

Deployment of Cellular-Based Ultrasonic Corrosion Measurement System for Refining & Petro-Chemical Plant Applications

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ABSTRACT

Recent technological advances in precision, fully-digital ultrasonic wall-thickness measurement systems coupled with cellular data back-haul are enabling very accurate, easily deployable, and more cost-effective corrosion monitoring systems that can compete with more traditional manual non-destructive testing (NDT) methods. Some comparisons with improved data accuracy of installed sensors in lieu of larger quantities of manual spot data are presented. This paper will include the design principles used in the creation of this next-generation platform, end-user input used to refine the design, and recent installation and operational experiences.

Key words: corrosion, ultrasound, permanently installed monitoring system

INTRODUCTION

In recent years, refineries across the country have been installing remote ultrasonic thickness monitoring devices to complement their inspection and stationary mechanical integrity programs. These programs include API⁽¹⁾ 570 piping inspection; API 580/581 risk-based inspection; failure modes, effects and criticality analyses (FMECAs); and integrity operating windows (IOWs), to name a few.

Refineries across the country are tasked with monitoring thousands of condition monitoring locations (CMLs) with established NDT techniques such as manual ultrasonic testing and radiography. While these techniques can provide valuable “snapshots” of the condition of particular locations, limitations and inherent errors with these techniques¹ can compound, leading to ill-advised decision making.

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Remote systems supplement piping inspection programs by providing accurate, repeatable data. After locating areas of interest with other established inspection techniques, remote systems can be used to confirm corrosion rates and help make well informed decisions about the remaining life of stationary equipment. When these systems confirm the absence of corrosion activity at a particular CML or within a circuit, inspection resources can be reallocated to higher risk locations. By helping locate areas of higher and lower likelihoods of corrosion, inspection resources can be optimized while simultaneously decreasing the overall risk of unexpected equipment failure within a unit.

Risk-based approaches are also used by refineries to help prioritize capital expenditures for equipment replacement and monitoring. Usually this involves ranking equipment by order of the largest to smallest consequence of failure (COF), such as through a reliability, availability, and maintainability (RAM) analysis. This equipment is then evaluated to identify damage mechanisms to which it may be susceptible. One such evaluation is known as a failure modes, effects, and criticality analysis (FMECA). Through this procedure, the likelihood of the equipment being affected by various mechanisms is assessed, and the probability of each of the mechanisms are summed to attain a likelihood of failure (LOF). Risk is often defined as the product of the COF and the LOF. Real-time corrosion monitoring can help reduce the total risk associated with a piece of equipment by minimizing the likelihood of experiencing an unanticipated failure event.

Another way refineries reduce their risk of accumulating equipment damage is by setting IOWs. These operating windows are meant to act as boundaries in which operating parameters can be controlled to minimize equipment damage. Usually, these targets or limits are set according to industry best practice. However, these industry guidelines are often based off of laboratory studies that do not always have a direct correlation to field experience. Automated corrosion monitoring can help bridge this gap by correlating unit-specific process data to real-time corrosion data. With this knowledge, unnecessary unit constraints can be avoided and replaced with realistic operating windows.

PERMANENTLY INSTALLED ULTRASONIC SENSORS

Similar to manual thickness gauging, permanently installed ultrasonic sensors use ultrasonic travel time to measure the wall thickness of a part (Figure 1). However, the technique is fundamentally different in that the transducers and instrumentation are deployed permanently with some means of automatic data retrieval such as wireless data backhaul. This addresses several of the shortcomings of existing manually-deployed 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; thus, the cost of access is reduced over time and operators are not deployed to the point of the inspection. Once the instrumentation is deployed, data can also be accessed remotely via the Internet.
- 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 and, subsequently, asset management.
- Data can be collected on a more frequent basis for example >1X per day for automated systems. This allows for more accurate corrosion-rate trending through statistical data analysis, such as linear least squares regression.
- The system 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. Wireless installed sensor systems can make use of various forms of data retrieval including the plant wired or wireless intranet, industrial wireless networks and

satellite or cellular networks for remote collection points, allowing real-time data/asset health availability.

