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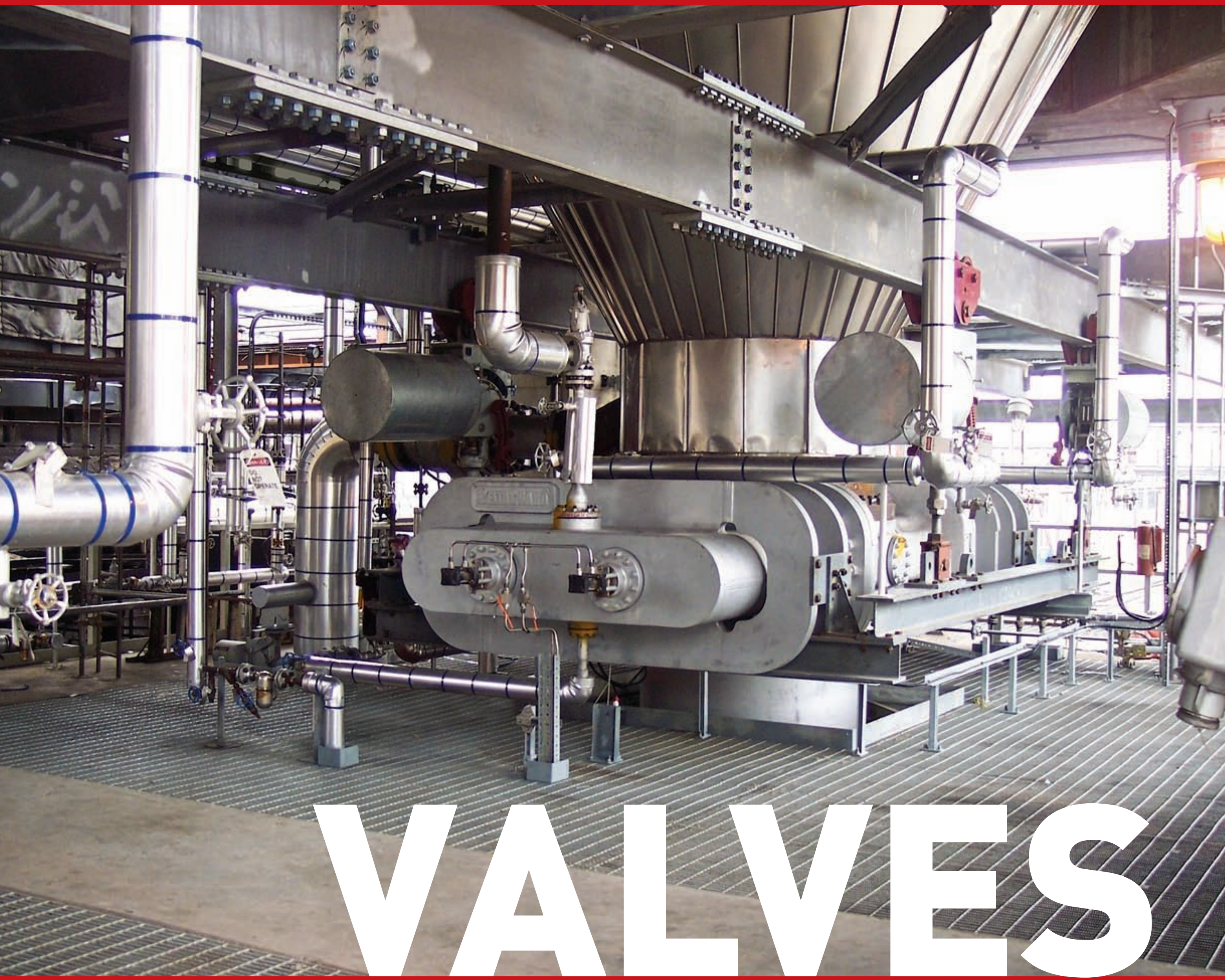

VALVES 2011

CONTENTS

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Fugitive emissions from valves: Update

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'Leak-free' involves monitoring and new equipment technology

Fugitive emissions awareness and mitigation have come a long way in the last 50 years, especially in the US. Initial fugitive emission studies of sources in the Los Angeles basin were done by Bernie Steigerwald in 1958. In the 1970s, the US Environmental Protection Agency (EPA) embarked on a substantial effort to quantify these emissions and develop a standard "sniff test" to identify hydrocarbon leaks using portable hydrocarbon analyzers (known as EPA Reference Method 21). The 1980's saw promulgation of the first significant regulations requiring synthetic organic chemicals manufacturing (SOCMI) industries and petroleum refineries to institute "find them and fix them" work practice programs. These programs were referred to as leak detection and repair (LDAR) programs.

