Internal corrosion: one of the leading causes of pipeline failure

ROHRBACK Cosasco Systems, based in California, is a pioneer in the measurement of corrosion by way of electrical resistance and ultrasound. The company has over 80 employees and 50 representative companies around the world (75% of their business is in the international O&G sector), with annual sales of over $20 million. "We saw the potential for a high-speed, high sensitivity device that could be permanently installed, and began to focus on development in 2003," says Brent Ford, the company's CEO. This report outlines the company's progress in this field, and looks at a particular application of its equipment for Panhandle Energy.

BEATEN IN the league of problems leading to pipeline failure only by third-party interference, internal corrosion is one of the leading causes, and one of the most difficult to detect. Pipeline accidents have caused catastrophic injury and destruction, resulting in the US Department of Transportation imposing integrity-management requirements on pipeline operators. To aid operator compliance, an American company has developed an efficient, reliable means of monitoring internal corrosion before it causes problems.

Keeping pipelines safe from internal corrosion can be a challenging and expensive business: industry estimates run to several billion dollars annually in the US alone. Panhandle Energy, a subsidiary of Southern Union, operates approximately 28,800km of interstate pipelines. "In 2006, Panhandle will perform over 300 anomaly investigations," says David McQuilling, a senior engineer for Panhandle Energy. "On average, we budget $50,000 per investigation in rural areas, but if you're in an urban area, $50,000 may not even cover permitting; I've heard of operators spending over $250,000 on a single dig."

Internal corrosion can occur when impurities are present within the natural gas, crude, and refined products being transported. Bill Shaw is an engineering professor at the University of Calgary and the director of the Pipeline Engineering Centre, which studies corrosion and monitoring. "Moisture is the big thing: if you had no moisture, for the most part, you'd be fine," he says. "It mainly mixes with salts, like chlorine, and sulphur compounds."

Corrosion can typically reduce a pipeline wall thickness at a rate of 2-3 mils/year, but it can happen much more quickly in the upstream area of operations. "Gathering systems are really bad: you have large quantities of hydrogen sulphide and brine," says Shaw. Water can chemically react to form very corrosive liquids that collect in low-lying spots. Corrosion rates in these areas may reach several hundred mils per year.

To mitigate the potential for incidents related to internal corrosion, the pipeline industry works assiduously to reduce risk. The US Department of Transport's Pipeline & Hazardous Materials Safety Administration (PHMSA) notes that 258 natural gas and liquid pipeline accidents (14% of which were caused by internal corrosion) occurred in the US in 2004. "It is important to place natural gas pipeline safety data in perspective," says Don Santa, president of the Interstate Natural Gas Association of America. "INGAA's members operate a network of approximately 320,000km of transmission pipeline, and this total does not include all of the intrastate transmission pipelines and LDC-owned pipelines that also are subject to the Department of Transportation's integrity-management rules. Pipelines are one of the safest modes of transportation."

But when they do fail, they tend to get noticed. Early in the morning of Saturday, 16 August, 2000, a natural gas line exploded in SE New Mexico near the Pecos River: 11 nearby campers were killed by the blast and fire. The ensuing fireball was large enough to be seen in Carlsbad, NM, 30km to the north. Federal investigators determined that the cause was severe internal corrosion; over 70% of the wall had been eaten away near the rupture.

Partly in response to the tragedy, the Bush Administration enacted the Pipeline Safety Improvement Act (PSIA) in

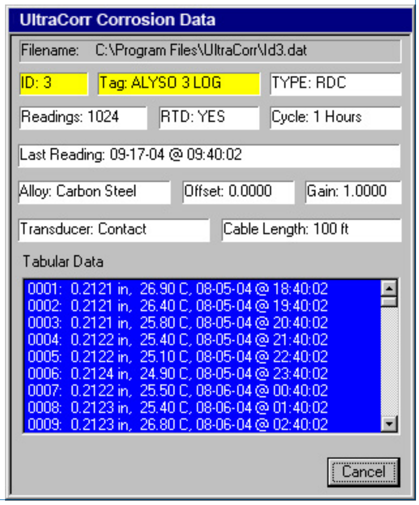

Sensors installed on a line prior to backfilling.

2002. "Under the PSIA, pipelines have to inspect all high-consequence areas (HCAs) within a 10-year span and then, after the initial inspections are done, they have to go back and inspect at seven-year intervals," says Don Santa. The Office of Pipeline Safety estimates that natural gas pipeline companies alone will spend $4.7bn over 20 years complying with the legislation (and for those that don't, civil penalties of $25,000 to $100,000, and fines up to $1m for repeat violations, could be levied).

