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ULTRASONIC SENSOR SYSTEM FOR WALL-THICKNESS MONITORING

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INTRODUCTION

Metal loss due to corrosion and erosion is a widespread issue in the oil & gas and power generation industries for tanks, high-energy piping, pressure vessels, and other critical assets. Metal loss can lead to loss of pressure containment, which can result in serious consequences such as loss of life, damage to assets, disruption of service, environmental harm, damage to public image, and regulatory fines. As such, asset inspections are required by operators and are mandated in regulations and codes such as 29CFR–1910; API 570, ASME Sections V & XI, ASTM E797, and NACE's IP 34101.

While there are many methods for measuring equipment wall thickness, a predominant method used in the O&G and power generation industries is portable ultrasonic equipment. Ultrasonic testing is non-intrusive because it is applied to the outside of a pipe or vessel. It is an accurate and relatively low cost non-destructive examination (NDE) method to deploy in most situations. However, it does have several shortcomings. Ultrasonic transducers or probes need to be applied in direct contact with the external surface of the pipe or vessel. This can require scaffolding, excavation, and stripping coatings or insulation. Thus, the cost of accessing the structure often far exceeds the basic cost of inspection. Furthermore, a trained and certified inspector is generally required to operate the ultrasonic instrumentation. In addition, ultrasonic testing sometimes requires personnel be exposed to potentially hazardous environments. The accuracy and repeatability of ultrasonic measurements are operator-dependent and recent studies have shown that the probability-of-detection (POD) can be poor1. Finally, the measurements are only performed periodically, taking a snap-shot of the plant condition.

Many end users are interested in investing in new technology to overcome these concerns. In the process industries, such as petrochemicals or refineries, critical process parameters are measured in real time. Information on vibration, flow, temperature, pressure, PH, equipment upsets, or unusual conditions is collected and reported on a continuing basis via key performance indicators or KPI's. The automation of thickness measurements would alter the paradigm from the current manual/periodic measurements, to measuring thickness and corrosion rates as an on-line process for monitoring plant health variables, which can be used to optimize asset use and inspections.

A NEW SOLUTION: INSTALLED ULTRASONIC SENSORS

Installed ultrasonic sensors are emerging as a new technology to compete with manual UT (Ultrasonic Testing) inspections and existing corrosion-rate monitoring solutions. This is due to their potential for improved data quality, one time, non-invasive installation, and their ability to operate remotely without human interaction. As with UT thickness gauging, the solution is based on relatively simple ultrasonic principles.

A transducer that can convert electrical energy to high-frequency acoustic or ultrasonic energy and vice-versa is semi-permanently attached to the surface of the object or asset under test. The transit time between the initial electrical-excitation pulse and return echoes (or between echoes) is used to calculate wall thickness. Features such as the distance to the back-wall or the distance to a pit or crack can be measured with this technique. One must size and space the transducer appropriately to know the probability of finding a pit above a certain diameter.

Operationally, the installed-sensor solution is similar to manual thickness gauging. However, it is fundamentally different in that the transducers and instrumentation are deployed/installed semi-permanently. This addresses several of the shortcomings of existing solutions. Some of the major advantages are as follows:

- Instrumentation and probes are deployed on the asset in a permanent or semi-permanent fashion and can be accessed remotely. This reduces the cost of access over time as operators are not deployed to the point of the inspection. Once the instrumentation is installed, data can be reviewed from a convenient access point for the manual data collection option or can be accessed remotely, via the Internet, for integrated systems.
- Due to the fixed transducer position and instrumentation, operator-to-operator, probe-to-probe, and instrument-to-instrument, variability is eliminated. This removes significant sources of error and allows for improved measurement resolution, precision, and accuracy, which is particularly important for accurate corrosion-rate trending.
- Data can be collected on a more frequent basis (>1X per day) for automated systems. This allows for more frequent corrosion-rate trending through statistical data analysis, such as linear least squares regression, which in turn should lead to improved data accuracy.
- These types of systems can be deployed with an integrated temperature measurement device so that changes in material acoustic velocity due to temperature variation can be automatically removed from the measurement, thus eliminating another significant source of measurement error.
- The data is accessible. Wired and/or wireless installed sensor systems can make use of various forms of data backhaul, including the plant's wired or wireless intranet, industrial

Figure 1. Ultrasonic installed sensor system with up to 8 dual-element transducers and cellular connectivity.

