# Recommended Practice for Analysis, Design, Installation, and Testing of Safety Systems for Subsea Applications

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## Introduction

This recommended practice (RP) presents a systematization of proven practices for providing a basic safety system for subsea applications. Proper application of these practices, along with good design, maintenance, and operation of the entire production facility can provide an operationally safe system.

# Recommended Practice for Analysis, Design, Installation, and Testing of Safety Systems for Subsea Applications

## 1 Scope

### 1.1 General

This recommended practice (RP) presents recommendations for designing, installing, and testing a process safety system for subsea applications. The basic concepts of subsea safety systems are discussed and protection methods and requirements of the system are outlined.

For the purposes of this RP, 'subsea system' includes all process components from the wellhead (and surface controlled subsurface safety valve [SCSSV]) to upstream of the boarding shutdown valve. For gas injection, water injection, and gas lift systems, the shutdown valve is within the scope of API 17V. This also includes the chemical injection system. Refer to Figure 1.

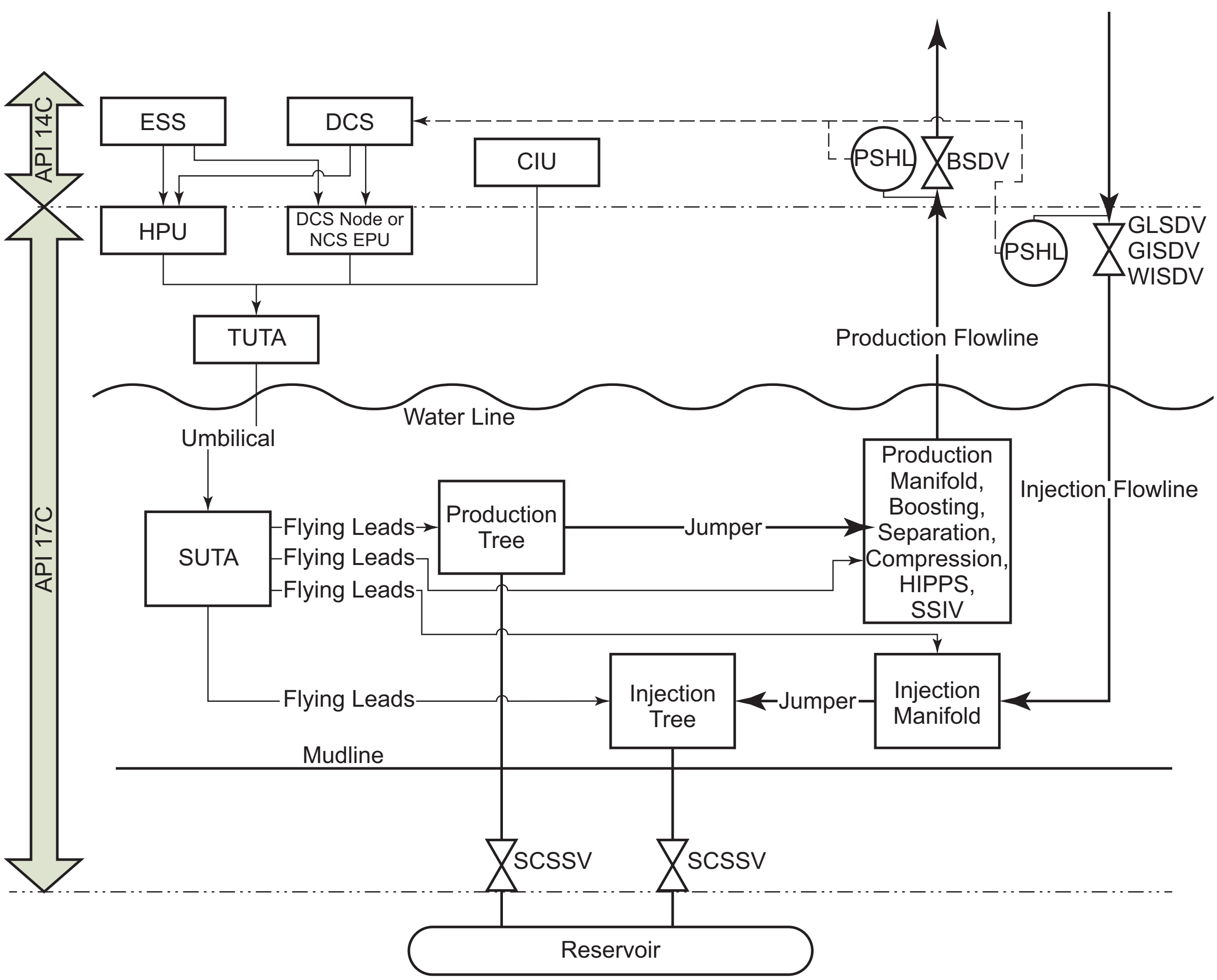


**Figure 1—API RP 17V Scope**

This document is a companion document to API 14C, which provides guidance for topsides safety systems on offshore production facilities. Some sections of this document refer to API 14C for safety system methodology and processes. This RP illustrates how system analysis methods can be used to determine safety requirements to protect any process component. Actual analyses of the principal components are developed in such a manner that the requirements determined will be applicable whenever the component is used in the process. The safety requirements of the individual process components may then be integrated into a complete subsea safety system. The analysis procedures include a method to document and verify system integrity. The uniform method of identifying and symbolizing safety devices is presented in API 14C and adopted in this RP.

Subsea systems within the scope of this document include:

— subsea trees (production and injection), flowlines, and SCSSVs;

— chemical injection lines;

— manifolds;

— subsea separation;

— subsea boosting;

— subsea compression;

— flowlines;

— gas lift;

— high integrity pressure protection system (HIPPS);

— subsea isolation valves;

— risers;

— hydraulic power unit.

The safety system includes valves and flow control devices in the production system. The safety system also includes sensors installed in the production system to detect abnormal conditions and allow corrective action to be taken (whether manual or automatic).

The intention is to design subsea safety systems to meet the requirements of IEC 61511; this document supplements these requirements.

Procedures for testing common safety devices are presented with recommendations for test data, test frequency, and acceptable test tolerances.

Instrumentation logic circuits are not discussed since these should be left to the discretion of the designer as long as the recommended safety functions are accomplished. Rotating machinery is considered in this RP as a unitized process component as it interfaces with the subsea safety system. When rotating machinery (such as a pump or compressor) is installed as a unit consisting of several process components, each component may be analyzed as prescribed in this RP.

### 1.2 Organization of Technical Content

The technical content of this RP is arranged as follows:

Section 2: Provides a listing of the normative references relating to this RP.

Section 3: A compilation of terms, definitions, acronyms, and symbols used throughout this document, including recommended standard symbols and abbreviations for safety device and process component identification.

Section 4: The general purpose, functional requirements, and basic premises of subsea safety system analysis and design.

Section 5: A detailed discussion of recommended safety analysis techniques, the concepts of protection from which they were developed, and a step-by-step procedure for analyzing and establishing design criteria for a subsea safety system.

Annex A: A safety analysis for each process component commonly used in a production process, including a checklist of additional criteria that should be considered when the component is used in a specific process configuration.

Annex B: A discussion of supporting systems that perform specific safety functions common to the entire facility.

Annex C: Testing procedures and reporting methods for the accumulation of safety system test data that can be used for operational analysis and reports that may be required by regulatory agencies.

### 1.3 Government Codes, Rules, and Regulations

Regulatory agencies have established certain requirements for the design, installation, and operation of offshore production facilities. In addition to federal regulations, certain state and local regulations may be applicable.

In addition to the regulations listed in API 14C, the following federal documents pertain to offshore oil and gas producing operations and should be used when applicable:

— 30 *Code of Federal Regulations* Part 250, Subpart H (O*il and Gas Sulphur Operations in the OCS*) and Subpart J (*Pipelines and Pipeline Right-of-Ways*);

— 40 *Code of Federal Regulations* Part 112, Chapter I, Subchapter D (*Oil Pollution Prevention*).

## 2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Specification 6A, *Specification for Wellhead and Christmas Tree Equipment*

API Specification 6AV1, *Specification for Validation of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service*

API Specification 14A, *Specification for Subsurface Safety Valve Equipment*

API Recommended Practice 14B, *Design, Installation, Repair and Operation of Subsurface Safety Valve Systems*

API Recommended Practice 14C, *Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms*

API Recommended Practice 14H, *Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore*

API Recommended Practice 14J, *Design and Hazards Analysis for Offshore Production Facilities*

API Specification 17D, *Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment*

API Recommended Practice 17O, *Recommended Practice for Subsea High Integrity Pressure Protection System (HIPPS)*

API Technical Report 6AF, *Technical Report on Capabilities of API Flanges under Combinations of Load*

IEC 61511 [1], Functional Safety—Safety Instrumented Systems for the Process Industry Sector

# 3 Terms, Definitions, Acronyms, and Abbreviations

For the purposes of this document, the following definitions apply.

## 3.1 Safety Device Symbols and Identification

A standard method for identifying, abbreviating, and symbolizing individual safety devices is necessary to promote uniformity when describing or referring to safety systems. This method can be used to illustrate safety devices on flow diagrams and other drawings, and to identify an individual safety device for any purpose. Refer to API 14C for functional device identification, symbols, component identification, and identification examples.

## 3.2 Terms and Definitions

For the purposes of this document, the following definitions apply.

**3.2.1**
**abnormal operating condition**
Condition that occurs in a process component when an operating variable ranges outside of its normal operating limits.

**3.2.2**
**abnormal temperature**
Temperature in a process component above or below the allowable temperature.

**3.2.3**
**backflow**
Fluid flow in a process component opposite to the normal flow direction.

**3.2.4**
**barrier**
Element forming part of a pressure-containing envelope that is designed to prevent unintentional flow of production/injected fluids, particularly to the external environment.

NOTE For more detail, refer to API 17A.

1 International Electrotechnical Commission, 3, rue de Varembé, P.O. Box 131, CH-1211, Geneva 20, Switzerland, www.iec.ch.

**3.2.5**
**choke**
Device that controls pressure and flow rate by a fixed or adjustable amount.

NOTE 1 Chokes are not considered a safety device.

NOTE 2 For the purpose of this document, figures may show chokes for clarity.

**3.2.6**
**detectable abnormal condition**
An abnormal operating condition that can be automatically detected.

**3.2.7**
**emergency shutdown (ESD) system**
System of manual stations that, when activated, initiates facility shutdown.

NOTE Activation of the emergency shutdown (ESD) system may also be initiated automatically by fire detection devices and other safety devices.

**3.2.8**
**fail closed valve**
A valve that will shift to the closed position upon loss of the power medium.

**3.2.9**
**fail open valve**
A valve that will shift to the open position upon loss of the power medium.

**3.2.10**
**failure**
Improper performance or operation of a device or equipment item that prevents completion of its design function or intent.

**3.2.11**
**final element**
Part of a safety instrumented system that implements the physical action necessary to achieve a safe state.

**3.2.12**
**flowline**
Piping that directs the well fluids from the wellhead to an offshore or onshore facility.

**3.2.13**
**flow safety valve**
A check valve installed in the system to minimize back flow.

**3.2.14**
**flowline segment**
Any portion of a flowline that has an operating pressure different from another portion of the same flowline.

**3.2.15**
**fully rated**
The design pressure of the system is greater than or equal to the maximum allowable working pressure.

**3.2.16**
**gas blowby**
The discharge of gas from a process component through a liquid outlet.

**3.2.17**
**high liquid level**
Liquid level in a process component above the highest operating level.

**3.2.18**
**high pressure**
Pressure in a process component in excess of the maximum operating pressure, but less than the maximum allowable working pressure (MAWP) (for flowlines, maximum allowable operating pressure).

**3.2.19**
**high temperature**
Temperature in a process component in excess of the design operating temperature.

**3.2.20**
**inherently safe design**
A design that avoids hazards instead of controlling them, particularly by reducing the amount of hazardous material and the number of hazardous operations.

