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DETECTION AND LOCALIZATION OF MICRO-LEAKAGES USING DISTRIBUTED FIBER OPTIC SENSING

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ABSTRACT

Distributed fiber optic sensing offers the ability to measure temperatures and strain at thousands of points along a single fiber. This is particularly interesting for the monitoring of pipelines, where it allows the detection and localization of leakages of much smaller volume than conventional mass balance techniques. Fiber optic sensing systems are used to detect and localize leakages in liquid, gas and multiphase pipelines, allowing the monitoring of hundreds of kilometers of pipeline with a single instrument and the localization of the leakage with a precision of 1 or 2 meters. This contribution presents recent testing results on controlled field trials. The tests demonstrate that it is possible to reliably detect oil leakages of the order of 10 liters to 1’000 liters per hour, corresponding to 0.01% to 0.1% of the pipeline flow. Tests were performed with small temperature differences between liquid and ground. The detection time was between 1 minute and 90 minutes. All simulated leakages were detected and localized to better than 2m accuracy. The paper describes the main parameters that affect the response time and detection volume, including the relative position of the leak to the sensing cable, temperature contrast and instrument performance. We also briefly report on relevant full-scale installations for the permanent monitoring of oil, brine and natural gas pipelines.

INTRODUCTION

Gas and liquid pipelines often cross hazardous environmental areas, from the point of view of natural exposures such as landslides and earthquakes, and from the point of view of third party interferences such as vandalism or obstruction. These hazards can significantly change the original functioning of the flowline, leading to damaging, leakage and failure with serious economic, social and ecological consequences. Furthermore, the operational conditions of the pipeline itself can induce additional wearing or even damage due to corrosion, erosion and fatigue. The distributed and functional monitoring can significantly improve the pipeline management and safety. Providing regularly with parameters featuring the functional condition of the flowline, monitoring can help (1) prevent the failure, (2) detect in time the problem and its position and (3) undertake maintenance and repair activities in time. Thus the safety is increased, maintenance cost optimized and economic losses decreased. The most interesting functional parameters are temperature distribution, leakage and third-party intrusion. Since the flowlines are usually tubular structures with kilometric lengths, functional monitoring of their full extent is an issue itself. The use of the discrete sensors, short- or long-gage is practically impossible, because it requires installation of thousands of sensors and very complex cabling and data acquisition systems, raising the monitoring costs. Therefore, the applicability of the discrete sensors is rather limited to some chosen cross-sections or segments of flowline, but cannot extend to full-length monitoring. Other current monitoring methods include flow measurements at the beginning and end of the pipeline, offering an indication of the presence of a leak, but limited information on its location. Recent developments of distributed optical fiber strain and temperature sensing techniques based on Raman and Brillouin scattering provide a cost-effective tool allowing monitoring over kilometric distances. Thus, using a limited number of very long sensors it is possible to monitor structural and functional behavior of flowlines with a high measurement and spatial resolution at a reasonable cost.

Unlike electrical and point fiber optic sensors, distributed sensors [1, 2] offer the unique characteristic of being able to measure physical and chemical parameters along their whole length, allowing the measurements of thousands of points using a single transducer. The most developed technologies of distributed fiber optic sensors are based on Raman and Brillouin scattering. Both systems make use of a nonlinear interaction between the light and the silica material of which the fiber is made. If light at a known wavelength is launched into a fiber, a very small amount of it is scattered back at every point along the fiber. Besides the original wavelength (called the Rayleigh component), the scattered light contains components at wavelengths that are different from the original signal (called the Raman and Brillouin components). These shifted components contain information on the local properties of the fiber, in particular strain and temperature. Figure 1 shows the main scattered wavelengths' components for a standard optical fiber. It can be noticed that the frequency position of the Brillouin peaks is dependent on the strain and temperature conditions that were present at the location along the fiber where the scattering occurred, while the intensity of the Raman peak is temperature dependent.

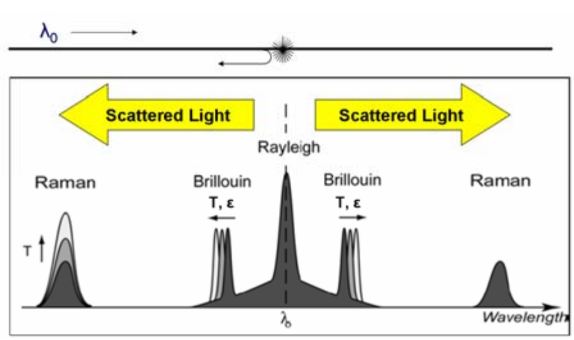

Fig.1. Light scattering in optical fiber

When light pulses are used to interrogate the fiber, it becomes possible, using a technique similar to RADAR, to discriminate different points along the sensing fiber by the different time-of-flight of the scattered light. Combining the radar technique and the spectral analysis of the returned light one can obtain the complete profile of strain or temperature along the fiber. Typically it is possible to use a fiber with a length of up to 30 km and obtain an average strain and temperature readings over 1 meter. In this publication we would talk of a distributed sensing system with a measurement range of 30 km and a spatial resolution of 1 m.

