MICROPACK Visual Flame Detection Application Note

ABSTRACT

Optical flame detection has evolved over the last 30 years with improved sensors, processing power, and high electronics reliability, which has greatly improved the acceptance and use of automatic optical fire detection in the harshest of environments and applications. Single wavelength ultraviolet (UV) detectors were originally used for the protection of large integrated oil and gas production platforms in the North Sea, followed by single wavelength infrared (IR) detectors, but problems with false alarms from numerous natural and artificial sources both on the platforms and from adjacent installations prompted the oil industry to search for a better technology. This paper covers the recurring problem of flare reflections on offshore platforms and how the evolving technology of visual flame detection has solved this problem.

BACKGROUND

The origins of visual flame detection came from developments in the North Sea offshore oil and gas industry in the mid 1990's. The UK oil sector started to look at the use of floating oil and gas production facilities, to develop oil reserves in deeper water than conventional fixed platforms could be cost effectively deployed. These floating facilities called FPSO's (floating production storage and offloading) created a wealth of different challenges from conventional

fixed platforms, including challenges to conventional infrared flame detectors. Due to the relative close proximity of the process relief flare to the top side exposed production modules, reflected radiation could adversely affect the operation of the flame detection system. It should be noted that these process relief flares can be up to 1,000 times the size of the industry standard test fire used to specify flame detector range. As there are multiple highly reflective surfaces on the facilities, including piping, vessels and skids, reflections from the process flare could be multi directional and not easy to identify or isolate. The use of shields or hoods to partially limit the field of view of the conventional flame detectors was a compromise that some oil companies were reluctant to undertake but had no choice. In practice, the use of shields or hoods was later proven to be ineffective. In 1997, a major oil company that had done extensive testing of optical flame detectors since the initial development of the first major oil field in the North Sea in the early 1970's was in the preliminary design phase of its first FPSO to develop an oil field in the North Atlantic Ocean, West of the Shetland Islands (see Figure 1). Company managers were aware of the challenge from the process relief flare being in such close proximity to the top side production facilities

and contacted a specialized fire detection consulting company to help work on a new type of flame detection system that would ignore reflections from the flare, whilst still providing fire detection coverage in these areas.

The consultant had been testing various brands

Figure 1. The original FPSO where visual flame detection was first used.

of flame detectors as a consultant to the North Sea oil industry and had developed a specialized and unbiased understanding of the strengths and weaknesses of optical flame sensors. Some of this testing combined with research into the use of charged coupled device (CCD) image sensors for flame detection brought about the development of the first visual flame detection system for this first North Sea FPSO.

THE TECHNOLOGY

Visual flame detectors employ a video imaging technique using standard CCD sensors that are used in closed circuit television cameras, combined with advanced algorithms. These algorithms process the live video image from the CCD array and interpret flame characteristics. As most of the original development of visual imaging based flame detection was carried out to ignore the reflections from the process flare, fire sensitivity was not the major objective. IR based flame detectors had better response times and could see fires at greater distances, but it was soon discovered that by not using the IR wavelength associated with most flame detectors, imaging based detectors were not affected by water absorption from rain or from CO_2 emissions from gas

turbine exhaust and other sources. Due to their spatial dependency, visual flame detectors would not adjust their sensitivity depending on what was in the field of view of the detector.

Other applications for flame detectors in the late 1980's like the protection of commercial and military aircraft hangars dictated that automatic flame detectors respond to fires at distances of 150 -200 feet. This became the de facto industry specification. As these detectors were then applied to the offshore oil industry, it was not readily apparent that, due to the very confined and condensed nature of the oil and gas processing areas, distances from a detector location to the actual fire source rarely exceeded 15- 20 feet, so the 200 feet potential range and sensitivity of these conventional flame detectors was not only unnecessary, but probably led to an increase in the false alarms from flare reflections. So even though the first generation visual flame detector had less than 50 percent of the sensitivity, compared to conventional type flame detectors, it did not matter in the close confines of an offshore platform. Never-

Figure 2. Large scale LNG fire testing

theless, a major weakness of visual based flame detection is that it cannot detect invisible type fires such as hydrogen or very weak flames such as pure methanol and pure sulphur.

Brightness associated with most hydrocarbons fires is one of the fundamental parameters of how the technology works. Combined with the live video output of the visual flame detector, operators in remote parts of the plant have the benefit of confirming the hazard and can take a more informed and safer course of action to combat the fire when detected with a visual flame detector. Some manufacturers of conventional multi -spectrum IR and combination UV/IR detectors have recently introduce models with a bolt-on surveillance camera to achieve the same verification capability. Naturally, the fundamental issue of false alarms from flare reflections is not resolved with this combination flame detector and camera.