In order to comply, pipeline operators rely on a range of survey methods supplied by third parties. Prominent companies supplying internal corrosion monitoring equipment include Rohrback Cosasco of the US, Corrocean in Norway, Cormon in the UK, and Caproco in Canada. The international market for corrosion-monitoring equipment is in the neighbourhood of $70m annually, and is growing rapidly due to the fast pace of oil and gas developments, expansion of pipeline networks around the world and the increasing stringency of regulation.

Generally, internal corrosion monitoring and detection is broken down into three techniques: intrusive, in-line inspection (ILI), and non-intrusive. "Intrusive methods include electrical resistance probes and coupons," says Shaw. The coupon is the original form of intrusive corrosion monitoring. It consists of a strip of metal about 75mm long and 3.175mm thick, made of material similar to the pipeline. It is weighed, then inserted it into an access point, and left for at least six months. The operator then removes the coupon and weighs it again to see what percentage is missing.

The coupon is inexpensive and reliable, but several factors can outweigh the advantages. First and foremost is access above the area of concern. "Corrosion often occurs at low spots, under roads or rivers," says McQuilling. "It's often



The UltraCorr *system showing* (clockwise from top right) *a sensor installed on a line, a screenshot of the analysis, a sensor in close-up, and the hand-held data logger.*

impossible to put a coupon in the location where the internal corrosion is occurring. If access to the area is possible, burial depths must be considered, as coupons are commonly installed and retrieved at line pressure. It is impractical to install coupons at pipe depths greater than 3-5m below grade. I've had situations where pipe was removed and replaced due to internal corrosion but a coupon was not considered due to safety concerns about insertion and extraction of a 8.8-m long coupon/coupon staff assembly at 135bar."

Secondly is the number of locations where coupons can potentially be installed. "With external pipeline corrosion protection, you've got a monitoring point every mile; that's not a lot – quite a few assumptions have to be made," says McQuilling. "With internal corrosion, you've got one every hundred miles if you're lucky; it's like getting eight pieces of a 1,000-piece jigsaw puzzle and asking what it looks like."

Thirdly, because coupons are most commonly left in the pipeline over a six-month period, the operator doesn't know if the corrosion occurred slowly over the time period, or quickly over a few days due to an unusual event.

In-line inspection (ILI) tools, or smart pigs, are intelligent sensing devices that are introduced into the line at a specialized entry point and most commonly conveyed by the product flow along the length of the pipe. "Pigs have great sensitivity, but there's a lot of piping that cannot be pigged easily," says McQuilling. "It's common to telescope vintage pipelines from 24in to 18in. Also, you can have a vintage 36-in pipeline with 24-in valves; you saved a considerable amount of money during construction and the flow restrictions due to undersized valves are negligible, but a pig won't go through: it's expensive to make some lines piggable."

"The preferred methodology is inline inspection with a pig, but certain sections can't use a pig due to age and configuration," agrees Santa. "You then have to dig up and visually inspect them, or hydrostatically test them, which from a practical standpoint is not all that convenient and potentially destructive."

External sensors help avoid such expensive intervention; various devices measure the physical properties of the pipeline through secondary techniques. "You can use acoustics to measure wall thickness or listen to the noise of corrosion," says Shaw. "Vacuum foil techniques measure hydrogen permeation."

The most common non-intrusive device is the ultrasonic monitor. To conduct a survey, the pipeline is dug up then a portable device is held against the metal. Inside the device, voltage is applied across a piezoelectric crystal to generate an ultrasonic sound wave that propagates through the metal. The time it takes to travel through the metal and back to the transducer is directly proportional to its thickness. The devices are quick, easy to use and inexpensive, and operators do not have to shut off flow or risk breeching the pipeline in order to take a reading. On the other hand, they still have to expend thousands of dollars digging up the pipeline each time they run a test. Also, traditional ultrasonic monitors have a sensitivity range in the order of 5-10 mils accuracy, so if the corrosion is only 3 mils/y, it takes three years to start to see it in a statistically-significant manner.

Rohrback Cosasco Systems has devised the *UltraCorr* wall-thickness monitor, a combination of permanently-mounted transducers and a portable data logger. "Problem areas, which are typically located at low spots, are identified by pigging or some other means, then dug up." says Brent Ford, the company's CEO. "Before the pipe is reburied, a series of transducers is permanently attached to the bottom of the pipe and leads are run to a test post at ground level. A dozen or so transducers should provide adequate coverage for most areas to be monitored, but this can vary depending on the actual surface area in question. Unlike normal ultrasonic devices, at a resolution of one tenth of a mil, *UltraCorr* is truly capable of monitoring low rates of corrosion."