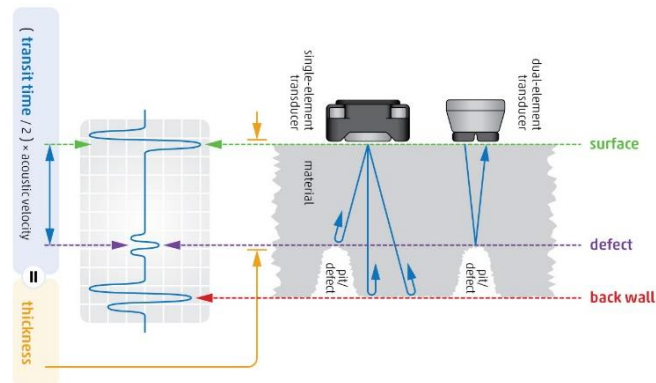


Figure 1: Ultrasonic principle for thickness measurement.

A recent development is the use of cellular radio for data backhaul. 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 network, gateways, and plant information technology (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 (Figure 1) is connected via an available cellular network to a cloud server(s) that is running application software which is designed to communicate with the instrument for the purpose of collecting ultrasonic or other data associated with the integrity of the asset being measured. The application software is also designed to store readings and has a browser-based user interface (Figure 3) 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.



Figure 2: Ultrasonic installed sensor system with up to 8 dual-element transducers and cellular connectivity.



Figure 3: Web-based interface for installed sensor data.

Ultrasonically, the system consists of a single ultrasonic channel that is multiplexed to up to 16 single-element or 8 dual-element transducers. The ultrasonic channels are programmable and can be deployed with various transducer types and/or frequencies. Dual-element transducers have become the industry's recommended standard for corrosion thickness gauging due to their superior performance in detecting pitting as well as their ability to measure thinner (0.040" or 1.0 mm) wall sections and operate over a wider temperature range such as zero to 300°F (-20 to 150°C). Additionally, a temperature-measurement channel is also included such that temperature measurements can be taken concurrently with the thickness readings for the purpose of correcting for temperature-induced measurement changes.

The Advantage 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 be otherwise available from manually collected measurements. The large amount of data allows, first-of-all, the ability to observe 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 mils per year (mpy). The use of data of marginal quality and spaced over long time periods can either overestimate or underestimate corrosion rate and 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 4(a) to Figure 4(d) 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.

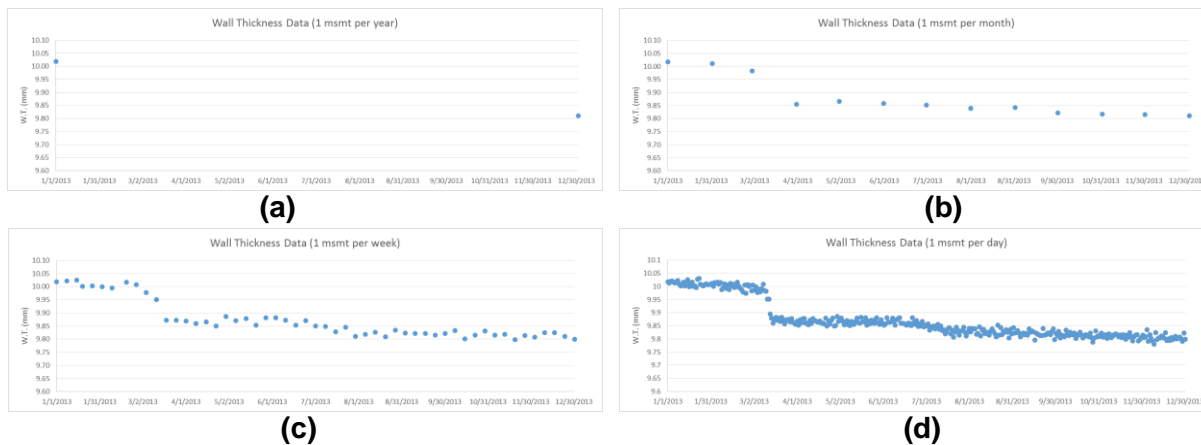


Figure 4: Wall thickness monitoring data with collection intervals of: (a) 1x/year, (b) 1x/month, (c) 1x/week and (d) 1x/day.