**3.2.21**
**interlock**
A function that prevents an action given a certain set of defined conditions are met.

**3.2.22**
**leak**
The inability of a device (i.e. valve) to seal, referring to internal leakage within the process.

**3.2.23**
**liquid overflow**
The discharge of liquids from a process component through a gas (vapor) outlet.

**3.2.24**
**logic solver**
The portion of a safety system that performs one or more logic function(s).

**3.2.25**
**loss of containment**
The escape of fluids from a process component to the environment; alternatively, the environment entering into the process in under pressured systems.

**3.2.26**
**low flow**
Flow in a process component less than the minimum operating flow rate.

**3.2.27**
**low liquid level**
Liquid level in a process component below the lowest operating level.

**3.2.28**
**low pressure**
Pressure in a process component less than the minimum operating pressure.

**3.2.29**
**low temperature**
Temperature in a process component less than the minimum operating temperature.

**3.2.30**
**malfunction**
Any condition of a device or an equipment item that causes it to operate improperly, but does not prevent the performance of its design function.

**3.2.31**
**maximum allowable working pressure**
**MAWP**
The highest operating pressure allowable at any point in any component other than a flowline during normal operation or static conditions.

**3.2.32**
**nuisance trips**
Activation of the safety system due to an internal systems failure or human error.

NOTE Commonly known as a false or spurious systems failure.

**3.2.33**
**overpressure**
Pressure in a process component in excess of the MAWP (for flowlines, maximum allowable operating pressure).

**3.2.34**
**permissive**
A function that allows an action or state when all defined conditions are met.

**3.2.35**
**process component**
A single functional piece of subsea production equipment and associated piping used, such as a separator, compressor, or pump.

**3.2.36**
**process shutdown**
The isolation of a given subsea process by dual barriers to shut-in flow.

**3.2.37**
**qualified person**
An individual with characteristics or abilities gained through training, experience, or both, as measured against established requirements, such as standards or tests, which enable the individual to perform a required function.

**3.2.38**
**safety device**
An instrument or control device used within the safety system.

**3.2.39**
**sensor**
A device used to sense or measure the condition of a process variable or condition of a piece of process equipment and provide input to the process control or safety system.

**3.2.40**
**safety instrumented function**
**SIF**
A function implemented by a safety instrumented system (SIS) to achieve or maintain a safe state for the process in a specific hazardous event. Each SIF is designed and tested to meet its target safety integrity level (SIL).

**3.2.41**
**safety instrumented system**
**SIS**
A system of sensors, logic solvers, and actuators that take a process to a safe state when normal predetermined set points are exceeded or safe operating conditions are violated.

**3.2.42**
**shutdown valve**
**SDV**
An automatically operated, fail closed valve used for isolating equipment.

**3.2.43**
**source**
Any contained volume of hydrocarbons.

**3.2.44**
**subsea isolation valve**
**SSIV**
An emergency shutdown valve located in the flowline that is normally installed below the splash-zone, often on the seabed.

**3.2.45**
**subsea safety system**
An arrangement of safety devices and ESSs to effect the subsea system shutdown.

NOTE The system may consist of a number of individual process shutdowns and may be actuated by either manual controls or automatic devices sensing detectable abnormal conditions.

**3.2.46**
**under pressure**
Pressure in a process component less than the design collapse pressure.

**3.2.47**
**underwater safety valve**
**USV**
An automatic valve assembly (installed at an underwater wellhead location) that provides a tested barrier to the wellstream and is fail closed.

**3.2.48**
**undesirable event**
An adverse occurrence or situation in a process component or process station that poses a threat to safety, such as overpressure, under pressure, liquid overflow, etc.

## 3.3 Acronyms and Abbreviations

The following acronyms and abbreviations are used in this specification:

| | |
|---|---|
| AMV | annulus master valve |
| ANSI | American National Standards Institute |
| AWV | annulus wing valve |
| API | American Petroleum Institute |
| ASME | American Society of Mechanical Engineers |
| BSDV | boarding shutdown valve |

| | |
|---|---|
| CIU | chemical injection utilities |
| CIV | chemical injection valve |
| DCS | distributed control system |
| EPU | electrical power unit |
| ESD | emergency shutdown |
| ESS | emergency support system |
| FSV | flow safety valve |
| GISDV | gas injection shutdown valve |
| GLIV | gas lift isolation valve |
| GLSDV | gas lift shutdown valve |
| HAZOP | hazard and operability study |
| HIPPS | high integrity pressure protection system |
| HPU | hydraulic power unit |
| ISA | International Society of Automation |
| LAH | level alarm high |
| LAHH | level alarm high high |
| LAL | level alarm low |
| LALL | level alarm low low |
| LSH | level safety high |
| LSL | level safety low |
| MAWP | maximum allowable working pressure |
| MCS | master control station |
| NACE | National Association of Corrosion Engineers |
| OCS | outer continental shelf |
| PMV | production master valve |
| PSH | pressure safety high |
| PSHL | pressure safety high/low |
| PSL | pressure safety low |
| PSV | pressure safety valve |
| PT | pressure transmitter |
| ROV | remotely operated vehicle |
| RP | recommended practice |
| SAC | safety analysis checklist |
| SAFE | safety analysis function evaluation |
| SAT | safety analysis table |
| SCSSV | surface controlled subsurface safety valve |
| SDV | shutdown valve |
| SIF | safety instrumented function |
| SIL | safety integrity level |
| SIS | safety instrumented system |

| | |
|---|---|
| SITP | shut-in tubing pressure |
| SSIV | subsea isolation valve |
| SSV | surface safety valve |
| SUTA | subsea umbilical termination assembly |
| TR | technical report |
| TSH | temperature safety high |
| TSHL | temperature safety high/low |
| TSL | temperature safety low |
| TUTA | topsides umbilical termination assembly |
| USV | underwater safety valve |
| WISDV | water injection shutdown valve |
| XOV | crossover valve |

# 4 Introduction to Safety Analysis and System Design

## 4.1 Purpose and Objectives

Subsea safety systems protect personnel, the environment, and the facility from production process threats. A safety analysis identifies undesirable events that might pose a threat to safety and/or environment, and defines reliable protective measures that will prevent such events or minimize their effects if they occur.

Potential threats to safety and/or the environment are identified through proven system analyses that have been adapted to the production process. These analyses include hazard identification (HAZID), hazard and operability study (HAZOP), layer of protection analysis (LOPA), and failure modes, effects, and criticality analysis (FMECA), among others. Recommended protective measures are common industry practices that are proven through experience. System analyses and protective measures have been combined into safety analyses for subsea production systems.

The subsea safety system shall meet the requirements of IEC 61511.

The content of this RP establishes a firm basis for designing and documenting a safety system for subsea components, systems, and processes.

Moreover, it establishes guidelines for analyzing components or systems that are new or significantly different from those covered in this document. However, it is incumbent on the user to apply appropriate additional hazardous analysis methodologies to ensure that hazards are identified and mitigated.

Before a production subsea safety system is placed in operation, procedures should be established to assure continued system integrity. Annex C may be used for this purpose.

## 4.2 Safety Flow Chart

The safety flow chart in Figure 2 depicts the manner in which undesirable events could result in personnel injury, pollution, or facility damage. It also shows where safety devices or procedures should be used to prevent the propagation of undesirable events. As shown on the chart, the release of hydrocarbons is a factor in virtually all threats to safety. Thus, the major objective of the safety system should be to prevent the release of hydrocarbons from the process and to minimize the adverse effects of such releases if they occur.

a) Referring to Figure 2, the overall objectives may be enumerated as follows:

1) prevent undesirable events that could lead to a release of hydrocarbons;

2) shut-in the process or affected part of the process to stop the flow of hydrocarbons to a leak or overflow if it occurs.

b) Accidents caused by events external to the subsea system are not self-propagating unless they affect the process or start a fire. If they affect the process, the safety system should shut down the process or affected part of the process. If they result in fire, the safety system should shut down all subsea activity. Such accidents may be caused by natural phenomenon, dropped objects, failure of tools and machinery, or mistakes by personnel. These types of accidents may be prevented or minimized through safe design of tools and machinery, safe operating procedures for personnel and equipment, and personnel training. Figure 2 indicates the manner in which external accidents may affect the process.

## 4.3 Safety System Operation

The safety system provides protection in the following ways:

a) automatic monitoring and automatic protective action if an abnormal condition indicating an undesirable event can be detected by a sensor;

b) protective action manually actuated by personnel who observe or are alerted to an unsafe condition by an alarm;

c) continuous protection by support systems that minimize the effects of escaping hydrocarbons.

The emergency shutdown (ESD) system is required for all offshore facilities. These ESD systems are required for those facilities that are not continuously occupied, because many accidents and failures are caused by human error and may occur on normally unoccupied facilities during those times when personnel are aboard and conducting maintenance or other activities. Thus, personnel may be available to actuate the system.

## 4.4 Premises for Basic Analysis and Design

The recommended analysis and design procedures for a subsea safety system are based on the following premises.

a) The subsea facility will be designed for safe operation in accordance with good engineering practices.

b) The principles of inherently safe design are followed.

c) The safety system should provide two levels of protection to prevent or minimize the effects of an equipment failure within the process.

d) The two levels of protection should be the highest order (primary) and then the next highest order (secondary) available. Judgment is required to determine these two highest orders for a given situation. As an example, two levels of protection from a rupture due to overpressure might be provided by a pressure safety high (PSH) or pressure safety valve (PSV). The PSH prevents the rupture by shutting in affected equipment before pressure becomes excessive, and the PSL shuts in affected equipment after the rupture occurs. However, a PSV is selected in lieu of the PSL, because it prevents the rupture by relieving excess volumes to a safe location. Moreover, its fast response could prevent a rupture in situations where the PSH might not effect corrective action fast enough.

e) The use of proven systems analysis techniques, adapted to the production process, determine the minimum safety requirements for a process component. If such an analysis is applied to the component as an independent unit, assuming worst case conditions of input and output, the analysis will be valid for that component in any process configuration.

