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Paper 3.3

Field Data of an E-RTTM Based Leak Detection System

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1 INTRODUCTION

Numerous pipeline leak detection and localisation systems are available today, varying from low-end volume balance to high-end RTTM (Real Time Transient Modelling). Despite the fact that pipeline leak detection plays an important role in safe pipeline operation, legislation and methods to compare the different systems are still limited. In Germany pipeline leak detection is goverend by law in the TRFL (Technical Rules for Pipelines). The American Petroleum Institute's API 1130 describes 'Computational Pipeline Monitoring for Liquid Pipelines' and API 1155 provides a method to compare the various systems.

To get a better understanding of the capabilities of modern leak detection systems, this document describes two case studies. One study refers to a gas pipeline and focuses on leak detection under transient conditions and subsequent detection times. The second study refers to a (multi-product) liquid pipeline and focuses on leak localisation and leak rate calculation. KROHNE's PipePatrol E-RTTM (Extended Real Time Transient Modelling) has been installed on both pipelines and the systems were tested by leak trials which are described in the case studies. The paper starts with a brief introduction into E-RTTM based leak detection system, which forms the basis for the case studies.

2 E-RTTM, EXTENDED REAL TIME TRANSIENT MODELLING

E-RTTM is a further development of conventional RTTM technology. The development comprises the introduction of a leak pattern recognition algorithm to avoid compromising between a minimal detectable leak rate and a maximum allowed number of false alarms. A second enhancement is the introduction of Statistical Analysis based leak detection as a back-up option in case of multiple sensors failure.

2.1 Basic Explanation of RTTM

PipePatrol-RTTM permits the calculation of flow, pressure, density and temperature along an entire pipeline. Inputs are pressure and fluid temperature at inlet and outlet, and one ground temperature reading (or water temperature for sub-sea pipelines) at either inlet or outlet of the pipeline. Inlet and outlet density are usually calculated form pressure and temperature or, in case of a non-constant standard density, is measured directly. For liquid hydrocarbons API D2540 can be used, for gases, the adequate thermodynamic state equations can be used. With RTTM the (calculated) flow and pressure at any point in the pipeline are known entities. For information a mathematical description of the RTTM algorithms can be found in annex 1.

The calculated flow or pressure is subsequently compared to a measured flow or pressure (from a flowmeter at any point in the line or a pressure sensor somewhere other than at inlet and outlet). Typically RTTM is used to compare measured and calculated flow at inlet and outlet, since flowmeters are usually installed at this position. In case additional measurement instrumentation is available (e.g. intermediate pressure sensors), the readings of these instruments can be compared to a calculated value, thereby improving the reaction time of the leak detection system.

Figure 1 shows a typical RTTM approach where measured and calculated flow at inlet and outlet are compared. In the left-hand graph the measured and calculated flow at inlet (lower two lines) and the measured and calculated flow at outlet (upper two lines) are shown. The upper right graph shows the difference between calculated and measured flow at outlet, called the outlet residual. The bottom right graph shows the difference between calculated and measured flow at inlet, called the inlet residual. In a pipeline with no leaks, the residuals should be zero (any fluctuating around zero being due to inaccuracies in the field instruments) since the RTTM calculates flow using a model that describes a leak-free pipeline. Note that the presented data are true data coming from a transiently operated gas pipeline.

