line. Heat is transferred from the fluid to the environment rather slowly, especially as the temperature of the environment immediately surrounding the pipe and the temperature of the fluid approach thermal equilibrium. After this equilibrium is reached, any change in flow rate will result in a new change in the shape of the temperature/density profile and a new thermal profile will be established over time as heat transfer rates along the line approach new quiescent states as illustrated in Figure 2 – *Density Profile*.

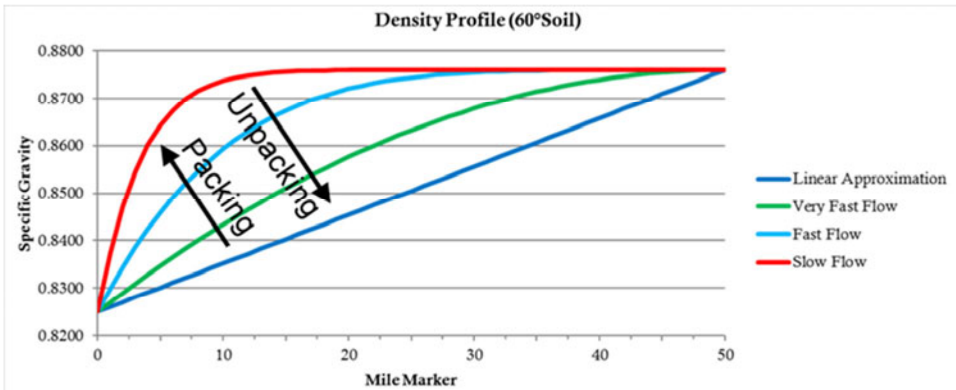

Figure 2 – Density Profile

Step changes in flow rates can result in a slow transition to a new equilibrium in volumetric flow measured at each end of the segment. While this equilibrium develops, the linear velocity of the fluid varies within the line according to the position and fluid density at that point, thus disturbing the thermal profile a small amount due to fluids of a particular temperature shifting positions in the pipeline until thermal stability is again achieved. Any time this occurs, there is a noticeable change in any imbalance between incoming and outgoing flows as the temperature/density profile drifts toward its steady-state condition. On many pipelines operated in a steady-state mode, this phenomenon is not a problem for most leak detection systems. Algorithms for estimating fluid temperatures and densities between measurement points may include simple averages, weighted averages, and modeled heat transfer for more exact estimation. When injection characteristics vary with regard to fluid type or temperature, more sophisticated leak detection algorithms may be required to understand this phenomenon and account for it. Otherwise, the desired leak detection performance expected using good instrumentation may be thwarted. Selection of tools with algorithms that minimize uncertainty in estimating hydraulic conditions allow greater sensitivity in desired detection windows and/or shorter detection times with fewer false alarms for desired sensitivities.

API-1149 Pipeline Variable Uncertainties and Their Effects on Leak Detectability - Limitations

API-1149 is a tool that accepts parameters associated with the pipeline operation and provides an estimate of the best possible leak detection performance to be expected. Actual detection thresholds usually include margins of safety to prevent false alarms. Some important parameters that influence leak detection performance, such as temperature uncertainty, are unknowable. Measuring temperature at stations is a very common occurrence. However, where injection temperature is significantly higher than delivery temperature, knowing the temperature profile along the pipeline is difficult without a well-tuned model-based system to model heat transfer from the fluid to the environment. As heat migrates to the soil along the pipeline, the fluid density changes such that fluid is absorbed into the linepack due to increased density along the line. The problem is further complicated in API-1149 by the fact that, once steady-state operation is achieved such that the temperature/density profile becomes stable, the effects of temperature uncertainty dissipate. In effect, with a stable pipeline inventory, injections and deliveries must balance even though fluid densities may differ at injection and delivery sites, thus making net measurements balance while raw uncompensated measurements differ.

Step changes in injected fluid temperatures will create a significant thermal transient that contributes to uncertainty in the thermal profile while the profile evolves. Over time, heat migration results in equilibrium between the temperature of the fluid and immediate surrounding environment at each point on the line. Trying to derive the temperature profile along the pipeline from endpoint measurements in this case without a thermal model can result in a very large temperature uncertainty. In cases where steady-state operation is disturbed by changes in flow rates, a thermal transient also results in a disturbance in pipeline inventory due to a change in the temperature/density profile.

API-1149 makes no provision for declining effects of temperature uncertainty as steady-state operation is achieved. Nor does it attempt to handle thermal transients during transitions from one steady-state condition to another. The temperature uncertainty configured in API-1149 is considered persistent, and is treated as such. Unfortunately, transitions from transient to steady-state conditions are a common occurrence in many pipeline operations. Except in cases where a thermal model tracks the temperature profile along the line, sensitivity adjustments are made to avoid false alarms due to these transients.