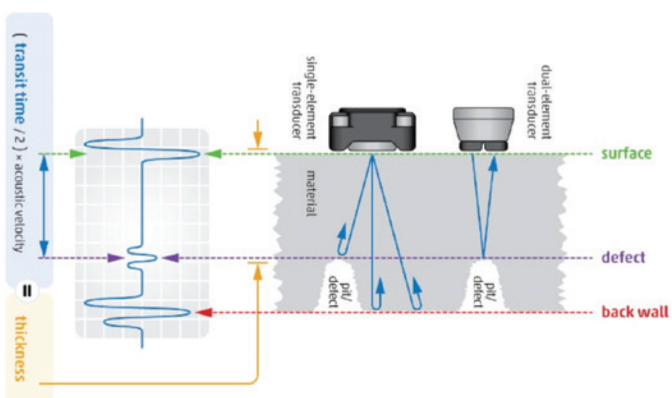

Figure 2. Single-element, including ultra-high-temperature delay-line, and dual-element transducers can be used with installed sensor systems.

Figure 3. A 16-channel ultrasonic system can be configured to support area coverage.

wireless networks such as 802.15.4, (wireless HART, ISA100 or ZigBee), and satellite or cellular networks for remote collection points, allowing real-time data/asset health availability.

USE OF CELLULAR NETWORKS

Flexible platforms are available for deploying ultrasonic sensors over both wired and wireless networks. A recent development is a device using a cellular radio for data backhaul (See **Figure 1**). Because the instrument is capable of connecting to and using available third-party cellular networks, it avoids the problems and high costs associated with mesh networks, gateways, and plant IT infrastructure. This allows the deployment of even single inspection points at low cost, without the expense of gateway installation and IT personnel evaluation. The instrument is typically connected via an available cellular network to a cloud server that is running application software designed to communicate with the instrument for the purpose of collecting ultrasonic or other asset integrity data. The application software is also designed to store readings and has a browser-based user interface that allows for the display of data and asset integrity information. The application can be viewed through standard browser-enabled devices such as laptop computers, tablets, and smart phones.

These systems can consist of a single ultrasonic channel that is multiplexed to up to 16 single-element or eight dual-element transducers. The ultrasonic channels are programmable and can be deployed with various transducer types and/or frequencies, as seen in **Figure 2**. Dual-element transducers have become the industry's recommended standard for corrosion thickness gauging due to their superior performance in detecting pitting, ability to measure thinner (0.040" or 1.0 mm) wall sections, and ability to operate over a wider temperature range (e.g. 0˚ F to 300˚ F (-20 to 150˚ C)). **Figure 3** shows an array of transducers deployed to provide area coverage. Additionally, a temperature-measurement channel can be included so temperature measurements can be taken concurrently with the thickness readings for the purpose of correcting for temperature-induced measurement changes.

COMPENSATION OF TEMPERATURE EFFECTS

The direct measurement made in an ultrasonic thickness gauge is time, not material thickness. Rather, material thickness is a measurement derived from the measured round-trip travel time of the ultrasonic wave in the object and the ultrasonic velocity of the material. As temperature is increased or decreased in a solid, the ultrasonic velocity also changes due to corresponding changes of the mechanical properties of the material. On average, the ultrasonic velocity decreases with an increase in temperature at a rate of approximately -1% per 100°F (55°C). See **Table 1**. Consequently, as asset temperature rises/falls, a thickness gauge will measure a change in time-of-flight and a corresponding increase/decrease in thickness if the ultrasonic velocity is not temperature-corrected.