LDAR program benefits. After several years of facility effort to sort out how to implement new LDAR programs, EPA began its first significant enforcement initiatives surrounding the monitoring requirements during the 1990s. Various EPA offices purchased hydrocarbon analyzers to do their own, independent reviews of a facility LDAR program. These reviews culminated into an Enforcement Alert from EPA, informing petrochemical industries of widespread disagreement between EPA- and industry-determined leak percentages (the percentage of equipment with leaks). The reviews alleged that industry failed to implement Method 21 correctly, and the agency estimated approximately 80 million pounds of undetected and unreported hydrocarbon emissions were being released annually in the US.[1]

Although proving a concrete violation that monitoring was conducted incorrectly was legally difficult (only one LDAR enforcement case has ever gone to trial in the US[2]) demanding stiff penalties, often in the millions of dollars, was not. Under the Petroleum Refining Initiative in the early 2000's, fugitive emissions became a marquee compliance issue for EPA with the petroleum refining industry. To avoid litigation, US refiners agreed to implement LDAR best-management practices, eventually referred to as Enhanced LDAR Programs or ELPs.

The ELPs reduced the repair action threshold—leak definition, in parts per million (ppm) total organic hydrocarbons,—increased leak monitoring frequency and required LDAR program training, procedures, and third-party audits. By 2008, reported fugitive emissions of toxic hydrocarbons—a subset of overall volatile organic compound (VOC) emissions—from the petroleum refining sector had dropped by 42% compared to the start of the decade.[3] While differences in emissions accounting methods may have contributed to the observed decrease, as shown in Fig. 1, ELPs are believed to be responsible for the largest part of the reduction. Reviews of toxic fugitive emission reductions from valves and pumps, the two equipment types impacted by most refinery ELP requirements. Reviews of toxic fugitive emission reductions from valves and pumps at one major refinery showed capacity-adjusted emissions dropped roughly 80% after the requirements took effect in 2003, as shown in Fig. 2.[4]

Bolstered by the success of these Enhanced LDAR Programs, EPA continued to pursue best practice agreements with the rest of the refining industry (approximately 20% since 2008), and began negotiations with several companies in the Chemical Manufacturing Industry (CMI) for alleged LDAR noncompliance with hazardous organic NESHAP (HON) regulations.[5] The CMI sector, partially regulated under SOCMI regulations from the 1980s, became subject to these substantially increased requirements in the mid-1990s. The petroleum refining ELPs in the 2000s aimed to achieve the same emission reduction levels as HON regulations had achieved for toxic air pollutants almost a decade earlier.

EPA was confronted with a dilemma—with already low repair-action thresholds and more frequent monitoring required under HON, what could be considered best practice and an enhancement in the CMI sector? Where could emissions still be reduced? In some cases, leak definitions were further lowered (e.g., from 500 ppm for valves and connectors to 250 ppm, and from 2,000 ppm for pumps to 500 ppm). Requirements for QA/QC and third-party audits were increased. However, overall emissions reductions from these enhancements were known to be significantly lower compared to the refining sector.

Older models present problems. Working closely with several industry partners, EPA's understanding of the fugitive emissions problem began to change. "Find it and fix it" work practice programs were limited in their ability to control fugitive emissions by the underlying process equipment technology. Older equipment, designed and manufactured with larger tolerances, *would always leak more.* Some packing and seal designs were inherently less effective at controlling emissions. Only by replacing these seals, packing, or equipment with advanced designs could long-term leak rates be reduced.

Responsible party dilemma. This understanding of *how* to control fugitive emissions accompanied a paradigm-shift in *who* at the site is best-suited to address the problem. The plant environmental department usually drove the LDAR program, because the requirements came from EPA and not from the Occupational Safety and Health Administration (OSHA), where process safety was the driver. However, the environmental department, being largely removed from the everyday operation and maintenance of the plant, was least-equipped to affect a direct change on equipment leaks. They could do monitoring and request repairs, but as long as the regulatory timeframes were met, not much more would be done.