Leak detection system vendors frequently declare their systems meet or exceed API-1149 performance predictions. Given the declining effect of actual temperature uncertainty, this is expected even in the most rudimentary systems under steady-state conditions. Any effort to consider API-1149 results applicable to a particular pipeline should include a review of several instances of temperature uncertainty. This will illustrate the wide variation in performance predictions that can be argued to be applicable in order to support such claims.

In spite of its limitations, API-1149 illustrates the benefits of smaller volumes between measurement sites and lower temperature uncertainties. Beyond that, any effort to associate numerical performance predictions with any particular leak detection product or implementation is simply reduced to configuration of unknowable parameters to achieve desired results.

SCADA Scan Rates

Optimum scan rates for liquid lines are in the neighborhood of three (3) to five (5) seconds because evidence of a leak appears rapidly in pipelines containing relatively incompressible fluids. However, there are several things to consider with regard to scan rate. In the early days of slow modems and long scan cycles, it was common to send a “freeze meters” command to the Remote Terminal Units (RTUs) in a broadcast mode in order take a snapshot of turbine or other volumetric measurements at a particular instant in time. However, under steady-state conditions where the period between scans for each RTU is stable, flow through each meter will be relatively consistent for each scan cycle. While the position or time of each RTU scan will differ on a communication link, and results in readings will be offset by the difference in time of each scan, the effect of this volume difference is minimized when the time between successive RTU scans is stable. Any potential error due to time skew is not cumulative because it is corrected, if not over-corrected, on the next scan.

Frequent scans are often assumed to be important for ultimate sensitivity (smallest detectible leak) because of the potential error due to time skew. However, this error is dwarfed by the throughput during longer observation intervals, and as described before, is not cumulative. Consequently, the effects of accumulated error due to time skew are not important during longer observation intervals.

The realized benefit of frequent scans can be a function of the algorithms used in the leak detection system. Where algorithms understand causes of short-term transients well, frequent scans can result in early detection of large leaks without a tendency toward undue false alarms. In any case, where persistence in the form of a number of successive scan periods showing evidence of a leak is employed to avoid false leak alarms, short scan periods can shorten detection times for major ruptures.

Where meters are deployed that produce only the current flow and not the accumulated volume between scans, the stability of the scan period is not critical under steady-state conditions provided the meter readings do not fluctuate due to flow conditioning issues. If the line is packing or unpacking rapidly during a control operation, instantaneous measurement of a varying flow can severely impact leak detection performance, especially in the short term unless the system tolerates such conditions well.

Time Stamps

Many leak detection products have the ability to correct meter readings to a common time by adjusting volumes through a meter using the elapsed time between successive scans. This is useful when scan intervals are inconsistent or when data is delayed in transit by data concentrators that collect readings in the field and report them periodically. If time stamps are used, they should be assigned to the measurement at the earliest possible time as the meter is read. Where data is acquired from RTUs that update their databases frequently, and there are no data concentrators between the RTU and SCADA system, it is not uncommon to ignore time stamps if scan cycles are stable.

Filtering

Some schools of thought support the idea that it is better to use unfiltered data for leak detection. Others, typically those whose performance goals are strict and algorithms are detailed, find that data filtering allows higher sensitivity and/or a lower false alarm rate. Common filters are those that combine old values (previous filtered value) with new readings in a ratio often described as a “k” factor. When filtering is used, it should be applied to all analog values involved with leak detection because there is an inherent time delay associated with filtered data. Any such time delay should be consistent for all measurements used in leak detection algorithms. It is very common for field systems to send the unfiltered data along with filtered data to SCADA. It is preferred that filtering be done in the field so that many filtering operations can be done between RTU scans. It is also common to store the “k” factor in the RTU or Programmable Logic Controller (PLC) so that the factor can be adjusted while the leak detection system is being implemented.

Volume Balance Techniques

Simple over/short tabulation is a familiar volume balance technique. This method tabulates apparent volume differences by accumulating volume data or integrating flow data over preconfigured intervals. Volume data may be gross measurements or net measurements corrected for temperature and pressure. Originally derived from manual tabulations, this tool is usually automated and incorporated in any meter-based system as a familiar diagnostic tool used by controllers to confirm hydraulic behavior is normal.

Flow Balance

The strict definition of flow balance would be instantaneous comparisons of incoming and outgoing flow. However, a common use of the terminology is volume balance without pressure and temperature compensation, thus leaving “volume balance” to mean balance of net volumes.