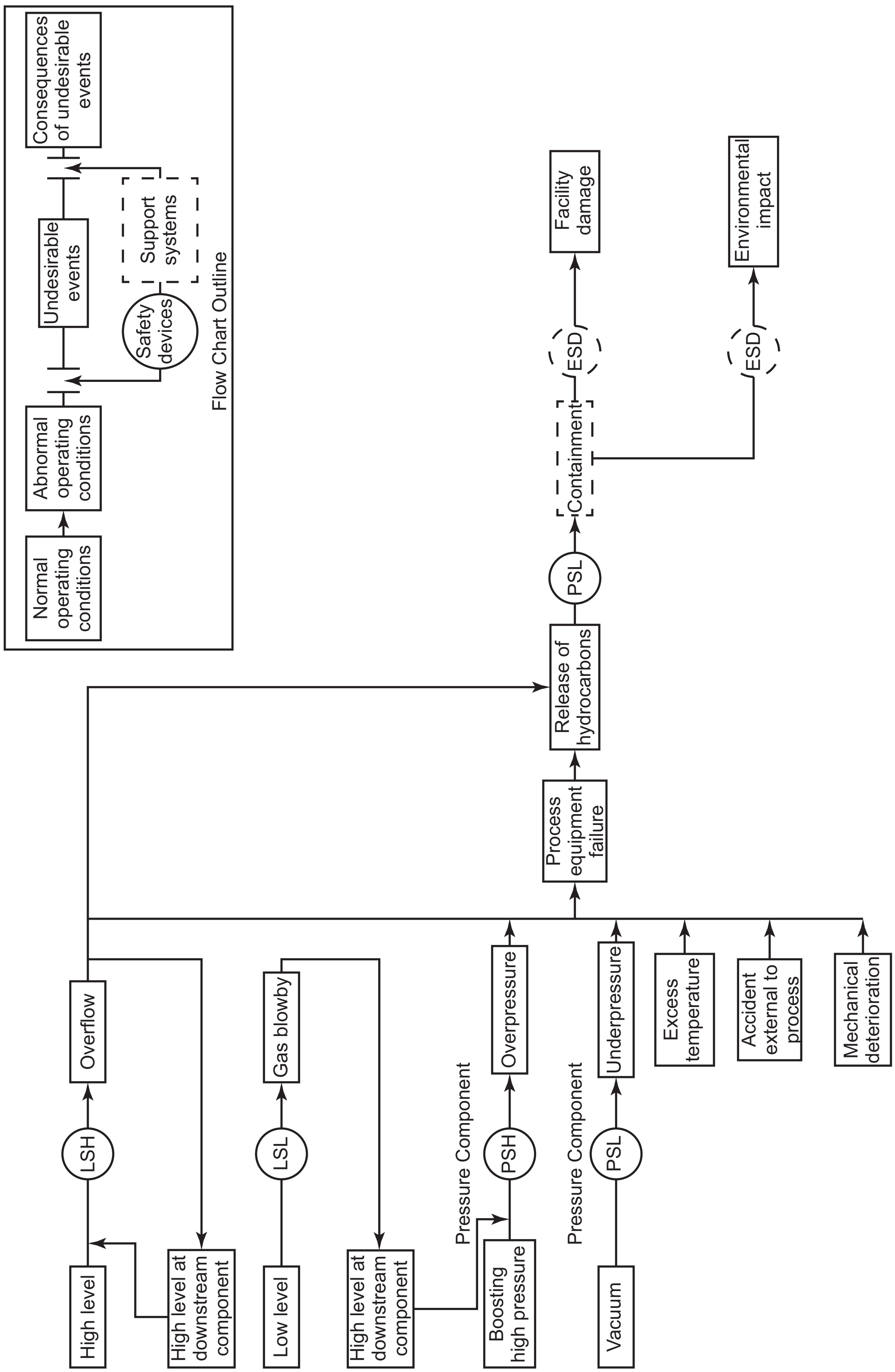


**Figure 2—Safety Flow Chart–Subsea Production Facility**

f) All the components from the wellhead (and SCSSV) to upstream of the boarding shutdown valve comprise the subsea system. This also includes the chemical injection system.

g) When fully protected process components are combined into a system, no additional threats to safety are created. Therefore, if all process component safety devices are logically integrated into a safety system, the entire facility will be protected. It is incumbent on the user to apply appropriate additional hazard analysis methodologies to ensure that hazards are identified and mitigated.

h) The subsea production control system is not considered a safety system; however, it contributes to the overall safety system.

i) The analysis procedure should provide a standard method to develop a safety system and provide supporting documentation.

# 5 Protection Concepts and Safety Analysis

## 5.1 Introduction

The analysis and design of a subsea safety system should focus on personnel safety, preventing releases of hydrocarbons, stopping the flow of hydrocarbons resulting from a loss of containment if it occurs, as well as preventing and mitigating the ingress of seawater resulting from a loss of containment in an under pressure system scenario.

Section 5.2 explains the basic concepts of protection used in the analysis. These concepts are repeated in Annex A, as applicable to individual component analysis.

Section 5.3 discusses methods of analyzing the process and establishing design criteria for an integrated safety system covering the entire subsea process.

Section 5.4 is a step-by-step summary for performing a safety analysis in accordance with this document. It is indicated that this method initially considers each component independently from the rest of the process and may recommend safety devices that are not required after larger segments of the process are considered. For example, many safety devices initially considered on manifolds are not normally required because their safety function is performed by devices on other components.

## 5.2 Protection Concepts

### 5.2.1 General

As defined in 1.1 and Figure 1, the boarding valve acts as a barrier between the subsea and topsides systems. The integrity of the boarding valve serves as the foundation of the protection concepts. It protects the topsides facility if an event occurs in the subsea system. Subsea systems are designed to be fully rated to shut-in tubing pressure (SITP). If the system is not fully rated (e.g. introduction of a HIPPS system), additional protection concepts are required as described herein.

Two barriers shall always be in place between a hydrocarbon source and the environment during normal production operations. However, it is acceptable practice to shut-in production and remove a pressure barrier (e.g. pressure cap) during temporary activities, such as well tie-in operations and remotely operated vehicle (ROV) sampling. For further definition of barrier philosophy, refer to API 17A.

### 5.2.2 Undesirable Events

#### 5.2.2.1 General

An undesirable event is an adverse occurrence in a process component that poses a threat to system integrity. The undesirable events discussed in this section can develop in a process component under worst-case conditions of input and output. An undesirable event may be indicated by one or more process variables ranging out of operating limits. These abnormal operating conditions can be detected by sensors that initiate shut down action to protect the process component.

Each undesirable event that can affect a process component is discussed according to the following format:

a) cause;

b) effect and detectable abnormal condition;

c) primary and secondary protection that should prevent or react to its occurrence.

#### 5.2.2.2 Overpressure

##### 5.2.2.2.1 General

Overpressure is pressure in a process component in excess of the maximum allowable working pressure (MAWP).

##### 5.2.2.2.2 Cause

Overpressure can be caused by various scenarios that develop a pressure that is in excess of the MAWP of the component. Typical causes of overpressure include, but are not limited to, the following.

a) An input source that will develop pressure in excess of a process component's MAWP if inflow exceeds outflow. Inflow may exceed outflow if an upstream flowrate control device fails, if there are restrictions or blockages in the component's outlets, or if overflow or gas blow-by from an upstream component occurs.

b) Backflow occurs from a downstream source with a higher operating pressure than the MAWP of the component. Backflow could occur when forward flow is stopped, allowing reverse flow to the upstream components. Typical examples include centrifugal pumps and compressors where the suction side has a MAWP lower than the downstream operating pressure. Check valves should not be assumed to prevent such backflow as they are subject to leaking and failing open on demand. Careful consideration should also be given to side streams feeding into the system.

c) Settle-out pressure resulting from compressor shutdown results in a pressure exceeding the MAWP of any component in the system. This scenario can occur when the MAWP of the suction side of a compressor is lower than the resulting settle out pressure.

d) Misdirected flow resulting from a high-pressure source inadvertently routed to a component having a lower MAWP.

Causes of overpressure can vary and will depend upon the facility design and operating conditions.

##### 5.2.2.2.3 Effect and Detectable Abnormal Condition

The effect of overpressure can be a sudden rupture and leak of hydrocarbons. High pressure is the detectable abnormal condition that indicates that overpressure may occur.

##### 5.2.2.2.4 Primary Protection

For the purposes of this RP, a fully rated system considers the equipment as primary protection. If the system is not fully rated, HIPPS shall be required.

##### 5.2.2.2.5 Secondary Protection

Secondary protection from overpressure in a pressure component should be provided by a PSH to shut off inflow.

##### 5.2.2.2.6 Location of Safety Devices

In a process component with both a liquid and a gas section, the PSH should be installed to sense pressure from the gas or vapor section. The sensing connections for the safety devices should be located at the highest practical location on the component to minimize the chance of fouling by flow stream contaminants.

#### 5.2.2.3 Loss of Containment

##### 5.2.2.3.1 General

A loss of containment refers to the escape of fluids from a process component to the environment or alternatively, the environment entering into the process in under pressured systems.

##### 5.2.2.3.2 Cause

A loss of containment can be caused by deterioration from corrosion, erosion, and mechanical failure or temperature effects; by rupture from overpressure or under pressure; or by accidental damage from external forces.

##### 5.2.2.3.3 Effect and Detectable Abnormal Conditions

The effect of a loss of containment is the release of hydrocarbons to the environment. Low pressure and low level are the abnormal conditions that might be detectable to indicate that a loss of containment has occurred. For under pressured systems, a loss of containment may result in sea water ingress into the system. In this instance, higher than normal pressures may be detected, or the presence of sea water in a topside separator are the abnormal conditions that might be detectable to indicate that a loss of containment has occurred. Salinity detection in topsides components or a drop in normal operating temperature may indicate loss of containment.

##### 5.2.2.3.4 Primary Protection

For the purposes of this RP, a fully rated system considers the equipment as primary protection.

In the case of a non-fully rated system where a HIPPS is installed, the system shall be fully rated for external pressure.

##### 5.2.2.3.5 Secondary Protection

Secondary protection from loss of containment should be provided by a topside PSH/PSL.

##### 5.2.2.3.6 Location of Safety Devices

In a process component with both a liquid and a gas section, the PSH/PSL should be connected to sense pressure from the gas or vapor section. The PSH/PSL should be installed at the highest practical location on the component to minimize the chances of fouling by flow stream contaminants. The level safety low (LSL) should be located a sufficient distance below the lowest operating liquid level to avoid nuisance trips, but with adequate volume between the LSL and liquid outlet to prevent gas blowby before shutdown is accomplished.

#### 5.2.2.4 Liquid Overflow

##### 5.2.2.4.1 General

Liquid overflow is the discharge of liquids from a process component through a gas or vapor outlet.

##### 5.2.2.4.2 Cause

Liquid overflow can be caused by liquid input in excess of liquid outlet capacity. This may be the result of failure of an upstream flow rate control device, failure of the liquid level control system, or blockage of a liquid outlet.

##### 5.2.2.4.3 Effect and Detectable Abnormal Condition

The effects of liquid overflow can be overpressure or excess liquids in a downstream component, or release of hydrocarbons to the environment. High level is the detectable abnormal condition that indicates that overflow may occur.

##### 5.2.2.4.4 Primary Protection

Primary protection from liquid overflow should be provided by a level safety high (LSH) to shut off inflow into the component.

##### 5.2.2.4.5 Secondary Protection

Secondary protection from liquid overflow to a downstream component should be provided by safety devices on the downstream component.

##### 5.2.2.4.6 Location of Safety Devices

The LSH should be located a sufficient distance above the highest operating liquid level of a component to prevent nuisance trips, but with adequate volume above the LSH to prevent liquid overflow before shutdown is accomplished.

#### 5.2.2.5 Gas Blowby

##### 5.2.2.5.1 General

Gas blowby is the discharge of gas from a process component through a liquid outlet.

##### 5.2.2.5.2 Cause

Gas blowby can be caused by failure of a liquid level control system or inadvertent opening of a bypass valve around a level control valve.

##### 5.2.2.5.3 Effect and Detectable Abnormal Condition

The effect of gas blowby can be overpressure in a downstream component. Low level is the detectable abnormal condition that indicates gas blowby may occur.

##### 5.2.2.5.4 Primary Protection

Primary protection from gas blowby should be provided by an LSL sensor to shut off the liquid outlet.

#### 5.2.2.5.5 Secondary Protection

Secondary protection from gas blowby to a downstream component should be provided by safety devices on the downstream component.

#### 5.2.2.5.6 Location of Safety Devices

The LSL should be located a sufficient distance below the lowest operating liquid level to avoid nuisance trips, but with an adequate volume between the LSL and liquid outlet to prevent gas blowby before shutdown is accomplished.

### 5.2.2.6 Under Pressure

#### 5.2.2.6.1 General

Under pressure is pressure in a process component less than the design collapse pressure.

#### 5.2.2.6.2 Cause

Under pressure can be caused by fluid withdrawal in excess of inflow that may be the result of failure of an inlet or outlet control valve, blockage of an inlet line during withdrawal, condensation of vapor in a closed system, or thermal contraction of fluids when the inlets and outlets are closed.

#### 5.2.2.6.3 Effect and Detectable Abnormal Condition

The effect of under pressure can be collapse of the component and a leak. Low pressure is the detectable abnormal condition that indicates under pressure may occur.

#### 5.2.2.6.4 Primary Protection

Primary protection for a pressure component subject to under pressure should be provided by a system that is fully rated for under pressure.

#### 5.2.2.6.5 Secondary Protection

Secondary protection should be provided by a topside PSL.