Maintenance and reliability personnel, however, could take the monitoring information and identify bad-actor equipment, and establish clearer mean-time-to-failure criteria so that equipment could be refurbished or replaced prior to failure. Maintenance could do root-cause analyses to identify equipment applications that were leak-prone so that other equipment types could be selected, and could determine which repair types were most successful and cost-effective over the long term. They could combine equipment manufacturer information with leak-performance data (see Table 1) to determine which vendors produced the best equipment for their processes. All of this information could be forwarded to the procurement department to ensure the best, most cost-effective equipment was purchased for the facility.

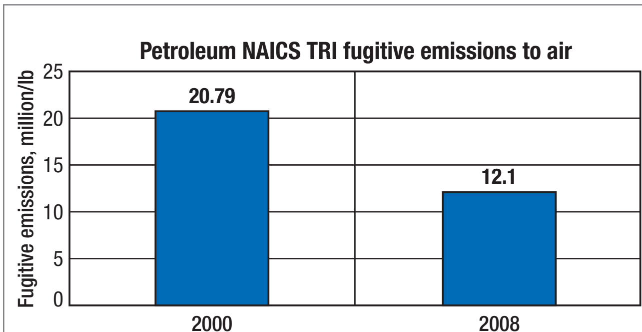

FIG. 1. Petroleum NAICS TRI fugitive emissions to air, million lbs.

TABLE 1. Leak percent of active inventory by manufacturer

Manufacturer	2005	2006	2007	2008	2009	Average leak rate at 500 ppm, %
A	96/12,852–0.7%	156/13,874–1.1%	161/15,969–1.0%	155/19,706–0.8%	135/21,726–0.6%	0.86
B	30/2,673–1.1%	57/3,544–1.6%	45/4,511–1.0%	53/6,125–0.9%	63/6,569–1.0%	1.11
C	108/6,737–1.6%	182/7,127–2.6%	193/7,954–2.4%	211/9,445–2.2%	139/9,937–1.4%	2.04
D	59/2,314–2.5%	69/2,847–2.4%	70/3,527–2.0%	79/4,381–1.8%	79/4,736–1.7%	2.09
E	0/31–0.0%	3/31–9.7%	2/417–0.5%	1/504–0.2%	1/572–0.2%	2.11
F	2/59–3.4%	1/61–1.6%	3/71–4.2%	2/82–2.4%	5/86–5.8%	3.50
G	1,196/18,966–6.3%	609/16,983–3.6%	287/10,708–2.7%	193/8,809–2.2%	275/8,329–3.3%	3.61
H	1/43–2.3%	3/45–6.7%	2/48–4.2%	1/54–1.9%	2/52–3.8%	3.77
I	24/409–5.9%	28/450–6.2%	30/483–6.2%	37/571–6.5%	35/617–5.7%	6.09
J	96/1,433–6.7%	121/1,595–7.6%	108/1,801–6.0%	109/2,204–4.9%	132/2,422–5.5%	6.14
K	91/1,406–6.5%	92/1,482–6.2%	132/1,655–8.0%	119/1,860–6.4%	155/1,947–8.0%	7.00
L	52/677–7.7%	54/738–7.3%	67/857–7.8%	95/1,047–9.1%	100/1,078–9.3%	8.23
M	81/1,219–6.6%	110/1,244–8.8%	136/1,322–10.3%	118/1,522–7.8%	207/1,678–12.3%	9.17

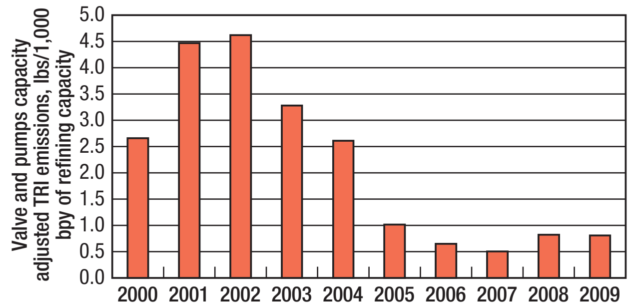

FIG. 2. Valve and pump capacity adjusted TRI emissions, lbs/1,000 bpy of refining capacity.

