CRUDE SLATE FLEXIBILITY THROUGH ONLINE CORROSION MONITORING

A Corrosion Monitoring Solution Guide

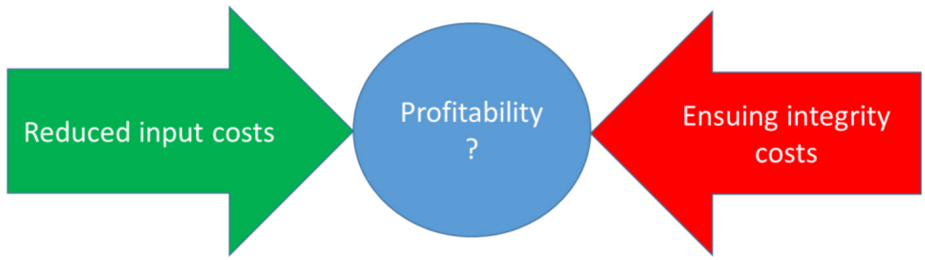
EMERSON™

1. INTRODUCTION

The pressure for refiners to deliver increased margins has never been greater, especially for integrated majors who are seeking to offset huge losses in the upstream. However, there is still very high crude price volatility and this, for a refiner who is poised to take advantage of high margin conditions, can mean the difference between profit and loss. An unusual level of variation in refining margins is making accurate crude selection and profit maximization from crude slate optimization difficult. Crude purchase lead times of many weeks mean that crude selection decisions made earlier may no longer be the most economic – and crude may be switched "on the water" and substituted for another grade of, sometimes, markedly different quality to fit better with the current market conditions.

Flexibility in the range of crudes that can be accepted by a refinery is paramount for maximizing profitability, and, in some regions, is key for the ongoing survival of the facility itself. Many of the lower cost crudes on the market – the so called "Opportunity Crudes" – are priced at a discount against the marker crudes because of their difficult processing properties – most notably, their corrosiveness, measured by the TAN (Total Acid Number), which is the laboratory test method used to characterize crudes that are prone to causing naphthenic acid corrosion.

Figure 1. Opportunity Crudes: balancing the potential for reduced input costs, with the increased risk to plant integrity (and ensuing costs)



The growing availability of less expensive light tight oil and heavy oil sands to the North American market is also resulting in the need for greater flexibility of feedstock that can be processed in crude slate flexibility through online corrosion monitoring refineries. These crudes, as well as older conventional oil fields where enhanced oil recovery and well stimulant technologies are applied, often rely on the injection of a corrosive cocktail of chemicals that finish up in the crude oil feedstock to a refinery. In addition, many of the Canadian oil sands have a high TAN in their own right, while transportation may involve the addition of H_2S passivation chemicals that can introduce other corrosion-related problems to refineries, such as salting of amine compounds in the top section of crude towers, with the resulting possibility for under deposit corrosion. The issue of 'dumb-bell' crude processing in North America – a mixture of light tight crude oil and heavy oil sands – giving tower stability, operational performance, and product quality control has been well publicized. However, the corresponding increase in corrosion risk from these crude mixtures has been less publicized but is an increasingly prevalent phenomenon.

Therefore, increasing flexibility in the range of crude qualities that can be processed at a refinery potentially increases the risk to plant integrity from elevated corrosion. This most often manifests itself as unplanned shutdowns driven by the identification of unacceptably high corrosion activity in a certain area of the plant. However, if unnoticed and unmitigated, this excessive corrosion could result in hydrocarbon leak and, in the worst case, an explosion or fire, which may lead to human tragedy, extended business interruption, loss of custom, the cost of extensive rebuilding of equipment, as well as the impact on the company's brand reputation, and future enhanced regulatory scrutiny.

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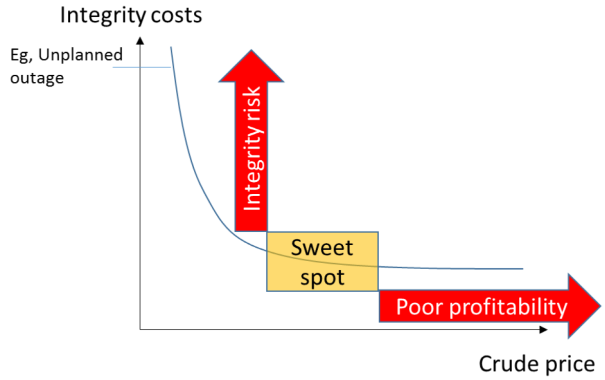
Figure 2. Selecting the balance between crude price/quality and increased risk of integrity issues risk to plant integrity (and ensuing costs)

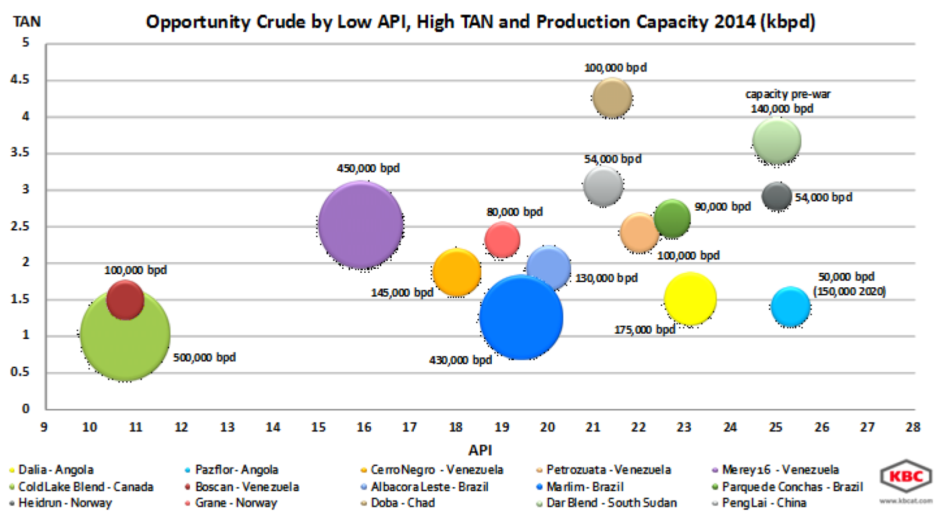


Unplanned outages in a critical process unit will usually cancel out the profit gained from a more corrosive crude diet, so refiners have to walk the narrow tightrope between maximizing profit and managing plant on-stream availability. Compound this with pressure to reduce costs, most notably through reduced head count and contractor use, often including inspection department resources, and the ability of a refiner to maintain an appropriate level of surveillance of plant integrity is further challenged.

