Safety practice

Piper Alpha — process safety then and now

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Introduction

With 167 fatalities, Piper Alpha is the deadliest accident in the history of the offshore oil and gas industry. There have been numerous articles, reports and documentaries coving the incident, possibly the best summary of the incident and the events leading up to it are contained in the Cullen Report.

The immediate cause of the accident was failure to adequately control maintenance activities, but a number of other factors arguably allowed a major accident to turn into a catastrophe. Some of the lessons are briefly described below.

Permit-to-Work (PTW) systems

There were severe and numerous defects in the PTW system. During the day shift, work to rectify Pressure Safety Valves (PSVs) had commenced. This required the PSV to be de-mounted and blind flanges fixed securely to the open piping. The related condensate injection pump had to be isolated to stop it being activated. While pump A was isolated and its PSV removed, condensate injection continued using parallel pump B. The PSV was lifted by a crane and taken to the workshop for recertification. A general overhaul of pump A was also due to be carried out but that work had not yet started.

All this was controlled by two separate PTWs. When the PSV had been recertified the fitter set about reassembling the valve to the piping, but no lifting equipment was available to hoist the PSV into position as had been planned. In consequence the fitter suspended the permit until the next day, leaving the piping blinded. When pump B failed some 3½ hours later, and couldn't be re-started, the operators believed they could get vital production re-started by removing the electrical isolation and restarting pump A. Soon after pump A was re-started the blind flanges started leaking hydrocarbon vapour which then found a source of ignition. This is the key moment that caused the disaster to unfold.

The permits for the pump and the PSV made no reference to each other and it is likely that they had been filed at separate locations. When the on-line condensate pump B failed later in the shift, it created a need to start pump A so that production could continue. Control room personnel were aware of the pump repair work, but not the work on the PSV, and proceeded to return the pump to service.

The PTW system was often not implemented according to procedure. For example:

- Omissions (e.g. signatures and gas test results) were common;
- Operations representatives often did not inspect the jobsite before suspending the permit at the end of the shift, or close the permit indicating the work had been completed; and
- Craft supervisors often left permits on the control room desk at the end of a shift, rather than personally returning them to the responsible operations representative, as required by the procedure.

Lack of learning

Although the PTW system was monitored by the lead safety operator, no indications of problems were reported, and management did not independently review the operation of the system. It is noted that a senior maintenance technician had voiced his concerns about the PTW system at a meeting at corporate headquarters earlier in the year. In addition, the company had entered a guilty plea in a civil legal proceeding involving a worker fatality caused, in part, by a PTW system problem; however, no substantive improvements in the PTW system resulted.

Fire water pumps

The diesel-powered fire pumps had been placed in manual control mode due to the presence of divers in the water around the platform. This practice was more conservative than company policies required and a 1983 fire protection audit report had recommended that this practice be discontinued. Placing pumps in manual meant that personnel would have to reach the pumps to start them after the explosion. However, conditions prevented this and, as a result the water deluge systems were inoperable.

Had fire water been available, its efficacy might have been limited. Distribution piping, including that in the platform module where the fires were most severe, was badly corroded and blocked sprinkler heads was a known problem as far back as 1984.

Control of pressure systems for hydrocarbons at high pressure

An offshore production platform contains a large amount of plant containing hydrocarbons at high pressure. The feed to this plant is from the wells, which can sometimes behave in an unpredictable way. The pipelines connected to the platform contain large quantities of hydrocarbon, with the high-pressure gas pipelines constituting a particularly serious hazard.

A comprehensive system is needed for the control of the total pressure system, covering design, fabrication, installation, operation, inspection, maintenance and modification, and

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including control of such features as materials of construction, lifting of loads etc. Personnel need to be trained in the purposes and operation of the system.

Emergency response training

The investigation revealed that emergency response training given to new platform personnel was cursory and not uniformly provided. Workers were required to be trained if they had not been on Piper in the last six months. However, training was often waived even if the interval was considerably longer, or if the individual reported that they had never been trained on the location of the life rafts or how to launch them. Evacuation drills were not conducted weekly as required (one six-month period recorded only thirteen drills). No full-scale shutdown drill had been conducted in the three years prior to the explosion.

UK legislation/regulatory control

The inquiry report into the disaster made recommendations for fundamental changes in the offshore safety regime.

The basis of the recommendations was that the responsibility for safety should lie with the operator of the installation and that nothing in the safety regime should detract from this.