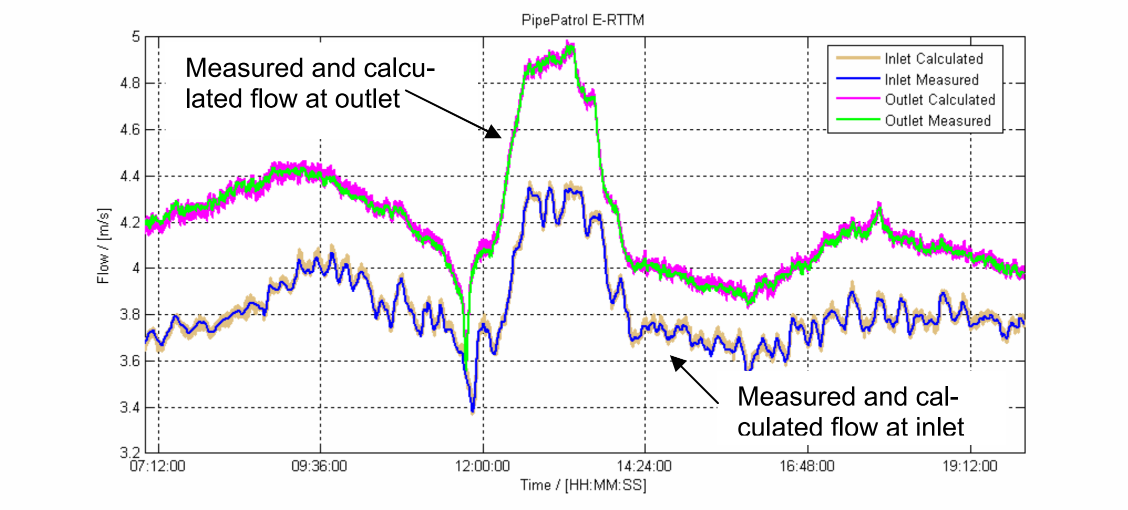

Figure 1 – Measured and calculated flow at inlet and outlet

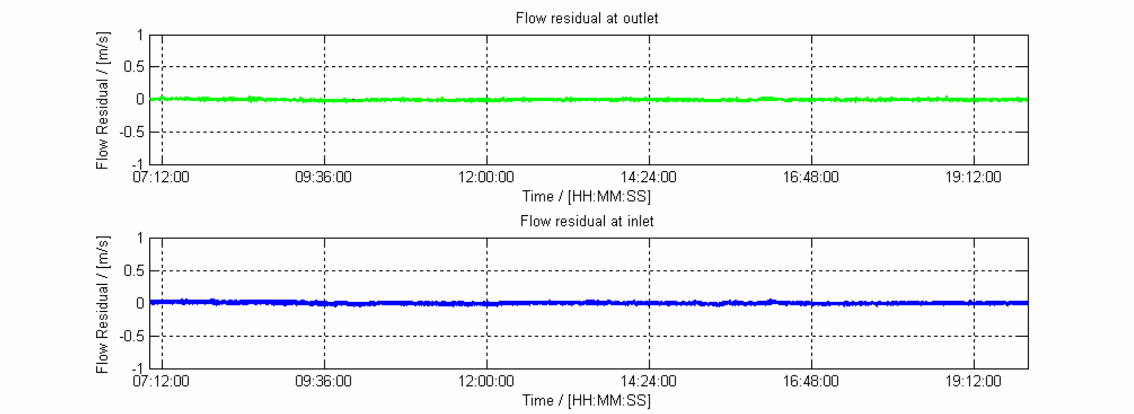

Figure 2 – Flow residuals for inlet and outlet

2.2 Leak Pattern Recognition

Combining a classical RTTM approach with a leak pattern recognition algorithm gives us E-RTTM. If a predefined threshold (i.e. the minimum detectable leak rate) is exceeded, the leak pattern recognition algorithm uses statistical analysis to determine whether the residual shows the dynamic effect that is typical for a spontaneous leak. If this effect is shown, a leak alarm will be given. If this effect does not show, the deviation is most likely caused by a drifting sensor and, after the sensor data has been analysed, a sensor warning will be given so the operator is aware that a sensor needs attention.

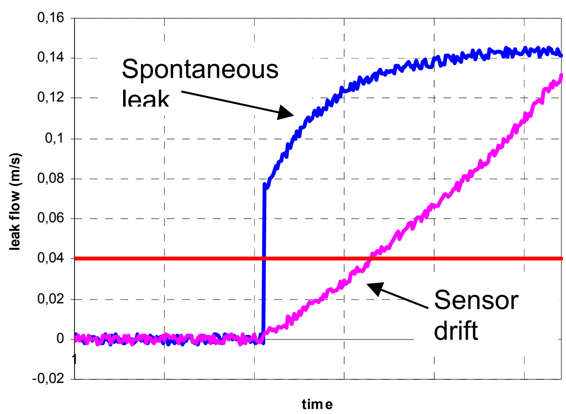

Figure 3 – Typical leak pattern, vs sensor drift

2.3 Leak Localisation

PipePatrol uses two principles for leak localisation; the Gradient Intersection method (also called Interpolation method, see figure 4) and the Wave Propagation method (also called time-of-flight method, see figure 5). The Gradient Intersection method is based on the fact the pressure drop over length (gradient) is non-proportional in case of a leak. In the left hand figure the leak is located at the point where the two lines intersect. The Wave Propagation Method looks at the time that is required for a pressure wave to propagate through the fluid or gas in the pipeline. When a leak occurs, a pressure wave travels through the medium. Depending on the location of the leak, the pressure wave will reach one end of the pipeline before it reaches the other end. By measuring the time difference between the arrival of the pressure wave on side of the pipe and on the other side of the pipe, the leak location can be calculated.

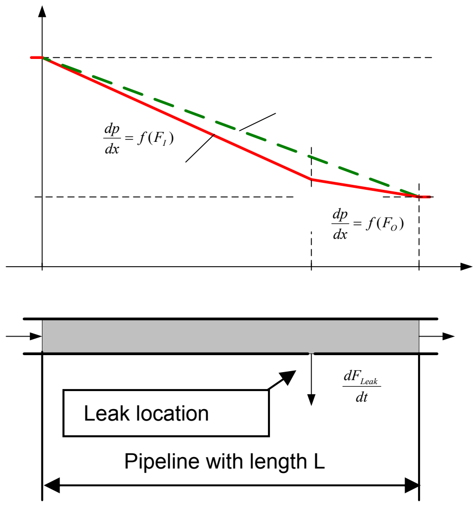

Figure 4 – leak localisation with the gradient intersection method

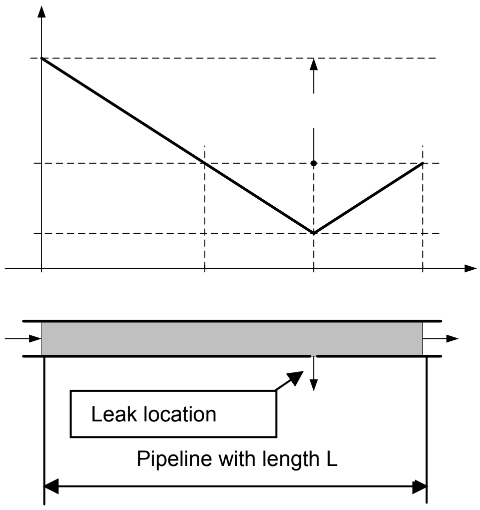

Figure 5 – leak localisation with the wave propagation method

2.4 Hardware Overview

Software based leak detection systems need a hardware platform to run their algorithms on. Typically the leak detection system runs on a separate computer that is connected to the existing SCADA system. Integrating the leak detection in the SCADA system is possible, however is not usual because of redundancy requirements. The leak detection computer reads measurement data from the SCADA system and performs the leak calculations. Depending on the LDS requirements the leak detection results are written to the SCADA system, presented on the LDS computer or presented on a separate desktop PC.

PipePatrol E-RTTM typically uses two computer, an industrial PC with redundant components to perform the leak detection calculations, called the Monitoring Station (MS) and a simple desktop PC that is used as a Human Machine Interface, called the Operator Station (OS). Depending on the existing SCADA system and customer requirements, the MS is connected to the SCADA system or a direct communication with the filed instrumentation is made.