Raman scattering is the result of a nonlinear interaction between the light traveling in a fiber and silica. When an intense light signal is shined into the fiber, two frequency-shifted components called respectively Raman Stokes and Raman anti-Stokes will appear in the backscattered spectrum. The relative intensity of these two components depends on the local temperature of the fiber. Systems based on Raman scattering typically exhibit a temperature resolution of the order of 0.1°C and a spatial resolution of 1m over a measurement range up to 8 km.

For temperature measurements, the Brillouin sensor is a strong competitor to systems based on Raman scattering, while for strain measurements it has practically no rivals. Brillouin scattering is the result of the interaction between optical and sound waves in optical fibers. Thermally excited acoustic waves (phonons) produce a periodic modulation of the refractive index. Brillouin scattering occurs when light propagating in the fiber is diffracted backward by this moving grating, giving rise to a frequency-shifted component by a phenomenon similar to the Doppler shift. The most interesting aspect of Brillouin scattering for sensing applications resides in the temperature and strain dependence of the Brillouin shift. This is the result of the change the acoustic velocity according to variation in the silica density. Systems based on Brillouin scattering systems offer a temperature resolution of 0.1°C, a strain resolution of 20 $\mu\varepsilon$ and a measurement range of 30 km with a spatial resolution of 1 m [3].

1. PIPELINE LEAKAGE DETECTION

The basic principle of pipeline leakage detection through the use of distributed fiber optic sensing relies on a simple concept: when a leakage occurs at a specific location along the pipeline, the temperature distribution around the pipeline changes. This change in temperature is localized both in space (a few meters around the leakage location) and in time (the onset of the leak). This makes the algorithmic detection of leaks relatively easy to implement. The origin of the temperature disturbance around the pipeline depends on the type of pipeline and its surroundings. The most typical effects are the following:

- The released liquid is warmer than the surrounding soil (typical for buried oil and liquid pipelines)
- The released gas produces a local cooling due to pressure release (typical for buried, underwater and surface gas pipelines)

- The released liquid changes the thermal properties of the soil, in particular thermal capacity, and influences the natural day/night temperature cycles.
- A warm plume is formed around the pipeline (typical for underwater oil and liquid pipelines)
- In the case of multiphase pipelines a combination of the above can occur.

The above effects influence the ideal cable placement around the pipeline.
In the case of a buried oil pipeline the best location for the sensing cable is below the pipe, but not in direct contact. At that position there is a maximum probability of collecting the released oil, independently from the leakage location. This is depicted in Figure 2.

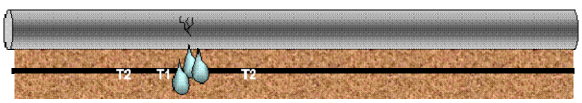

Fig.2. Detection of a liquid leak through a cable placed under the pipeline.

If the pipeline is installed below the water table or underwater, the oil will have a tendency to rise and not to sink. In this case, the ideal placement is reversed.
As we have pointed out, a gas leakage produces a temperature drop at the leak location. This has the tendency to cool down the pipeline itself and its surroundings. The best position for the temperature sensing cable in such a situation is in direct contact with the pipeline surface. In this case we make use of the good thermal conduction properties of the pipeline itself to transfer the cooling from the leak to the cable. An example of such installation is depicted in Figure 3.

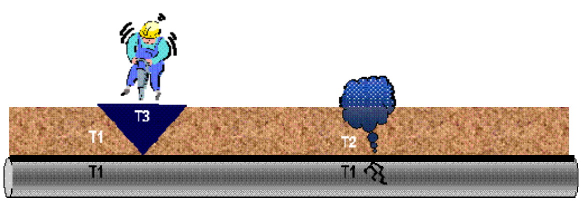

Fig.3. Detection of a gas leak through a cable placed above the pipeline. This arrangement can also be used to detect a third-party intrusion.

This arrangement can also be used to detect an intrusion attempt. When the pipe surface is exposed to the air; this also produces a local thermal change that can be detected by the same cable. In this situation, the best location is obviously above the pipeline.