For example, if a calibration is performed on a room-temperature calibration block at 70°F (21˚C) and then subsequently a measurement is performed on the same block at 970°F (521˚ C) without adjusting the velocity, the thickness will be overestimated by approximately 9% due to the shift in material velocity. In light of

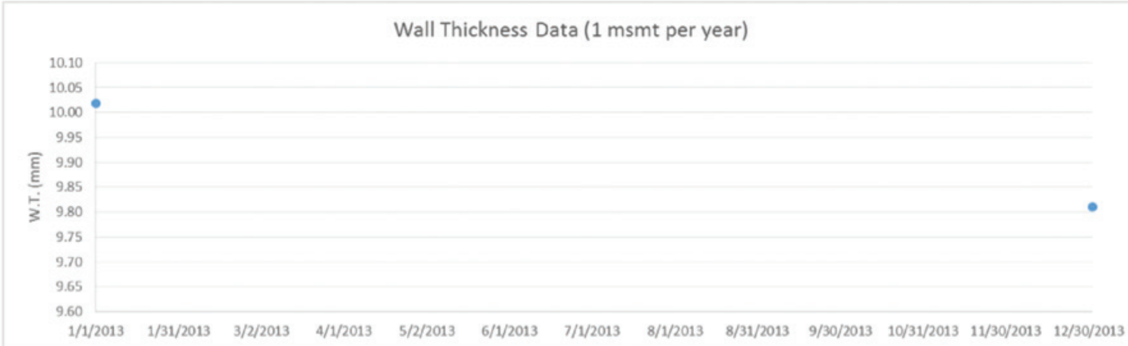

Figure 4a. Wall thickness monitoring data with collection intervals of: 1x/year

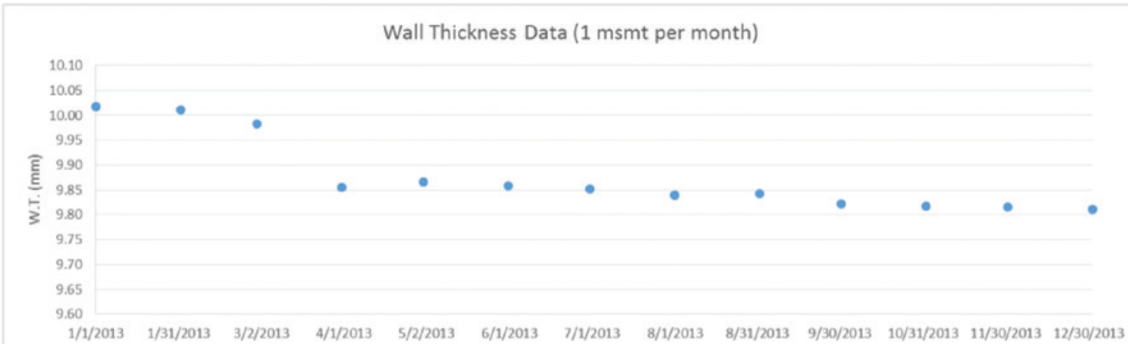

Figure 4b. Wall thickness monitoring data with collection intervals of: 1x/month

this potential reduction to accuracy and precision due to temperature variation, it is critical that a corrosion/erosion monitoring system also has the capability to measure test-part temperature by having a temperature monitoring device as part of the system, such as an integrated RTD (Resistance Temperature Detector) or thermocouple.

Table 1. – Correction factors for ultrasonic velocity in steel.

MATERIAL	CORRECTION FACTOR	SOURCE
Steel (Typical)	-0.0001 per °F (-0.00018 per °C) (-1.0% per 100°F (55°C))	Olympus
Steel (Typical)	-1.0 m/s per °C (-0.95% per 100°F (55°C))	Sensor Networks
Carbon Steel (Typical)	No Correction T<200°F (93°C)	ASTM E797
Carbon Steel (Typical)	-1.0% per 100°F (55°C) 200°F (93°C) < T < 1000°F (540°C)	ASTM E797
Plain Carbon Steel, AISI 1345	-0.7% per 100°F (55°C)	Marathon Oil Company[2]
Low-Alloy Steels AISI 4130 & 4340	-0.6% per 100°F (55°C)	Marathon Oil Company[2]
316 Stainless Steel	-0.9% per 100°F (55°C)	Marathon Oil Company[3]