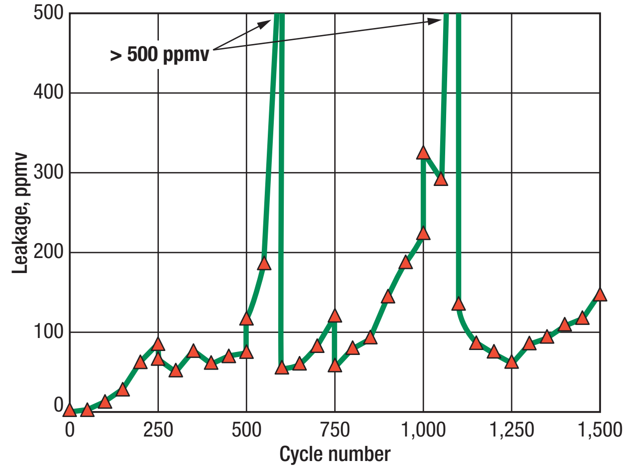

FIG. 3. Yarmouth Research API 622 Test Report.

In short, EPA determined, that while fugitive emissions may be the line where facility operations impact the community and the environment, they were merely the symptom of a larger problem outside the control of the environmental department. Fundamental, lasting change in equipment leaks could only be achieved by an integrated approach between maintenance, reliability, operations, procurement and environmental personnel. And this change would need to be technology-based.

Today. So, where is the hydrocarbon processing industry in 2011 regarding US fugitive emissions control? To enhance LDAR requirements further, the latest EPA ELPs include requirements for equipment-leak root-cause surveys, preventative maintenance tracking systems, implementation of innovative repair techniques for equipment which cannot be isolated, and replacement of valve and connector equipment with "low-leaking" technologies.[6,7] Low-leaking valve technologies are generally defined as equipment that has been designed to prevent leaks above 100 ppm for a period of five years, as demonstrated by testing or written manufacturer guarantee. Installing low-leaking equipment is required unless the technology is "commercially unavailable."

Companies subject to these new technology requirements are just now seeing some sticking points. First, what does a manufacturer guarantee really get you? Usually, valves are upgraded by installing new packing, unless it's more cost-effective to replace the entire valve. With labor costs typically at 90% of the total re-pack cost, requirements to deliver another $20 packing set, even if a site can demonstrate that all of the conditions of original installation were met, arguably does little to discourage companies from offering such a guarantee.

Second, testing results may be used to document that low-leaking technology has been installed, as long as the test has been conducted according to "generally accepted good engineering practices." Test protocols can vary widely, between 500 mechanical actuations and no thermal cycles, to 5,000 mechanical actuations and 10 thermal cycles.[8] Tests can be helium or other inert-gas, volume-based leak tests, as with ISO 15848A/B or with hydrocarbon, ppm-based to simulate Method 21 screening values, with ISO 15848-1. After numerous discussions with various organizations to standardize testing requirements around a particular protocol, EPA has recently backed away from endorsing any protocol due to safety and liability concerns.

Third, facilities must demonstrate that a particular technology is commercially unavailable to avoid having to install low-leaking equipment. Determination of availability may be based on numerous factors, including safety, process suitability, and even process-licensing restrictions.[9] However, facilities must usually demonstrate at least three vendors were contacted and could not meet the 100-ppm/5-year technology standard to invoke the exemption. Facilities still wonder, however, how hard EPA expects them to look for a suitable manufacturer. And what cost premium might this technology impose when identified?