Oil and gas facility operators the world over are solving this puzzle by proactively deploying permanently installed, continuous wall thickness monitoring systems at scale to track corrosion in critical locations. Not only does tighter monitoring enable cost-effective tracking of corrosion in areas of concern, but it enables a refiner to pinpoint specific feedstocks or process operations that result in accelerated corrosion rates – thereby facilitating optimization of corrosion mitigation strategies online and validation of the effectiveness of these mitigation strategies, so that timely, evidence-based, integrity management decisions can be made.

2. THE NEED FOR CRUDE PROCESSING FLEXIBILITY

Figure 3: TAN vs. API for new crude oils appearing on the market [courtesy of KBC Energy Economics]



Recent data, shown in Figure 3, provided by KBC Energy Economics shows that many of the newer crude oils that are appearing on the market are also challenging in terms of processing characteristics, and in particular, the acidity, or TAN. Many of the world's existing refineries were designed to process crudes with a TAN of 0.3 mgKOH/g or less, while the plot above shows that a total volume of almost 3% of global production has been/is being added which has a TAN of

1 mgKOH/g or more. These crudes are often discounted by several $/bbl against the normal marker crudes, like Brent or WTI. A discount of just $0.5/bbl from the standard crude slate for an opportunity crude could raise the profitability of a typical 200 kbpd refinery by $35 Million/year; far in excess of the cost of incremental chemical inhibition and monitoring, meaning that the payback time on the implementation of an inhibition/monitoring program can often be measured in terms of a few months.

In deciding to process more corrosive crudes, crude planners will often make an ‘allowance’ for the integrity impact, which will be based on the estimated replacement cost of certain critical items of equipment in a future turnaround. Unless the site has many years and several turnaround cycles of experience of processing that specific type of high acid crude, these allowances will be an ‘educated guess’, due to lack of hard data linking a specific crude type to the corresponding corrosion rate.

3. NAPHTHENIC ACID CORROSION

High TAN crudes bring naphthenic acid corrosion, which is a particularly aggressive and often localized corrosion mechanism, characterized by the ‘orange peel’ effect, shown in the photograph (Figure 4) below. While the majority of the issue is centred on the crude and vacuum distillation units, gas oil and residue products fed to downstream conversion and hydroprocessing units can also exhibit TAN levels that are problematic in feed section equipment fabricated from carbon steel.

Figure 4: Naphthenic acid corrosion [courtesy of Nalco Champion]

The aggressiveness of naphthenic acid corrosion is a function of four key parameters within the plant:

3.1. Temperature

Naphthenic acid attack begins to manifest itself in areas of the crude and vacuum distillation units above approximately 200 °C to 220 °C (390 °F to 430 °F) – starting at the hot end of the preheat train, through the charge heater coils and affecting the lower section of the crude distillation tower, light and heavy gas oil side draws and residue product rundown until they are cooled back below this critical temperature threshold. The danger areas are the same in the vacuum unit.

Figure 5: Variation of naphthenic acid corrosion with temperature [courtesy of Nalco Champion]

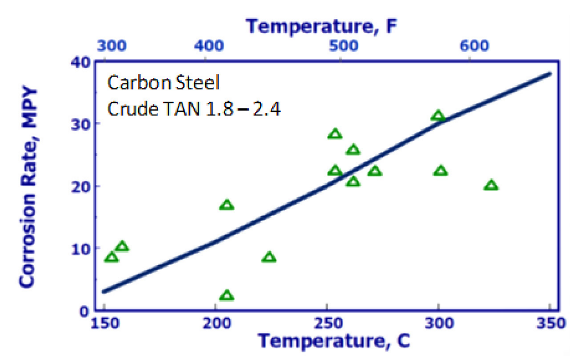
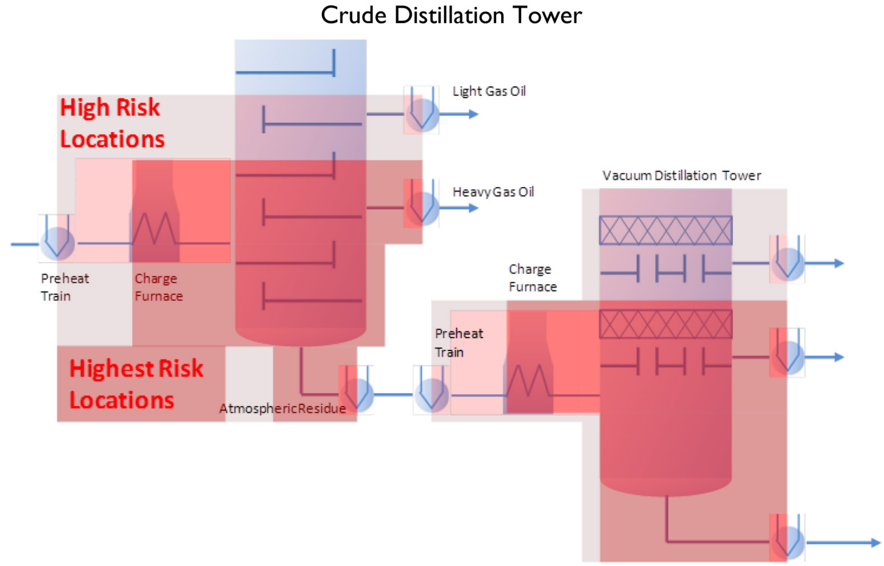


Figure 6: High risk locations for naphthenic acid attack in the crude and vacuum distillation towers