THE POWER OF HIGH-FREQUENCY & HIGH-QUALITY DATA

A major advantage of installed ultrasonic sensors is the ability to collect a larger quantity of high-quality thickness data than would otherwise be available from manually collected measurements. This large amount of data allows visibility to the dynamics of wall-thickness reduction. Corrosion rates are often not constant and can vary between periods of virtually zero corrosion to episodic events causing corrosion rates of hundreds or thousands of MPY (mils or thousandths of an inch per year). The use of data of marginal quality, spaced over long time periods, can lead to either overestimating or underestimating the corrosion rate. It also does not allow insight into the actual corrosion history of an asset.

Figure 4 (a-d) shows a data set including eight distinct corrosion rates with noise having a standard deviation of 0.0004" (0.01mm). Progressing from **Figure 4a** to **Figure 4d** is the same data, displaying discrete measurements from the data set on intervals of 1X per year, 1X per month, 1X per week and 1X per day.

When considering a measurement interval of once-per-year, as might be normally obtained from manual UT measurements, only a coarse corrosion-rate calculation is available. Over several years, an operator might get a general understanding for the long-term corrosion rate, but statistically, it is impossible to place an uncertainty on this measurement, so the ability to use the corrosion rate as a predictive tool (for scheduling maintenance for instance) is poor. Even moving to a relatively infrequent measurement cycle of 1X per month allows a much better picture of the process of wall-thickness reduction. Separate corrosion rates

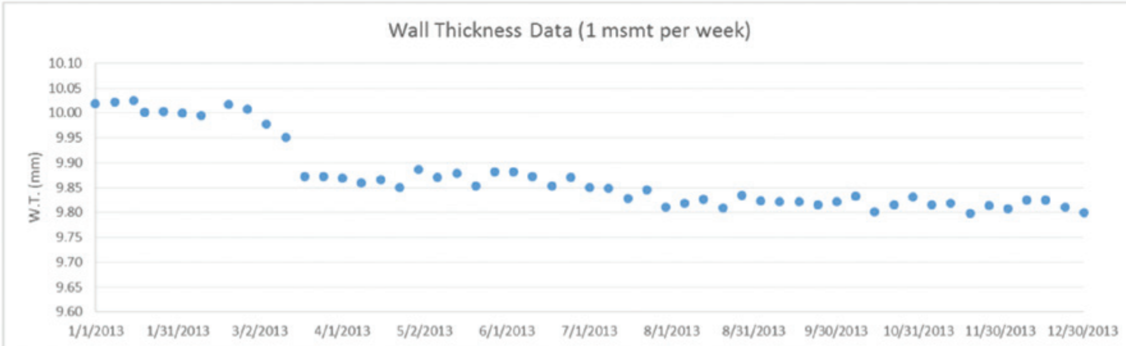

Figure 4c. Wall thickness monitoring data with collection intervals of: 1x/week

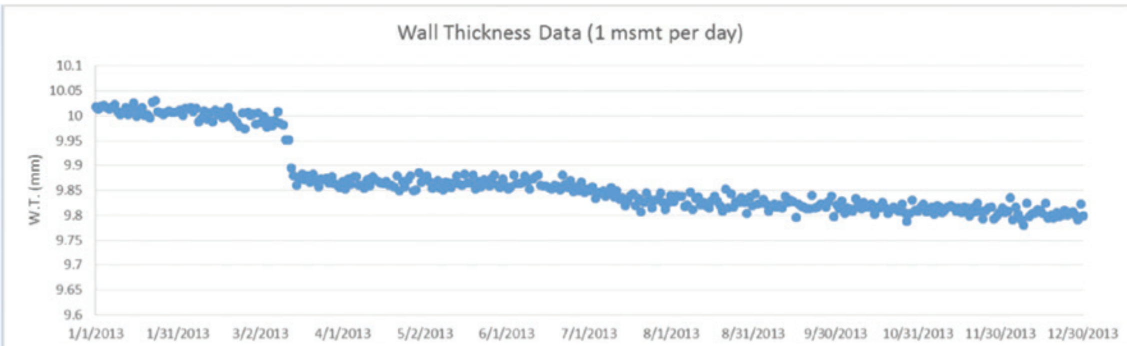

Figure 4d. Wall thickness monitoring data with collection intervals of: 1x/day.