Mass Balance

Mass balance is the unambiguous name for balancing net volumes passing through the pipeline segment bound by meters. This technique may estimate a temperature/density profile to improve results of the assessment. The degree of effectiveness of this compensation is determined by many influences including pipe segment length (volume) between instruments, flow rate, fluid injection temperature, soil characteristics, control actions, etc. Most algorithms do not deal with all significant influences on the fluid density profile.

Real-Time Transient Model (RTTM)

Mass balance assisted by a real-time transient model is the most sophisticated meter-based leak detection method available. It is able to account for usual transient conditions in its linepack assessment. The thermal model component tracks fluid temperature based on modeled heat transfer characteristics and accounts for the fluid density profile along the pipeline. Most such systems can deal with light “spongy” hydrocarbons and, therefore, can provide good leak detection on pipelines whose fluid types and/or operating strategies thwart other meter-based methods. RTTM solutions have a reputation for requiring ongoing maintenance. This belief is not entirely correct. Once a model is deployed and tuned to provide adequate performance, there is no need for further attention. However, these tools ALLOW continued refinement of modeled parameters, and any change in pipeline characteristics will require an update in the model configuration, as would be the case for other systems.

Statistical Methods

Statistical methods apply algorithms to determine the probability a leak exists based on relationships between pressures, temperatures, and flows. These tools can sometimes “learn” normal operational relationships to serve as the basis of future leak assessment. They typically support mass balance as a basis for the assessment, then apply their special algorithms to prevent false alarms. This method has been applied successfully in very transient environments where “learned” normal behavior does not generate alarms. However, the RTTM solution has a performance edge with its understanding of linepack changes rather than tolerance of them. The statistical system’s advantages are a low false alarm rate and a simpler configuration.

Direct Observation Methods

Direct observation methods are those that sense the actual released fluid or evidence of fugitive emissions. Such methods include the following:

- Hydrocarbon sensing cable for gasoline and diesel fuel,
- Vapor detection for liquid or gaseous products,
- Visual observation by traveling the right-of-way and observing vegetation stress,
- Airborne visual observation, and
- Sheen detection on water using vapor detection or optical analysis.

Hydrocarbon sensing cable is highly sensitive to small amounts of contaminant, potentially in the range of teaspoons with the necessary direct contact. Once contaminated, the activated portion of the cable and surrounding soil must be replaced. With the relatively short range possible with this method, it is not considered suitable for long transmission lines. However, it is suitable for high consequence areas.

Vapor detection can take on several forms. One involves drawing air through a perforated tube buried with the pipeline. Any hydrocarbon vapors drifting into the tube will be collected at the next sampling interval. Leak location can be determined by the location of the vapor in the flow stream if a marker gas is injected at the end of the tube to mark a complete sample. There is a finite time required to acquire a complete air sample from the right-of-way; thus preventing continuous monitoring of the entire pipeline for potential leaks. Another involves injection of a trace gas into a line and towing a sensor over the line to detect the trace gas. This method can confirm the presence of a leak in a busy right-of-way containing several pipelines and isolate the location of the leak.

Dead vegetation can indicate leaked hydrocarbons in the right-of-way. At least one pilot reported such evidence of a leak only to learn later in the investigation that a farmer cleared a corner of his field with Roundup® where a brush hog mower would not fit.

Sheen detection is viable downstream of a water crossing. However, in navigable waters an oil sheen can be a normal occurrence with winds concentrating the sheen on the downwind bank of the waterway. Provision should be made for deployment considering usual or seasonal wind directions and background sheen levels if they exist.

Acoustic Methods

Acoustic tools come in two (2) flavors. The first of which detects a pressure wave caused by the sudden onset of a leak. This tool cannot detect a leak if it is not active at the onset of the leak, but it can determine the location of a leak by measuring the arrival time of the pressure wave at sensors on either side of the leak. Small, slow growing leaks that do not provide a recognizable pressure wave are not detectible by this method. A second acoustic tool can detect the ongoing audible signature of escaping fluid. Both tools have limited range and are not subject to predictable leak sensitivities. Therefore, they are more suitable for short interplant lines or as companion methods to augment meter-based solutions. There are pig-like tools available to travel through the line internally to detect the acoustic signature of a leak, thereby providing full length integrity checks where injection and removal points exist.

Fiber Optic Techniques

Fiber optic technology is being commercially deployed with good success. This technology, in the form of Distributed Temperature Sensing (DTS), offers continuous monitoring of the pipeline and provides high accuracy measurement with regard to leak location and high sensitivity where fluid temperature is different from the environment to the degree that leaked fluid will affect the fiber temperature. The key to successful deployment of DTS technology is thermal isolation from fluid contained in the pipe combined with close thermal proximity of the fiber to released fluid. In the case of crude oil at elevated temperatures, the heat source is the original temperature of the fluid. In the case of most compressible gases, the expansion of the fugitive gas at the location of the leak provides a convenient temperature differential between contained fluid and released fluid that cooled upon escape.

