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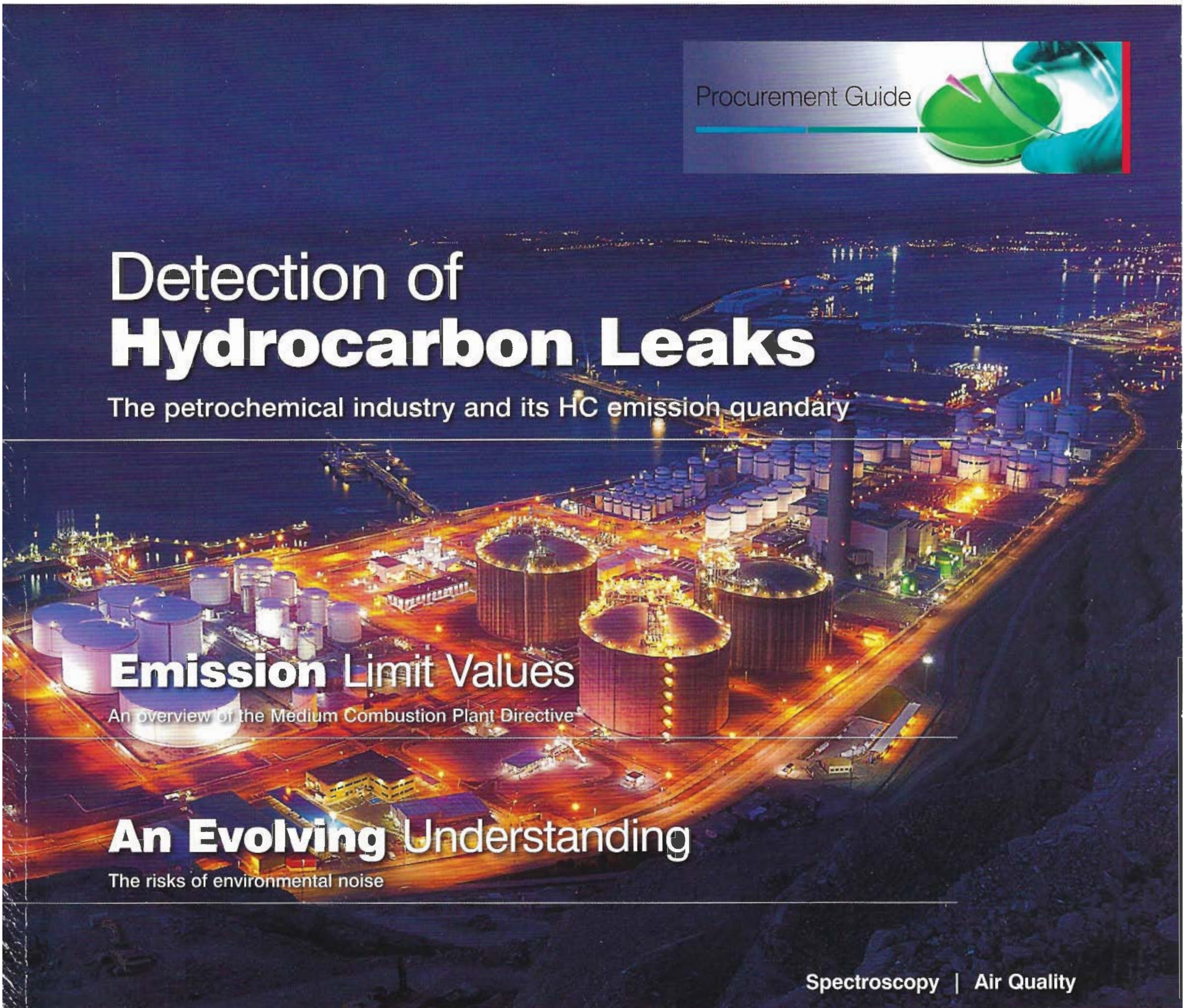