2. QUALIFICATION TESTS

In the following sections we will present two qualification tests that were performed to demonstrate the ability of a distributed fiber sensor to detect oil and gas leakages, respectively.

2.1 OIL MICRO LEAKAGE SIMULATION

To simulate an oil micro leakage from a buried pipeline, a test has been performed at the premises of Praoil in Italy. The optical fiber cable, containing two optical fibers, was buried in a small layer of sand at approximately 1.5 m below ground. Successively, a polyethylene pipe was placed above the cable, in a serpentine, and provided with taps allowing a controlled injection of water in the ground. Several taps were installed with varying horizontal and vertical distances in respect to the sensing cable. Each tap was also instrumented with a volume meter to asses the leak volume. The temperature of the injected water could also be adjusted to simulate different operational conditions. Figure 4 illustrates the testing setup.

Fig.4. Leakage detection simulation arrangement. Warm water is injected in the ground at different positions with respect to the sensing cable position. Several taps, with volume meters are used to generate controlled leaks.

In a first testing session, four micro leakages were produced in sequence at different locations. The following table summarizes the leaks.

TIME	TAP	FLOW RATE [l/min]	TOTAL LEAK VOLUME [m^3]
15.12	D1 opening	10	0.08
15.20	D1 closing		
15.20	D2 opening	16	0.40
15.45	D2 closing		
15.45	D3 opening	14	0.91
16.50	D3 closing		
17.00	D4 opening	6	0.06
17.10	D4 closing		

Table 1. Test program

The next Figure 5 shows the raw temperature data recorded during the test. Although temperature profiles were recorded every minute, for clarity, we have depicted only one measurement every 10 minutes.

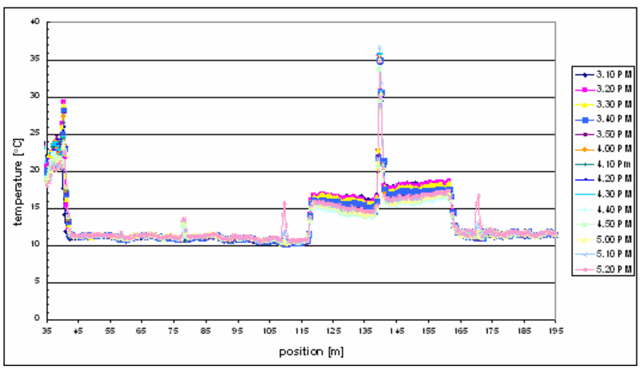

Fig.5. Raw temperature data for the leakage test.

The initial temperature variations, from the beginning of the cable to approximately 38m corresponding to a section of the sensing cable above ground are due to different contact with the ground and sunshine conditions. From meter 38 to 117 the optical cable is buried in the ground and its temperature is much more constant, around 12°C. From meter 117 to 158 the optical cable is again in the air and than re-enters the ground coming back in the opposite direction. The interesting section for the experiment is therefore the one between 38 and 117 meters. In figure 7 it is already possible to observe a couple of temperature peaks at leakage locations, however other leaks are not easily visible and additional processing is therefore necessary.

The first step is to transform absolute information into relative information where the temperature is plotted relatively to a reference temperature profile obtained at the beginning of the test. Once this is done, we obtain the results shown in Figure 6. All four micro leakages are now clearly visible. It has also been noticed that the first leakage was in the transition zone between buried and exposed section of the pipe and optical cable.

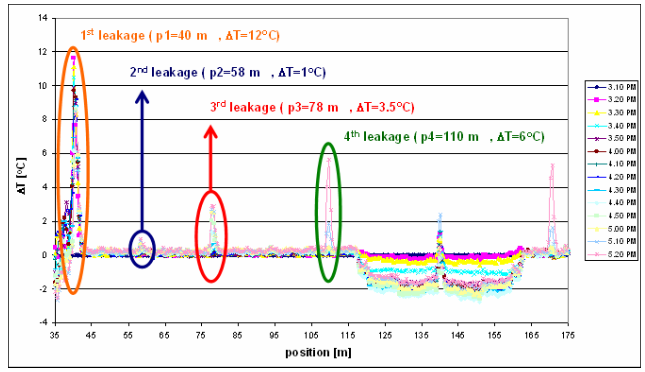

Fig.6. Relative temperature data for the leakage test. The temperature peaks from the four leakages are clearly visible.

In order to quantify the detection time and released volume we will now concentrate on a single leak and observe the associated temperature evolution. Figure 7 shows the temperature evolution at the location of leakage 3.