3 FIELD DATA ON A GAS PIPELINE

Understanding how RTTM systems work from the previous chapter, this chapter now describes field data of PipePatrol E-RTTM on a gas pipeline. The pipeline is owned by a mayor German chemical company and transports CO (carbon monoxide) gas between two plants. The pipeline is characterised by (heavy) transient operation since the inlet and outlet factories operate independently and the line is used as a buffer storage facility. With CO being a colourless and toxic gas, strong requirements were placed on leak detection under (heavy) transient conditions.

3.1 Application Details

Details of the application can be found below. Field instrumentation was already present and measurement readings were sent directly to the PipePatrol Monitoring Station (MS) over a fibre optic cable. The MS is installed in the control room and writes the leak detection results to the SCADA system via OPC. A layout of the instrumentation can be found in figure 6.

Product
- Carbon Monoxide gas (CO)

Pipeline
- Length 11 km (7 miles)
- Diameter DN 150 (6")
- Location 1 meter (40") underground
- Unidirectional

Instrumentation
- Flow at inlet and outlet (from turbine meters already installed)
- Pressure at inlet and outlet
- Temperature of product at inlet and outlet
- Temperature of ground at outlet

Flow data
- Nominal flow of 4000 Nm^3/h (or 400 m^3/h under operational conditions)
- Nominal pressure 10 Bara (at inlet side)
- Strong transient behaviour most of the time

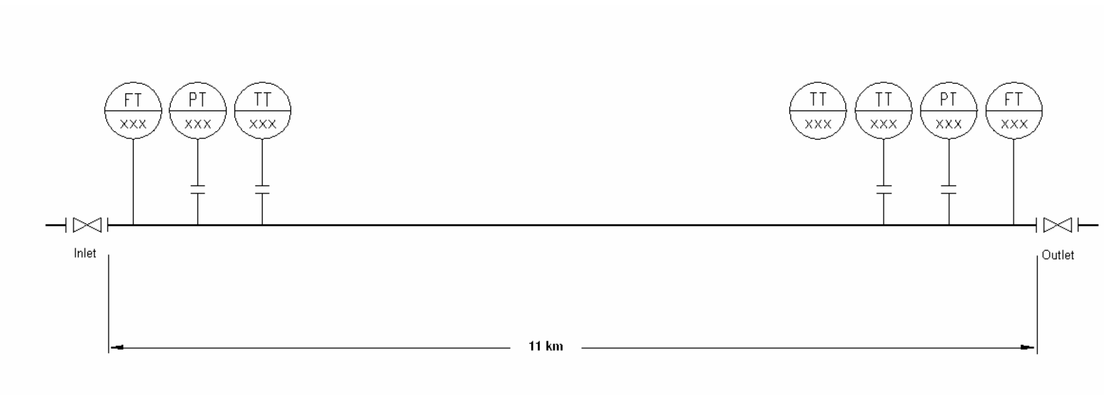

Figure 6 – Instrumentation layout of gas pipeline.

3.2 Leak Trials

Leak trials were held to test the performance of the leak detection system. The leak trials involved opening a valve at 50 meters from the inlet and leading the escaped gas back to a flare installation. Three different tests were held:

- 2.5 % of nominal flow for 32 minutes
- 0.5 % of nominal flow for 33 minutes
- 1.0 % of nominal flow for 9 minutes

To give an impression of the transient behaviour of the pipeline, figure 7 shows the flow and pressure behaviour of the pipeline over 24 hours. The period where the three leak trials were carried out is highlighted, and it is clear by just looking at pressure and flow that the leak cannot be identified. Even zooming in on the flow and pressure during the leak trial period (see figure 8), does not allow identification of the leaks. This changes when RTTM algorithms are applied. In figure 9 the measured and calculated flow at inlet and outlet are shown. During the leak periods, the calculated flow at does not match the measured flow at the inlet.