3.2. Metallurgy

Naphthenic acid attack is most aggressive to carbon steel, with rates of 40 mm to 50 mm per year (1600 mpy to 2000 mpy) being recorded with crude TAN of 3 mgKOH/g or more, at temperatures above 300 °C (572 °F). Stainless steels show greater resistance to naphthenic acid attack, although different grades offer varying levels of corrosion resistance within certain temperatures bands, as shown in the table below:

Figure 7: Variation of naphthenic acid corrosion with metallurgy [courtesy of Nalco Champion]

		mm/yy (MPY)			
Temp	**Acid No.**	**C.S.**	**410**	**304**	**316**
377 °C [711 °F]	3+	48+ (1890+)	22 (870)	0.09 (3.5)	0.06 (2.3)
342 °C [648 °F]	3.6	49+ (1930+)	0.5 (20)	33 (1300)	0.08 (3.1)
338 °C [640 °F]	3.6	48+ (1890+)	30 (1180)	30 (1180)	4.8 (190)
300 °C [572 °F]	4.1	37 (1460)	5.8 (230)	10 (390)	0.01 (0.04)

3.3. Velocity

The naphthenic acid molecules themselves can be relatively inert until they are 'activated' by high shear velocities – such as that found at flow discontinuities caused by reducers and expanders, by elbows and bends and by tee sections, or downstream of any flow disturbances, such as a pump discharge, injection nozzles or intrusive probes. This makes these areas most susceptible to naphthenic acid corrosion.

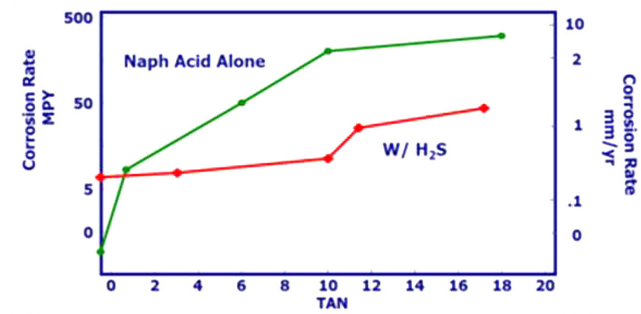
Figure 8: Variation of naphthenic acid corrosion with flowing velocity [courtesy of Nalco Champion]

Material	TAN	Linear Velocity ft/sec (m/sec)	Corrosion rates at elbows mm/yr (MPY)
C.S.	1.5	73 (22.5)	12 (472)
C.S.	1.5	26 (8)	6 (236)
5Cr-1/2Mo	1.5	73 (22.5)	2 (79)
5Cr-1/2Mo	1.5	26 (8)	0.6 (24)
9Cr-1Mo	1.5	73 (22.5)	0.7 (28)

3.4. Crude oil sulphur content

There is also field evidence to demonstrate that sour, high TAN crudes can be less corrosive than sweet, high TAN crudes. This is due to the formation of an iron sulphide passivation layer that protects the metal surfaces. Several of the commercially available naphthenic acid inhibition chemicals operate using the same passivation principal. However, it should be remembered that the formation of the iron sulphide layer itself chemically and permanently consumes metal from the equipment wall. It is also an unstable phenomenon which is lost, for example, when the unit is shutdown or when flowing velocities change significantly.

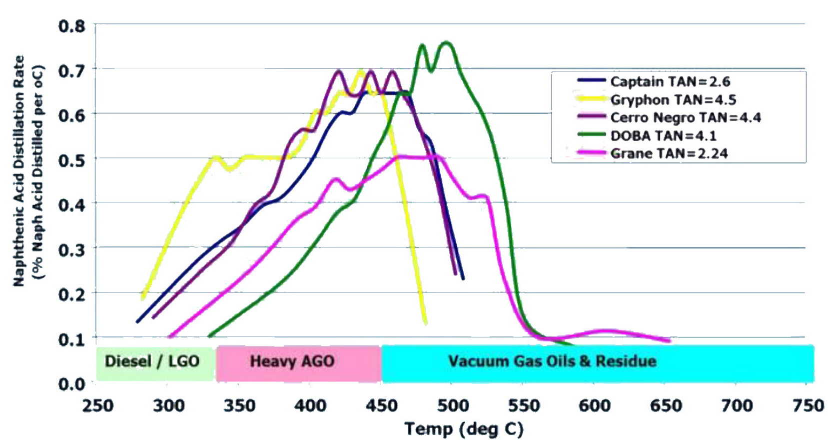
Figure 9: Variation of naphthenic acid corrosion rate with sulphur content [courtesy of Nalco Champion]



3.5. Naphthenic acid partitioning with boiling point

Different crude oils with similar whole crude TAN levels can contain different forms of naphthenic acid molecules which partition at different boiling temperatures. In the chart below, for example, naphthenic acid attack from Gryphon, Captain, and Cerro Negro crudes would be centred on the crude distillation unit, while naphthenic acid attack from Doba crude would be focused on the vacuum unit. Knowledge of the naphthenic acid partitioning with temperature is critical in defining a monitoring strategy.

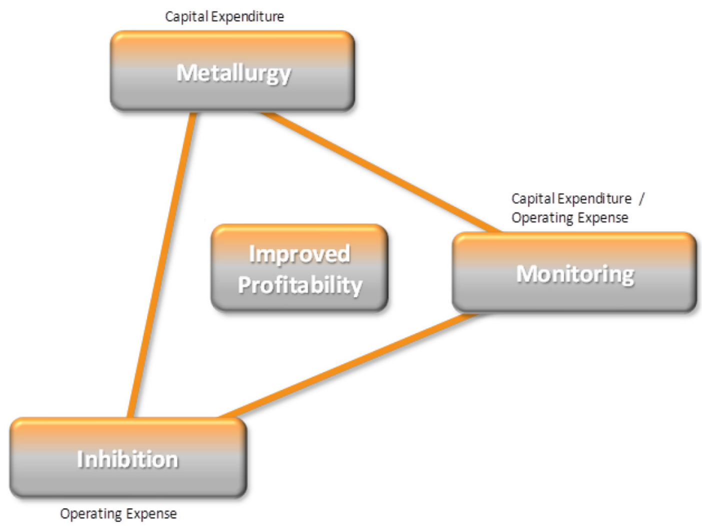
Figure 10: Variation of TAN with boiling temperature for various crude types [courtesy of Nalco Champion]



4. NAPHTHENIC ACID CORROSION MANAGEMENT

Refiners have two principal mitigation strategies for naphthenic acid corrosion – they can upgrade the metallurgy of many/all of the susceptible areas of the unit(s), or they can use chemical inhibitors. In both cases, these strategies should be combined with tighter corrosion monitoring at critical locations to verify the inhibitor distribution and/or the effectiveness of the metallurgy upgrade. The choice between these options is usually a question of capital budget availability. In the current climate, where capital budgets are being cut, many operators are choosing chemical inhibition and monitoring over metallurgical upgrading, especially since the optimization of the inhibitors and the installation of integrity monitoring systems can be carried out on-the-run without the need for a plant shutdown.