#### 5.2.2.6.6 Location of Safety Devices

The PSL should be installed at the highest practical location on the component to minimize the chances of fouling by flow stream contaminants.

### 5.2.2.7 Temperature Effects

#### 5.2.2.7.1 General

Temperature effects involve temperatures above or below that in which a process component is designed to operate.

#### 5.2.2.7.2 Cause

High temperature can result from producing from a reservoir that is higher than design temperature. Decreased temperature can result from Joule-Thomson (JT) effect across chokes.

#### 5.2.2.7.3 Effect and Detectable Abnormal Condition

The effects of process fluid temperature can be a reduction of the working pressure and subsequent leak or rupture of the affected component and/or overpressure of the system. High temperature, low flow, and low level are the detectable abnormal conditions that indicate that abnormal temperature may occur.

#### 5.2.2.7.4 Primary Protection

Primary protection from process fluid temperature resulting from abnormal temperatures should be provided by a temperature safety high (TSH)/temperature safety low (TSL) to shut off flow of hydrocarbons.

#### 5.2.2.7.5 Secondary Protection

Secondary protection from process fluid temperature effects should be provided by a PSH/PSL.

#### 5.2.2.7.6 Location of Safety Devices

In a two-phase (gas/liquid) system, the TSH/TSL should be located in the liquid section.

### 5.2.2.8 Leak

#### 5.2.2.8.1 General

A leak refers to the inability of a device (i.e. valve) to seal, referring to internal leakage within the process. For leak to the environment, refer to 5.2.2.3.

#### 5.2.2.8.2 Cause

A leak can be caused by deterioration from corrosion, erosion, and mechanical failure or temperature effects.

#### 5.2.2.8.3 Effect and Detectable Abnormal Condition

The effect of a leak is the passage of hydrocarbons to the downstream process. Low pressure and low level are the abnormal conditions that might be detectable to indicate that a leak has occurred. A leak may also be detected as a high pressure downstream of the component.

#### 5.2.2.8.4 Primary Protection

Primary protection from a leak that creates an abnormal operating condition within a pressure component should be provided by a PSH/PSL. Primary protection from a leak from the liquid section may also be provided by a LSL.

#### 5.2.2.8.5 Secondary Protection

Secondary protection from all detectable leak(s) should be provided by using a topside PSH.

#### 5.2.2.8.6 Location of Safety Devices

In a process component with both a liquid and a gas section, the PSH/PSL should be connected to sense pressure from the gas or vapor section. The PSH/PSL should be installed at the highest practical location on the component to minimize the chances of fouling by flow stream contaminants. The LSL should be located a sufficient distance below the lowest operating liquid level to avoid nuisance trips, but with adequate volume between the LSL and liquid outlet to prevent gas blowby before shutdown is accomplished.

### 5.2.3 Safety Device Selection

The required safety device protection is categorized into primary and secondary protective devices. The primary device will react sooner or more reliably than the secondary device. The primary device will provide the highest order of protection and the secondary device should provide the next highest order of protection. General requirements include the following.

a) An underwater safety valve (USV), SCSSV, and boarding shutdown valve (BSDV) are required as a minimum for all subsea production systems.

b) When gas injection, gas lift, or water injection is used, a gas injection shutdown valve (GISDV), gas lift shutdown valve (GLSDV), or water injection shutdown valve (WISDV) shall maintain the same requirements as a BSDV.

c) A single safety device may not provide complete primary or secondary protection because the results of a failure can vary by degree or sequence. Thus, several devices or systems may be shown, the combination of which will provide the necessary level of protection. For example, a PSL sensor and a shutdown valve can be required to stop flow to a leak. These two devices can provide the primary level of protection.

d) The protection devices determined in the safety analysis table (SAT) protect the process component in any process configuration, in conjunction with necessary SDVs or other final control devices. It is important that the user understand the SAT logic and how the SATs are developed.

e) The location of SDVs and other final control devices must be determined from a study of the detailed flow schematic and knowledge of operating parameters. When an undesirable event is detected in a process component, the component can be isolated from all input process fluids, heat, and fuel, by either shutting in the sources of input or diverting the inputs to other components where they can be safely handled. If the process input is to be shut-in, it should be performed as close to the source as practical.

f) All safety devices shown in the figures in Annex A for each component would be considered and installed unless conditions exist whereby the function normally performed by a safety device is not required or is performed adequately by another safety device(s). The Safety Analysis Checklists (SACs) in Annex A list equivalent protection methods, thereby allowing the exclusion of some devices.

g) If a process component is used that is not covered in Annex A, a SAT for that component should be developed.

### 5.2.4 Protective Shut-in Action

When an abnormal condition is detected in a process component by a safety device or by personnel, all input sources of process fluids, heat, and energy should be shut off or diverted to other components where they can be safely handled. If shutoff is selected, process inputs should be shut off at the primary source of energy (e.g. wells, pump, and compressor). It is not advisable to close the process inlet to a component if this could create an abnormal condition in the upstream component, causing the safety devices to shut it in. This would be repeated for each component back through the process until the primary source is shut-in. Therefore, each component would be subjected to abnormal conditions and must be protected by its safety devices every time a downstream component shuts in. This cascading effect depends on the operation of several additional safety devices and may place undue stress on the equipment, in which:

a) it may be desirable to shut-in the inlet to a process component for additional protection or to prevent upstream components from equalizing pressure or liquid levels after the primary source is shut-in; if this is desirable, the primary source of energy should be shut-in simultaneously with or prior to closing of the component inlet valve;

b) there may be special cases where shut-in by cascading is acceptable.

#### 5.2.5 Emergency Support Systems

For emergency support system (ESS) guidance, refer to Annex B.

## 5.3 Safety Analysis

### 5.3.1 Safety Analysis Table

SATs for the basic process components of a subsea production facility are presented in Annex A. The SATs are applicable to a component regardless of its position in the process flow. The boundaries of each process component include the inlet piping, control devices, and the outlet piping to another component. Every outlet pipe and pipe branch should be included up to the point where safety devices on the next component provide protection.

The safety analysis of each process component highlights undesirable events (e.g. effects of equipment failures, process upsets, or accidents), in which protection should be provided, along with detectable abnormal conditions that can be monitored for safety surveillance. These detectable conditions are used to initiate action through automatic controls to prevent or minimize the effect of undesirable events. The tables present the logical sequence of safety system development, including undesirable events that could be created in downstream process components due to failures in the equipment or safety devices of the component under consideration.

The generic causes of each undesirable event are listed. The primary causes are equipment failures, process upsets, and accidents, but all primary causes in a category will create the same undesirable event. Thus, a blocked line could be due to plugging, freezing, or other failure of a control valve, or the inadvertent closing of a manual valve. The undesirable events should be determined from a detailed investigation of the failure modes of the component and its ancillary equipment. These failure modes are grouped under causes, according to the manner in which they may generate the undesirable event.

The protective safety devices and ESSs that prevent or react to minimize the effects of undesirable events should be designed in accordance with 5.2.

### 5.3.2 Safety Analysis Checklist

Individual SACs are shown in Annex A as an aid for discussing the application of the safety analysis to each individual component. The SAC lists the safety devices that would be required to protect each process component if it were viewed as an individual unit with the worst probable input and output conditions. Certain conditions are listed under each recommended device that eliminates the need for that particular device when the component is viewed in relation to other process components. This action is justified because safety devices on other components will provide the same protection, or because in a specific configuration, the abnormal condition that the device detects will not lead to a threat to safety.

A composite SAC for normally used process components can be found in API 14C.

### 5.3.3 Safety Analysis Function Evaluation Chart

The safety analysis function evaluation (SAFE) chart in API 14C is used to relate all sensing devices, shutdown valves (SDVs), shutdown devices, and ESSs to their functions. All equipment, topside and subsea, shall be listed on the same SAFE chart. The SAFE chart should list all process components and ESSs with their required safety devices and the functions to be performed by each device. If the device is not needed, the reason should be listed on the SAFE chart by referring to the appropriate SAC item number. If the reason for eliminating a device is that a device on another component provides equivalent protection, this alternate device should also be shown on SAFE chart. The relation of each safety device with its required function can be documented by checking the appropriate box in the chart matrix. Completion of the SAFE chart provides a means of verifying the design logic of the basic safety system.

For an example SAFE chart, refer to API 14C.

#### 5.3.4 Additional Safety Analysis Tools

API 14J is the recommended practice for hazard analysis for offshore production facilities.

### 5.4 Analysis and Design Procedure Summary

The analysis and design of a subsea safety system should include the following.

— Describe the process by a detailed flow schematic and establish the operating parameters. The flow schematic and operating parameters should be developed based on equipment design and process requirements.

— From the SATs, verify the need for basic safety devices to protect each process component viewed as an individual unit. The SAC for individual components is then used to justify the elimination of any safety device when each process component is analyzed in relation to other process components. The SAC lists specific conditions under which some safety devices may be eliminated when larger segments of the process are considered.

— If a process component significantly different from those covered in this RP is used in a process, develop an SAT and SAC table for that component.

— Using the SAFE chart, logically integrate all safety devices and self-protected equipment into a complete facility safety system. List all process components and their required safety devices on the SAFE chart. Enter the functions the devices perform and relate each device to its function by checking the appropriate box in the chart matrix.

— If designing a new facility, show all devices to be installed on the process flow schematic.

— If analyzing an existing facility, compare the SAFE chart with the process flow schematic and add the devices required but not shown.

The analysis should define the monitoring devices (sensors) and self-actuating safety devices needed for a process facility. The analysis should establish the safety functions required (e.g. shutdown, diverting the input, pressure relief).

# Annex A
(normative)

# Process Component Analysis

## A.1 General

Annex A presents a complete safety analysis of each basic process component normally used in a subsea production process system. The component analysis includes the following.

— A description of each process component.

— A typical drawing of each process component showing all recommended safety devices that should be considered based on individual component analysis. A discussion of each process component is included and outlines recommended safety device locations.

— A SAT for each process component analyzing the undesirable events that could affect the component.

— A SAC for each process component listing all recommended safety devices and showing conditions under which particular safety devices may be excluded. A discussion of the rationale for including or excluding each safety device is presented.

## A.2 Production Trees and Flowlines

### A.2.1 Description

Production trees furnish control (operator and automatic) and containment of well fluids and provide downhole access for well servicing. Flowlines transport hydrocarbons from the tree to the surface facility.

For analysis purposes and assignment of safety devices, flowlines may be divided into flowline segments. Each flowline segment must have the MAWP greater than or equal to the SITP. If the SITP exceeds the MAWP, refer to Section A.10. Recommended safety devices for typical trees and flowlines are shown in Figure A.1.

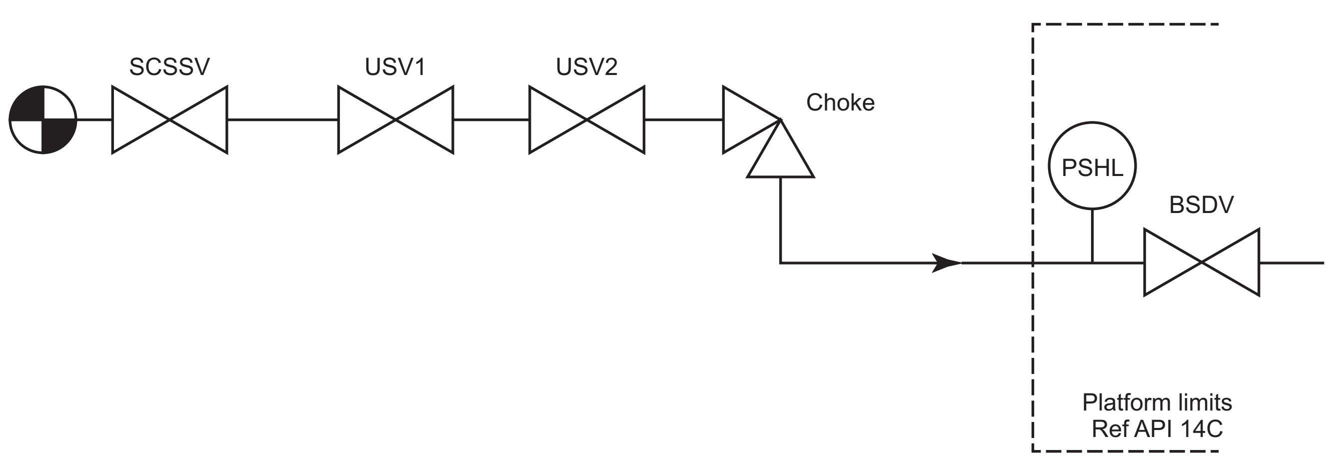


**Figure A.1—Recommended Safety Devices for Typical Trees and Flowline Segment**

## A.2.2 Safety Analysis

### A.2.2.1 Safety Analysis Table

The SAT for a tree and flowline segment is presented in Table A.1. The undesirable events that can affect a tree or flowline segment are overpressure, high temperature, low temperature, loss of containment, and leak.