When considering a measurement of once-per-year as might be normally obtained from manual ultrasonic testing (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. Moving to even a relatively infrequent measurement cycle of 1X per month allows a much better picture of the process of wall-thickness reduction. Separate corrosion rates are evident in the data, including evidence of an episodic event of very high wall-thickness reduction. While 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, achieving corrosion-rate measurement precision in the range of 1 mpy. As such, installed ultrasonic 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 software.

CASE STUDIES

Several applications were studied using permanently installed ultrasonic sensors with cellular backhaul and a web interface for data collection. The motivation for monitoring varied, but included the general themes of life extension, high consequence locations, challenging access conditions, and process optimization. Project motivation, results, and discussion are presented for each case study.

HF Alky Overhead Monitoring

Background

Hydrofluoric (HF) acid alkylation units are some of the most profitable units in refineries, especially in summer months when regulations come into effect to lower the Reid Vapor Pressure (RVP) of gasoline. Refineries meet this increased demand for lower RVP gasoline by combining or “alkylating” lower molecular weight (higher RVP) hydrocarbons into larger, less volatile hydrocarbons (such as heptane and octane). Margins for these larger molecular weight hydrocarbons are significantly greater than the parent feedstock with the increased summer demand. Additionally, alkylated gasoline has a significantly higher octane rating, which sells at a higher price point.

HF alky units also happen to be among the units with the highest COFs in the refining industry. Hydrofluoric acid, the catalyst to the alkylation reaction, can be extremely toxic if direct exposure to the chemical is encountered. Therefore, refineries deploy advanced automated systems, undergo rigorous inspection, and enforce strict safety standards (PPE, safe handling procedures, etc.) to prevent exposure to the chemical.

Motivation

Remote corrosion monitors were placed on a 24" overhead elbow of the isostripper tower. In a recent turnaround, the top of the tower had been replaced and upgraded with a Monel (UNS04400) liner due to corrosion. The overhead condensers had a history of corrosion requiring weld build up and equipment replacement, and the overhead line had been replaced on at least one occasion. Remote corrosion monitors were installed on known low spots on the overhead elbow to help better understand how operating conditions affected corrosion activity. With this knowledge, IOWs could be directly correlated to real-time equipment damage. By collecting accurate corrosion rates, the necessary replacement date of the elbow could be predicted with increased confidence. The remote system could also help decrease the frequency of manual inspections for this equipment. To put this in perspective, prior to replacing the top of the tower, inspection crews had been climbing the 130ft tower weekly to collect manual UT readings.

Monitoring Solution

Figure 4 shows the installation of a cellular based ultrasonic monitoring system including (8) dual element transducers. A viscoelastic ultrasonic couplant and magnetic attachment was used to mount and couple the transducers to the piping. The viscoelastic couplant was chosen rather than a rigid adhesive so that the transducers can be easily removed and reattached. This allows for removal for automated UT scanning and/or redeployment to other monitoring locations in the facility. The transducers were placed at positions where low spots had been identified through manual UT. The system was powered by batteries and, thus, needed no external connections to either power or plant IT infrastructure. Data was backhauled on a 1/day reading schedule to a cloud based data server. A web browser application was used to view and analyze the data.



Figure 4: HF alky monitoring installation.

Results and Discussion

The HF alky monitoring began in July 2016 and is ongoing. Figure 5 shows the web based analysis of the results of one of the eight measurement points. The software automatically calculates a short term and long term corrosion rate using linear regression using a 30 day measurement interval for the short term rate and a 360 day interval for long term.