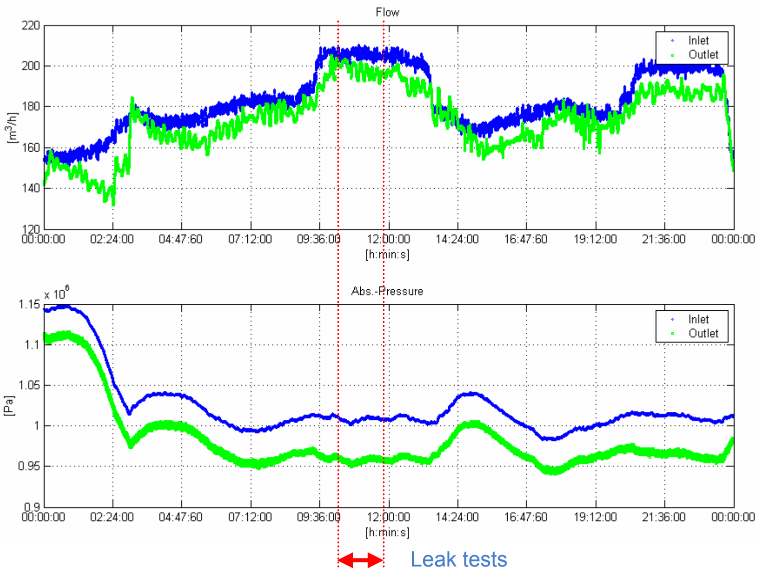

Figure 7 – Flow and pressure over 24 hours

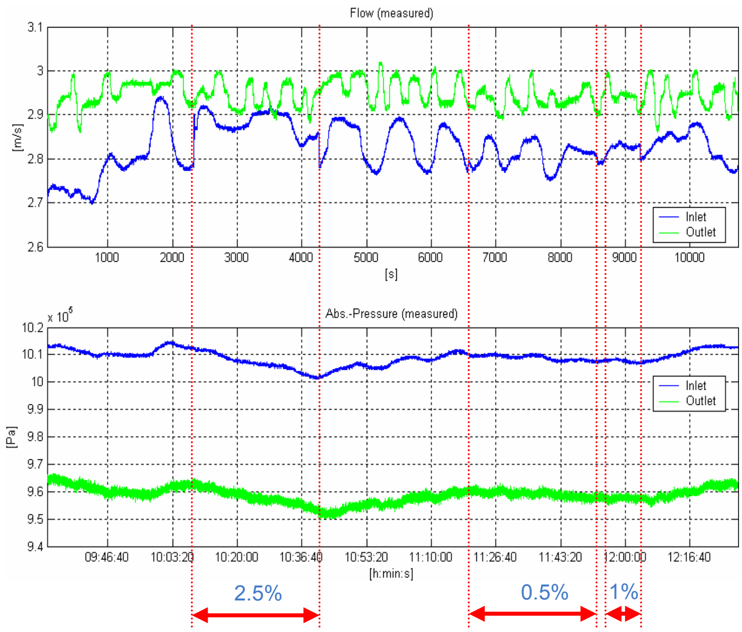

Figure 8 - flow and pressure during the leak trials period

The reason for this is that the RTTM describes a pipeline without leaks, and calculates a flow in the pipeline as if there were no leaks. Since there is however a leak the calculated flow will be lower than the measured flow. Figure 10 shows the residuals for inlet and outlet (difference between measured and calculated flow). As this leak was located close to the inlet (gas had to be lead back to the flare installation), most of the effect (in effect 11000 / 50 ≈ 95,5%) is seen at the inlet side.

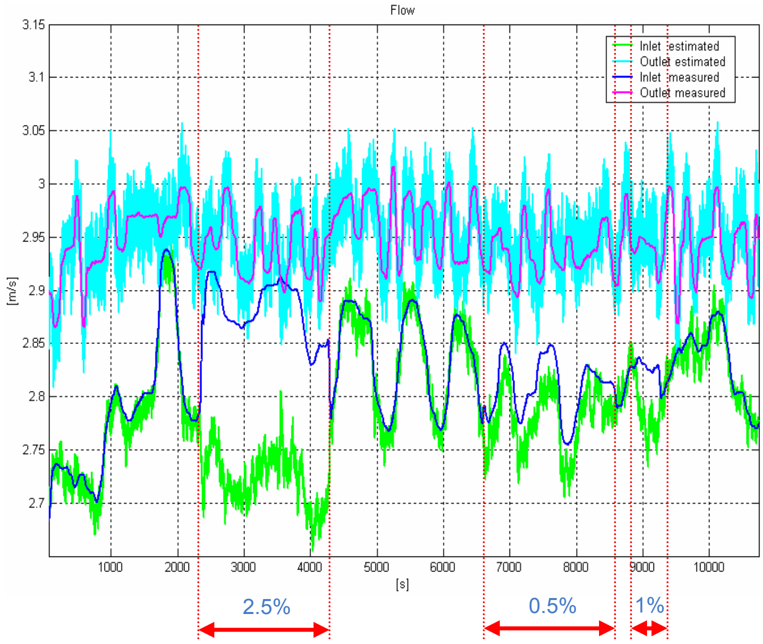

Figure 9 – measured and calculated flow at inlet and outlet during leak trial period.

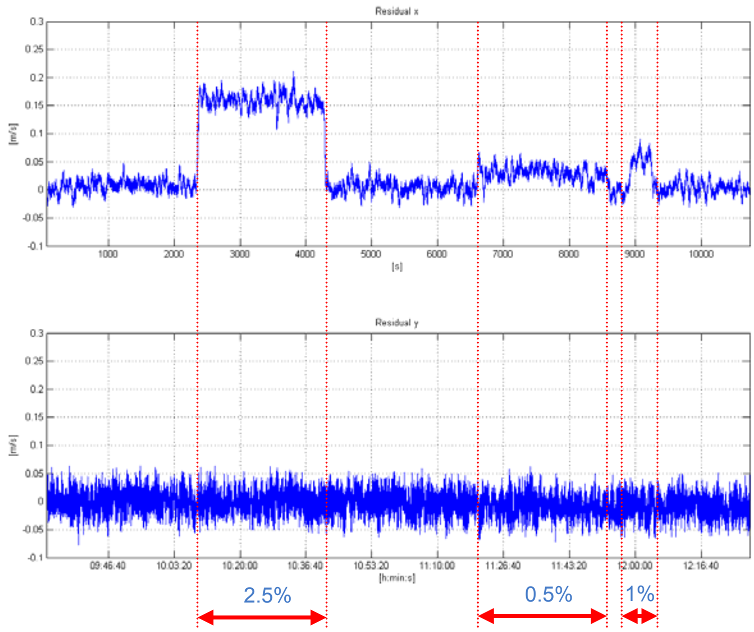

Figure 10 – residuals for inlet (x-residual) and outlet (y-residual)

3.3 Maximum Allowed Leak Detection Time

An important, and often overseen, parameter for leak detection systems is the time required to detect a leak. When a system is capable of detecting leaks of 1%, but it needs several hours to detect this leak, the system will probably be of little use. In general, however, a longer detection time will allow smaller leaks to be detected, due to the statistical analysis that is applied to interpret the signals. This is best shown by figure 11 and 12 below. These figures show the maximum deviation between calculated and measured flow that has been seen over a period of 4 months. As can be seen in figure 11 the maximum deviation is 1.19% when a maximum leak detection time of 80 seconds is allowed. This figure changes when the allowed detection time is increased. In figure 12 the detection time is 440 s, resulting in a maximum deviation between calculated and measured flow of 0.42%.