Figure 11: The choice between metallurgical upgrading and chemical inhibition for naphthenic acid corrosion mitigation



5. COMMONLY APPLIED TECHNOLOGIES FOR CORROSION MONITORING

There are several types of instruments that have traditionally been used for monitoring corrosion in oil refineries. Two of the most common are corrosion probes and manual ultrasound.

5.1. Corrosion (or Electrical Resistance, ER) probes

Intrusive corrosion probes have been in use since the 1960s and are a very well established technology. They rely on an intrusive element with a sacrificial tip, that sits in the process fluid and is (normally) made from the same grade of material as the surrounding equipment. As the sacrificial tip corrodes, its electrical resistivity changes, which is recorded externally (usually on a locally mounted data logger) but these are also increasingly available wirelessly connected. The corrosion of the sacrificial tip is used to infer the level of corrosion being experienced by the surrounding equipment.

Intrusive corrosion probes suffer from a number of disadvantages:

- **Indirect measurement:** The corrosion of the probe is used to infer the corrosion that is experienced by the equipment itself – often, the two are not the same due to differences in material and the shear velocity effects described previously.
- The tip often corrodes away after two-to-three-or-four years (or even less with “high sensitivity” applications), while many refineries are now operating 5+ years between major turnarounds. Thus, the corrosion probe tip will usually need to be replaced on-the-run. Very careful safety procedures and intensive technician training are required to avoid any

danger to personnel. In spite of this, there have been several well-documented safety incidents caused by probes being ejected at high velocity under residual pressure. Several international oil companies have banned removal of intrusive probes while the plant is running, with the result that they operate 'blind', from a corrosion standpoint, for the final, and most critical, one or two years of the cycle between turnarounds.

- The intrusive nature of these probes means that they cannot be installed during normal operations, since they require special mounting flanges to be bored and welded to the piping.
- The intrusive probe creates a disturbance in the flow of the fluid that can potentially induce corrosion to occur further downstream.
- Many of the older type, data logger-based probes require an engineer to visit the equipment to download data. They therefore require physical access to the probe location and have an inherently low acquisition rate and non-continuous information supply.

5.2. Manual ultrasound

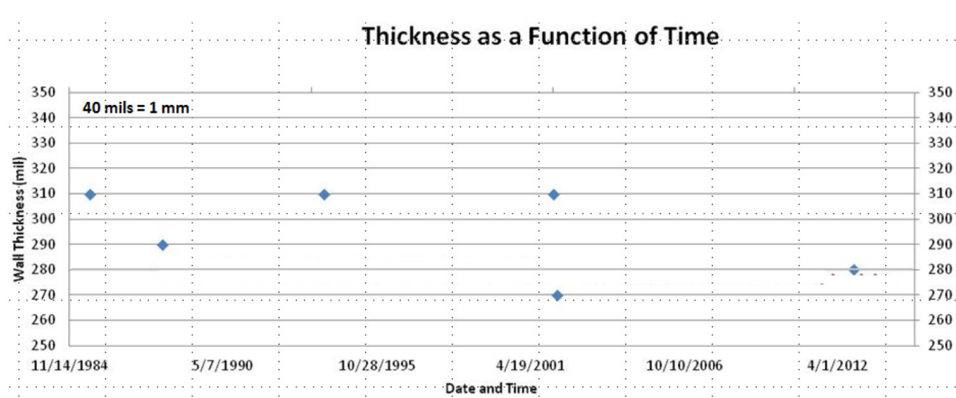
Ultrasound has been applied in the oil and gas industry for the past 50+ years and is a well-established technique. The technique involves the generation of ultrasound from a transducer that is placed directly onto the metal surface. The ultrasound is transmitted through the metal until it is reflected off the inside back wall. The reflected ultrasound signal (or A-scan) is recorded and the time difference (the 'time-of-flight') between the sending and reflected signals provides the measurement of the wall thickness.

While the technique can be reliable, completion of a full set of measurements for a medium-sized refinery with 80,000+ corrosion measurement points (often called Thickness Measurement Location, or TMLs) is very time consuming and labor intensive, such that the wall thickness at an individual low-to-medium risk point may only be measured every 5+ years. It is therefore very difficult to take measurements in key locations with enough frequency to measure corrosion rates with any confidence, or to link periods of high wall loss to specific feedstocks or process operations (which require measurements on the time scale of days to be useful).

In addition, while being relatively simple, manual ultrasound methods have the following disadvantages:

- Repeatability and reproducibility errors – it is highly unlikely that consecutive measurements will be taken in precisely the same location by the same NDE technician using the same equipment. The chart below shows manual measurements at a single (nominal) location over time from 1984 to 2013. It is clear that different conclusions regarding wall thickness and corrosion rate can be drawn over time as each measurement has been made. From such data, it could be inferred that the accuracy of manual ultrasound is ±0.5 mm to 1 mm (±20 though to 40 thou).

