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Integrity of Aging Assets: Using Corrosion Data to Stave Off Extinction

Petroleum refineries built in the 1960s and 1970s have trouble dealing with the corrosive effects of modern feedstocks. Continuous monitoring of corrosion can prevent process equipment failures

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IN BRIEF

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FIGURE 1. Aging refineries are now dealing with highly corrosive feedstocks

Aging assets that are past their original design life are becoming an increasingly stark problem for the global oil-and-gas industry. In fact, mature assets currently account for more than 70% of global oil-and-gas production.

When the oil and gas fields these assets were designed to use as feedstock were first discovered, enhanced oil recovery techniques, such as thermal recovery, hydraulic fracturing, and gas- or chemical-injection technologies had not yet been employed. With the evolution of technology, operators have been able to increase the volumes of recoverable reserves from around 20 to up to 70%. However, oil and gas produced using these modern extraction methods often present corrosion and other problems.

Many operators today are dealing with mature assets installed in the 1960s and 1970s (Figure 1) with an original design life of around 20 years. Having now been in operation for more than double that time, they're at the highest risk point of their lifecycle.

When faced with this scenario, operators need a strong defense to maintain safe, economic production. This is especially true when facing one of aging assets' greatest threats: corrosion.

Corrosion in the oil-and-gas industry is caused by contaminants in produced hydrocarbons that, over time, lead to deterioration of pipe and vessel walls. And it's a growing problem. Experts at NACE International (Houston; www.nace.org), the global corrosion authority, put the total annual cost of corrosion in the oil-and-gas industry at $1.372 billion. Loss of equipment integrity can result in unplanned downtime and costly repairs, or in the worst case, an incident posing major risk to personnel, the environment and stakeholder value.

Aging assets

When building new greenfield assets, corrosion is a problem that can be addressed from the beginning. But when operating brownfield assets, it's a problem that needs

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FIGURE 2. High TAN crudes cause naphthenic acid corrosion

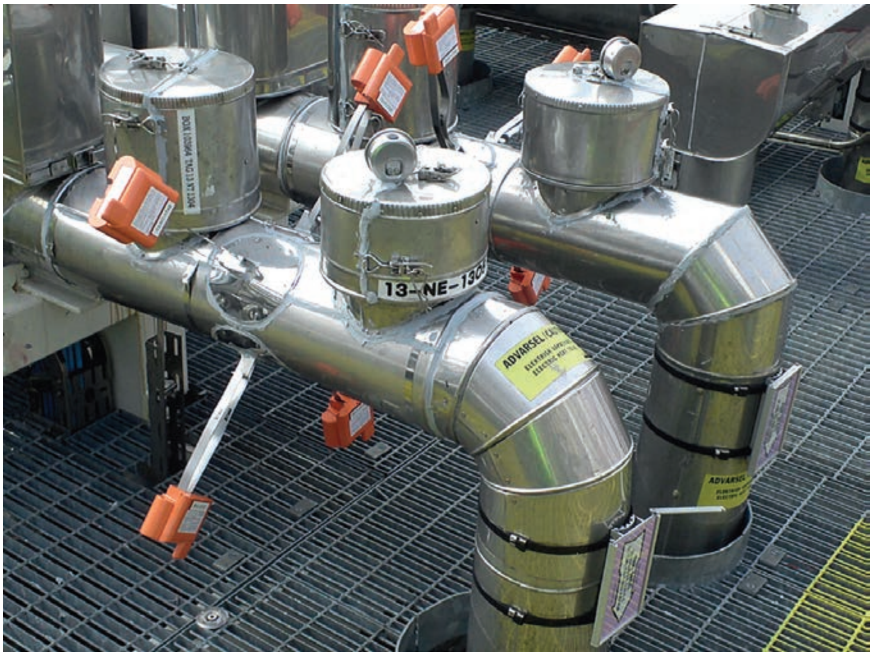

FIGURE 3. Many areas in refineries are susceptible to corrosion, but corrosion monitors can detect problems

to be addressed after the fact in an operating facility. Operators are being faced with a situation where the asset is at its weakest, while the threat of corrosion is at its highest. Corrosion is thus adding another layer of complexity to assessing future asset strategies and their economic feasibility.