With a permanently-installed system, internal corrosion surveys can be incorporated into normal maintenance practice; most pipeline companies have field technicians patrolling the right-of-way on a frequent basis to check cathodic protection systems. "The technician takes an *UltraCorr* data logger, a hand-held device, and loads the transducer information from the test post," says Ford. "It's easy to use, and only takes seconds per reading." Readings stored on the portable data logging unit can be uploaded to a PC, where proprietary software is used to organize, store, and graphically display data. Simple plots of thickness versus time are augmented with a cursor-driven corrosion-rate calculator permitting detailed event analysis. "Operators know with confidence the condition of their pipe."

Costs for *UltraCorr* are reasonable. "Depending on the number of transducers required, our device might be $8-$12,000 per dig to install, but you only have to do it once," says Ford. "The hand-held device is around $6,500; you only need one per field area."

Right from the beginning, Panhandle Energy has been interested in the system. "It's simple, clean and cheap; you don't have to blow-down the pipe, which really gets expensive, or do a hot tap," says McQuilling. "You just buff-off a spot on the pipe and attach it with epoxy, then backfill and set up a post for the transducer wires, and you're done."

In addition to saving excavation costs down the line, McQuilling notes there are also savings in operation and maintenance costs. "With a coupon, it can take an hour to pull one, and there's an increased potential of injury. With *UltraCorr*, they can do a reading in a few minutes, and there's limited potential for injury."

Since the majority of Panhandle's system handles clean, dry gas, there is little corrosion along mainlines. "Panhandle has numerous locations where we believe the *UltraCorr* will be beneficial," says McQuilling. "Historically, most of our internal corrosion issues occur at our underground gas storage fields. Panhandle operates six gas storage fields which are depleted gas reservoirs used to store gas. We inject clean, dry, pipeline quality gas, but it often comes back up wet and potentially corrosive. A typical storage field has 50-65km of pipe and 70-80 wells, creating numerous opportunities for internal corrosion monitoring."

Although McQuilling is enthusiastic about the system, he is well aware that others may not be so. "Lots of readers will be sceptical; some operators put earlier versions of *UltraCorr* into operation and the epoxy failed within months," he notes.

"We had an early prototype with reliability issues," acknowledges Ford. "We spent over a year and $1m improving reliability and sensitivity before starting field tests. We are confident that the new system will meet expectations."

"They've put the latest epoxy through torture to improve it," notes McQuilling. "We've had the latest probes in-service since October, 2005, and so far, it's worked and worked well. We've stuck with them because there's great potential for a low-cost monitoring system that may eliminate the need for future excavations. With this system, when the Office of Pipeline Safety comes in after seven years and says "You've got to re-inspect that portion of pipeline," we hope to say "We've done real time monitoring; here's the data."

For industry observers, a permanent, non-invasive system could improve safety. "The best safety programme is damage prevention, and if you can address corrosion before it is an incident, that is the best way to deal with the issue," says INGAA's Don Santa.

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ULTRACORR®

High Resolution On-line Pipe Thickness Monitor

Fixed Sensor

Transducers permanently bonded to Pipeline before installation

Features:

- ***Ideal for ICDA* Compliance***
- ***Highest Resolution Transducer Available***
- ***Portable Instrument***
- ***Automatic Corrosion Data Collection***
- ***Automatic Download to PC***
- ***Battery Operated for Maximum Versatility***
- ***Smart Sensor Enables Electronic Tagging***
- ***Resolution of 0.1 mil (0.0001 inches) provides true corrosion monitoring***

ULTRACORR® utilizes high sensitivity ultrasonic technology to provide **nonintrusive** monitoring of corrosion and erosion. The instrument can be used to log multiple transducers from a common connection point, to provide periodic time and date stamped measurements of wall thickness, or for more critical applications. It can automatically collect and store continuous measurements from a single transducer.

ULTRACORR® is ideally suited to form the backbone of an ICDA asset integrity system for pipeline operators. Sensors are permanently attached to the exposed surface in areas such as low lying spots, drips on other locations where corrosion should be monitored. After backfilling, the sensors are read from the surface by way of attached cables. The high resolution of ULTRACORR® enables pipeline operators to detect changes in corrosion rates and readjust accordingly scheduled reassessment intervals to suit. Repeat excavations are unnecessary, and the guesswork about reinspection intervals is removed.

Typical measurement time per transducer is a few seconds. The user can program the ULTRACORR® Instrument to collect data from as many as 50 transducers, or alternatively, it can be programmed to collect up to 1,024 data points from one transducer at programmed intervals. Operation is made very simple by a series of user prompts shown on the LCD display. A rugged package along with extended battery life provides maximum versatility for the corrosion technician.

The software included with the instrument facilitates the transfer of data to a PC for analysis and permanent storage. ULTRACORR® is also compatible with the CORRDATA® Plus (for Windows™ XP) software used with the industry favorite CORRDATA® Remote Data Collection System.

*ICDA – Internal Corrosion Direct Assessment

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