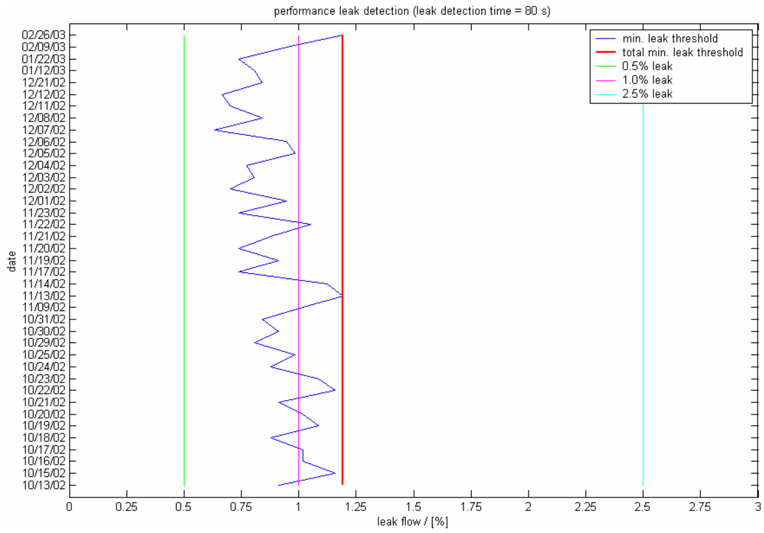

Figure 11 – Maximum deviation between calculated and measured flow for 80 s detection time

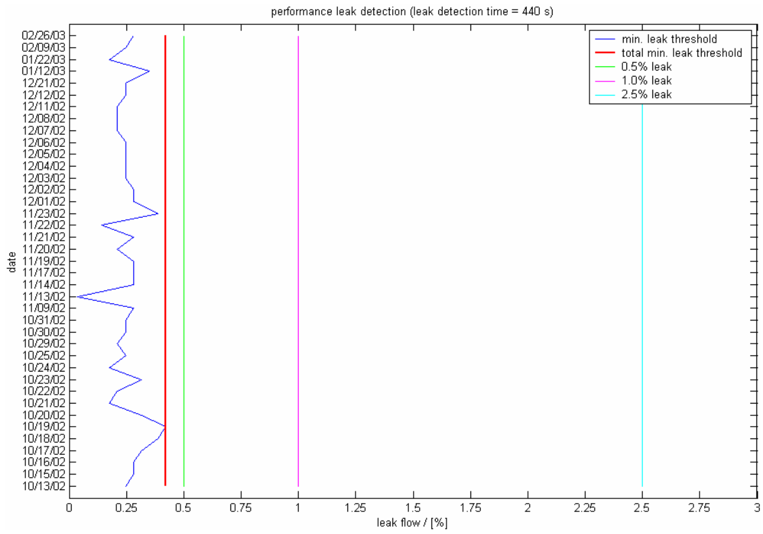

Figure 12 – Maximum deviation between calculated and measured flow for 440 s detection time

After four months of data recording, the maximum deviation between calculated and measured flow was plotted for different maximum allowed detection times. This resulted in figure 13 below. Subsequently a 'reference point' was chosen. Obviously this point should never lead to a false alarm (so it should not be on the left of the blue line), then again it should permit fast detection of small leaks (meaning it should not to be too far right from the blue line). For the project described in this paragraph the 'reference point' was set at a 1% leak and a detection time of 5 minutes (300 seconds).

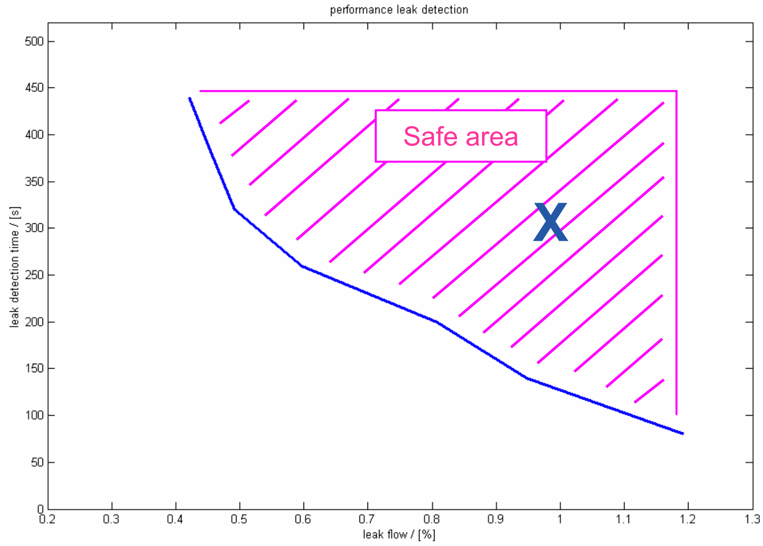

Figure 13 – Maximum deviation between calculated and measured flow vs. maximum allowed detection time.

3.4 System Reliability and False Alarms

The system described went completely live in February 2003 and since this time only one false leak alarm was given. This leak alarm was caused by abnormal pipeline conditions during emergency shutdown tests. Breakdown of the inlet turbine flowmeter caused a sensor alarm (i.e. not a leak alarm). After investigation this meter was replaced by a Coriolis massflow meter. Since commissioning no system parameters have been changed except for when the turbines were replaced.

4 FIELD TEST DATA ON A LIQUID PIPELINE

This chapter describes a multi-product liquid pipeline. The pipeline is used to transport refined liquid hydrocarbons between two refineries in the north of Germany. The pipeline has three intermediate valve stations and one of these stations was used to conduct leak trails. The Intermediate valve stations do not have permanent instrumentation installed as they are only used for emergency shut-down.

4.1 Application Details

Details of the application can be found below. Field instrumentation was already present and sent the measured data to the existing data communication system. The PipePatrol Monitoring Station was installed in the control room and communicates to the SCADA system via OPC.

A layout of the instrumentation can be found in figure 14. The VoS (velocity of sound) signal from the ultrasonic flowmeters was used to identify the product entering the pipeline. This product identification is required for batch tracking and for informing the RTTM when a new product (with a different density and viscosity under standard conditions) enters the pipeline.