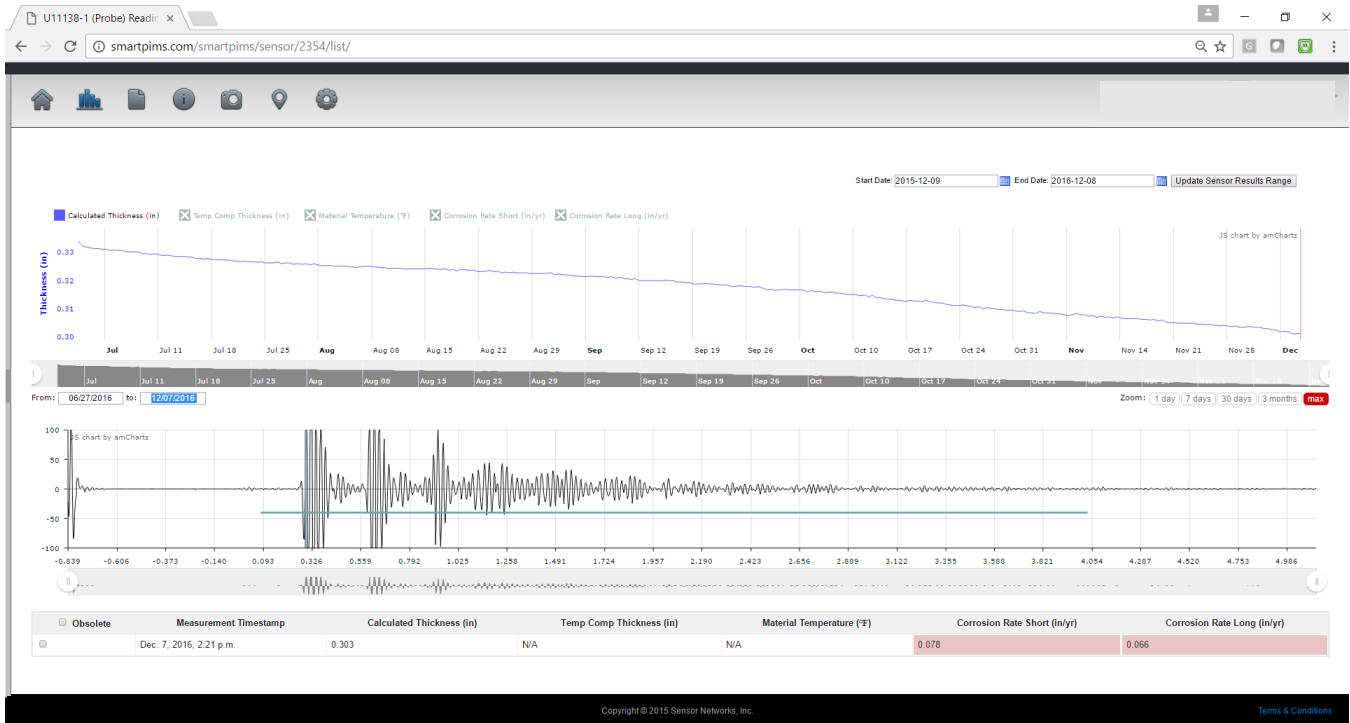


Figure 5: Results of installed ultrasonic monitoring of HF Alky overhead.

Sulfidation Corrosion / Atmospheric Gas Oil Circuit

Background

The refining industry has continued to address the concerns with sulfidic corrosion (sulfidation) of carbon steel and chromium steels in service temperatures above 500°F (260°C). The corrosion rate of the metal is based on a number of factors such as sulfur content, velocity, temperature, silicon and chromium content (within specification range), wall shear stress and solids content of stream. These variables may change the corrosion rates dramatically in a matter of weeks. Installed sensor thickness readings at these temperatures not only provide continuous corrosion rates but also eliminate the concern with proper calibration that may greatly affect the validity of the readings. Installed sensors can account for these differences automatically and eliminate this source of error.

Motivation

A 3-inch (7.6cm) Sch 40 atmospheric gas oil (AGO) circuit was chosen for monitoring due to high levels of sulfidic corrosion in the line. The piping was already subject to greater than 50% wall loss, and the process temperature had been decreased to attempt to mitigate the corrosion process. A turn-around

that would replace the subject pipework was scheduled within the 12 months, but there was a desire to validate that the corrosion rate was reduced sufficiently to operate the line until the planned outage.

Monitoring Solution

Figure 6 shows the installation of a cellular based ultrasonic monitoring system including (4) high temperature transducers and a resistance temperature detector (RTD). The transducers are clamped using brackets and U-bolts as an alternative to welding brackets to the pipework, which would be problematic on this line due to its remaining wall thickness. The high temperature solution utilizes a metal-to metal-coupling with a gold foil couplant layer between the probe and pipework. This type of solution is necessary for pipe circuits operating above approximately 400°F (204°C) as organic adhesives or other ultrasonic coupling methods are unreliable. Process temperatures for the subject pipework were measured to be approximately 500°F (260°C). The system was powered by batteries , needing no external connections to either power or plant IT infrastructure. Data was backhauled on a 4-hr reading schedule to a cloud based data server. A web browser application was used to view and analyze the data.