Figure 12: Manual ultrasound measurements at a fixed location over time [courtesy of Chevron]



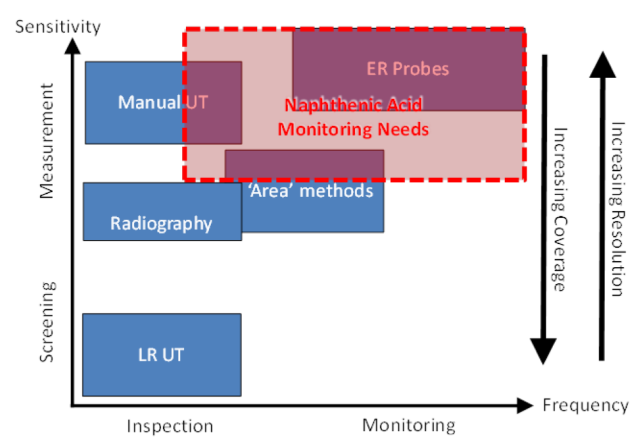
- Susceptibility to internal metal surface roughness, for example, localized pitting – it is a limitation of ultrasonic physics that very small defects on the inside surface of the metal will scatter the ultrasound and create a distortion in the reflected signal. This can manifest itself as an apparent increase in the metal wall thickness compared to an earlier reading which is, of course, impossible. Human nature will often discard this measurement, and the operator would shift the probe slightly to one side or another until a 'normal' reading was obtained (i.e. the same or less than the previous reading). Thus, this limitation of ultrasound could result in very valuable information about the onset of roughening of the internal surface, as an indication of the presence of corrosion activity, being missed.
- Equipment/technician damage at high temperatures – temperatures above approximately 100 °C (212 °F) can permanently damage the electronics of the transducer. In addition, for temperatures in excess of this level and certainly for the types of temperatures at which naphthenic acid would be prevalent, it is not safe for inspectors to be working in close proximity of the hot metalwork, even wearing protective equipment.
- Requirement for physical access – the technician needs to be able to have access to the equipment at the measurement location of interest, therefore requiring scaffolding (possibly permanently installed) and stripping of insulation to expose the metal work to make the manual measurements, with consequential costs and energy losses.

6. MODERN PERMANENTLY INSTALLED, CONTINUOUS CORROSION MONITORING TECHNOLOGY

There are several modern and well-proven corrosion measurement technologies available now that seek to overcome the disadvantages of both intrusive probes and manual ultrasound. These technologies fall into two main categories:

- Permanently installed, local/point measurement
- Permanently installed, area measurement

Figure 13: Categorization of technologies – sensitivity versus measurement frequency



The diagram above shows this categorization of the various technologies, including intrusive (ER) corrosion probes and manual ultrasound (UT) described in the previous section, according to whether it is a screening or a measurement technique, and whether it can be used for inspection purposes or for monitoring purposes.

Area measurement methods provide a valuable way of determining that there is corrosion activity going on within a given system, and the approximate extent of that total metal loss. However, an increase in measurement area carries an associated reduction in resolution or sensitivity of those measurements. If these instruments indicate a 1% loss of metal volume across the entire measurement area, it requires very skilled and highly trained specialists to interpret whether this is a uniform loss of metal across the entire area, or the loss of metal from a single pit, which could be almost through the entire wall thickness. In practice, area measurement tools are most useful for screening. Data collected by these systems is often sent away periodically for interpretation by specialists for processing and return at a later time, with an additional data processing cost and delay. Very often this equipment is complex in structure, with sophisticated metal surface wired couplings, making it expensive to buy and install and easy to damage in an industrial environment. Many of these type of systems require the inspector to go into the field to retrieve the data, so requiring physical access to the equipment. Once deployed, these systems cannot be re-located in the event of subsequent equipment replacement.

Many of the point measurement monitoring methods available today suffer from the disadvantages described earlier:

- Unsuitable for high-temperature applications due to sensitivity of the transducers or electronics.
- Distortion of the ultrasonic reflection from rough internal surfaces resulting in confusing wall thickness trends.
- Inherent lack of field robustness and high installation costs due to cabling between various components of the monitoring system, e.g., between transducers and associated electronics/data loggers, resulting in poor quality data or high system maintenance costs.
- Poor quality data overload: large quantities of poor quality data are collected, creating resource-intensive data interpretation before any value can be derived.

The red box shown on Figure 13 indicates the measurement frequency and sensitivity required for effective measurement of naphthenic acid corrosion. This indicates that manual UT, ‘area’ methods and ER probes can each provide part of the solution, but none of these methods fulfills all of the requirements.

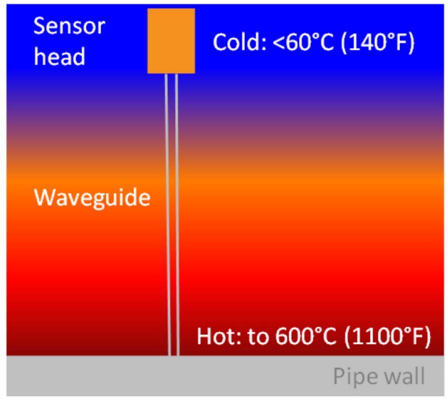
7. TECHNOLOGY OVERVIEW

Our corrosion and erosion monitoring products have overcome the three limitations above, making it the ideal monitoring solution for naphthenic acid corrosion monitoring – having both sensitivity to small changes in wall thickness and robustness to extreme plant conditions, while being simple and cost-effective to install at scale.

7.1. Resilience to high temperature

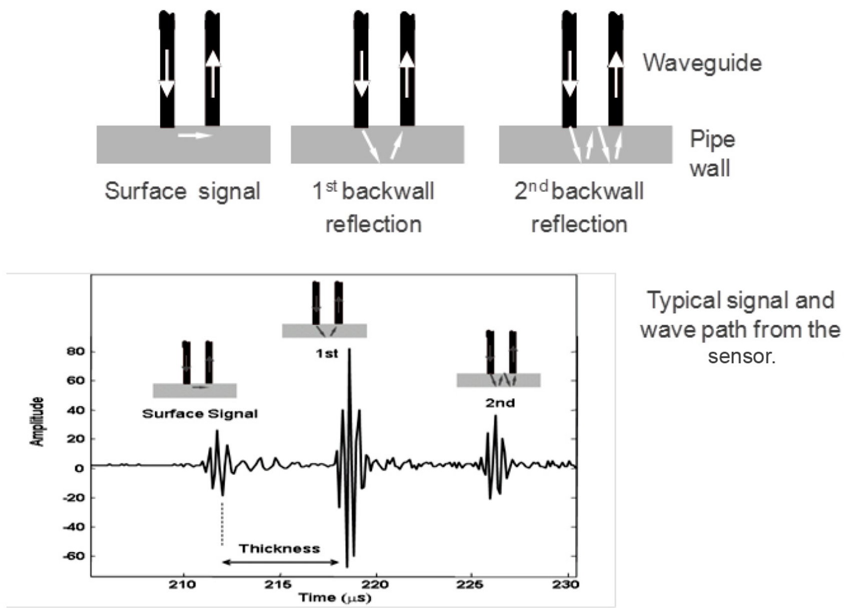
The design of the WT sensor incorporates a unique and patented ‘waveguide’ design as shown in Figure 14. The waveguides are made from stainless steel, which is a poor conductor of heat, and so the electronics are kept safely away from the hot metal surface (up to 600 °C /1100 °F). It is the only point measurement technology currently available on the market that can operate at these elevated temperatures.

