WELLHEAD FLOWLINE PRESSURE PROTECTION USING HIGH INTEGRITY PROTECTIVE SYSTEMS (HIPS)

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Abstract

For many years, owner/operator pipe specification practices have required that wellhead downstream piping be adequate to sustain a full wellhead shut-in. This inherently safer design practice ensured that flowline pipe was specified with a maximum allowable working pressure (MAWP) equal to or greater than the maximum pressure expected to be produced by the well. This practice has been proven to provide adequate protection in thousands of wellhead installations throughout the world.

Inherently safer practice has been challenged recently with the introduction of electric submersible pumps (ESPs) in new and existing wells. The maximum discharge pressure under block-in conditions is greater than the MAWP of existing flowline pipe. A safe alternative to replacing the pipe is the use of a high integrity protective system (HIPS) designed and managed as a safety instrumented system (SIS). While the HIPS protects the flowline, the implementation of the HIPS introduces a new cause for blocked ESP discharge, which can result in significant ESP damage and production losses. This new hazard scenario must be addressed in the overall risk reduction strategy for the ESP and pipeline.

This presentation explains how HIPS can be applied as a layer of protection against flowline overpressure in single and multiple wellhead installations. It also discusses how HIPS implementation affects the necessary ESP protection.

Introduction

An enhanced oil recovery solution, especially in ultra deep (4,000 ft.) subsea applications, is to utilize electric submersible pumps (ESP) to boost well pressure. Reasons given for installing an ESP include:

- Older, sometimes abandoned, wells still contain valuable oil reserves but insufficient pressure for efficient recovery,
- Connecting wells with different production pressures to common manifolds,
- Desire to increase production rates, and
- Existing production wells are being connected to more distant processing facilities.

A major challenge in developing these deepwater enhanced oil recovery solutions is the maximum allowable working pressure (MAWP) limitation of the downstream flowline pipe. Conventional wellhead piping practice requires that downstream piping be adequate to sustain a full wellhead shut-in. This practice has proven to be safe and effective in thousands of wellhead installations throughout the world. However, the introduction of high pressure ESPs in many off-shore fields has increased the maximum shut-in pressure beyond the MAWP of the downstream flowline pipe.

A safe and reliable alternative to replacing the existing wellhead flowlines relies on the use of a High Integrity Protective Systems (HIPS) to detect unacceptable operating pressure and initiate closure of block valves upstream of the flowline specification break, protecting the lower rated piping downstream. This solution is gaining acceptance with the latest release of API 521 providing guidance on its implementation and the Minerals Management Service (MMS) approving HIPS as a new technology application for off-shore installations in the Gulf of Mexico.

A HIPS (Figure 1) is a special class of safety instrumented system (SIS), which should be designed and managed according to ISA 84.01-2004/IEC 61511. The term “high integrity” is a reference to the amount of risk reduction typically required from the SIS in these applications. HIPS are generally assigned a target safety integrity level (SIL) of SIL 2 or SIL 3. HIPS are used when there are no other practical means to address pressure events through mechanical design.

Figure 1. High Integrity Protective System

High Integrity Protective Systems are Safety Instrumented Systems (SIS) designed and managed to achieve high integrity (e.g., SIL 2 or SIL 3) The major elements of these systems are:

Sensor(s): Detect abnormal operating conditions (over/under pressure, temperature, flow, etc.).

Logic solver: Electrical/Electronic/Programmable Electronic System that process input conditions and change outputs to initiate final element action.

Final element(s): Take the process to the safe state.
Figure 1. High Integrity Protective System

The HIPS can be designed to protect against pressure challenges from single wells or multiple wells attached to a single flowline. When the HIPS takes action, it protects the flowline by initiating wellhead shut-in, which in the event of a high pressure situation is a sound and appropriate action to take. If the HIPS acts without cause, or spuriously operates, the HIPS action results in significant economic losses from lost production. Consequently, the HIPS should be designed to be highly reliable in addition to providing high integrity for operation on demand. Redundant user-approved equipment and frequent maintenance are generally necessary to achieve these requirements.