**Table A.1—SAT–Production Trees and Flowline Segment**

| Undesirable Event | Cause | Detectable Abnormal Condition at Component |
|---|---|---|
| Overpressure | Blocked or restricted line<br>Downstream choke plugged<br>Hydrate plug<br>Upstream flow control failure<br>Changing well conditions<br>Closed outlet valve<br>Chemical injection<br>Thermal expansion<br>Inflow exceeds outflow<br>Secondary recovery | High pressure |
| High temperature | High reservoir temperature<br>Joule-Thomson heating | High temperature |
| Low temperature | Joule-Thomson cooling | Low temperature |
| Loss of containment | Deterioration<br>Erosion<br>Corrosion<br>Impact damage<br>Vibration<br>Seal failure<br>Connector failure | High pressure<br>Low pressure |
| Leak | Deterioration<br>Erosion<br>Corrosion<br>Vibration<br>Seal failure | High pressure<br>Low pressure |

### A.2.2.2 Safety Analysis Checklist

Table A.2 presents the SAC for a production tree and flowline segment.

### A.2.2.3 Shutdown Devices

A BSDV shall be installed; refer to API 14C. A USV shall be designed, installed, and tested in accordance with API 14H, API 17D, API 6A, and API 6AV1. A SCSSV shall be designed, installed, and tested in accordance with API 14A and API 14B.

### A.2.2.4 Pressure Safety Devices

Wells are the primary source of pressure; therefore, a topside PSH and a PSL to shut-in the well(s) shall always be provided on the riser to detect abnormally high or low pressure. A single pressure safety high/low (PSHL) on the facility may protect multiple subsea flowlines that tie into a single riser. Refer to API 14C.

NOTE Pressure sensors installed subsea may be used for indicating purposes, but are not required as part of the shutdown system unless part of HIPPS.

**Table A.2—SAC–Production Trees and Flowline Segment**

| |
|---|
| a. Pressure Safety High (PSH)<br>1. Production tree and flowline segment has a MAWP greater than or equal to the maximum SITP and is protected by a PSH on the final flowline segment. |
| b. Pressure Safety Low (PSL)<br>1. Production tree and flowline segment has a MAWP greater than or equal to maximum SITP and is protected by a PSL on the final flowline segment. |
| c. Temperature Safety High (TSH)<br>1. Production tree and flowline segment has a maximum design temperature greater than or equal to the maximum temperature.<br>2. Production tree and/or flowline segment has a maximum design temperature less than the maximum temperature. Perform a risk assessment to determine what level of risk reduction is required. Install the appropriate type of SIF required by the risk assessment. |
| d. Temperature Safety Low (TSL)<br>1. Production tree and flowline segment has a minimum design temperature lower than the minimum temperature.<br>2. Production tree and/or flowline segment has a minimum design temperature higher than the minimum temperature. Perform a risk assessment to determine what level of risk reduction is required. Install the appropriate type of SIF required by the risk assessment. |
| e. Downhole Safety Valves<br>1. SCSSV(s) installed. |
| f. Boarding Shutdown Valve (BSDV)<br>1. Flowline segment is protected by BSDV in final flowline segment/riser. |
| g. Underwater Safety Valve (USV)<br>1. Flowline segment is protected by USV in subsea tree. |

#### A.2.2.5 Temperature Safety Devices

Wells are the primary source of temperature; therefore, a topside TSH and a TSL to shut-in the well(s) shall always be provided on the riser to detect abnormally high or low temperature, if the system is not rated for temperature extremes.

NOTE Temperature sensors installed subsea may be used for indicating purposes, but are not required as part of the shutdown system unless a risk assessment determines that there is a loss of containment risk, when a Safety Instrumented Function (SIF) may be required.

### A.2.3 Safety Device Location

#### A.2.3.1 Pressure Safety Devices

The PSHs and PSLs should be located for protection from damage due to vibration, shock, and accidents. The PSH and PSL should be located upstream of the BSDV, and the sensing point should be on top of a horizontal run or in a vertical run. The PSHs and PSLs may be combined into a single PSHL.

#### A.2.3.2 Temperature Safety Devices

If required, the TSHs and TSLs should be located for protection from damage due to vibration, shock, and accidents. The TSH and TSL should be located in a position determined by risk assessment. The TSHs and TSLs may be combined into a single TSHL.

#### A.2.3.3 Downhole Safety Device

A SCSSV shall be installed in the production tubing beneath the wellhead.

#### A.2.3.4 Shutdown Device

The BSDV shall be installed in accordance with API 14C, API 6A, API 6AV1, and API 6AF.

The USV should be upstream of the subsea tree choke. The subsea tree may be equipped with more than one valve qualified to be designated as a USV.

## A.3 Injection Trees and Flowlines

### A.3.1 Description

Injection trees transfer fluids to the wellbore for reservoir injection purposes. Recommended safety devices for typical subsea injection trees are shown in Figure A.2 and Figure A.3.

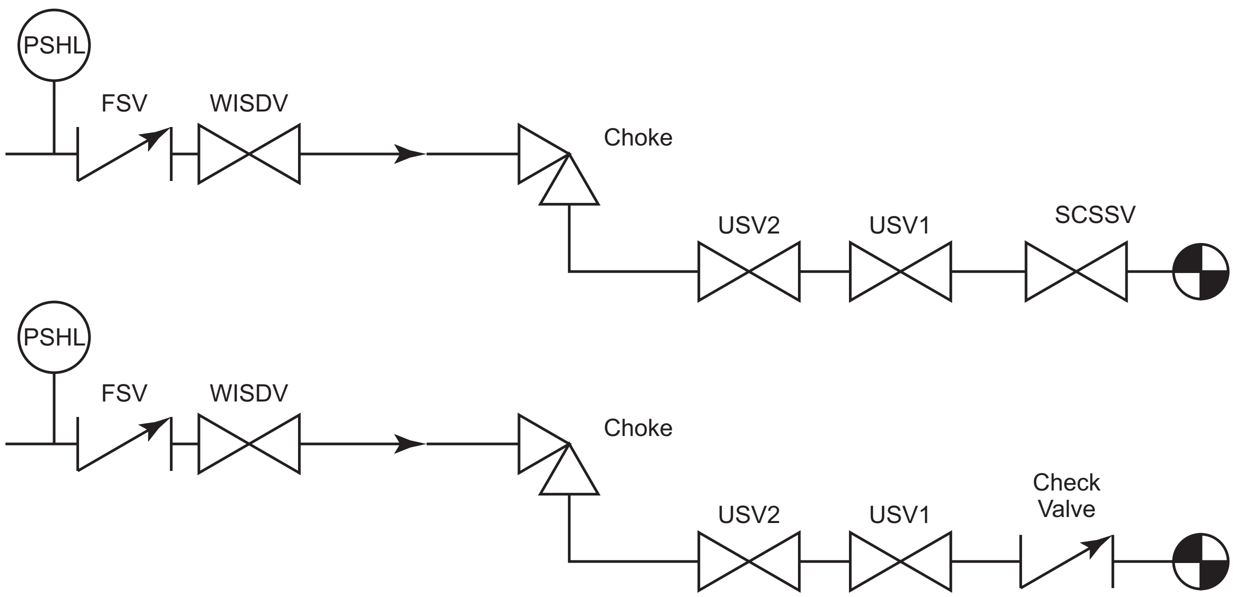


**Figure A.2—Recommended Safety Devices for a Typical Subsea Water Injection Tree**

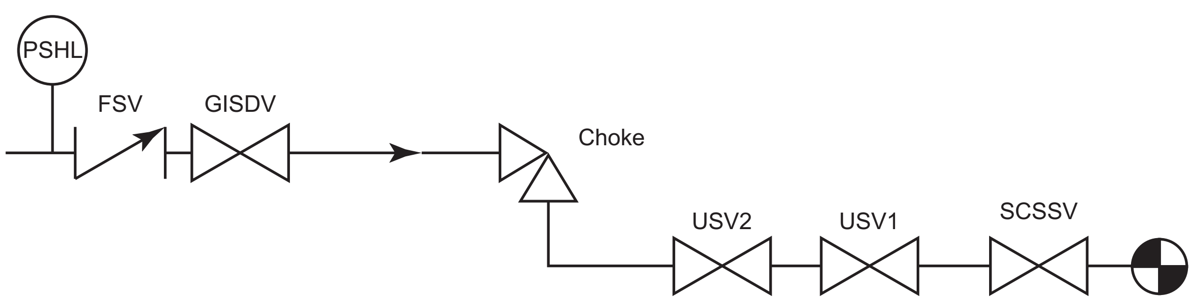


**Figure A.3—Recommended Safety Devices for a Typical Subsea Gas Injection Tree**

## A.3.2 Safety Analysis

### A.3.2.1 Safety Analysis Table

The SAT for wellhead injection lines is presented in Table A.3. The undesirable events that can affect an injection line are overpressure, high temperature, low temperature, loss of containment, and leak.

**Table A.3—SAT–Injection Trees and Flowlines**

| Undesirable Event | Cause | Detectable Abnormal Condition at Component |
|---|---|---|
| Overpressure | Blocked or restricted outlet<br>Hydrate plug<br>Upstream control failure<br>Plugged formation<br>Chemical injection<br>Water hammer | High pressure |
| High temperature | High reservoir temperature<br>Joule-Thomson heating | High temperature |
| Low temperature | Joule-Thomson cooling | Low temperature |
| Loss of containment | Deterioration<br>Erosion<br>Corrosion<br>Impact damage<br>Vibration<br>Seal failure<br>Connector failure | High pressure<br>Low pressure |
| Leak | Deterioration<br>Erosion<br>Corrosion<br>Vibration<br>Seal failure | High pressure<br>Low pressure |

### A.3.2.2 Safety Analysis Checklist

Table A.4 presents the SAC for injection lines.

### A.3.2.3 Shutdown Devices

A GISDV or WISDV shall be installed in accordance with API 14C, API 6A, API 6AV1, and API 6AF. A USV shall be included in the well's subsea tree per A.2.3.3 and manufactured in accordance with API 14H, API 17D, API 6A, and API 6AV1. A SCSSV shall be designed and installed in accordance with API 14A and API 14B. As an alternative to an SCSSV, a downhole check valve may be installed for water injection.

### A.3.2.4 Pressure Safety Devices

Pressure protection is usually provided by a PSH and a PSL on the injection source, such as a compressor or pump, to shut off inflow. If the PSHs and PSLs also protect the injection line, wellhead, and other equipment, these devices are not required on the injection line. The injection line shall be designed to be fully rated unless it is protected by additional safety devices as per API 14C.