Figure 14: Effectiveness of patented waveguide technology to protect electronics from high temperatures



The ultrasound is transmitted from the 'sending' transducer , down one waveguide and the reflection is transmitted up the other waveguide to the 'receiving' transducer. As with manual ultrasound, the 'time-of-flight' difference between the 'surface wave' signal and the first reflection from the internal metal surface provides the wall thickness measurement, as shown in the diagram below.

Figure 15: Signal and wave path of the ultrasonic sensor



7.2. Resolution of roughness effects

By analyzing over 10,000 sensors deployed throughout the oil & gas industry since 2008 (collecting over 13 million wall thickness measurements from live plant), the need to overcome physical limitations associated with standard ultrasonic wall thickness measurements with a rough or pitted internal surface was identified.

The solution to this issue is the proprietary and patented AXC (Adaptive Cross Correlation) ultrasonic signal processing method, introduced in 2015. Instead of scanning for the peak of the first ultrasound reflection from the internal surface, AXC makes use of the previous waveform structures to improve the reliability of detection of the first echo, even in the presence of distortion from a rough internal surface. AXC enables the separation of the wall thickness measurement from the onset of roughening of the internal surface – however, the presence of roughness is now captured separately as a color bar. Data from a monitoring location that begins to experience napthenic acid attack is shown in Figure 16.

Figure 16: Wall thickness trend from a permanently installed ultrasonic sensor using standard signal processing, subjected to a localized corrosion mechanism

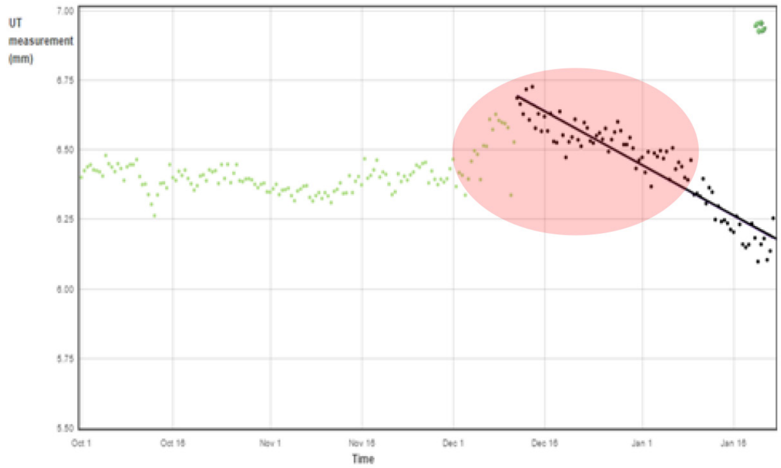
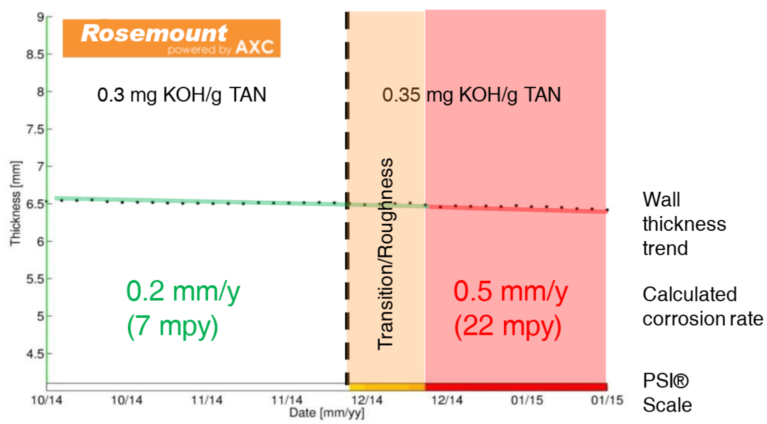


Figure 17: AXC processed wall thickness data for naphthenic acid corrosion mechanism



Thus, in this case study, shortly after the crude TAN was increased over a relatively modest range (0.3 to 0.35 mgKOH/g), the PSI scale changed color to yellow very quickly, showing the onset of roughness activity on the internal surface. Once a steady corrosion rate had been established (about one week later), the PSI scale turned red indicating rapid changing of the shape of the inside metal surface. The wall thickness measurements indicated that the corrosion rate had increased markedly from 0.2 mm/year to 0.5 mm/year. This improved processing method makes the interpretation of the ultrasonic thickness measurements significantly easier.

8. LOCAL MEASUREMENTS | AREA COVERAGE

The system is designed to have a low cost of installation, through use of wireless communications and battery power-packs, avoiding any need for cabling with the required consequent armoring, conduit, or cable tray installation. This simplicity of installation makes these sensors ideal for use in remote locations which are only accessible during turnarounds.

Each sensor has a measurement footprint of an area of approximately 1 cm^2, which is similar to the manual ultrasound method. Thus, the probability of detection of localized corrosion, such as that found with the naphthenic acid corrosion mechanism, using a single sensor would be small. In order to increase the probability of detection, sensors are installed as multi-point arrays, at the highest risk locations based on understanding of the temperature, metallurgy, the equipment geometry and the acid boiling range distribution for the crude oil type. The number

of sensors needed for each array is driven by historical inspection records, or by the proportion of the area being monitored that is affected by corrosion – the smaller the affected area as a proportion of the whole equipment being monitored, the more sensors that are required to achieve 90% confidence in detecting the onset of that localized corrosion activity.