HIPS design should consider the fast system response time necessary to act within the available process safety time. On wellhead shut-in, the ESP typically produces pressure sufficient to challenge the mechanical integrity of the flowline very quickly. The pressure rise is related to the compressibility of the material, but the pressure rise is generally rapid, resulting in a very short process safety time. For example, in liquid service, the time may be less than 5 seconds.

For wellhead protection, the greatest challenge to successful HIPS implementation is the long-term inspection, preventive maintenance, and proof testing required to maintain the equipment in the “as good as new condition.” With numerous locations scattered across large areas, owner/operators require that the equipment be maintainable by the local workforce and be environmentally robust. These requirements, in combination with the low number of inputs and outputs, favor an electrical system, using relays or trip amplifiers.

Finally, the HIPS design requires careful consideration for common cause, common mode, and systematic failures. This increases when networks of flowlines with multiple HIPS are involved and fast response times are required. When multiple HIPS functions are placed in the same logic solver, the logic solver becomes a single point of failure for the spurious shutdown of multiple wells and for dangerous failure resulting in overpressure of the flowline downstream of the pipe specification break. The probability of failure on demand (PFD) can be calculated for the HIPS using the data for the operating environment. Example data is provided in Figure 2.

Figure 2. Assumptions used in calculations

Equipment (MTTFD):
Pressure transmitter (150 years)
Trip amplifier (715 years)
Solenoid operated valve (60 years)
Block valve (60 years)

Diagnostics:
Detected faults for transmitters result in the transmitter failing to the safe state, causing the channel to vote to trip. For 2oo3 voting, the process remains on-line, because two votes to trip are required for shutdown to occur. The vote to trip initiates an alarm on the operator interface, so that maintenance is initiated in a timely fashion. The operator responds to the alarm according to a written procedure.

Common cause:
2% for pressure transmitters and trip amplifiers
0.2% for the solenoid operated valve and block valve

Test interval:
1 year

Single well protection

The production from a single well can be improved through the installation of an ESP. The production increase comes with a new hazard; the potential overpressure of the flowline on ESP shut-in. The hazard is present any time there is a flowline blockage downstream of the pipe specification break, such as closure of the boarding valve.

A HIPS can be implemented to prevent this higher pressure from propagating to the lower MAWP specification flowline by isolating the pressure source upstream of the pipe specification break. The HIPS illustrated in Figure 3 uses two out of the three (2oo3) pressure transmitters to detect high pressure in the flowline. The logic solver outputs initiate shutdown of the block valves located upstream of the pipe specification break. The final element action prevents overpressure and possible rupture of the flowline.

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The same sensors can be used to detect flowline rupture or significant flowline leakage, and the same final element action can be taken with the block valves to isolate the flowline stopping the release.

While closing the block valves protects the flowline against upstream pressure, it causes a cascade event - the ESP shut-in. The piping between the ESP and the block valves is fully rated and presents little possibility for loss of containment. However, blocking the ESP discharge can damage the ESP. The pump discharge can become blocked by various errors and failures, such as the boarding valve closing, the HIPS taking action on process demand, or either block valve failing closed spuriously. The losses associated with ESP replacement normally justify the expense of an automated ESP shutdown using an instrumented system classified as an asset protection system.

The ESP protection can be accomplished by:

- Measuring the discharge pressure upstream of the block valves and shutting off the ESP
    - protects pump against all causes of block-in downstream of the pressure transmitter whether identified or not
- Monitoring the valve position with limit switches and shutting off the ESP when either valve closes
    - this protect against closure of the block valves but no other sources of block-in downstream
    - can be a spurious trip problem; limit switches are notorious
- Initiating ESP shutdown when HIPS takes action
    - often distance between HIPS and ESP is too great
    - protects ESP (economic), so it can be sent back via communications (SCADA); not as reliable first option above