Product data
- Nine refined liquid hydrocarbons (including diesel, heating oil, kerosene, naphtha, petroleum)

Pipeline data
- Length 31.5 km (20 miles)
- Diameter DN 250 (10”)
- Mainly underground, partially above ground

- Bi-directional

Instrumentation

- Flow and VoS at inlet and outlet (Ultrasonic Flowmeters)
- Pressure at inlet and outlet
- Temperature of product at inlet and outlet
- Temperature of ground at inlet and outlet

Flow data

- Nominal flow of 300 m^3/h
- Nominal pressure 18 Bara (at inlet side)
- Transient behaviour during batch changes, start-up and shut-down

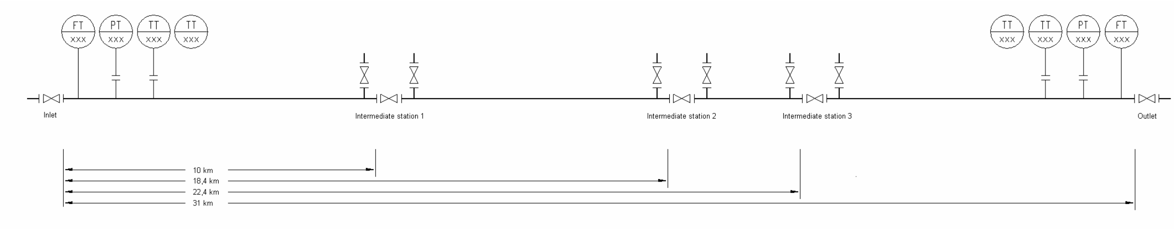

Figure 14 – Instrumentation lay-out of liquid pipeline.

4.2 Leak Trials

In contrast to the gas pipeline, where the leaks trials had to be conducted at the inlet to allow the gas to be fed back to the flare installation, leak trials on the liquid pipeline were positioned at an intermediate valve station. During the trial period the line was pumping naphtha. Trials were held at valve station 3 (22.4 km from the inlet) and the released naphtha was pumped into an empty tanker truck. The leak rate was set at 1.5% of the nominal flow (minimum leak rate for this system is 3m^3/h or 1% of nominal flow), thus creating a leak flow of approximately 5 m^3/h. The test was carried out 3 times consecutively, whereby each leak was detected within 30 seconds (or after 42 litres of naphtha leaked out) and a confirmed leak alarm was given within 60 seconds (or after 83 litres leaked out).

Figure 15 below shows the inlet and outlet residual during one of the leak trial periods. The leak started at 11:45 (42280 s after midnight) and ended at 11:50 (42650 s after midnight). Since the leak was positioned at 22.4 km from the inlet in a 31.5 km long pipeline, 71% of the leak effect is seen at the outlet side (the leak is closed to the outlet) and 29% of the leak effect is seen at the inlet side. This effect is caused by the gradient intersection principle as described in paragraph 2.3 and, together with the wave propagation method, forms the basis for leak localisation. Test data on the leak localisation can be found in paragraph 4.3

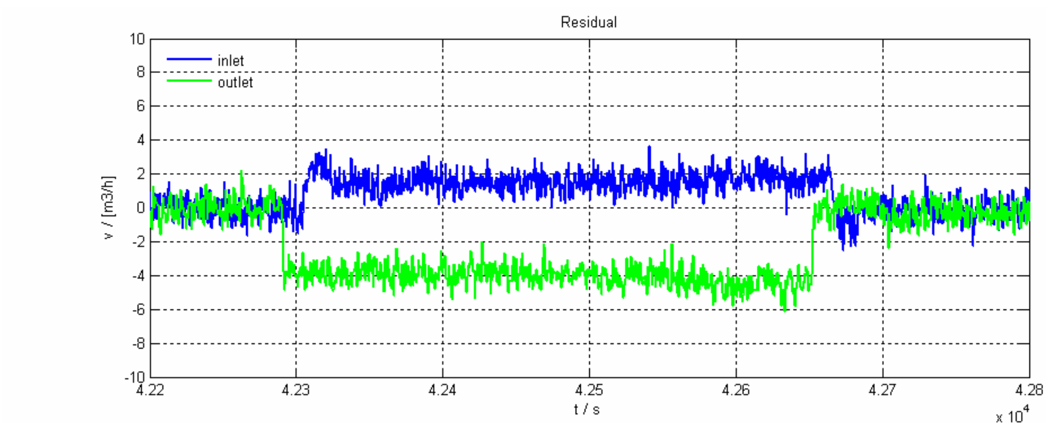

Figure 15 – Inlet and outlet flow residual during leak trial

4.3 Leak Localisation and Leak Rate Calculation

Two different mechanisms were applied to calculate the leak location (see paragraph 2.3 for more details). Figure 16 shows the results from the Wave Propagation Method (22246 meters); Figure 17 the results of the Gradient Intersection Method (22005 meters). Averaging these results gives a leak position at 22125 meter from inlet (normally only one result is shown). With the actual leak at 22400 meter, the leak localisation error is 275 meter or 0,87% of the pipeline length.

Time required to localise the leak with the wave propagation method is 60 s, the time required to locate the leak with the gradient intersection method is about 4 minutes since some time is required for the leak flow to stabilise. Figure 18 shows the calculation of the leak rate. Some time is required for the leak flow to stabilise and 220 s after the leak was detected, the leak flow was calculated to be 5.3 m^3/h.