Figure 18: Variation of number of sensors with area of corrosion and probability of detection

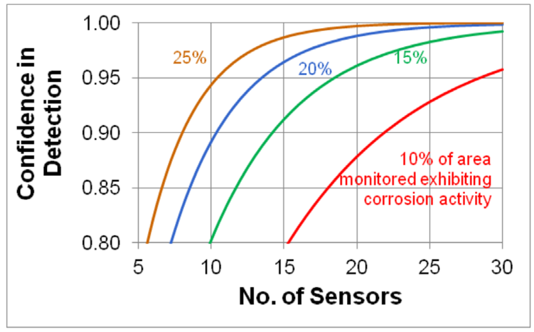


Figure 18 shows the result of mathematical analysis carried out the Department of Non-Destructive Evaluation at Imperial College in London, showing the relationship between array size, the area of the corrosion activity as a proportion of the total area being monitored and the probability of detection.

This analysis results in arrays of sensors such as this 26 sensor system, shown schematically in Figure 19, for a crude heater transfer line below, and a 14 sensor array for a bend:

Figure 19: Schematic of actual installation of crude heater to tower transfer line point sensor monitoring array layout at a U.S. Midwest refinery

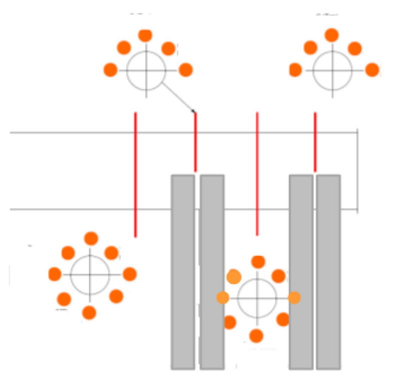
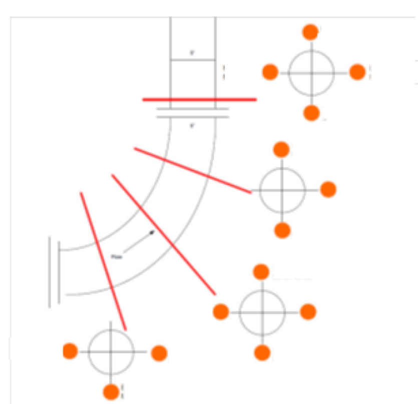


Figure 20: Schematic of actual installation of bend monitoring array layout



9. POINT MEASUREMENT RESOLUTION AND THE EFFECT OF PROCESS TEMPERATURE VARIATIONS

All ultrasound-based measurements are affected by process temperature variations, due to the change in speed of sound through the metal.

Figure 21: Variation of wall thickness measurement and wall temperature with time at a single location

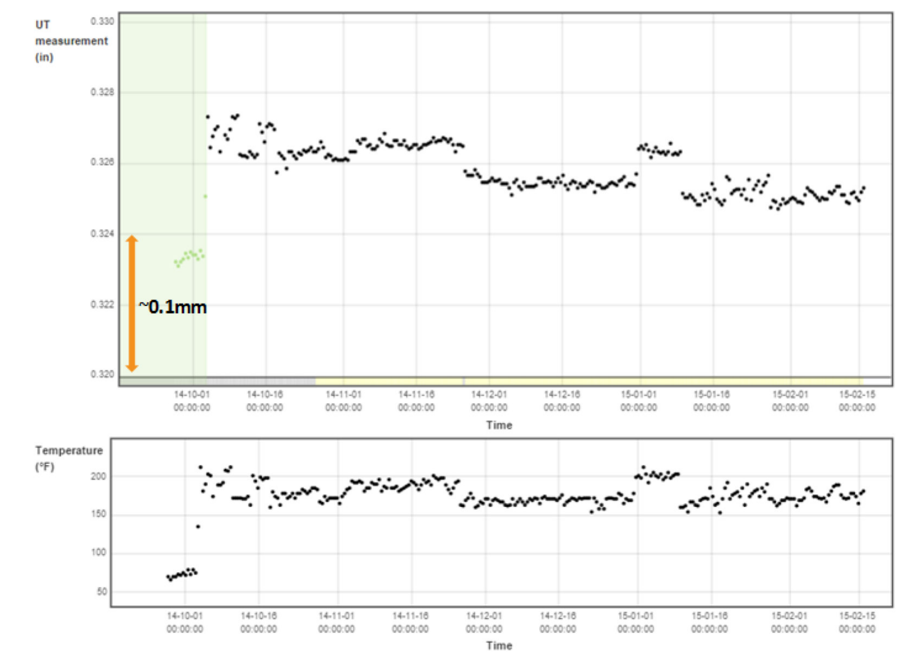
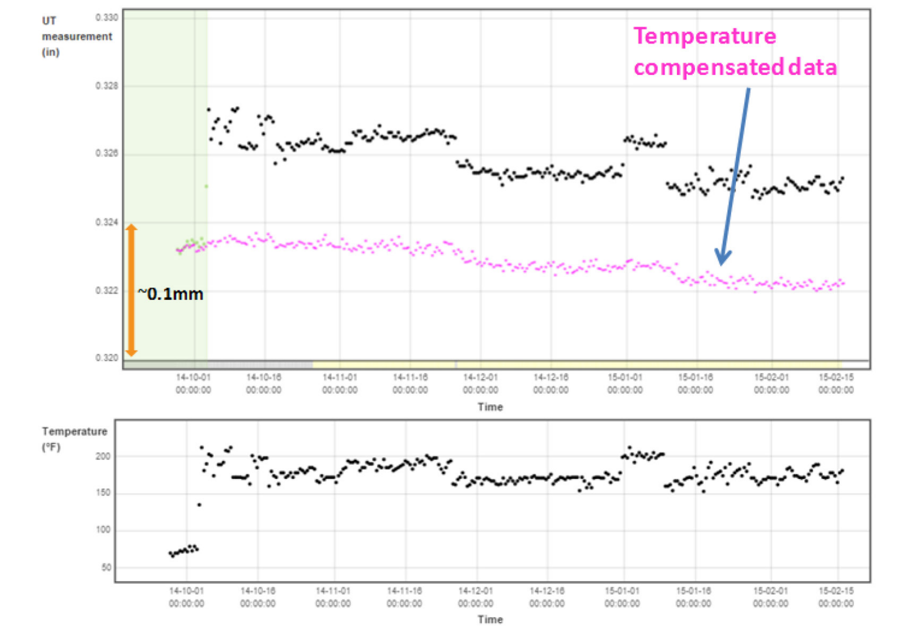