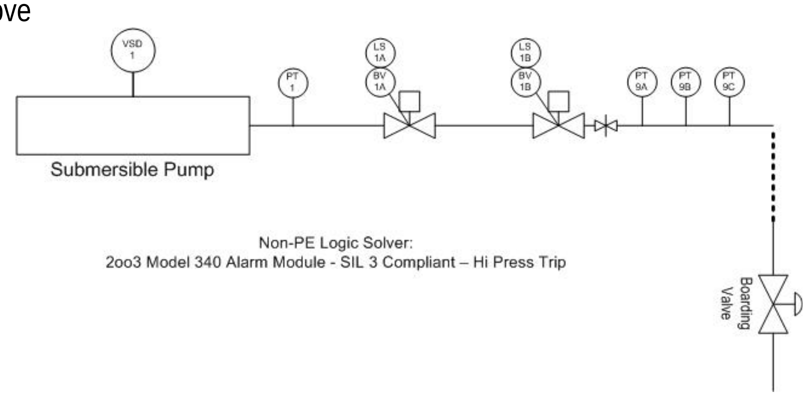

Figure 3. Single well installation

The overall risk reduction strategy for the single well installation shown in Figure 3 can be defined as:

- Prevent flow line rupture:
    - Close block valves on 2oo3 high pressure to isolate the pressure source. PFD=4.472E-04, which meets SIL 3
- Detect flowline rupture:
    - Close block valves on 2oo3 low pressure to isolate wellhead. PFD=4.472E-04, which meets SIL 3

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- Prevent pump damage:
  - Shutdown the pump on high discharge pressure. PFD=4.769E-03, which meets APL 2.

On further consideration, the need to protect the pump has now resulted in a new protection layer for high pressure. Preventing flowline rupture starts at the pressure source -- the ESP. The ESP protection could be reclassified as an SIS and implemented as part of the flowline protection strategy. The ESP protection detects high pressure on the ESP discharge and takes action to stop the ESP. The pressure propagates down the pipeline if the ESP shutdown does not work. The presence of high flowline pressure initiates closure of the block valves. If the two systems are implemented in separate SISs, the HIPS predicted performance greatly exceeds the required risk reduction. If any components are shared by both SISs, these components must be designed and managed to support the overall required risk reduction,

Multiple well protection

Many fields contain multiple wells that should be assessed as part of a network. When multiple wells are involved, the analysis and design become more complex. In the illustration (Figure 4), there are four ESPs that can overpressure the flowline when the boarding valve closes. Wellhead networks can easily exceed four interconnected wellheads.

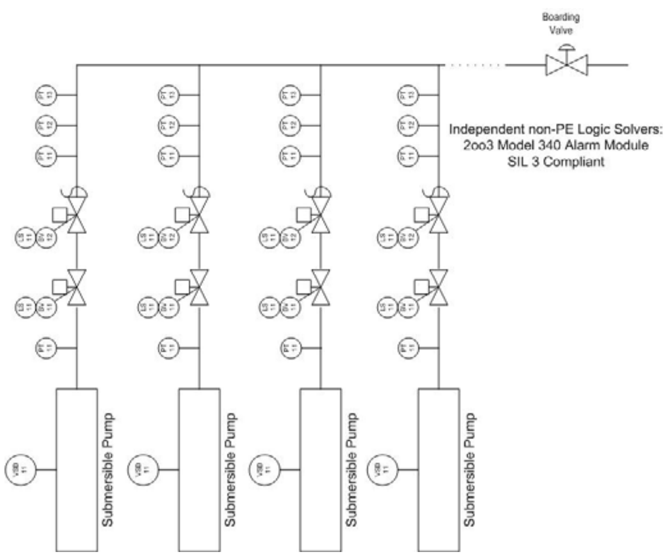

Figure 4. Four networked wells protected by individual HIPS

As more wells become networked, the risk to the flowline becomes increasingly larger. It also becomes harder to achieve the required risk reduction for the flowline protection. The PFD of the network can be approximated as 4 x 4.472E-04 = 1.789E-03, if separate and independent non-PE logic solvers are used. Even with separate SISs, the network PFD still does not meet SIL 3. As the network grows in size, the protection provided to the flowline by the HIPS declines further. Since the individual HIPS block the discharge of their respective ESP, the asset risk is similar to a single wellhead.