The offshore regime envisaged in the recommendations was one in which the emphasis was on the operator demonstrating to the regulatory authority the safe design and operation of its installation rather than demonstrating mere compliance with regulations. In this regime, the preferred form of regulation was goal-setting rather than prescriptive.

The recommendations envisaged that Formal Safety Assessment (FSA) would play a major role. It was to be used to demonstrate compliance with a goal-setting regulation or with the general requirements of the Health and Safety at Work etc. Act (HASAWA). The evidence showed that many companies which operate installations onshore and offshore have formal systems for safety assessment and practice FSA routinely. FSA was considered to have considerable benefits and provides a suitable basis for dialogue between the company and the regulatory body. A safety case is a particular form of FSA. This safety case was to be broadly similar to that required for onshore installations but there were some important differences. In the offshore safety case, it would be required that the operator demonstrate that the installation has a Temporary Refuge (TR) in which personnel on the installation could shelter while the emergency was brought under control and evacuation organized.

Further, it was recommended that the demonstration should be by Quantitative Risk Assessment (QRA). This meant that there should be criteria which define the failure of the TR and criteria for its endurance and its failure frequency. The criteria could then be met by reducing the frequency of accidental events, by increasing the durability of the TR or by some combination of these.

The recommendation on the safety case included a requirement that the operator should demonstrate that it has a Safety Management System (SMS) to ensure the safe design and operation of the installation. This SMS was required to draw on the principles similar to those of ISO 9000.

The report also considered that the then current regulatory body, the Department of Energy (DoEn), was unsuitable as the body to be charged with implementing the new regime as it was also responsible for development of hydrocarbon resources and would suffer a conflict of interest. The report recommended the transfer of responsibility for offshore safety to the HSE.

These recommendations were accepted immediately by the government and the new regime under the HSE began in April 1991 with the introduction of safety regulations requiring the operator/owner of every fixed and mobile installation operating in UK waters to submit to the HSE, for their acceptance, a safety case. This was subsequently formalized with the introduction of The Offshore Installations (Safety Case) Regulations which came into force in 1992.

International legislation/regulatory control

Similar legislation has been adopted by various countries around the world in order to embrace the safety of offshore oil and gas installations. The way that some countries carried this out is summarized below.

Australia originally opted for prescriptive regulatory requirements but altered its stance after the Piper Alpha disaster and largely adopted a performance-based safety regime. Operators are now required to prepare safety cases for all offshore petroleum facilities, with mitigating actions focused on effective barrier management. The regulations, which have an emphasis on environmental safeguarding, are based on individual responsibility and enforcement.

In Brazil, the National Agency of Petroleum, Natural Gas and Biofuels, or the ANP, introduced new rules of safety management in 2007 which established the offshore safety regulatory regime known as the Operational Safety Management System. This implied a strong move from prescriptive to functional requirements, with the establishment of 17 management practices encompassing leadership involvement, risk assessment, integrity management, HSE procedures and employee training, among others.

In the European Union, in 2010, the European Commission launched the idea of comprehensive EU legislation to ensure the European offshore oil and gas industry would respect the highest safety, health and environmental standards in the world. This was refined into a proposal for regulation in 2011, and finally adopted as a directive in 2013. As a directive, the burden was on member states to transpose the directive into their own national law by July 2015. Industry then had to adapt to the new standards by July 2016 for planned operations and July 2018 for existing operations. The new directive is based on industry and regulators' global best practice for prevention of major offshore accidents and advocates a goal-setting regulatory philosophy.

The governance for Arctic petroleum activities are unilateral in safety and resource management by each of the five coastal states. In addition, there are non-binding initiatives from the International Maritime Organization (IMO), the OSPAR Convention, the Arctic Council and the International Organization for Standardization. In tandem with these binding and non-binding governmental processes, industry-based private governance is increasing significantly for Arctic petroleum activities.

In Alaska and the USA, the regulatory regime is primarily

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prescriptive, and following Macondo, the Bureau of Safety and Environmental Enforcement (BSEE) hired many new staff to carry out more offshore inspections. Companies report process safety metric standards and any loss of containment events, which are published and copied to the International Regulators Forum for international comparison. The workplace Safety Rule (also known as the Safety and Environmental Management System Rule) was issued in October 2010 and made mandatory the previously voluntary practices of the American Petroleum Institute's Recommended Practice 75 (Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities).