This presents petroleum-refinery operators with a pressing economic decision: do they decommission the asset at a substantial cost and search for ways to replace its production, continue to produce at a potential profit with the associated risk, or find a way to continue operation in a cost-effective and safe manner?

Since capital investment budgets are always limited and risk-reduction is paramount, closely monitoring for signs of poor asset integrity and proactively addressing problems is often the preferred option.

Changing resources

Aging petroleum refineries were originally designed to handle a certain type of oil, such as "sweet crude." The changing nature of oil being supplied for processing magnifies corrosion problems in aging refineries. The availability of light tight oils (LTOs) is driving U.S. refiners to take advantage of the significantly higher margins that can be achieved from processing this feedstock.

The production of LTOs relies on the use of fracking fluids, a combination of chemicals used to stimulate oil to flow from the field. In many instances, these chemicals can end up in the crude oil feedstock to the refinery. In addition, the transportation of LTOs by railcar requires the addition of H_2S scavenger chemicals that can introduce other corrosion-related problems. These amine-based compounds can deposit as salts in the top section of crude towers, top pumparound and draw trays — with the resulting possibility of more corrosion.

Canadian oil sands often have a high total acid number (TAN). Many of the world's existing refineries were designed to process crudes with a TAN of 0.3 mg KOH/g or less, but some oil sands have a TAN of 1 mg KOH/g or more. These crudes are often discounted by several dollars per barrel ($/bbl) against the normal marker crudes, like Brent or West Texas Intermediate (WTI). A discount of just $0.50/bbl from the standard feedstock slate for an opportunity crude could raise the profitability of a typical 200,000-bbl/d refinery by $35 million/yr.

High TAN crudes bring naphthenic acid corrosion, a particularly aggressive and often localized form of corrosion, characterized by the "orange peel" effect (Figure 2). While this issue is primarily centered on crude and vacuum distillation units, gasoil and residue products fed to downstream conversion and hydroprocessing units can also exhibit TAN levels that cause problems in feed section equipment, especially when fabricated from carbon steel.

In addition to LTOs and oil sands, many operators are exploring a wider range of feedstocks and are testing new crudes. This creates the possibility of other corrosive species such as acids, which are usually residues from chemicals used for well stimulation in the upstream oil production process, being introduced into the crude unit.

Refiners have two principal mitigation strategies for acid corrosion: they can upgrade the metallurgy of many or all susceptible areas, often to high grade, expensive alloys, such as hastelloy, monel or titanium; or they can use chemical treatment. In both cases, these strategies should be combined with tighter corrosion monitoring at critical locations to verify inhibitor distribution and effectiveness, and/or the effectiveness of the metallurgy upgrade.

Assets at risk

Aging assets that are prone to corrosion include sour water strippers, crude overheads, amine units and many other operating units (Figure 3).

Sour-water-stripper tower corrosion and fouling from corrosion byproducts, such as iron sulfide, are common operational problems compromising asset integrity. Tower and crude overhead sections are exposed to high levels of H_2S and NH_3 and can

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FIGURE 4. Corrosion in crude overhead

experience high rates of ammonium bisulfide corrosion. Corrosion risks can be compounded by high levels of cyanides from upstream units that concentrate in the overheads.

Sour crude processing often results in excessive crude nitrogen content, which is a precursor to the production of cyanides, such as HCN. Cyanides can create corrosion issues in the sour-water system. Produced in the downstream conversion units, such as the fluid catalytic cracker (FCC) or delayed coker, cyanide compounds concentrate in the water phase of the main fractionator overhead. Free cyanides can be deposited in the wet gas stream, causing hydrogen blistering. Cyanides can destabilize any passivation (iron sulfide) layer, causing it to flake off as free iron sulfide, resulting in plugging and fouling downstream (Figure 4).

Amine systems are subject to corrosion by both carbon dioxide and hydrogen sulfide in the vapor phase, the amine solution, and the regenerator reflux, as well as producing amine degradation products in the amine solution. In refineries specifically, amine systems suffer from corrosion by several components not generally found in natural and synthesis gases such as ammonia, hydrogen cyanide and organic acids — some of which will accumulate at various points around the refinery amine system.