CURRENT DEVELOPMENTS

Since the introduction of the first generation of visual flame detection, the visual flame devices are now into their third generation. With the introduction of colour images for real time surveillance, the facility operator now gets a human eye view of the area being covered. The newer sensor has a larger array, thus providing more pixels for detection, offering over twice the sensitivity of the original mono only visual flame detector. Due to the aforementioned issue with multi spectrum IR flame detectors being affected by hot CO_2 from exhausts of turbine driven compressors and generators, the current generation visual flame detection can indeed surpass the sensitivity of multi spectrum IR as there is no need to reduce the sensitivity depending on what is in the detectors field of view. A micro memory card has been added on board the electronics module to provide pre and post fire incident recording. With the wide variety of product offerings in the security industry, it is now much easier to interface the video surveillance image with video IP encoders and digital video recorders as opposed to having proprietary hardware and HMI software. With the use of IP encoders the video from the flame detectors can now be reviewed remotely, practically from anywhere in the world. Some companies are using the video output from the surveillance sensor to provide intrusion monitoring of the areas being protected. Again, standard off the shelf surveillance equipment now incorporates motion detection algorithms. Hence, provided viewing zones are set up within the detector's field of view, visual imaging can respond to the presence of intruders in an area. Oil and gas companies have made good use of this feature by deploying visual flame detectors in remote unmanned platforms targeted by pirates.

Figure 3. Operators are provided with instantaneous and vital visual confirmation of the hazard

FLAME DETECTION PERFORMANCE TESTING STANDARDS

The national fire code relating to automatic fire detection NFPA72 now recognizes video based detection for both flame and smoke detection and a number of companies are introducing video based smoke detection devices for the protection of large spaces such as stadiums, convention centres, and warehouses. The main challenge to the acceptance of video based smoke detection is the lack of approval standards for this method of detection.

Because visual imaging flame detection was originally developed to reduce false alarms from reflected flare radiation, it was never designed to be the sole flame detection technique. As there are traditional types of optical flame detectors offered in the marketplace, approval standards like FM 3260, the current ANSI standard for radiant energy flame detectors, are more forgiving when the standardized tests are performed on conventional flame detectors. As more manufacturers enter the fray with imaging flame detection, the standards are likely to change to accommodate

the different way imaging fire detectors detect fires.

One particular challenge with standards testing is associated with the very nature of fires. Since fires change constantly, it is often difficult to represent their erratic behaviour with standard fires. For example, a Bunsen burner methane flame in the laboratory is precise and controlled. Consequently, testing flame detectors to this type of flame may not necessarily yield results that correlate well with device performance in the field. After all, flame detectors are designed to detect uncontrolled fires in hazardous processing environments.

THE IMPORTANCE OF DETECTION SYSTEM COVERAGE DESIGN

It is also important to have a defined fire target size for any given risk or application and then the flame detection system can be designed accordingly. A few of the major oil companies have defined fire size targets, depending on the level of risk associated with the process. All too often a designer will take the maximum detection distance as stated on the flame detection manufacturers' data sheet and apply this specification across the facility without taking into consideration the variety of sources from the process that can limit the sensitivity of typical flame detectors. There are software mapping tools available today that take into consideration the shadowing effect the process plant has on detector coverage, allowing designers to maximize the coverage using a minimum number of detectors. These tools also produce drawings, indicating the design criteria for the detection system and the way in which the design was achieved showing detector positions and their coverage. Many operators in the oil industry use this study as part of their safety case for the regulatory authorities. Figure 4 shows a typical computer model of fire dispersal at a plant.

