AN ALTERNATIVE APPROACH TO WELLHEAD FLOWLINE PRESSURE PROTECTION

Dr. Angela E. Summers, Ph.D., P.E., President, and Bryan Zachary, Director, Product & Application Engineering, SIS-Tech Solutions, LP

Presented at the 2007 Offshore Technology Conference, Houston, Texas.

Abstract

For many years, owner/operator pipe specification standards have required that wellhead downstream piping be adequate to sustain a full wellhead shut-in. This inherently safer design practice ensured that the 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 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) with a safety integrity level (SIL) 3. This presentation explains how the HIPS approach can be applied as a layer of protection against flowline overpressure in single and multiple wellhead installations.

Introduction

When the price of crude oil started to rise above $50 per barrel, oil producing companies aggressively pursued efforts to increase or renew production in existing oil wells at a reasonable capital expenditure. 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. A major challenge in developing these deepwater enhanced oil recovery solutions is the maximum allowable working pressure (MAWP) limitation of the downstream flowline pipe. A solution gaining in popularity is the implementation of a high integrity protective system (HIPS) to close block valves located prior to the pipe specification break, protecting the lower rated piping downstream.

Conventional wellhead piping practice requires that downstream piping be adequate to sustain a full wellhead shut-in. These practices have proven 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 shutr-in pressure beyond the MAWP of the downstream flowline pipe. 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.

The design of the instrumented system response is complicated by the need to respond quickly. 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, e.g., in liquid service, the time may be less than 5 seconds.

In typical on-shore process industry applications, an overpressure hazard, such as the one presented by the ESP well flowline, would be addressed by a pressure relief device (PRD) and a disposal system, such as a flare or scrubber to safely process the material relieved during an overpressure event. When PRDs are installed in conventional flowline designs, they are typically sized to mitigate only thermal expansion of the material when the flowline is blocked-in. For HIPS flowline designs, the PRD sizing should also consider possible block valve leakage.

On-shore, the operator has time to respond to the PRD operation by manual isolating the pressure sources. The holding or disposal system is sized for the rate and duration of relief expected to occur, considering the time required for the operator to take action and for the process to achieve a safe state. This approach is impractical and uneconomic for wellhead applications. If the material could be safely held or disposed of, the holding or disposal system would be large, costly and would pose its own environmental and safety risks.

A safe and reliable alternative to replacing the existing wellhead flowlines relies on the use of a HIPS to detect unacceptable operating pressure and initiate closure of block valves. 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 high risk reduction requirements that are placed on the SIS.

Figure 1. High Integrity Protective System

High Integrity Protective Systems are Safety Instrumented Systems (SIS) designed and managed to achieve high integrity. The major elements of these systems are:

Initiator(s): Analog or discrete element(s) that measure the initiating condition (over/under pressure, temperature, flow, etc.).

Logic solver: Logic solver(s) (programmable or relay) that evaluate initiator inputs and determine the appropriate final element output action.

Final element(s): Final elements (i.e., actuators and valves) that mitigate unsafe conditions.

HIPS may be implemented to protect against pressure challenges from single wells or multiple wells attached to a single flowline. The production losses associated with well shut-in are generally high enough that the HIPS must be highly reliable, as well as demonstrate high integrity in the operating environment. Redundant user-approved equipment and frequent maintenance are generally necessary to achieve these requirements. HIPS complexity requires careful consideration for common cause, common mode, and systematic failures. The complexity increases when networks of flowlines 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.

For wellhead protection, the greatest challenge to successful design and management of the HIPS is the long-term inspection, 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.

Single Well Protection

The production from a single well can be improved through the installation of an ESP. Improved production 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 (Figure 2). The ESP shut-in results in a rapid increase in discharge pressure. The HIPS measures the pressure downstream of the pipe specification break. When two out of the three (2oo3) pressure transmitters indicate a high pressure condition, the logic solver outputs initiate shutdown of the block valves located prior to the pipe specification break. This action prevents overpressure and possible rupture of the flowline.

The intent of the HIPS is to prevent pressure from propagating to lower MAWP specification flowlines by isolating the pressure source. While closing the block valves accomplishes this, it causes a cascaded event - the ESP shut-in. While the upstream piping is fully rated and presents little possibility for loss of containment, blocking the pump discharge can damage the ESP, which is an important asset and very expensive to replace. The pump discharge can become blocked by various errors and failures, such as the boarding valve closing, the HIPS taking action on process demand, and either block valve failing closed spuriously. The protection of the pump is outside the scope of this paper, but consideration should be given to an automated shutdown of the submersible pump, since the process safety time is seconds, rendering operator response to an alarm ineffective.

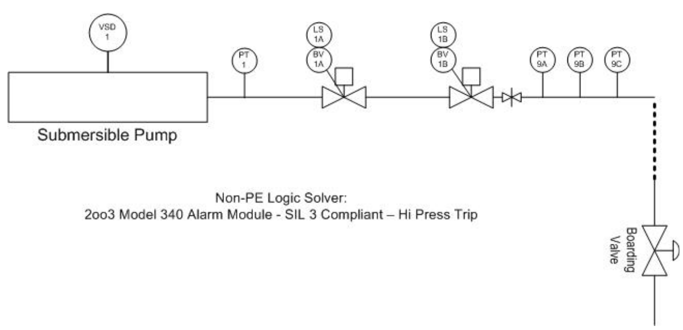

Figure 2. Single well installation

Finally, flowline overpressure, loss of mechanical integrity, or external impact may cause a rupture of the flowline or in a significant leakage from it. Low pressure can be detected by the same transmitters used to detect high pressure. Consequently, the overall risk reduction strategy is:

<u>Prevent flow line rupture:</u>

1. Shutdown submersible pump on 2oo3 high pressure to stop the pressure source and
2. Close block valves on 2oo3 high pressure to isolate the pressure source.