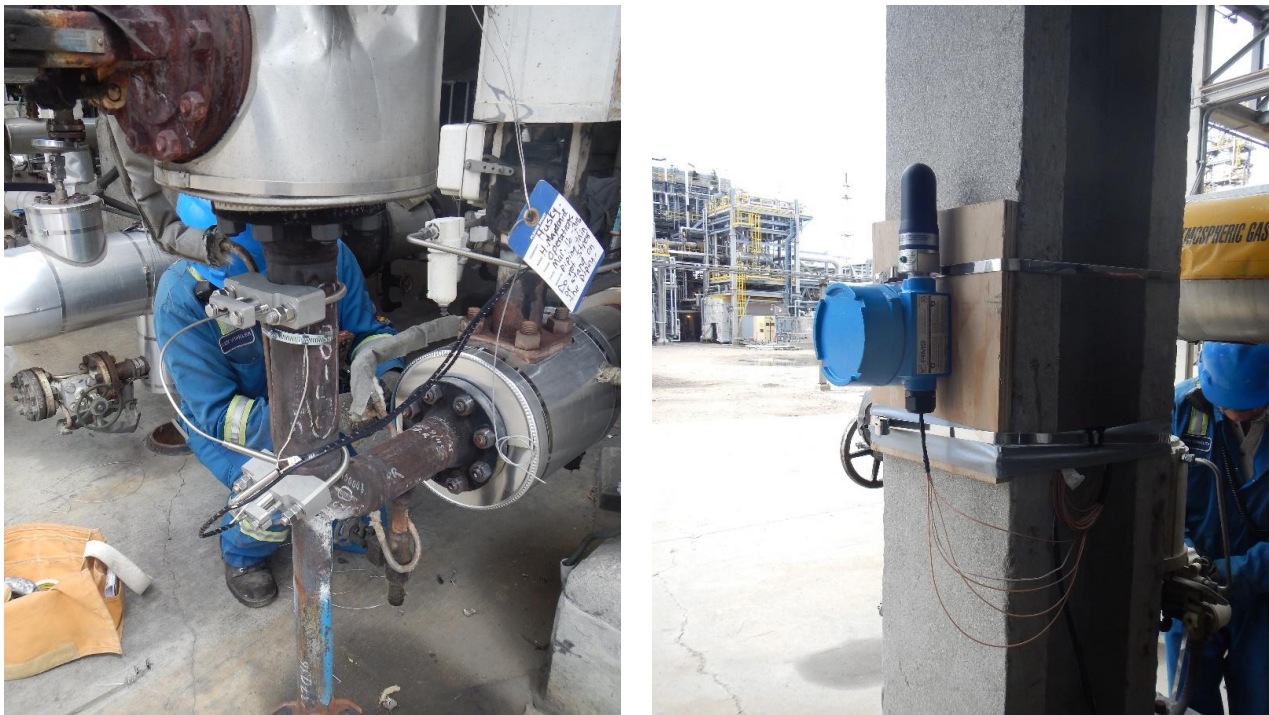


Figure 6: AGO Monitoring Installation.

Temperature monitoring was included to compensate for reading variations due to temperature, as temperature is one of the largest noise factors in installed ultrasonic sensor data. Table 1 shows the variation of ultrasonic velocity to temperature to be approximately -1% per 100°F (55°C). Consequently, as temperature rises, any ultrasonic thickness gauge will measure an increase in time-of-flight and a corresponding increase 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.

Table 1
Correction factors for ultrasonic velocity in steels

Material	Correction Factor	Source
Plain Carbon Steel, AISI 1345	-0.7% per 100°F (55°C)	Biagiotti ²
Low-Alloy Steels AISI 4130 & 4340	-0.6% per 100°F (55°C)	Biagiotti ²
316 Stainless Steel	-0.9% per 100°F (55°C)	Biagiotti ²
Carbon Steel (Typical)	No Correction T<200°F (93°C)	ASTM ⁽¹⁾ E797
Carbon Steel (Typical)	-1.0% per 100°F (55°C) 200°F (93°C) < T < 1000°F (540°C)	ASTM E797

Results and Discussion.