are evident in the data, including evidence of an episodic event of very high wall-thickness reduction. While this is a large improvement over a once-per-year measurement cycle, the relatively small amount of data still limits the ability to calculate corrosion rates accurately. Thus, the ability to distinguish two different corrosion rates is impaired; which limits the efficacy of using the measurement as a process-control tool.

More frequent measurements, for instance once-per-week, once-per-day, or even more often, allows statistical tools to be used to characterize and remove measurement noise, reaching a corrosion-rate measurement precision in the range of 1 MPY. As such, installed ultrasonic sensor thickness measurements become a tool for monitoring process conditions as they impact the corrosion/erosion rate within a piping circuit, vessel, heat exchanger shell, or other asset. Numerical tools such as data filtering and linear regression are easily deployed in compatible software.

APPLICATIONS OF INSTALLED UT SENSORS

Any asset or TML (Thickness Monitoring Location) currently being monitored for corrosion/erosion or crack propagation is a potential candidate for UT sensor installation. The choice of converting a point from conventional monitoring can involve many considerations, such as the criticality of the asset and the desire for improved corrosion management, including trending, verification of corrosion mitigation, the need for high-integrity data to enhance RBI (Risk-based Inspection) and mechanical integrity programs, the desire to eliminate human factors present in manual UT, the removal of inspection personnel from hazardous areas, and regulatory or code compliance.

Locations currently monitored using ER probes

There are many traditional points in a refinery's crude unit where process corrosion rate is measured using electrical-resistance (ER) probes. While this technology is readily used, it suffers from several shortcomings, including measurement noise due to temperature changes, susceptibility to conductive deposits causing "negative" corrosion readings, and a relatively short life. ER probes only give a proxy to asset health, as the actual asset is not being measured. Furthermore, the probes are invasive and need to be replaced periodically. The replacement operation usually must be done on an energized circuit and failures during that process have had catastrophic consequences, including loss of life. Installed ultrasonic sensors, including instrumentation that is designed to have high measurement precision, can approach the corrosion rate precision of ER probes using regression analysis. The technology is installed directly on the asset, so in addition to measuring corrosion rate, the wall thickness is measured, providing a direct indication of asset health. UT probes are non-invasive and can be deployed on live piping circuits without the risk associated with penetrating the vessel or pipe's pressure boundary.

Injection / Mix-point Corrosion

Injection/mix-point corrosion has been responsible for many serious refinery incidents and is episodic in nature; only occurring under certain process conditions or during process upsets. API 570 specifies inspection guidelines and NACE IP 34101 provides specific process guidelines to minimize injection point damage. While manual UT and RT provide static monitoring of potential damage areas, their use may not coincide with the timeframe where episodic damage occurs, and therefore, require repeat inspections of potential damage areas. Installed UT sensors can provide dynamic monitoring of suspected injection point damage locations without repeated access mobilizations.

Crude Overhead

Crude unit overhead with chemical injection and/or water washes are subject to periodic inspections per API 570. Many overhead lines have no platform access making these inspections difficult and costly. UT and RT (Radiographic Testing) can provide useful inspection data, but they are costly to obtain if crane access or scaffolding is required. Installed UT sensors can be installed and accessed on a continuous basis to reduce cost of access and to improve plant operational knowledge.

Buried Pipelines

Smart pigging is the often-used solution for monitoring pipelines, and most large-diameter, long-distance transmission lines are fitted with the proper valves and pig launchers to allow inspection with smart pigs. Most secondary lines, however, are too small in diameter and not appropriately configured to allow pigging, thus requiring excavation and visual inspection. Federal regulations such as Title 49 CFR (Code of Federal Regulations) require repeated excavation of problem areas. Installed UT sensors can be buried in problem areas and then can be periodically measured without further excavation costs.