Good news. Both costs and availability are headed in the right direction. According to David Reeves, senior specialist for Bolting and Sealing Technology at Chevron, the company has now identified five valve packings which will meet the stringent ChevronTexaco testing protocol/standard (up from one just a few years ago). Additionally, costs for some of these technologies are similar and sometimes less than costs for similar equipment.[10]

TABLE 2. Leak rate comparison for normal-to-monitor (NTM) valves vs. difficult-to-monitor[13]

		500 ppm Leak definition, %			10,000 ppm Leak definition, %		
Facility	Valves	Average	Max	Min	Average	Max	Min
3	DTM	4.06	7.74	0.44	0.79	2.02	0.00
3	NTM	3.16	5.13	1.02	0.41	0.61	0.14
4	DTM	0.78	1.22	0.38	0.46	0.73	0.11
4	NTM	2.10	3.37	1.19	0.63	1.06	0.33
6	DTM	1.43	2.48	0.69	0.22	0.42	0.00
6	NTM	2.02	2.36	1.23	0.34	0.55	0.21
7	DTM	0.29	0.53	0.15	0.31	0.43	0.23
7	NTM	1.55	1.99	1.14	0.00	0.00	0.00
11	DTM	2.45	3.61	1.39	0.25	0.38	0.07
11	NTM	2.04	2.44	1.58	0.25	0.31	0.16
12	DTM	0.75	1.04	0.47	0.10	0.20	0.00
12	NTM	0.90	1.02	0.78	0.18	0.23	0.13
Overall	DTM	1.63	2.77	0.59	0.36	0.70	0.07
Overall	NTM	1.96	2.72	1.16	0.30	0.46	0.16

As EPA continues to impose new ELPs on the last refineries and companies in the CMI sector, some facilities are looking to retire their agreements with EPA. While no facilities have been successful to date, many are lined up with documentation demonstrating they are in "substantial and material compliance" with the provisions of their consent decree. EPA has not weighed in officially on what those terms mean, however. Does that mean 51%, 90% or 99.9% compliance? With over a million LDAR compliance events are done annually at many sites, there is a big difference in these numbers. Even a 99.9% compliance level could still mean over 1,000 possible violations.[11]

Outside the enforcement process that is driving these ELP agreements, EPA continues to sharpen the pencil on LDAR. "Drill and tap" repair, once thought to be an extraordinary repair technique by EPA and industry, has become a quasi-regulatory requirement for leaking valves that otherwise cannot be repaired without shutting down the process unit.[12] Refinery or SOCMI process units newly built, reconstructed or modified after Nov. 7, 2006 must meet ELP-like repair-action thresholds (500 ppm for valves and 2,000 ppm for pumps). SOCMI units must monitor connectors.

The future. EPA is currently developing additional, "universal standards" for LDAR, and is hoping in the process to clarify many long-standing concerns with various federal LDAR requirements. One of these is optical imaging (OI), which many had hoped would revolutionize LDAR in the US by improving leak-scanning speeds and reducing costly repairs to small leaks. Because the final EPA rule language allowing OI as an alternate detection methodology is still coupled to the traditional Method 21 monitoring, much of the cost-effectiveness failed to materialize, resulting in few sites using this alternate method. However, EPA may now allow facilities to use OI for elevated equipment that is difficult-to-monitor (DTM) see Table 2. Since scaffolding and man-lift costs to do DTM monitoring safely (Table 2) can cost millions of dollars per year, use of OI could result in significant cost-savings, since typically only about 1% of DTM valves leak annually.[13]

With changes like these, the future of LDAR in the US is looking brighter. Most companies will tout how much cleaner their plants are now, despite grumblings about EPA compliance enforcement. Hopefully, we'll one day get to that magic pot of gold at the end of the rainbow, where all are happy, industry and environment together. **HP**

FIG. 4. Hydrocarbon optical imaging camera (Photo courtesy of FLIR Systems, Inc., model GasFindIR GF320).

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Mr. Wilwerding previously functioned as a primary national technical expert for fugitive emissions and LDAR programs at the US EPA, and was involved with numerous regulatory and policy position documents regarding fugitive emissions, including the 2006 NSPS Subpart VV revisions, the alternate work practice for leak detection, EPA internal LDAR enforcement strategy documents, and EPA's LDAR Best Practice Guide. Mr. Wilwerding worked at the EPA National Enforcement Investigations Center for 11 years, performing CAA audits around the US at large petroleum refining, petrochemical and manufacturing facilities. He provided litigation and negotiation technical support on single/multimedia compliance cases, and helped negotiate national/global consent decrees with petrochemical companies regarding fugitive emissions best management practices and enhanced LDAR programs.

SAGE Environmental Consulting, LP (www.sageenvironmental.com) is a leading provider of air pollution consulting services to the refining and petrochemical industries.