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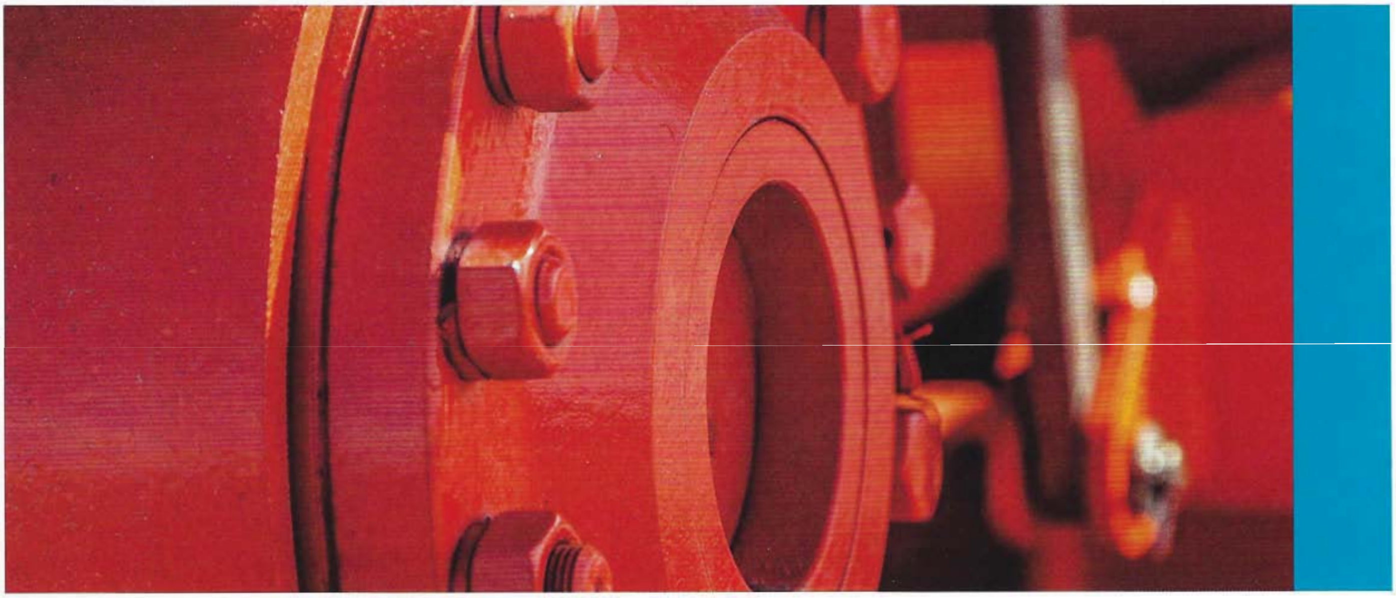

Detection of hydrocarbon leaks is mandatory for the oil and gas processing industry. Such leaks can create explosive conditions that, if ignited, endanger workers and release hydrocarbons (HCs) jeopardising air quality and posing a danger to public health. In addition, there is the cost factor. Massive leaks can force an entire facility to shut down until the sources are repaired. A lengthy unplanned turnaround time for resuming operations means extremely high financial outlays while the plant, or sections of it, remain idle.

In the United States, the Environmental Protection Agency has established standards and guidelines for leak detection and repair (LDAR). However, for reasons related to processes such as shutdown and turnaround time, LDAR standards may vary with individual companies. Most global concerns rely not on governmental edict, but a rule of thumb: leakages of 100,000 ppm or less are not viewed as immediate environmental threats. Little or no corrective actions are taken as long as fugitive emissions – the industry-preferred term for HCs, gases or vapours unintentionally released into the atmosphere – do not exceed the 100,000 ppm standard.

In its *Background Technical Support Document-Petroleum and Natural Gas Industry*, the EPA establishes 100,000 ppm as a "threshold analysis" applicable for carbon dioxide emissions. The figure also appears in a separate EPA document, *Protocol for Equipment Leak Estimates*, in which the agency considers emissions measured from 10,000 ppm to 100,000 ppm as a leak. The guideline, however, does not require immediate action by the petrochemical facility when emissions occur within the range. Numerous cost benefit analyses explain the industry's reluctance to immediately repair leaks that do not exceed the higher range. Nonetheless, the petrochemical industry "devotes considerable resources to leak detection to ensure the safety of workers, to protect the environment and to maximise production efficiency," according to a 2017 article in the *Journal of Safety, Health & Environmental Research*, a publication by the American Society of Safety Engineers.