When the ESP protection is reclassified as an SIS, the flowline protection can be provided by two independent SISs. The overall risk reduction provided by the two independent SISs exceeds the requirements. Again, if any components are shared by both SISs, these components must be designed and managed to support the overall required risk reduction, An alternative process design (Figure 5) moves the flowline specification break to the header. This increases the amount of piping that must be rated for maximum ESP discharge pressure. The HIPS consists of a single SIS isolating the header on high pressure. The PFD meets 4.472E-04, which is the same the single well case. When the single HIPS acts, it blocks the discharge of multiple ESPs, resulting in multiple ESPs being damaged and for multiple wellheads to cease production.

As with the single well case, the implementation of individual ESP protection systems prevents flowline rupture, since each isolates the pressure source. The ESP trips also reduce the potential ESP damage and business losses from the multiple wellhead isolation, because the SIS on the flowline would only act if the ESP trip did not operate properly. If the ESP trip malfunctions, the only choice is to protect the flowline, block the ESP's discharge, and accept ESP damage. When the ESP trip is considered part of the HIPS, the predicted performance of the HIPS exceeds risk reduction requirements.

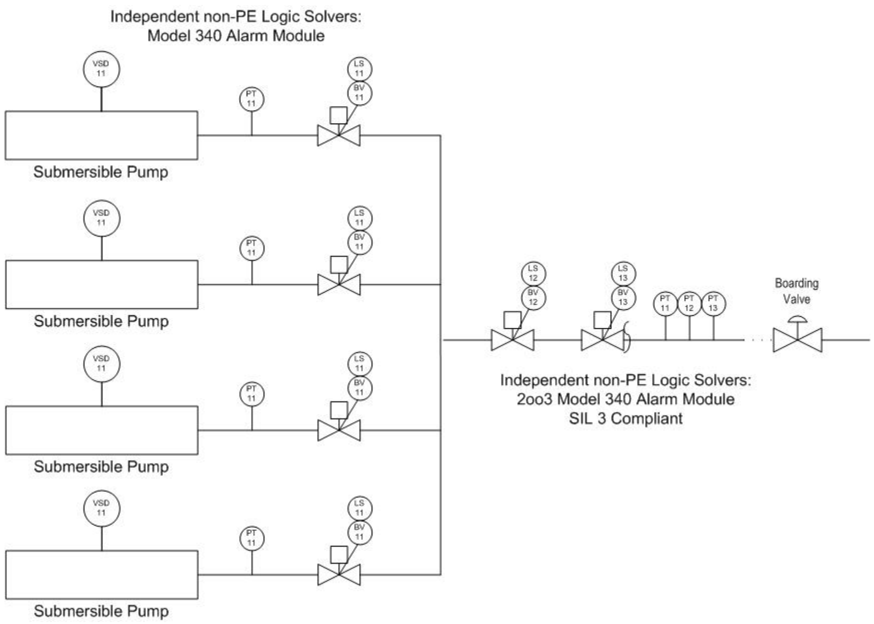

Figure 5 Four networked wells protected by single HIPS

Conclusions

An effective risk reduction strategy can only be developed based on an understanding of the overall risk to the process equipment. The overall risk includes the risk associated with the initiating cause propagating to the final consequence and the risk associated with secondary events initiated by the chosen risk reduction strategy.

A single well can be protected using a dedicated HIPS, consisting of 2oo3 pressure transmitters, 2oo3 trip amplifiers, and 1oo2 block valves. With annual testing, the PFD meets SIL 3 requirements. As more wells are networked, the flowline risk is increased and the HIPS design becomes more complicated.

When multiple, individual wellheads must be protected, it can become difficult to meet the high integrity requirements expected of HIPS. When the pipe specification break is moved to a main flowline, the network of wellheads can be protected by a single HIPS, which meets desired risk reduction.

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When a trip is added to protect the ESP from damage due to blocked discharge, a new solution to meeting the risk reduction requirements is identified. The ESP protection can be classified as an SIS and implemented as part of the HIPS strategy. The use of two independent SIS makes it possible to achieve the high risk reduction requirements.

Reference

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