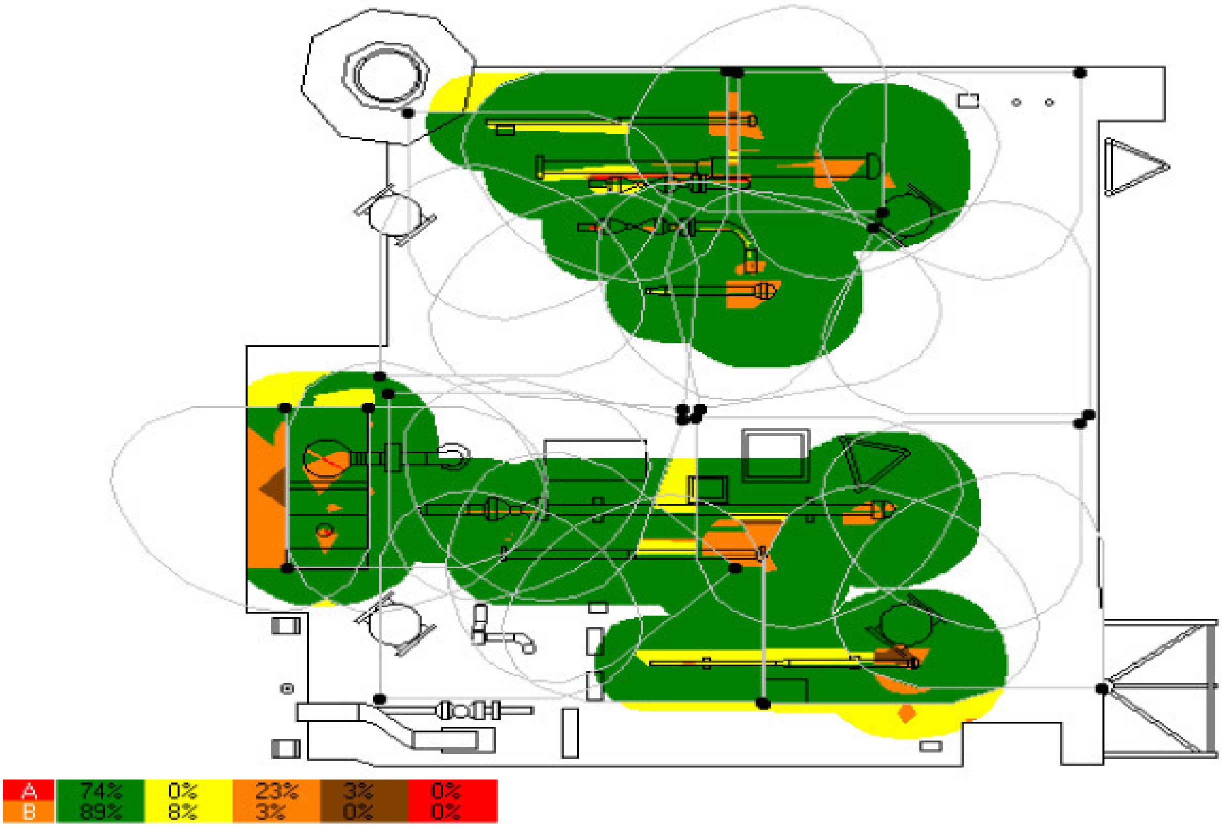

Figure 4. Typical flame detection assessment from software mapping tool.

LESSONS LEARNED

As the flare reflection issue has become more widely understood by the oil and gas industry, a number of FPSO's, offshore platforms, and onshore plants have specified visual flame detection either as the only flame detection technology or in combination with conventional flame detectors, where the visual flame detector is located in areas most prone to reflections from the flare. A number of facilities both onshore and offshore have had to replace their existing flame detectors with visual flame devices due to the high frequency of false alarms. In the case of a Norwegian North Sea FPSO, which was recently started up, the reflections from the process flare tripped dozens of flame detectors, initiating an emergency shutdown (ESD), when the vessel was offloading oil to a shuttle tanker. Another case involving a major scale onshore gas processing and export facility has a large ground flare. During a particular process upset, the flare tripped several triple-IR flame detectors, some of which were located up to half a kilometre away from the flare. As the detectors in various parts of the plant activated simultaneously, again an automatic ESD was initiated, disrupting the transfer of oil from the offshore platforms to an onshore plant. In another instance, surge tanks feeding a large export pipeline were also affected by false alarms. As major production losses estimated to exceed $100 million were incurred by the oil company, the decision was made to replace all of their detectors on the site with visual flame detectors. To date no false alarms have been reported from the visual flame detection system.

Figure 5. A typical application for visual flame detection, on an offshore oil and gas production

THE FUTURE

Although visual flame detection is not a panacea and is not suitable for every type of hazard, the benefits of imaging technology are being recognized by more of the major oil companies around the world. Combined with improvements in performance, visual flame detectors will become more sensitive to smaller fires at much greater distances with quicker speed. The future looks bright for intelligent imaging based fire detection.

Figure 6: Visual flame detector with process relief flare in background.

REFERENCES

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National Fire Protection Association NFPA 72 2006 Edition

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