Sand Erosion / Riser Monitoring

Sand erosion can occur at change-in-direction or change-in-diameter in offshore production risers due to solids production. This erosion is typified by a smooth surface with a sand-dune pattern. Riser locations where sand erosion may occur can be difficult to access and inspect with conventional UT or RT, in addition to the high mobilization costs of personnel to offshore facilities. Helicopter access to an offshore facility can cost in the range of $50,000 USD per trip. While acoustic technologies can be used to detect the impingement of sand particles on the internal bore of the riser, these techniques only determine the presence or absence of sand and do not measure the remaining wall thickness of the asset. UT installed sensors can be applied to suspect areas for accurate monitoring without the need for manual access and can be integrated with platform or FPSO control systems for a "control panel" view of asset health.

SUMMARY

Corrosion/erosion is a widespread and costly problem for U.S. and global infrastructure. Currently, manual ultrasonics and radiography are widely deployed to measure asset integrity for wall-thickness degradation. While these techniques are common and accepted, there are drawbacks in the accuracy and precision of these measurements and they only take a periodic snapshot view of asset health. Asset managers desire a more real-time view of the health of their facilities and equipment similar to the KPI view that they get when monitoring process variables. Additionally, the difficulty and cost of access, safety concerns, and regulatory environment changes are further driving interest in installed monitoring systems.

Installed ultrasonic sensors have the potential to improve asset-health monitoring as compared to current manual inspection techniques. They are non-intrusive and are being permanently installed with automated or semi-automated data-collection schemes, which reduce key variables like operator interaction, resulting in improved measurement accuracy and precision. Other key noise variables such as temperature change can be removed automatically with temperature sensors and software. Thus, installed ultrasonic monitoring systems can provide more and better data, allowing the use of statistical tools, such as linear regression, to provide corrosion-rate measurements on par with other technologies such as ER probes, further allowing enhanced trending and feedback to process variables.

Opportunities for corrosion/erosion monitoring systems are widespread, including applications such as ER probe or coupon replacement, mix-point corrosion, crude overhead lines, effluent air coolers, buried pipelines and offshore risers as well as almost any application where conventional UT and RT inspections are deployed. The need exists for a flexible and cost-effective solution to meet the application and customer requirements, including wired and wireless solutions depending on the unique plant or asset situation. ■

For more information on this subject or the author, please email us at inquiries@inspectioneering.com.

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Mike Nugent has been a Principal Engineer with E2G for the past 6 years and has spent his career in equipment assessment, evaluation, and repair for the Power and Petrochemical industries. He is currently the Project Manager for the Joint Industry Program for High Temperature Hydrogen Attack which is a consortium of 10 Major Owner Users and is a Technical Advisor for SNI. Mike has both a Bachelors and Master's Degree from Stevens Institute of Technology, where he has been an Adjunct Professor in the School of Engineering for the past 18 years. Mike has over 25 years of Materials/Corrosion Engineering in the Oil Refining and Petrochemical industry with Exxon/Tosco/ConocoPhillips in addition to 10 years in the Fossil/Nuclear Power industry with ConEd of NY where he worked extensively with EPRI in many NDE applications. Mike is a member of NACE, ASM and a Fellow in ASNT. He has over 50 publications and holds a patent for a hand held UT Boiler Tube scanner.

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Mr. Bruce A. Pellegrino is co-founder, Chairman and Vice President of Marketing for Sensor Networks, Inc. based out of its Morristown, NJ location. Bruce is a 37-year veteran of the NDT product & service business having founded EMCO as a NDT sales company in 1978 and Visual Inspection Technologies in 1983. Bruce oversaw the merger of VIT with Everest Imaging and subsequently ran Everest VIT, Inc. as President & CEO from 1999 until 2005 when it was acquired by GE. Bruce held various management positions – Product, Marketing, Government Relations and Business Development—at GE Inspection Technologies from 2005 until 2014.