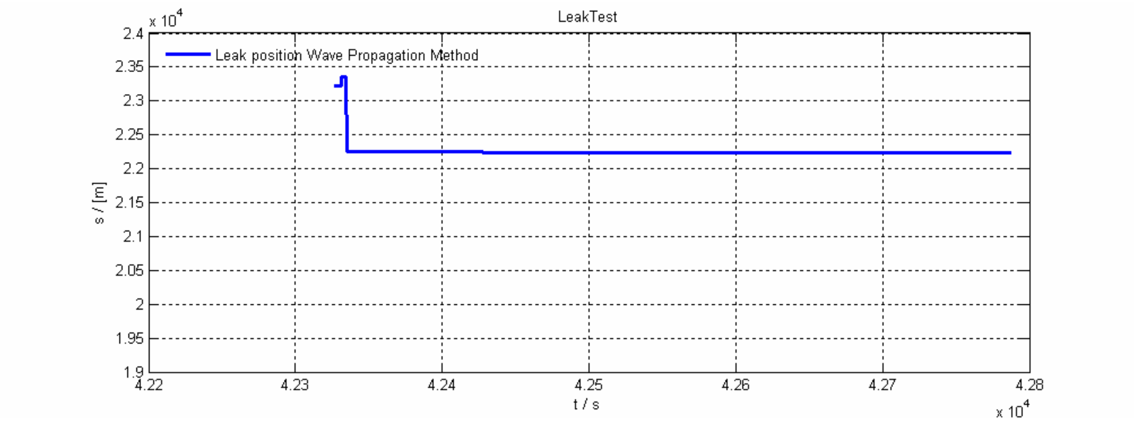

Figure 16 – Leak localisation by using the Wave Propagation Method

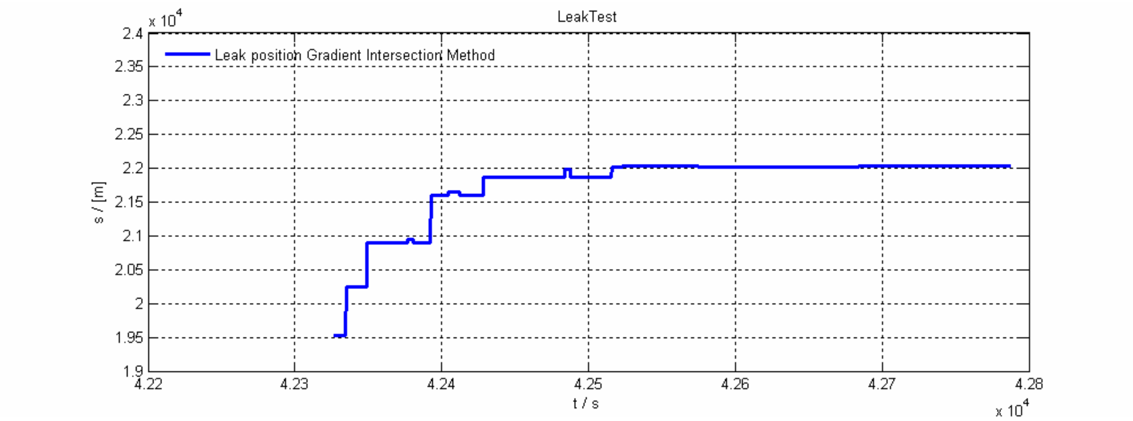

Figure 17 – Leak localisation by using the Gradient Intersection Method

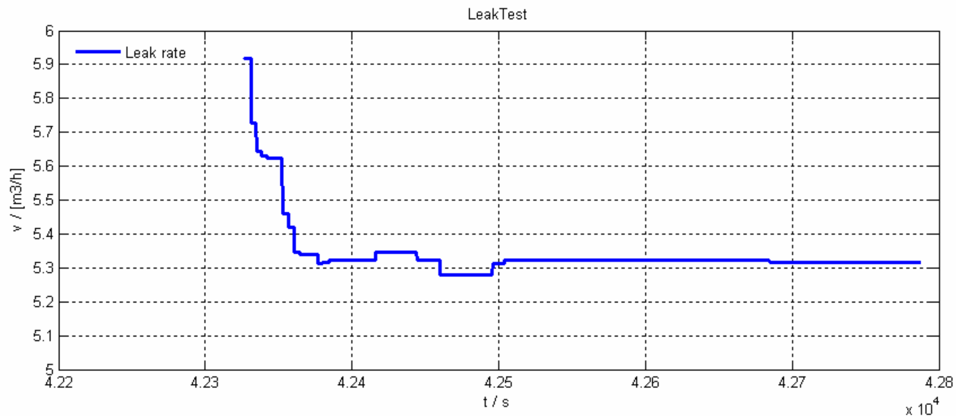

Figure 18 – Calculation of leak rate

5 CONCLUSION

Field test data are described for two pipelines that use KROHNE's PipePatrol E-RTTM. The first application shows how a 1% leak in a transiently operated gas pipeline is found in 5 minutes. The second application shows how a 1.5% leak in a multi-product liquid line is detected within 1 minute and located and quantified within 4 minutes.

Combining RTTM technology with leak pattern recognition, resulting in an E-RTTM approach, minimises the number of false alarms. The gas pipeline has experienced one false leak alarm since start-up early in 2003. The liquid application was commissioned only recently and has not yet seen any false leak alarms. A similar multi-product liquid application (although using orifice plates instead of ultrasonic flowmeters) has seen less then 1 false alarm per year since commissioning in 2001.

6 ABREVIATIONS

SCADA	Supervisory Control And Data Acquisition
OPC	OLE for Process Control (communication protocol)
MS	Monitoring Station (PipePatrol computer that holds E-RTTM)
OS	Operator Station (PipePatrol computer that holds Human Machine Interface)
RTTM	Real Time Transient Modelling
E-RTTM	Extended Real Time Transient Modelling
VoS	Velocity of Sound
PDE	Partial Differential Equation
MOC	Method Of Characteristics
DRA	Drag Reduction Agent

7 REFERENCES

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8 ANNEX 1, MATHEMATICAL BACKGROUND OF RTTM

Using the increasing computing power of modern digital computers, it is possible to calculate in real time the profiles for flow *v* (Relation to volume flow is given by $\dot{V} = A \cdot v$), pressure *p* and density *ρ* (or temperature *T*) along the pipeline. This requires solving a partial differential equation (PDE) system as a result of applying

continuity equation

$$\frac{d\rho}{dt} + \rho \cdot \frac{\partial v}{\partial x} = 0$$

momentum equation

$$\frac{dv}{dt} + \frac{1}{\rho} \cdot \frac{\partial p}{\partial x} + f_D = 0$$

and energy equation

$$\frac{dh}{dt} - \frac{1}{\rho} \cdot \frac{dp}{dt} - l_L = 0$$

Remarks:

- These equations describe (for simplicity) one-dimensional (location *x*) transient (time *t*) single-phase fluid (liquid and gas) flow in a single pipeline segment without diffusion. It is a hyperbolic type PDE system.
- Appropriate thermodynamic state equations $p = p(\rho, T)$ and $h = h(\rho, T)$ are required to eliminate enthalpy h, leading to three equations with three unknowns ρ, v and p.
- Drag force f_D per unit mass includes force of gravity per unit mass and friction force per unit mass: $f_D \equiv f_G + f_F$.
- Losses l_L per unit mass includes heat flow per unit mass and dissipative losses per unit mass: $l_L = l_Q + v \cdot f_F$.
- The computation of heat flow per unit mass l_Q requires an additional thermal model.
- Special model extensions could be required for multi-phase conditions and other non-standard conditions (slag-line, usage of drag reducing agents, DRA).

Up to now, there is no known analytical solution. Therefore, numerical algorithms have to be used instead. Examples are method of characteristics (MOC) and finite difference, finite volume and finite element methods.

The resulting numerical algorithm is of boundary value problem type with three boundary conditions required.

Friction force. Using Darcy-Weisbach equation, friction force per unit mass f_F for a pipeline with diameter D is given by

$$f_F = f\,\frac{v|v|}{2D}$$

with Darcy-Weisbach friction factor f, often calculated for turbulent flow using Colebrook-White formula

$$\frac{1}{\sqrt{f}} = -2\cdot\log\left(\frac{1}{3.7}\frac{\varepsilon}{D} + \frac{2.523}{\mathbf{R}\cdot\sqrt{f}}\right)$$

with Reynolds number **R** and roughness height ε; For laminar flow this simplifies to

$$f = \frac{64}{\mathbf{R}}$$

State equations. It is interesting to see, that the thermodynamic state equations $p = p(\rho, T)$ and $h = h(\rho, T)$ are the only fluid specific equations for the continuity, momentum and energy equations. The simplest approach for an ideal gas results in

$$p = p(\rho, T) = 1\cdot\frac{R}{M}\cdot\rho\cdot T$$

with gas constant R and molecular weight M, and

$$dh = \left(\frac{\partial h}{\partial T}\right)_p dT = c_p dT$$

with constant-pressure specific heat c_p.

Simplifications. Simpler mathematical models can be derived using additional assumptions like adiabatic or isothermal flow, sometimes reducing the order of the PDE system equations for continuity, momentum and energy. For liquids, neglecting heat transfer and the conversion of frictional work into thermal energy leads the water hammer equations, a PDE 2nd order PDE system.

Multi-phase flow, slack line. Condensation from gas into liquid often can be observed in gas pipelines from off-shore wells, resulting in a two-phase gas-liquid flow. Condensate pipelines that are liquid only due to pressurization or crude pipelines that run through mountainous terrain exhibit the opposite problem: slack line, introducing some volume of gas in the pipeline. Both phenomena have a significant impact on the hydraulic operation of the pipeline. The modeling of multi-phase flow requires the introduction of multi-component transport and the model being capable of performing the individual boiling or condensation of each of the individual components.

Drag reducing agents, DRA. DRAs improve the delivery capability and reduce the cost of pressurization by reducing the pressure drop per unit length of pipeline. The impact of DRAs can be modeled by

$$f'_F = \kappa\cdot f_F = \kappa\cdot\frac{f\,v|v|}{2D}$$

using friction force per unit mass f_F according to Darcy-Weisbach κ is the effectiveness of the DRA, which depends on the DRA concentration.

Alternative approaches. Transfer function models for the PDE system equations of continuity, momentum and energy are obtained by linearizing these equations and carrying out a

Laplace transformation. The resulting transfer function is transcendent. Simple models of the pipeline in the form of a lumped parameter system can be obtained by a Taylor series expansion of transcendent transfer functions. The resulting algorithms are less time-consuming and hence better suited for critical real time applications. Use of Neural Nets (NN) presents another possibility for system modeling using a black box approach: trained by field data, NN are able to describe the pipeline behavior without any knowledge about pipeline physics. NN are of special interest:

- for pipelines with complex physical behavior, where a physical description is time consuming (or maybe not possible to find), or
- as an addendum to conventional RTTM approaches according to equations of continuity, momentum and energy

LDS using RTTM. Using and solving the equations for continuity, momentum and energy in real time, it is possible to eliminate transient effects introduced by

- fluid compressibility and pipe wall elasticity, and
- temperature dependence of the density.

Corresponding LDS are called real time transient model (RTTM) systems. RTTM-LDS can also be used during transient pipeline operation, e.g. during start-up of a pipeline; this is especially useful for gas pipelines, where large compressibility results in severe transients. Two possibilities for using mathematical model information are given here:

Deviation analysis: Only three boundary conditions are required to drive the numerical solution algorithm, e.g. $p_I(t)$ and $p_O(t)$ for inlet and outlet and $\rho_I(t)$ (or $T_I(t)$) for inlet. If more measurements are available (e.g. flows $v_I(t)$ and $v_O(t)$ or additional pressure measurements along the pipeline), these measurements can be compared with the simulated values. If there is a significant deviation, leak alarm will be given. See the new RTTM LDS approach given later for further details.

Model Compensated Mass Balance: The RTTM can be used to calculate the line fill

$$M_L = \int_0^L \rho(x)A(x)dx \, .$$

in real-time. The imbalance subsequently can be compared with

$$R \quad \begin{cases} < A & \Rightarrow \quad no\ leak \\ \geq A & \Rightarrow \quad leak \end{cases}$$

against a threshold *A* to evaluate the leak alarm.