<u>Prevent pump damage:</u>

1. Shutdown the pump on blocked discharge (not in scope of paper).

<u>Mitigate flowline rupture:</u>

1. Shutdown the pump and block valves on low-low pressure to stop the flow of material upon loss of flowline integrity (i.e., leak, rupture, etc.).

The probability of failure on demand (PFD) is calculated by fault tree analysis using the device mean time to failure dangerous (MTTFD), the voting architecture, the proof test interval, and the mean time to repair. The equipment MTTFD is as follows: pressure transmitter (150 years), trip amplifier (715 years), solenoid operated valve (60 years), and block valve (60 years). Detected faults in the transmitter result in the transmitter failing to the safe state, causing the channel to vote to trip. 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 is assumed to be 2% for the pressure transmitters and trip amplifiers, while 0.2% was assumed for the solenoid operated valve and block valve. With an annual proof test interval and a 72 hour mean time to repair (MTTR), the PFD is 4.472E-04, which meets SIL 3.

Multiple Well Protection

Many fields contain multiple wells, which should be assessed as part of a network. When multiple wells are involved, the analysis and design become more complex. In the illustration below, there are four pumps that can overpressure the flowline on boarding valve closure.

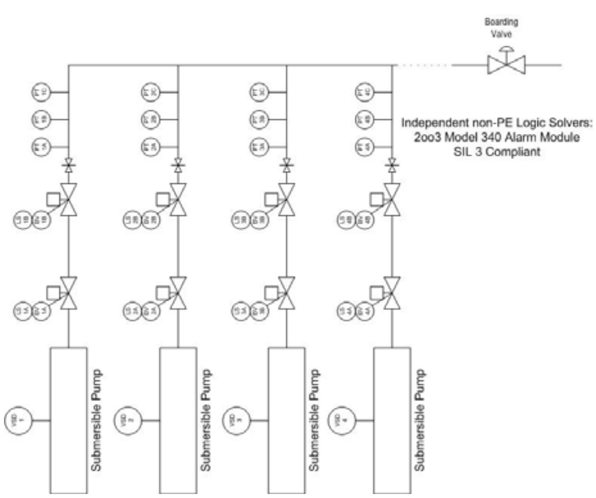

Figure 3. Four networked wells protected by individual HIPS

As more wells become networked, the risk to the flowline becomes increasingly larger. Consequently, it becomes harder to achieve the required risk reduction for the pipeline protection. The PFD of the network can be approximated as 4 x 4.472E-04 = 1.789E-03, if the four HIPS are implemented as independent and separate systems. If the HIPS are implemented in one logic solver, the logic solver becomes the single point of dangerous and spurious failure for the network. Even with separate non-PE logic solvers, the network PFD still does not meet SIL 3. As the network grows in size, the performance declines further.

An alternative process design moves the pipe specification break to the header as shown below. This increases the amount of piping that must be rated for maximum pump discharge pressure. The risk reduction for the flowline protection is achieved using a single HIPS on the header. It is important to recognize that a single HIPS can now result in the blocked discharge of multiple pumps. The PFD for the network of pumps is 4.472E-04.

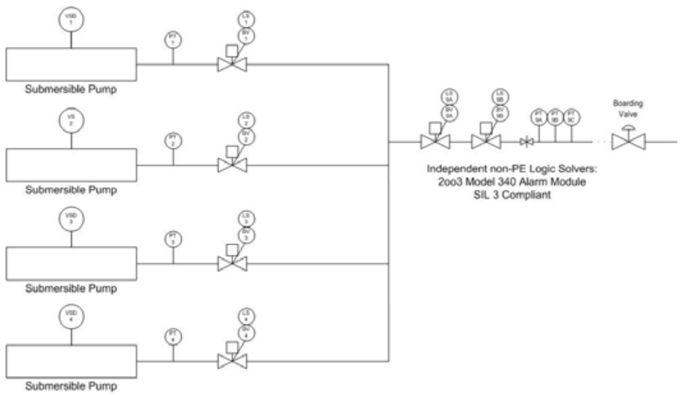

Figure 4. Four networked wells protected by single HIPS

Conclusions

An effective risk reduction strategy can only be developed based on an understanding of the overall risk presented by the initiating cause. A single well can be protected using a dedicated HIPS, using 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 cumulative and the HIPS design becomes more complicated. If individual wellheads must be protected, it can become impossible to meet the high integrity requirements. When the pipe specification break is moved to a main flowline, the network of wellheads can be protected by a single HIPS, making it possible to achieve the risk reduction requirements.

Reference

IEC 61511, Functional Safety: Safety Instrumented Systems for the Process Industry Sector, International Electrotechnical Commission, Geneva, Switzerland (2003).

ANSI/ISA 84.00.01-2004 (IEC 61511 modified), Functional Safety: Safety Instrumented Systems for the Process Industry Sector, Instrumentation, Systems, and Automation Society, Research Triangle Park, NC (2004).