The AGO monitoring began in June 2016 and is ongoing. Figure 5 shows a 2 month portion of data for one of the four measurement points. Linear regression is used to calculate corrosion rates in the thickness data. For Figure 6, the regression equation is shown on the chart, the slope being in units of inches/day. Converting to units of mils/year (mpy) yields a corrosion rate of 1.4 mpy. Similar rates were obtained at the other three monitoring locations, giving the customer confidence to continue operation until the pipe replacement can be completed in approximately 12 months.

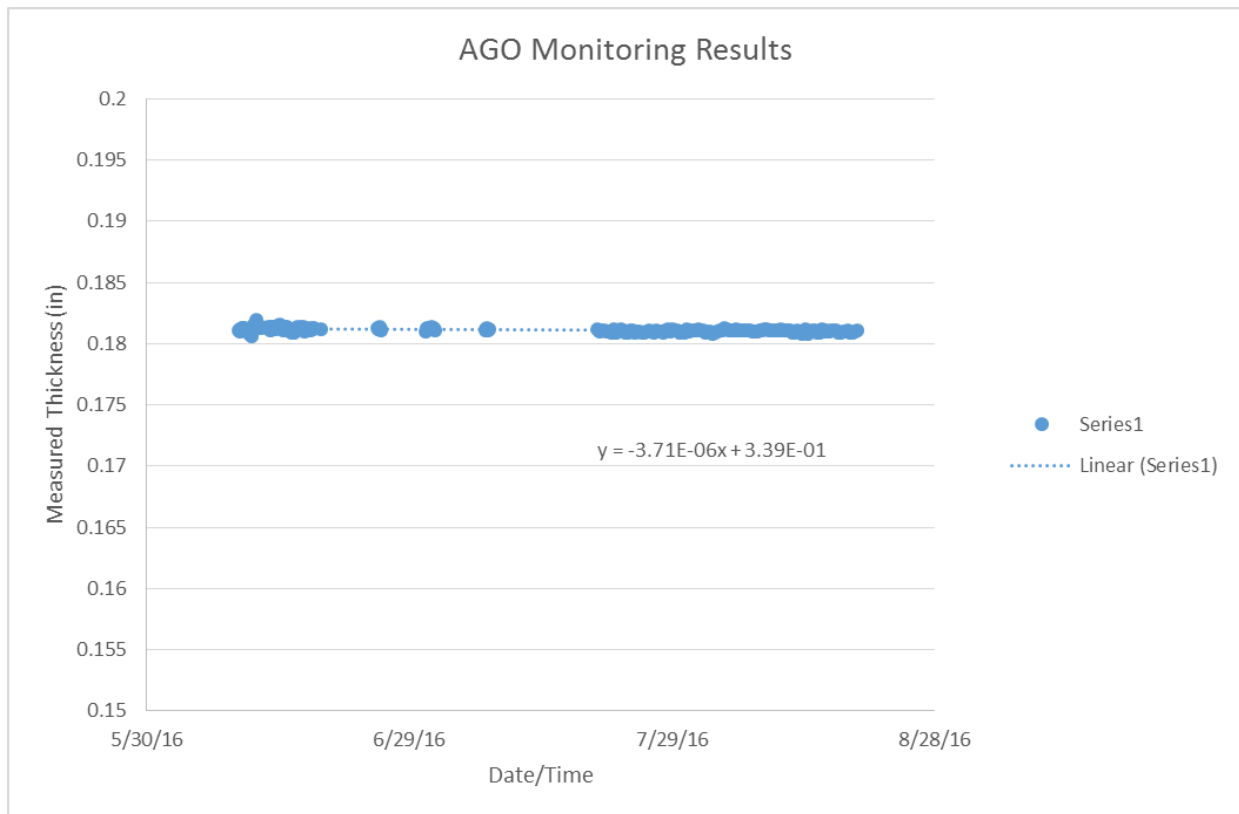


Figure 7: Results of installed ultrasonic monitoring of 3” (7.6cm) Sch 40 AGO line.

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Injection Point and Difficult Accessibility: Crude Unit Overhead Lines

Background.