Another fiber optic technique is acoustic detection which monitors the pipeline for acoustic emissions associated with a leak. Sensors are sufficiently sensitive that they can reproduce the sound of a shovel stroke in sand one hundred (100) feet from the sensor or footsteps in the ROW. This method provides good right-of-way encroachment protection as well as the opportunity to detect soil percolation and other evidence of a leak.

Commercial products can ignore vehicles crossing the ROW, but issue an alarm if one remains in the ROW for a period of time if it is not scheduled to be there. It is also suitable for detecting seismic activity.

Fiber optic techniques can also be deployed as a continuous strain gage to monitor deformation of the pipe due to shifting soil. It can also be deployed separately to detect soil shift in the vicinity of the pipe where ground faults are known to exist.

Fiber optic technology also offers great high speed communications which can be deployed concurrently with leak detection infrastructure. Fiber optic tools are not cheap, but they are very effective in environments where they are applicable.

Controller Training

Training in the use of information provided by any leak detection system is critical to the success of any pipeline integrity monitoring program. Rather than simple cookbook style steps to take when certain events occur, a culture of concern regarding pipeline integrity and due diligence must be the basis of an effective training program. Only then can the controller feel free to shut down the line for further testing when a leak is suspected. When a leak is suspected at any particular point on the line, the controller should have handy formal procedures to place the pipeline in the safest configuration for the suspected leak location. All necessary contact information should be at hand to facilitate rapid deployment of response teams. Controllers should be expected and trained to err on the side of caution, but suffer no penalties for reasonable judgment. When possible, second opinions should be sought, but not at the expense of a rapid response.

Technology Options

There are many choices among leak detection technology options. There always exists a cultural bias in pipeline companies toward using technology with which the staff is comfortable, or technology that served them well for decades. In some cases where staff is proactive by nature and eager to embrace new, but proven, technology, the more capable solutions along with good instrumentation are deployed. In other companies, there is resistance to change, both in cost and comfort level. There are two (2) basic viewpoints at work. One involves the probability of a leak with expectations that any damage will be absorbed over time and prudence dictates adherence to applicable regulations and minimum industry practices. Some companies in this camp are not fully aware of the risks or their narrow view of options worthy of consideration. Some believe they are industry leaders. Other companies who are less courageous when it comes to accepting risk, but are unafraid to embrace new technology tend to deploy new technology on a more frequent basis in order to have the best leak detection possible. The difference is largely driven by business decisions based on the perceived benefits of investment in leak detection technology. Companies with vast networks tend to believe it is more appropriate to absorb the impact of any incident rather than attempt to control the impact of an incident by investing in costly top-of-the-line systems along with its supporting infrastructure. Some avoid improving their level of sophistication where it is needed on particular lines because of a perception that the new technology will be expected on all pipelines, even where the benefits may not be so great.

There are many considerations. Directions taken are usually influenced by experience along with confidence, courage, and desire to be respected by management and peers. It behooves the company to ensure the technical staff keeps up with available technology and feels free to recommend new solutions as the needs arise.

Conclusion

Selection of technologies should be made considering pipeline operations, fluids transported, and performance expectations. For example, for highly compressible fluids, such as natural gas, the sensitivity of vapor detection tools would far exceed that of meter-based solutions, but at a cost of occasional operation rather than continuous detection. However, meter-based solutions may recognize pipeline ruptures more quickly because of its continuous operation.

It would be counter-productive to deploy duplicate solutions based on similar technologies. In the case of two (2) meter-based solutions, one would become more trusted than the other due to performance advantages provided by threshold settings or false alarm rate, yet their strengths and weaknesses would be very similar. Instead, it is worthwhile to deploy different technologies in order to benefit from different strengths of each solution. In such a case, there is no expectation that the tools would have similar performance. It is especially beneficial to deploy a meter-based solution along with a tool capable of locating a leak more accurately, even if the secondary tool is operated periodically instead of continuously. Protocols should be developed to use secondary tools to verify leak alarms issued by the primary system if possible.

The State of Alaska's Department of Environmental Conservation (ADEC) hosts a Pipeline Leak Detection Technology Conference every five (5) years for the purpose of supporting their mandated requirement for use of "Best Available Technology" on their pipelines. The proceedings, including technical slide presentations by vendors of several technologies, for the 2011 Pipeline Leak Detection Technology Conference can be found at:

http://dec.alaska.gov/spar/ipp/docs/Final%20PLD%20Technology%202011%20Conference%20Report%20March%202012%20-%20Revised%20041912.pdf.

The combined descriptions of generic technology strengths and limitations, and vendor presentations focused on their products results in a useful information resource for matching products with project characteristics.