Most of the time, the amine absorption and regeneration system operates satisfactorily, and needs little attention and minimal focus from plant operators and engineers. But in the petrpleum refining industry, increasing severity of operation of hydrotreating units driven by ever-lower sulfur specifications for finished gasoline, jet fuel and diesel has increased the pressure on the amine absorption and regeneration

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FIGURE 5. Ultrasonic corrosion sensors can be permanently installed on a pipe line

system, and the quantity of H_2S has increased as a result. In some cases, the original facilities are being operated at significantly higher processing rates and amine H_2S loading than the original design.

Many refineries and oil terminals are located beside major stretches of water, either sea or river, to provide an easy and cost-effective transportation route via jetties for crude oil and feedstock imports and finished-product exports. Jetties can often be several hundred feet long with multiple berths, and must handle many different products simultaneously.

As a result, multiple oil-product lines are run from shore, suspended below the jetty. In most instances, it wasn't cost effective to construct these jetty pipelines from stainless or alloy steel; instead, carbon steel was used to build the pipelines decades ago.

The use of carbon steel, however, opens up the risk of internal corrosion, particularly with higher-sulfur-content oils (like fuel oils) and fuels containing potentially corrosive additives. The presence and buildup of water allows the accumulation of bacteria that cause microbial-induced corrosion. This issue is especially likely in jetty lines, since they have intermittent or slow flowrates, allowing water to settle in low points.

If undetected, a hydrocarbon leak resulting from corrosion in a jetty line will go straight into the water, interrupt jetty operations while the leak is sealed, and necessitate complex oil-spill response procedures to clean up the water.

In addition to the obvious safety and operational risks, industry regulations are also in place to protect personnel, the environment and equipment from piping leaks. Operators are expected to demonstrate that operational risk from corrosion is as low as reasonably practicable. How can operators of aging assets ensure they are meeting this requirement?

Seeking solutions

The solution is having access to accurate, realtime information about the impact that contaminants are having on the pipe wall thickness of aging assets.

Traditional manual inspection techniques can be used to measure the thickness of the metallurgy at three- to six-month intervals. Aside from the obvious safety risks associated with sending personnel offshore or into a petroleum refinery, measuring pipe-wall thickness at three-month intervals — when a serious event can happen in a matter of days — is a dangerous risk. These traditional methods cannot provide the accuracy, quality and frequency of data necessary to detect potential problems.

Permanently installed, ultrasonic, wireless wall-thickness-monitoring sensors (Figure 5) are ideal for corrosion monitoring because they provide the data required to make proper decisions on a continuous basis.

The installation cost of ultrasonic sensors is low due to their non-intrusive measurement method, allowing them to be mounted almost anywhere. Wireless data retrieval enables cable-free installation, further reducing installation cost and removing any ongoing operating costs. The sensor power packs are designed to last until the next plant turnaround (nine years is typically achievable), so no maintenance is required between turnarounds. This simplicity of installation makes ultrasonic sensors ideal for use in remote locations only accessible during turnarounds.

Once installed, these sensors measure the thickness of the pipe wall and send data directly to server-based analysis software via a wireless network. With the enhanced insight provided by this realtime data, refinery operators can quickly realize improved safety, reduce operational expenditure and increase production from their aging assets.

For example, one commercial software product analyzes and displays information from dozens or even hundreds of corrosion sensors in a plant or refinery, and informs operators when a problem is discovered.

Giving operators access to this kind of corrosion information enables them to make the right decisions at the right time about when and where critical maintenance should be carried out to support safer and more economic operations.

Installing corrosion sensors, a wireless network and server-based software to process the data may sound like a multi-day project requiring asset shutdown, but realtime and wireless integrity monitoring solutions can be easily installed at strategic locations on the outside of equipment in a matter of hours.

Final remarks

Aging assets are at the weakest point in their lifecycle, but when equipped with information about corrosion problems, operators can spot the dangers posed by corrosion and take preventive action before it becomes a major operational risk. Ultimately, in this economic environment, informed decisions can mean the difference between profit and loss, and between asset survival and extinction. ■

Edited by Gerald Ondrey

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