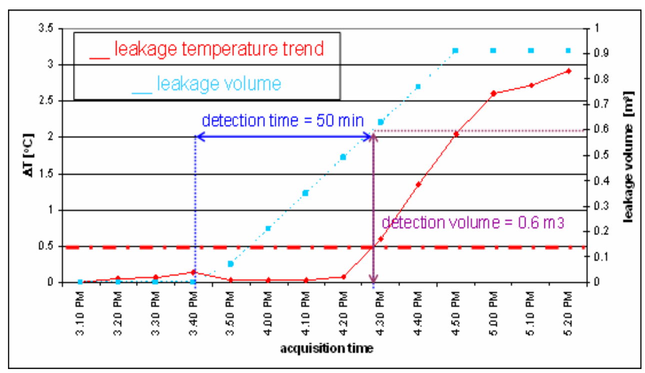

Fig.7. temperature and leaked volume evolution at leak location 3.

In this case the leakage was started at 3:40 PM. The temperature started rising at 4:20 PM and reached the preset threshold level of 0.5°C at 4:30, 50 minutes after the leakage started. During those 50 minutes a total of 0.6 cubic meters of water have been released in the ground. The maximum temperature change was of the order of 3.5°C, while the injected water had a temperature of 20°C above the ground temperature. This experiment was one of those showing a relatively slow response because of the large lateral distance between the injection point and sensing cable.

In a second testing day, one micro leakage was produced at position 110 m along the pipeline. The particularity of this test was the low ΔT of approximately 3°C between the injected water and the ground. Although these environmental conditions are unusual for oil pipeline it has been decided to perform this test to evaluate monitoring system capabilities. All the considerations that have been done for the first testing session are still valid. After acquisition and data processing we obtained the result shown in Figure 8 where the micro leakage is clearly visible.

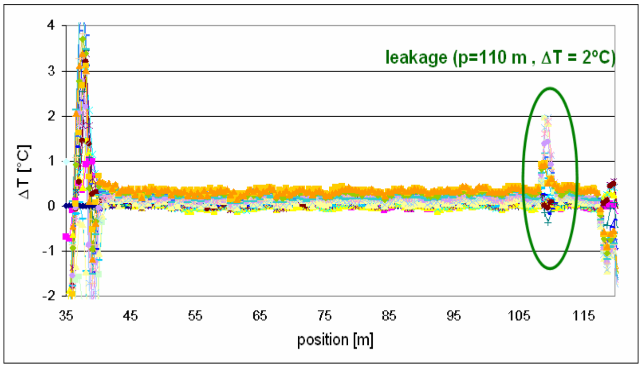

Fig.8. Relative temperature data for the leakage test. The temperature peaks from the leakage is clearly visible.

In order to quantify the detection time and released volume we will now concentrate on the leak trend and observe the associated temperature evaluation. Figure 9 shows the temperature evaluation and leakage volume.

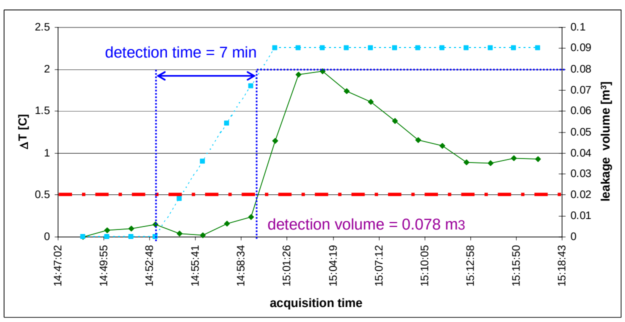

Fig.9. Temperature and leaked volume evolution at leak location D5, 2nd test with ΔT=3°C.

In this case the leakage was started at 14.52 PM, the temperature started rising at 14.57 PM and reached the preset threshold level of 0.5°C at 14.59 PM, 7 minutes after the leak started. During those 7 minutes a total of 0.078 cubic meters of water have been released in the ground. The temperature change was of the order of 2°C.

The following table resumes the results of all the performed tests, where ΔT is the water to ground temperature difference:

TAP	FLOW RATE [l/min]	ΔT [°C]	DETECTION TIME [min]	LEAK DETECTION LACKAGE VOLUME [m^3]
D1	10	20	1	0.005
D2	16	20	80	0.400
D3	14	20	50	0.600
D4	6	20	2	0.010
D5	13	3	7	0.078

Table 2. Test results

In summary, these tests used a small diameter pipe to simulate micro leakage along a larger pipeline with a typical flow rate between 300 and 3500 m^3 per hour. Average flow rate of the leakage is 0.6 m^3 per hour, corresponding to a detected leakage of 0.1 for a flow of 300 m^3/h and of 0.01% for a flow of 3500 m^3/h. This is significantly better than any available volume balance method currently available. Detection time was between 1 and 80 minutes and the accuracy in leakage localization was better than 2 m (difference between detected position and real position along the pipeline). In test 5, performed in a different day, the temperature difference between liquid and ground was only 3°C, but the detection time remained of only 7 minutes for a leakage of 0.078%.