Those resources range from the most sophisticated imaging equipment to long-time but less advanced devices that may be incapable of detecting initial hydrocarbon release or other volatile organic compounds (VOCs). >

Leak detection devices

No doubt the most common resource for monitoring fugitive emissions is the flame ionisation detector (FID), a device to measure concentrations of HCs that could be emanating from several pieces of equipment. These include flanges, pumps, compressors, control valves, pressure release valves, vessels and exchangers, all potential sources for HC emissions. FID measurements are based on the range and rate in which hydrocarbon gases are likely to ignite. A low explosive limit is set as the benchmark. The measurement process consists of a probe placed in proximity to the suspected emission source. Positive findings register on a monitoring scale.

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The drawback with FIDs is that most have limited access to other potential emission sources. Depending on their location, they may not detect large and potentially catastrophic leaks. For large-scale leak detection, various types of infrared (IR) detectors, which are handheld as is the case with FIDS, are the most frequently utilised monitoring devices.

In most facilities, leaks of VOCs exceeding 100,000 ppm are marked with a red tag displaying the necessity for immediate repair. Leaks below that figure have yellow tags showing that the leak is below the baseline and poses no immediate jeopardy for worker and facility safety based on the guideline range.

A more technologically-advanced method of detection proven effective for petroleum and natural gas firms is optical gas imaging. Like so much technology, it, too, continues to evolve with versions improving and expanding detection capabilities. The previously cited Journal report documents the results of eight years of research by ExxonMobil and Providence Photonics teams, which examined the possibility of developing "reliable IR based optical gas imaging technologies that can be used for hydrocarbon leak detection for use in safety applications." Another area of study for the teams is: "automating existing IR-based optical gas imaging systems to eventually replace handheld IR cameras and remove field operators from the equation."

Their research led to the development of two advanced technologies, one of which consists of single and dual sensor systems. The single system detects hydrocarbon plumes utilising an imager and algorithm; the dual has two imagers to eliminate background interference even when the device is in motion. The other technological advancement the research produced is an optical gas imaging system that applies quantitative algorithms for measuring the extent of emissions and concentrations within gas plumes.

Other manufacturers offer optical gas imaging cameras designated intrinsically safe. The National Electrical Code (U.S.) defines intrinsically safe as "a circuit in which any spark or thermal effect is incapable of causing ignition of a flammable or combustible material in air under prescribed test conditions." A major petroleum storage facility >

located in the Middle East has had success with infrared radiometers, an intrinsically safe optical gas imaging system, for scanning a large area and identifying leaks. The technology is most effective when used in conjunction with FID. "Since both technologies offer useful and different applications, (the) recommendation is to apply both," the facility advises its management and teams. Accompanying the equipment recommendation is a call by the company for a "balanced approach" due to the possibility that detected leaks could be "schedule breakers". Interpretation: don't overreact and initiate a shutdown/turnaround time protocol unless the leaks exceed industry-accepted guidelines.

Yet with the availability of all these state-of-the-art options, why can so many leaks above 100,000 ppm go undetected for so long? The answer exemplifies the ongoing quandary facing the petrochemical industry. It has nothing to do with equipment shortcomings and everything to do with a lengthy time lag between LDAR testing and repair.

Is three years too long?

The EPA has never issued a mandatory threshold for fugitive hydrocarbon emissions for petroleum storage tanks or associated equipment, which may explain the industry's invocation of yet another rule of thumb pertaining to the frequency of leak detection analysis. For many, the average time between LDAR for various components is three years – a timeline that may shock those unfamiliar with the petrochemical industry. Certainly, an immediate response is initiated when sudden problems occur due to accidents or malfunctions with safety critical equipment (SCE) or the release of unacceptably high GHGs, HCs or other fugitive emissions. Excluding those issues, the industry, basing its decisions on its global benchmarking standards, cites several reasons for justifying the three-year time lapse.