The main industry legislation for the Canadian Arctic is the Canada Oil and Gas Operations Act (COGOA), which regulates exploration for resources and the operation of offshore activities. Under COGOA the National Energy Board (NEB) is responsible for regulating Arctic offshore oil and gas exploration and development. The board combines the use of prescriptive and performance based regulations, but is moving towards putting more emphasis on the latter.

In Norway, regulations cover all phases of the petroleum activities and may be described as performance based and multi-disciplinary. The regulations address the responsibility of the licensee, operator and other parties. Furthermore, it is also self-regulatory in that it is the responsibility of the company itself to comply with regulations. Norway's most notable offshore accidents – the capsizing of the Alexander Kielland semi-submersible and the blowout on the Bravo platform – occurred in the Ekofisk field. The Alexander Keilland incident in 1980 led to the loss of 123 lives and fundamental changes to the regulatory regime, resulting in the introduction of internal control systems and risk based regulations. The 1977 Bravo accident, meanwhile, caused the largest oil spill in Norwegian history, ushering in a stronger focus on oil spill preparedness and the establishment of the Norwegian Clean Seas Association for Operating Companies (NOFO) in 1978.

International Practice

Actual practices around the world vary significantly. The very large investments required for offshore activities have the potential to cause severe financial difficulties, if not bankrupt companies. It is therefore no surprise that a huge amount of assessment occurs on flagship projects, such as FLNG units.

Within developing countries standards are very variable with some developing countries constructing and operating platforms to similar standards to those found in Europe. In other cases, standards may be much lower – even for large state oil companies. Even in the days of buoyant oil prices poor safety practices could be observed ranging from a failure to replace damaged hand rails on walkways (only warning tape was installed in the areas where the barriers should be placed) and gaps in floor gratings not being covered.

More serious situations, during construction and shutdown maintenance, have included exceeding the SOLAS rules by having insufficient lifeboat/life-raft places for the number of people working on the platform. On one construction project, mattresses were brought on board the platform as the number of cabin berths were inadequate for the construction/commissioning workforce.

The cause of the initial hydrocarbon leakage on Piper Alpha was leakage from a flange and instances still occur where "short bolting" occurs. One example noted was on a large diameter sour gas line operating at around 50 barg.

Piper Alpha might have survived the initial explosion if the subsequent fire had not been fed with high pressure gas from three pipelines. This possibility is recognized in the design, and ESDV (Emergency Shut Down Valves) are generally installed to prevent pipelines depressuring into a damaged platform. However, the ESDVs can themselves be subject to damage in an explosion and it is common for sub surface ESDVs to be installed – which will not be affected by an explosion above water. These valves should fail closed but there are cases where these valves have not been commissioned removing an important mitigation feature. The provision of sub surface ESDVs is not universal practice.

Platforms of various sizes and complexities continue to be built. These include wellhead platforms, originally designated as being unmanned and therefore requiring minimum safety facilities. A number of these subsequently require to be permanently manned and basic accommodation is therefore provided. In some cases, during the days of high crude prices, platforms would enter production before construction was complete. Whilst no examples have been encountered of operation before fire water systems have been commissioned, there have been cases where platforms are in operation before the helideck has been completed and certified, which could cause evacuation difficulties in an emergency.

Fire water systems are an essential part of all but the most basic platforms but mistakes in the design and operation of fire water pumps are common. Whilst the provision of back-up pumps is standard practice, there are cases where all the pumps are located in the same area and are all vulnerable to a single event. Routine testing of fire pumps frequently fails to comply with NFPA (the US National Fire Protection Requirements) – this is a problem onshore as well as offshore.

As Piper Alpha demonstrated, a well-designed and operated PTW system is essential to safe operation. There are a tremendous variety of systems in operation both on and offshore. The quality of systems varies tremendously but most follow standard practice, including a requirement for authorizing and receiving signatures both before and after work takes place, together with risk assessments and auditing programmes. Whilst most systems generally work as designed, many have some shortcomings – a common one being an incomplete set of handback signatures. Whilst isolation of electrical equipment generally requires breakers to be locked open, isolation of valves does not always require valves to be locked open. Occasional examples of blinds not being installed when pumps or other equipment have been removed still occur.

Whilst most operators have a Management of Change (MOC) procedure which "ticks all the boxes", they may not always work well in practice. In one recent case, electrical cabling run after commissioning was routed through a doorway, preventing it from closing.

Whilst almost anyone involved in the hydrocarbon industry worldwide, will have heard of Piper Alpha and probably have an overview of the causes, there is still a long way to go before the lessons learned can be considered to be applied universally.

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