Crude unit overhead lines are where the lighter hydrocarbons and fractions are carried out of the atmospheric tower. Along with these hydrocarbons, hydrochloric acid vapors, H₂S, CO₂, and other corrosive gasses are also removed. Many refiners inject chemicals and/or water washes to control the corrosion potential. When functioning properly and in tune with the crude slate, little to no corrosion may be observed for long periods. Changes in crude slate, desalter operations, or atmospheric tower loadings may upset this balance. In addition, the inhibitor and neutralizers may be corrosive if not properly mixed and injected through the proper hardware.

Motivation.

In an effort to optimize chemical and water injection to minimize corrosion, the proper and continuous amounts of each must be injected through the proper hardware. Failure of the hardware and over/under injection can produce corrosion rates of 20-50+ MPY. In addition, there have been significant incidents related to chemical injection and mix points such that a periodic inspection is prescribed in API⁽¹⁾ 570. These inspections for API Code compliance may be as often as 3-4 times a year. These should be done more routinely if pipe wall thickness is to be used in conjunction with corrosion probe, pH, and metals content monitoring. Many overhead lines have no platform access, making these inspections difficult and costly. UT and radiographic testing (RT) can provide useful wide area inspection data, but it is costly to obtain if crane access or scaffolding is required.



Figure 8: Sensors mounted on a crude unit overhead line.

Monitoring Solution.

Installed UT sensors can be installed and accessed on a continuous basis to reduce cost of access and improve plant operational knowledge of the crude overhead corrosion control system. Figure 8 shows the installation of a cellular-based ultrasonic monitoring system, including (8) dual-element transducers. As in the HF case, an ultrasonic couplant and magnetic attachment were used to mount and couple the transducers to the piping. The transducers were placed at positions where high corrosion could be

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expected based on plant experience during aberrant operation. The system was powered by batteries and, therefore, needed no external connections to either power or plant IT infrastructure. Data was backhauled on a 1/day reading schedule to a cloud based data server.

Results and Discussion.

Figure 9 shows the web-based analysis of the results of one of the eight measurement points on a crude overhead installation. The software automatically calculates a short term and long term corrosion rate using linear regression. Currently, the corrosion rate is measured to be 8 mpy at the measurement location. These rates can be compared to crude and inhibitor rates at that time to optimize economic performance against corrosion rates.



Figure 9: Results of installed ultrasonic monitoring of an overhead crude line.

ADDITIONAL APPLICATIONS OF INSTALLED UT SENSORS

The potential applications of installed UT sensors are virtually unlimited, any asset or CML currently being monitored for corrosion/erosion or crack propagation being candidates. As such, the choice of converting a point from conventional monitoring can involve many factors, including: the criticality of the asset, the desire for improved corrosion management (e.g., trending, verification of corrosion mitigation, the need for high-integrity data to enhance risk-based inspection (RBI) and mechanical integrity programs), the desire to eliminate human factors present in manual UT, and the removal of inspection personnel from hazardous areas and regulatory or code compliance.

Locations Currently Monitored Using Electrical Resistance (ER) Probes

There are many traditional points in a refinery's crude unit where the process corrosion rate is measured using electrical-resistance probes. While this technology is currently standard practice, it suffers from several shortcomings including measurement noise due to temperature changes, susceptibility to conductive deposit 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 and 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, giving 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, only happening for certain process conditions or during process upsets. API⁽¹⁾ 570 specifies inspection guidelines and NACE⁽²⁾ 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 wherein episodic damage occurs, and therefore will require repeat inspections of potential damage areas. Installed UT sensors can provide dynamic monitoring of suspected injection point damage locations without repeated access mobilizations.

SUMMARY

Corrosion/erosion is a widespread and costly problem for refinery infrastructure. Currently, manual ultrasonics and radiography are widely deployed to measure asset integrity for wall-thickness degradation. Although these techniques are common and accepted, there are drawbacks in the accuracy and precision of these measurements because 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 key performance indicator (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 for improved asset-health monitoring as compared to current manual inspection techniques. Ultrasonic sensors are non-intrusive and are being permanently installed with automated or semi-automated data-collection schemes, which reduce key variables such as 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 in ER probe or coupon replacement, mix-point corrosion, crude overhead lines, effluent air coolers, buried pipelines and offshore risers, as well as an almost unlimited variety of applications where conventional UT and RT inspections are deployed. Recent case studies have shown the utility of the solution for remote monitoring of critical assets. 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.

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