Consistency

No detection of SCE issues or fugitive emission concentrations exceeding the 100,000 ppm standard on a particular storage vessel or component since the previous detection process three years earlier.

Competition for resources

This is a far-ranging area that, if lacking, jeopardises the entire LDAR process, which can be a costly burden; for example, when a pressure release categorised as SCE fails and the facility lacks replacement parts. The company then finds itself in competition with other energy sites to acquire spare parts and components such as valve seats, valve springs and check valve transmitters. Many liquid natural gas companies, particularly the smaller to mid-size firms, cannot afford to stock up on spares, putting them at risk for long and expensive shutdowns and restarts if any emergency shutdown is ordered. By the time those spares arrive, sizable revenues are lost and costs for turnaround escalate.

Need major equipment for repairs

In some cases, companies hire a crane from a distant locale to repair a pressure or storage vessel, possibly as high as 13-stories. Cost factors for owning a crane are so prohibitive that most companies will not consider the purchase.

Lack of regulation

This is an ongoing problem in which the petrochemical industry is left to its own guidelines and policies. A growing debate within the industry and from such external influences as environmental agencies centres on that 100,000 ppm threshold. Some may argue that this level is too high and detection of these hydrocarbon leaks in the maximum range should trigger process repair immediately. The industry counters that lowering standards of GHG and HC emissions beneath the threshold that the USEPA provides as a guideline is so cost prohibitive that a number of facilities could be forced to close. The EPA Technical Support Document cited earlier only adds to the uncertainty associated with timing of repairs. "Equipment leaks by nature occur randomly within the facility," it states. "Therefore, there is no way of knowing when a particular source started emitting." All the industry can do is to detect it, hopefully in a timely manner. >

An internal finding by another global firm is telling in its conclusions following a LDAR exercise. "Lack of regulation creates problems with establishing priorities (making it) difficult to establish a programme before the baseline is established," it states. Here again, the baseline is dependent solely on the facility and an agency guideline, not a rule or rigid governmental standard. The staff may be concerned about leaks below 100,000 ppm, but cannot justify the costs for immediate rectification, which explains why the industry has shown no interest in lowering the maximum range of HC emissions.

This is not to suggest a lack of concern with environmental responsibilities. Damage from a catastrophic emissions incident and its danger to public health can be incalculable. Two tragic examples occurred in India with lax detection systems listed among the causes: the massive leak of methyl isocyanate from a Union Carbide pesticide plant in Bhopal in December 1984, and an underground gas explosion in June 2014 of the GAIL pipeline. In the Bhopal tragedy, 40 tons of methyl isocyanate (MIC), a highly flammable organic compound in pesticide production extremely toxic to humans and animals, were released into the air. The National Centre for Biotechnology Information found that the MIC emissions killed "more than 3,800 people… causing significant morbidity and premature death to many thousands more."

Advanced technology applicable for different types of leak detection was unavailable in 1984, but a major factor – one that never changes regardless of technology – is training and employee education. Investigators found the Bhopal plant severely lacking in both.

The second tragedy, the explosion and fire from the gas pipeline operated by GAIL India Ltd., a state-owned utility, claimed 29 lives in the state of Andhra Pradesh. It could have been prevented had GAIL taken advantage of leak detection technology. According to India's *Economic Times*, the pipeline was used to transport dry gas to a nearby plant, but for inexplicable reasons, also transported "wet gas containing water/condensate" that led to corrosion of the pipeline and the subsequent leak. The newspaper reported GAIL admitted to "various lapses" including transporting wet gas through a dry pipeline without initiating any safety measures.

Process safety, LDAR and KPIs

Leak detection entails more resources than a two-member survey team with an FID and an optical gas imaging system. LDAR is a subset of a wide-ranging process comprising a significant number of teams, all of which have major tasks. An area operations manager decides the time for the next LDAR according to a previously mapped-out schedule in consultation with the environmental officer, assuming the facility or that portion of it has had neither shutdown nor restart within the previous year.