Figure 21 shows the variation of wall thickness, measured using a permanently installed ultrasonic sensor. When zoomed in, as shown, the variation is of the order of 0.05 mm (2 thou), for process temperature fluctuations of 20 °C (40 °F). This level of variation, while small, is not ideal for determination of short-term changes in corrosion rates, driving some operators to continue to rely upon ‘high sensitivity’ intrusive probes, in spite of all of their problems (discussed previously). The latest generation of sensors (WT210) make use of an integrated thermocouple to measure the metal surface temperature, and can automatically compensate the wall thickness data for process temperature variations, as demonstrated in Figure 21 for the same data shown in Figure 22.

Figure 22: Temperature compensated wall thickness measurement



The temperature compensated data shows variation of less than 10 microns (0.2 thou). This degree of precision enables detection of much smaller, shorter term corrosion rates, with confidence. However, as importantly, the corrected data shows that corrosion was not continuous at this location and there are two discrete corrosion events, which were masked by process temperature variation effects in the original data. The precision achievable with the latest sensor model and automated data processing is comparable to that of high sensitivity intrusive probes, but without their inherent safety problems and other issues.

Figure 23: Sensitivity versus measurement frequency and applicability for naphthenic acid corrosion monitoring

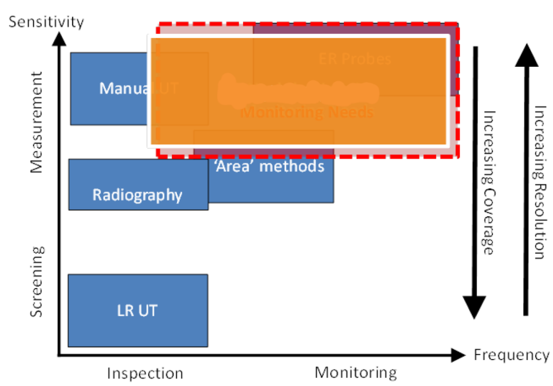


Figure 23 replicates Figure 13, but now shows the applicability of the technology, incorporating the latest technology advances to compensate for internal surface roughness and process temperature variations, overlaid on the requirements for effective naphthenic acid corrosion monitoring. If this diagram was extended in 3D, with temperature as the z-axis, this technology would stand out as being uniquely applicable for monitoring of naphthenic acid corrosion associated with high TAN crudes.

10. CONCLUSIONS

1. Market conditions are driving refiners to seek new ways to raise profitability. This includes processing more corrosive and more variable quality crude oils – the, so called, 'Opportunity Crudes'. In doing so, the risk of a corrosion-driven failure is increasing, in a cost-constrained environment where inspection head count and contract resource can be limited.

2. The growing availability of high TAN crudes, plus North American heavy oil sands and light tight oil, which have their own integrity-related processing issues, are resulting in a choice between upgrading of metallurgy and chemical inhibition/corrosion monitoring. With tight budgetary constraints in place, many oil companies are opting for chemical inhibition and tighter monitoring. Payback times from an inhibition/enhanced monitoring strategy can often be measured in the order of two months, assuming a 100 sensor monitoring system.

3. Naphthenic acid attack is a localized phenomenon that occurs at high temperatures. Attack centers on certain types of metallurgy in geometries which induce shear stresses at the wall surface. Effective monitoring requires a technology that can cope with high temperatures, is sensitive to small changes in internal surface roughness to enable detection of the onset of pitting and is simple and cost-effective to install at the necessary scale.

4. Intrusive corrosion probes have the required sensitivity and responsiveness, but are complex to install and maintain and suffer from potential safety problems when changing the sacrificial tips. They represent a single-point measurement that infers the impact of the corrosiveness of the process fluid on the equipment wall. Manual ultrasound suffers from repeatability/reproducibility issues due to variations between measurements in measurement location, operator, and equipment. However, in common with all ultrasound-based technologies, the signal can be confused by scattering effects caused by localized roughness of the internal surface. Area-type monitoring technologies do not have the desired local resolution or ease of data interpretation to make them suitable for naphthenic acid monitoring.

5. This technology, installed in arrays, provides both the high-temperature resistance, the local resolution accuracy and the required area coverage to be the perfect solution for naphthenic acid monitoring. With the advent of the proprietary Adaptive Cross-correlation (AXC) ultrasound signal processing, the onset of localized roughness and pitting, characteristic of naphthenic acid attack, can be detected with confidence, whilst avoiding the ultrasound scattering issues that are problematic for all other ultrasound methods. The latest generation of sensors are able to provide equivalent accuracy to 'high sensitivity' intrusive probes, by using automated temperature compensation, enabling measurement of short-term changes in corrosion rates with confidence but without the safety/maintenance headaches of intrusive probes. This makes the technology ideal for tracking corrosion from short crude processing campaigns.

6. Installed at more 120 facilities world-wide, operated by international oil companies, independents as well as national oil companies, these monitoring systems have automatically delivered more than 13 million on-line measurements over the past eight years to those personnel who need the data to make better informed operational and asset integrity management decisions.

For more information about our continuous corrosion and erosion monitoring solutions, please contact us at RFQ.RMD-RCC@Emerson.com.

Global Headquarters
Emerson Automation Solutions
6021 Innovation Blvd.
Shakopee MN 55379
USA
+1 800 999 9307 or +1 952 906 8888
+1 952 949 7001
RFQ.RMD-RCC@Emerson.com