**Table A.4—SAC–Injection Trees and Flowlines**

| |
|---|
| a. Pressure Safety High (PSH)<br>1. Flowline segment has a MAWP greater than or equal to the maximum injection pressure and is protected by a PSH on the first flowline segment. |
| b. Pressure Safety Low (PSL)<br>1. Flowline segment has a MAWP greater than or equal to maximum injection pressure and is protected by a PSL on the first flowline segment. |
| c. Line and Equipment Pressure Rating<br>1. Line and equipment have a MAWP greater than or equal to the maximum pressure that can be imposed by the injection source.<br>2. Line and equipment are protected by topside facilities per API RP 14C. |
| d. Downhole Safety Valves<br>1. SCSSV(s) installed.<br>2. For water injection, check valves installed. |
| e. Gas Injection Shutdown Valve (GISDV)<br>1. Flowline segment is protected by GISDV in first flowline segment of a gas injection well. |
| f. Water Injection Shutdown Valve (WISDV)<br>1. Flowline segment is protected by WISDV in first flowline segment of a water injection well. |
| g. Underwater Safety Valve (USV)<br>1. Reservoir is protected by a USV in the injection tree to guard from potential flowback. |
| h. Flow Safety Valve (FSV)<br>1. FSV installed. |

#### A.3.2.5 Flow Safety Valve

An FSV should be provided on each injection line to minimize backflow from the injection line per API 14C.

### A.3.3 Safety Device Location

#### A.3.3.1 Pressure Safety Devices

For water injection systems, the PSHs and PSLs should be located upstream of the check valve, and the sensing point should be on top of a horizontal run or in a vertical run. The PSV should be located so that it cannot be isolated from any portion of the injection line.

For gas injection systems, the PSHs and PSLs should be located upstream of the GISDV, and the sensing point should be on top of a horizontal run or in a vertical run.

#### A.3.3.2 Downhole Safety Device

A SCSSV or check valves shall be installed in the injection tubing beneath the wellhead.

#### A.3.3.3 Shutdown Devices

Injection line SDVs (GISDVs or WISDVs) should prevent backflow and should be located as near to the riser as is practical to minimize the amount of line exposed to piping failure. The shutdown valve (SDV) should be manufactured as a surface safety valve (SSV) in accordance with API 6A.

A WISDV is not required if the injection line serves the purpose of injecting water and the subsurface formation is incapable of back-flowing hydrocarbons. Consideration shall be made for the life of the field.

The USV should be in a practical location in the wellhead flow stream downstream of the choke. The tree may be equipped with more than one valve qualified to be designated as a USV.

### A.3.3.4 Flow Safety Valve

An FSV should be provided on each injection line.

## A.4 Chemical Injection Lines

### A.4.1 Description

Injection lines transfer fluids for chemical injection into the production stream. Recommended safety and subsea isolation devices for typical tree injection lines are shown in Figure A.4 and Figure A.5.

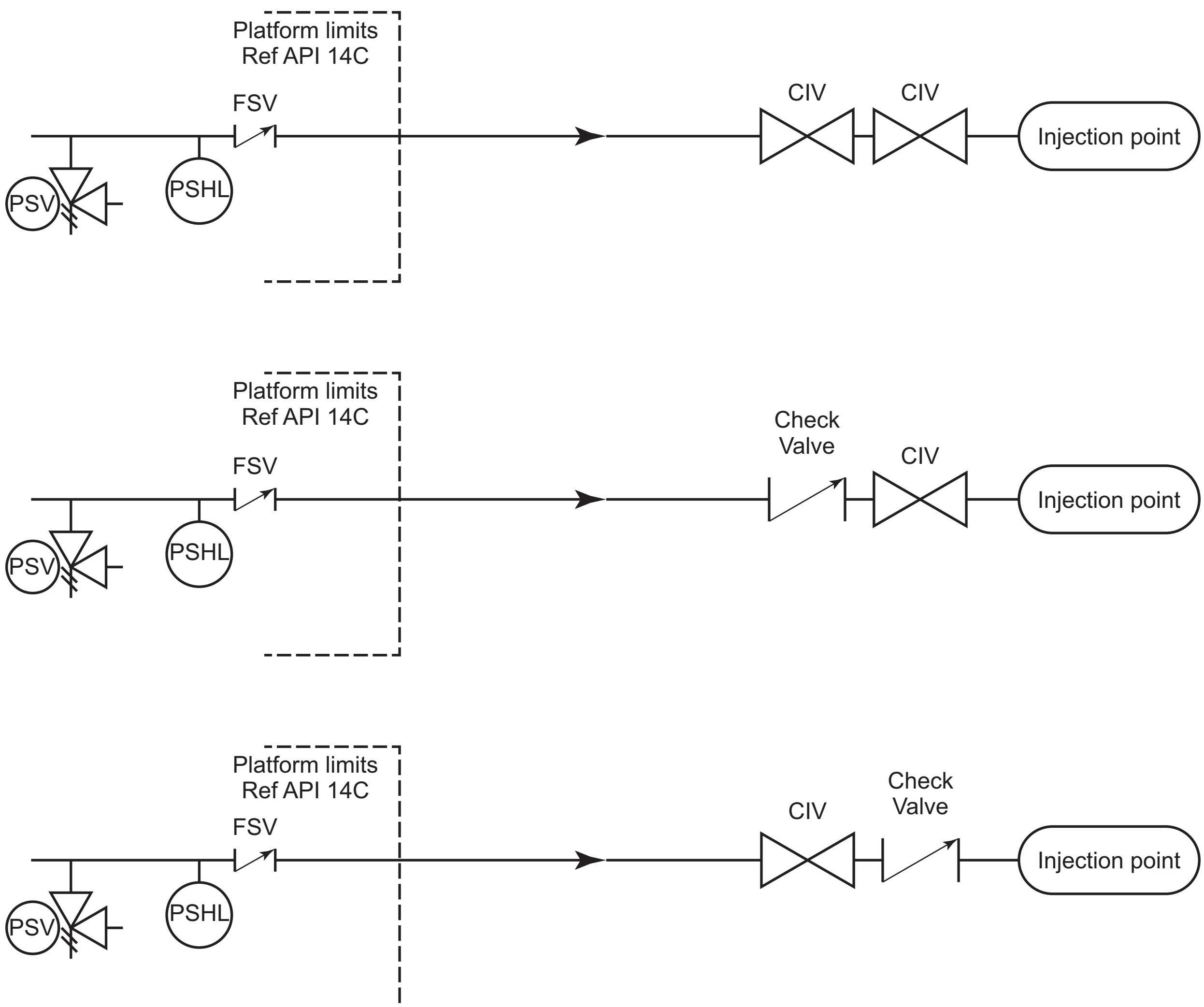


**Figure A.4—Recommended Safety and Subsea Isolation Devices for a Typical Downhole Chemical Injection System**

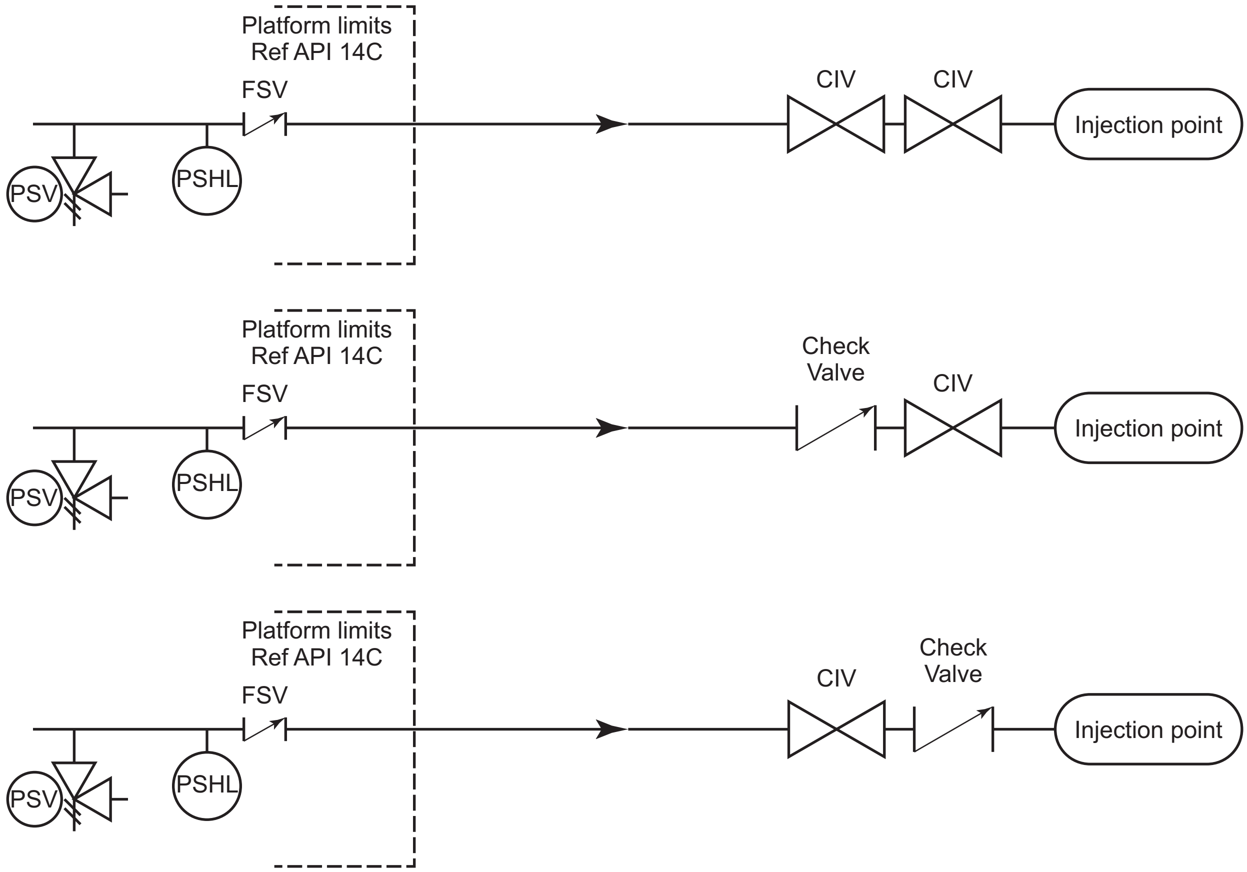


**Figure A.5—Recommended Safety and Subsea Isolation Devices for a Typical Chemical Injection System Above Production Master Valve**

## A.4.2 Safety Analysis

### A.4.2.1 Safety Analysis Table

The SAT for wellhead chemical injection lines is presented in Table A.5. The undesirable events that can affect an injection line are overpressure, leak, loss of containment, and under pressure.

### A.4.2.2 Safety Analysis Checklist

Table A.6 presents the SAC for wellhead injection lines.

### A.4.2.3 Pressure Safety Devices

Pressure protection is provided topside; refer to API 14C.

### A.4.2.4 Subsea Isolation Devices

When injecting chemicals below the wellhead, dual isolation devices shall be installed and consist of one of the following combinations:

a) two remotely actuated CIVs;

b) one check valve and one remotely activated CIV.