The variability in the detection time and volume reflects the different local conditions and in particular:

- Permeability of the soil (type of soil)
- Compaction of the soil (presence of cracks and pockets)
- Distance between the leakage and the sensor
- Difference between temperature created by leakage and temperature of the ground.

2.2 GAS LEAKAGE SIMULATION

To evaluate the suitability of an optical distributed temperature sensing system for gas leakage detection, an experiment was performed on a real gas pipeline in Italy. A fiber optic temperature sensing cable was installed on the top of a 10” gas pipeline over a length of 500m. This installation was part of a larger test for measuring strain induced in the pipeline by a landslide. During installation of the sensors and burying of the pipe, an empty plastic tube was installed connecting the pipeline surface to the open air, 50 m far from the beginning of the instrumented zone. This tube was used to simulate a leakage of gas. In fact, carbon dioxide was injected in the tube, cooling down the pipe and making the thermal field surrounding the area between the pipe and the tube similar to the conditions expected in case of a leakage. This process is presented in Figure 10. A total of 4 carbon dioxide tanks were discharged through the dummy pipe.

A reference measurement was performed before the tube was cooled down. After the carbon dioxide was inserted, the temperature measurements were performed every 2 to 10 minutes and compared with the reference measurement. The results of the test are presented in Figure 11. The test was successful and the point of simulated leakage was clearly observed in diagrams (encircled area in Figure 11). The recorded temperature drop was of 3.5°C.

Fig.10. Gas leakage detection simulation test.

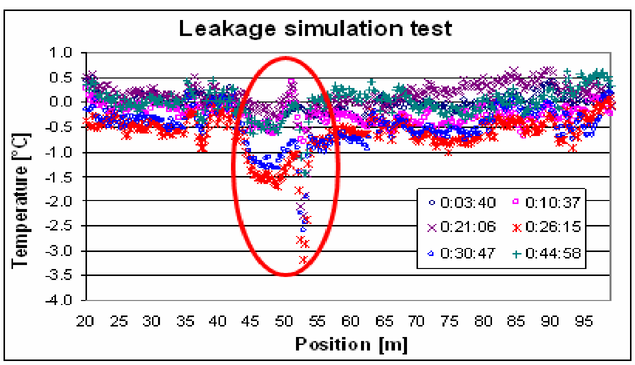

Fig.11. Temperature drop due to gas pressure release indicates the presence of a leakage.

2.3 OTHER APPLICATIONS

Besides the presented qualification tests, the described monitoring systems have been applied in the following other pipeline applications:

- Brine pipeline of 55 km in Germany [4], leakage detection
- Crude oil pipeline in Germany, temperature profile during pigging operations
- Monitoring of a 500 m section of gas pipeline in Italy, evaluation of strain induced by landslide [1]
- Ammonia pipeline of 3 km in Italy, leakage detection
- Ammonia pipeline of 2 km in Italy, leakage detection

CONCLUSION

The use of a distributed fiber optic monitoring system allows a continuous monitoring and management of pipelines, increasing their safety and allowing the pipeline operator to take immediate decisions on the operations and maintenance of the pipe. The presented monitoring system and the qualification tests shown in this paper demonstrate how it is possible to detect and precisely localize micro leakages from oil and gas pipelines with unprecedented sensitivity.

Through the identification of temperature anomalies, it is possible to detect and localize small leakages, which cannot be detected by conventional volumetric techniques. Furthermore, the ability to pinpoint the exact location of the leak allows an immediate reaction at the event location, minimizing downtime and ecological consequences.

Recent developments in distributed fiber sensing technology allow the monitoring of 60 km of pipeline from a single instrument and of up to 300 km with the use of optical amplifiers. To achieve the above-mentioned goals and take full advantage of the described sensing technology, it is however fundamental to select and install appropriate sensing cables, adapted to the specific sensing need. While it is generally easier to install sensing cables during the pipeline construction phases, it is sometimes possible to retrofit existing pipelines. In some cases it is even possible to use existing fiber optic telecommunication lines installed along a pipeline for temperature monitoring and leakage detection.

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