Maintenance engineers, instrumentation and control teams are part of the process. A maintenance engineer must ensure that every >

detected leak is repaired according to the priority assigned to it. A leak that does not involve SCE or exceed the baseline can be repaired either during a scheduled shutdown or, in some instances, online.

Shutdown and turnaround teams have rather onerous burdens. Both must thoroughly review their processes and validate that a precise shutdown will not jeopardise workers, equipment and the environment. The turnaround team is in a similar position. Turnarounds are not seamless. Inventory issues are high on the list of immediate concerns. Ideally, a facility would have from 65 to 75 percent of the critical equipment in stock such as valves and springs, but all too often this doesn't happen. As is the case with LDAR, a priority list has to be established and followed.

Key performance indicators (KPIs) dictate the success or failure of LDAR, shutdown and turnaround and their impact on financial viability. KPIs – the quantitative measurement of performance outcomes against a set of standards – are also relevant for assessing a company's environmental success in safeguarding against leaks. The assumption is that the standards established for the KPIs throughout every process are realistic; often they are not.

One example is the flange tightening process. Incorrect tightening has been responsible for hydrocarbon emissions exceeding 100,000 ppm at more than a few storage plants. Flanges require tightening to specifications and fugitive emissions are the likely result without absolute specification adherence. Overtightening is not a remedy; it, too, can exacerbate the leak.

Sadly, governance of this and other processes is lacking. Specifications followed by the LDAR team could be insufficient because there has been no review of the current KPIs. When a leak less than 100,000 ppm is detected, it is considered low priority. The same reading three years later could yield the same result. In fact, identical emission readings for that time period that stay below the top range may never lead to repair work orders, since there is no sense of urgency. The USEPA recommends repairs but has had nothing to say about the timelines set by the industry thus far.

Company processes also merit serious review. Process engineers may strongly recommend some plant modifications that are viewed as low priority. That may seem like good news for the environment, but in reality, implementation can increase the level of HSE (health safety environment) risks when several modifications occur simultaneously. The industry can cite case studies where multiple changes at one time produced more leaks including SCE at the point of origin.

Management of change (MOC) based on arbitrary key performance indicators could damage both plant and environment should the KPIs be flawed or outdated. MOC projects that tend to focus on several plant expansion upgrades could increase the overall site risks in addition to the ever-present quandary in which LDAR costs are weighed against, allowing baseline leaks to continue. EPA recommendations may not align with the U.S. petrochemical industry KPIs, but more corporations are basing their leak thresholds on EPA guidelines as they reformulate their indicators.

Recommendations for industry and environment

The confusion between KPIs and environmental agencies is a latent clash scenario demanding cooperation and resolution before it erupts. Here are some suggestions to help resolve the dilemma and avoid confusion and a worst case environmental outcome:

1. Pull together and establish realistic KPIs that accurately reflect a situation. Shortages of SCE and spare parts are unconscionable for their impact on plant and environment, yet there is no concerted effort to rectify this condition. How many spares are on hand for SCE and other components that are on the verge of exceeding 101,000 ppm? KPIs covering these shortages are practically non-existent and there is no governance that would force the industry to change, something it would likely oppose. These need to be addressed.

2. Re-evaluate the time between LDAR. Three years may well be an acceptable time frame if there are no SCE incidents or readings above the threshold, but it deserves another look. The issue is worthy of a new cost/benefit analysis encompassing leak detection and repair costs including shutdown and turnaround. A long-time axiom is worth repeating: "the longer you delay, the higher your repair costs."

3. Find the right process. U.S. industry should undertake a serious review of processes and analyse whether its KPIs align with EPA guidelines. Currently there are neither figures nor indicators for this type of process – a shortcoming requiring a coordinated study.

Effective resolution based on these above recommendations will do more than improve the financial bottom line of petrochemical plants. Cost-efficient LDAR and revised KPIs in conjunction with environmental guidelines and requirements will provide more timely control of fugitive VOC, HC and GHG emissions – a positive outcome to be welcomed by environmental and industrial advocates. ■

Author

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