**Table A.5—SAT–Chemical Injection Lines**

| Undesirable Event | Cause | Detectable Abnormal Condition at Component |
|---|---|---|
| Overpressure | Blocked or restricted outlet<br>Hydrate plug<br>Upstream control failure<br>Plugged formation<br>Backflow from formation<br>Chemical injection into a low rated manifold or flowline | High pressure |
| Leak | Deterioration<br>Erosion<br>Corrosion<br>Seal failure<br>Vibration | High pressure<br>Low pressure |
| Loss of containment | Deterioration<br>Erosion<br>Corrosion<br>Impact damage<br>Seal failure<br>Vibration<br>Connector failure | High pressure<br>Low pressure |
| Under pressure | Thermal cooling<br>Under pressured well | Low pressure |

**Table A.6—SAC–Chemical Injection Lines**

| |
|---|
| a. Pressure Safety High (PSH)<br>1. PSH installed.<br>2. Line and equipment are protected by an upstream PSH. |
| b. Pressure Safety Low (PSL)<br>1. PSL installed.<br>2. Line and equipment are protected by an upstream PSL. |
| c. Pressure Safety Valve (PSV)<br>1. Line and equipment have a MAWP greater than or equal to the maximum pressure that can be imposed by the injection source.<br>2. PSV installed on the topside injection source per API 14C discharge set at or below the MAWP.<br>3. Line and equipment are protected by an upstream PSV set at or below the incidental allowable overpressure.<br>4. A set of interlocks/permissives should be provided to ensure that the lower rated systems are isolated from the higher pressure source at a pressure equal to or greater than or equal to their design rating. |
| d. Dual Subsea Isolation Devices<br>1. Injection point below the wellhead:<br>i. Two CIVs installed.<br>ii. CIV and check valve installed.<br>2. Injection point downstream of the master valve:<br>i. One CIV installed<br>ii. One check valve installed |
| e. Flow Safety Valve (FSV) (Topsides)<br>1. FSV installed. |

When injecting chemicals downstream of the master valve, only a single additional isolation device shall be installed and consist of one of the following:

a) remotely actuated CIV,

b) check valve.

#### A.4.2.5 Flow Safety Valve

A topside FSV should be provided on each injection line to minimize backflow. Refer to API 14C.

### A.4.3 Safety Device Location

#### A.4.3.1 Pressure Safety Devices

The PSHs and PSLs should be located upstream of the check valve in accordance with API 14C.

NOTE When designing common injection systems that go into wellheads, flowline systems, and manifolds, consider that they may have different design pressures. Flowlines and manifolds design pressure may be less than the maximum design pressure. An appropriate level of system integrity should be maintained.

A set of interlocks/permissives should be provided to ensure that the lower rated systems are isolated from the higher pressure source at pressures greater than or equal to their design rating.

A single PSV at the injection source without any system interlocks or permissive should only be used when the maximum pressure will not exceed the incidental allowable overpressure defined by the applicable design code.

#### A.4.3.2 Subsea Isolation Devices

The valves should be located on or as near to the wellhead as is practical so that the entire line is protected from backflow in accordance with API 17D. Chemical injection lines upstream of the PMV should have two barriers. Chemical injection lines downstream of the PMV should have one barrier.

## A.5 Manifolds

### A.5.1 Description

Manifolds receive production from two or more sources and distribute production to the required flowlines, such as the production and test flowlines. Refer to Figure A.6.

If water injection or gas lift is also present on the manifold, they will not be analyzed under this section. Refer to the relevant sections of this document.

### A.5.2 Safety Analysis

#### A.5.2.1 Safety Analysis Table

The SAT for manifolds is presented in Table A.7. The undesirable events that can affect a manifold are overpressure, loss of containment, and leak.

#### A.5.2.2 Safety Analysis Checklist

The SAC for manifolds is presented in Table A.8.

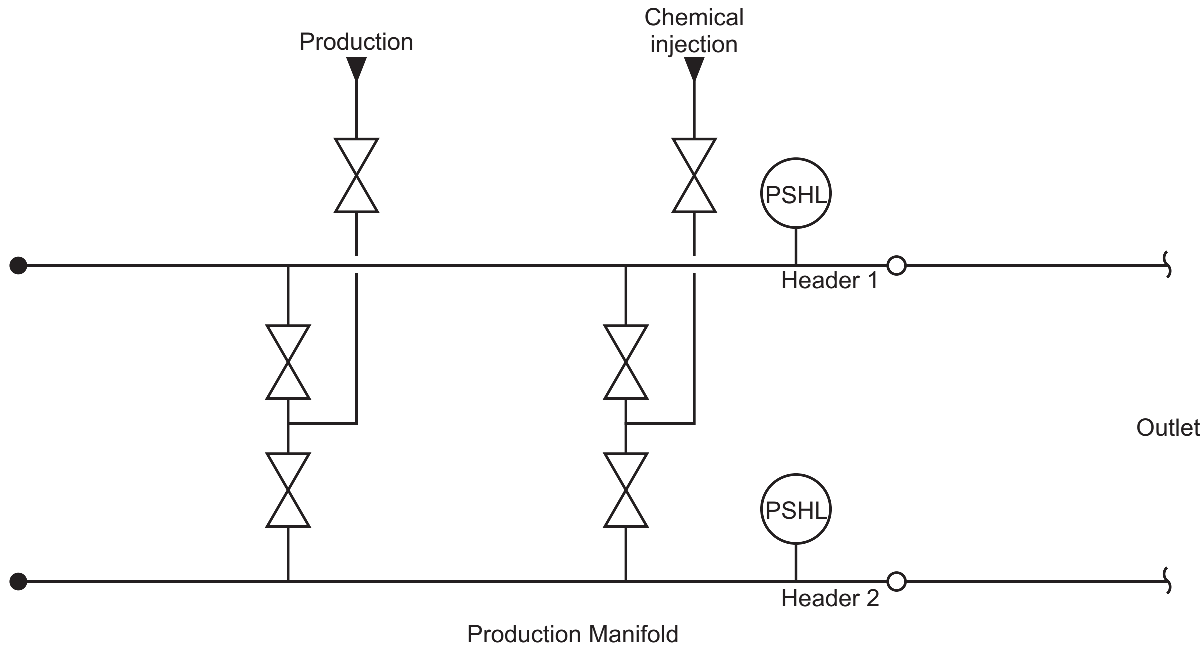


**Figure A.6—Production Manifold**

**Table A.7—SAT–Manifold**

| Undesirable Event | Cause | Detectable Abnormal Condition at Component |
|---|---|---|
| Overpressure | Blocked or restricted outlet<br>Hydrate plug<br>Upstream control failure<br>Excess inflow<br>Injection in closed manifold<br>Chemical injection | High pressure |
| Loss of containment | Deterioration<br>Erosion<br>Corrosion<br>Impact damage<br>Vibration<br>Seal failure<br>Connector failure | Low pressure |
| Leak | Deterioration<br>Erosion<br>Corrosion<br>Vibration<br>Seal failure | Low pressure |

**Table A.8—SAC–Manifold**

| |
|---|
| a. Pressure Safety High (PSH)<br>1. Each final flowline segment is equipped with a PSH set less than the MAWP of the manifold and cannot be isolated.<br>2. The manifold, flowlines, and production system to the BSDV outlet is rated for the gas only SITP. |
| b. Pressure Safety Low (PSL)<br>1. Each final flowline segment is equipped with a PSL and cannot be isolated. |

#### A.5.2.3 Pressure Safety Devices

Each manifold shall have an MAWP greater than or equal to the maximum source pressure. If not, refer to A.10. The final flowline segment shall be equipped with a PSH and PSL to shut off all input sources and protect the manifold. ROV-operated valves installed as installation aids do not have to be considered if appropriate procedures are in place to prevent closure during normal operation.

### A.5.3 Safety Device Location

Pressure safety devices (PSH and PSL) are not required on the manifold, but may be installed for operational reasons.

## A.6 Subsea Separation

### A.6.1 Description

Subsea separators break up production into their constituent components of oil, gas, and water. Recommended safety devices for typical subsea separators are shown in Figure A.7.

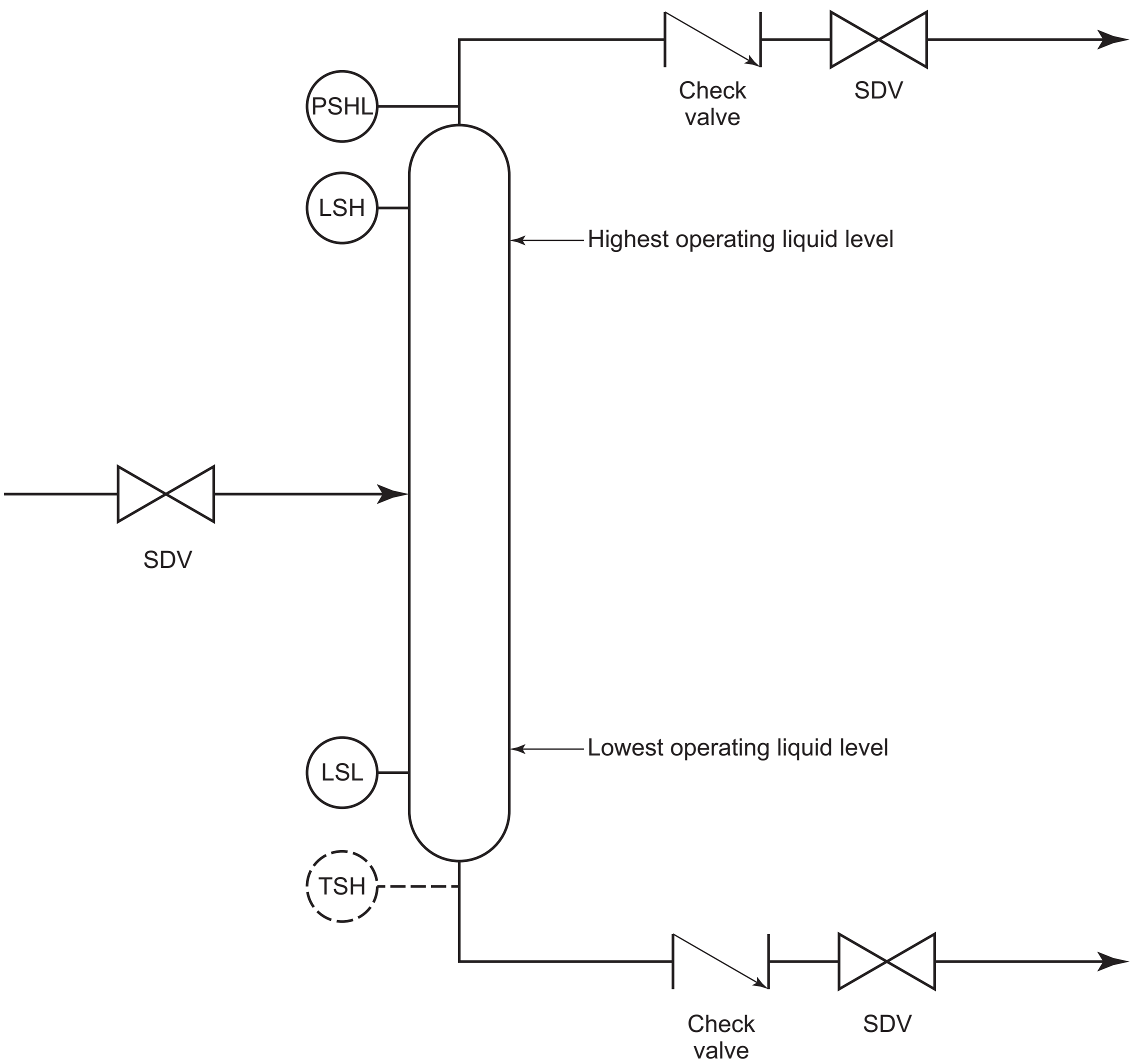


**Figure A.7—Recommended Safety Devices for a Typical Subsea Separator**

## A.6.2 Safety Analysis

### A.6.2.1 Safety Analysis Table

The SAT for subsea separators is presented in Table A.9. The undesirable events that can affect a subsea separator are overpressure, under pressure, liquid carryover, gas blowby, leak, loss of containment, and high temperature if the vessel is heated.

### A.6.2.2 Safety Analysis Checklist

Table A.10 presents the SAC for subsea separators.

### A.6.2.3 Pressure Safety Devices

A PSH to shut off inflow to the vessel should protect a subsea separator that receives fluids from a well or from other sources that can cause overpressure. The PSH is not necessary on the vessel if a PSH on other process components will sense vessel pressure and shut off inflow to the vessel, and the PSH cannot be isolated from the vessel. A PSH should always protect a subsea separator receiving fluids from a well, because the pressure potential of a well may increase due to changes in reservoir conditions, artificial lift, or work-over activities.

**Table A.9—SAT–Subsea Separators**

| Undesirable Event | Cause | Detectable Abnormal Condition at Component |
|---|---|---|
| Overpressure | Blocked or restricted outlet<br>Inflow exceeds outflow<br>Gas blowby<br>Pressure control system failure<br>Thermal expansion<br>Excess heat input<br>Chemical injection | High pressure |
| Under pressure | Withdrawals exceed inflow<br>Thermal contraction<br>Open outlet<br>Pressure control system failure | Low pressure |
| Liquid carryover | Inflow exceeds outflow<br>Liquid slug flow<br>Blocked or restricted liquid outlet<br>Level control system failure | High liquid level |
| Gas blowby | Liquid withdrawals exceed inflow<br>Open liquid outlet<br>Level control system failure | Low liquid level<br>Low temperature |
| Leak | Deterioration<br>Erosion<br>Corrosion<br>Vibration<br>Seal failure | Low pressure<br>Low liquid level |
| Loss of containment | Deterioration<br>Erosion<br>Corrosion<br>Impact damage<br>Vibration<br>Seal failure<br>Connector failure | Low pressure<br>Low liquid level |
| High temperature | Temperature control system failure<br>High inlet temperature | High temperature |

**Table A.10—SAC–Subsea Separators**

| |
|---|
| a. Pressure Safety High (PSH)<br>1. PSH installed.<br>2. Input is from a pump or compressor that cannot develop pressure greater than or equal to the MAWP of the vessel.<br>3. Input source is a subsea tree, production manifold, or flowline and each input source is protected by a PSH that protects the vessel.<br>4. Adequately sized piping without block or regulating valves connects gas outlet to downstream equipment protected by a PSH that also protects the upstream vessel. |
| b. Pressure Safety Low (PSL)<br>1. PSL installed.<br>2. Each input source is protected by a PSL and there are no pressure control devices or restrictions between the PSL(s) and the vessel.<br>3. Adequately sized piping without block or regulating valves connects gas outlet to downstream equipment protected by a PSL that also protects the upstream vessel. |
| c. Level Safety High (LSH)<br>1. LSH installed.<br>2. Equipment downstream of gas outlet can safely handle maximum liquid carry-over. |
| d. Level Safety Low (LSL)<br>1. LSL installed.<br>2. Equipment downstream of liquid outlet(s) can safely handle maximum gas rates that can be discharged through the liquid outlet(s), and vessel does not have an immersed heating element subject to high temperature. Restrictions in the discharge line(s) may be used to limit the gas flow rate. |
| e. Check Valve<br>1. Check valves installed on each outlet.<br>2. The maximum volume of hydrocarbons that could backflow from downstream equipment is insignificant.<br>3. A control device in the line will effectively minimize backflow. |
| f. Shutdown Valve (SDV)<br>1. SDV installed. |
| g. Temperature Safety High (TSH)<br>1. TSH installed if required. |

A subsea separator should be provided with a PSL to shut off inflow to the vessel when internal leaks large enough to reduce pressure occur, unless PSLs on other components will provide necessary protection and the PSL cannot be isolated from the vessel when in service.

The separator should be designed for full collapse pressure.

### A.6.2.4 Level Safety Devices

An LSH should protect subsea separators unless downstream process components can safely handle maximum liquids that could overflow. A subsea separator should be protected from gas blowby by an LSL to shut off inflow to the vessel or close the liquid outlet. The LSL is not required if a liquid level is not maintained in the separator during normal operation, or if downstream equipment can safely handle gas that could blowby.

#### A.6.2.5 Check Valves

A check valve may be installed in each gas and liquid discharge line if significant fluid volumes could backflow from downstream components in the event of a leak. A check valve is not required if a control device in the line will effectively minimize backflow.

#### A.6.2.6 Temperature

If temperature is a concern, steps should be taken to mitigate this issue. This should be addressed in hazard analysis.

#### A.6.2.7 Shutdown Devices

SDVs shall be provided to prevent the flow of hydrocarbons through the separator and into the flowline to prevent loss of containment.

All SDVs shall be actuated by a signal from the ESD system and by any abnormal pressure condition.

### A.6.3 Safety Device Location

#### A.6.3.1 Pressure Safety Devices

The PSHs and PSLs should be located to sense pressure from the gas or vapor section of the subsea separator. This is usually on or near the top. However, such devices may be located on the gas outlet piping if the pressure drop from the separator to the sensing location is negligible and if the devices cannot be isolated from the vessel. Such isolation could be caused externally (e.g. by blocked valves on gas outlet) or internally (e.g. by plugged mist extractors).

#### A.6.3.2 Level Safety Devices

The LSH should be located a sufficient distance above the highest operating liquid level to prevent nuisance trips, but with adequate separator volume above the LSH to prevent overflow before shutdown can be affected. The LSL should be located a sufficient distance below the lowest operating liquid level to prevent nuisance trips, but with adequate liquid volume between the LSL and liquid outlet to prevent gas blowby before shutdown can be affected.

#### A.6.3.3 Check Valves

Check valves may be located in outlet piping.

#### A.6.3.4 Shutdown Devices

SDVs should be located upstream and downstream of the separator.

#### A.6.3.5 Temperature Safety Devices

The TSH should be located in the liquid section.

## A.7 Subsea Boosting

### A.7.1 Description

Subsea boosting pumps transfer fluids within the production process. Recommended safety devices for typical pump installations are shown in Figure A.8.

A HIPPS shall be used if there is a possibility of over pressuring any downstream components.

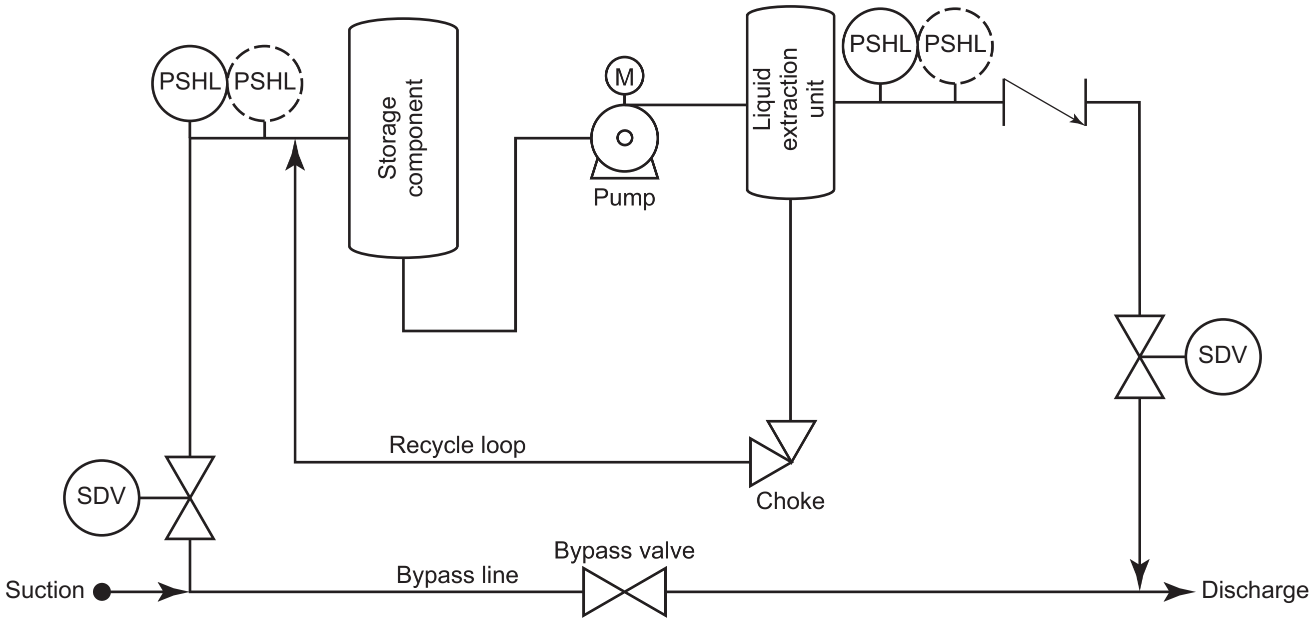


**Figure A.8—Recommended Safety Devices for a Typical Subsea Boosting Pump**

## A.7.2 Safety Analysis

### A.7.2.1 Safety Analysis Table

The SAT for subsea boosting pumps is presented in Table A.11. The undesirable events that can affect a pump are overpressure, under pressure, loss of containment, and leak.

### A.7.2.2 Safety Analysis Checklist

The SAC for pumps is presented in Table A.12.

### A.7.2.3 Pressure Safety Devices

Dual PSHs and PSLs shall be provided on all subsea boosting pumps inlet and discharge to shut off power to the pump and the inlet valve if the maximum pump discharge pressure can exceed 70 % of the MAWP of the discharge line at maximum inlet pressure.

If the maximum pump discharge pressure cannot exceed 70 % of the MAWP of the discharge line at maximum inlet pressure, a single PSH and PSL may be provided to shut down the pump and the inlet valve.

### A.7.2.4 Check Valves

A check valve shall be provided in the pump discharge line to minimize backflow.

### A.7.2.5 Shutdown Devices

SDVs shall be provided to prevent the flow of hydrocarbons through the pump and into the flowline to prevent loss of containment.

All SDVs shall be actuated by a signal from the ESD system and by any abnormal pressure condition.

**Table A.11—SAT–Subsea Boosting**

| Undesirable Event | Cause | Detectable Abnormal Condition at Component |
|---|---|---|
| Overpressure | Blocked or restricted discharge line<br>Excess back pressure<br>High inlet pressure (centrifugal)<br>Overspeed<br>Fluid density increase<br>Chemical injection | High pressure |
| Under pressure | Withdrawals exceed inflow<br>Thermal contraction<br>Blocked inlet<br>Pressure control system failure | Low pressure |
| Loss of containment | Deterioration<br>Erosion<br>Corrosion<br>Impact damage<br>Vibration<br>Seal failure<br>Connector failure | Low pressure |
| Leak | Deterioration<br>Erosion<br>Corrosion<br>Vibration<br>Seal failure | Low pressure |

**Table A.12—SAC–Subsea Boosting**

| |
|---|
| a. Pressure Safety High (PSH)—Flowline Pumps.<br>1. Dual PSH installed.<br>2. Maximum pump discharge pressure does not exceed 70 % of the MAWP of the discharge line. |
| b. Pressure Safety Low (PSL)<br>1. Dual PSL installed. |
| c. Check Valve<br>1. Check valve installed. |
| d. Shutdown Valve (SDV)<br>1. SDVs installed. |

## A.7.3 Safety Device Location

### A.7.3.1 Pressure Safety Devices

Dual PSHs and PSLs located on the pump inlet should be located downstream of any block valve. Dual PSHs and PSLs located on the pump discharge should be upstream of the check valve or any block valve.

### A.7.3.2 Check Valves

The check valve should be located on the pump discharge.

### A.7.3.3 Shutdown Devices

SDVs should be located upstream and downstream of the subsea boosting pump.

## A.8 Subsea Compression

### A.8.1 Description

Subsea compressor units transfer hydrocarbon gases within the production process. Recommended safety devices for a typical compressor unit are shown in Figure A.9.

### A.8.2 Safety Analysis

#### A.8.2.1 Safety Analysis Table

The SAT for subsea compressor units is presented in Table A.13. The undesirable events that can affect a compressor unit are overpressure, under pressure, leak, loss of containment, and abnormal temperature.

#### A.8.2.2 Safety Analysis Checklist

Table A.14 presents the SAC for compressor units.

#### A.8.2.3 Pressure Safety Devices

Dual PSHs and PSLs shall be provided on all subsea compressor inlets and discharges to shut off power to the compressor if the maximum discharge pressure can exceed 70 % of the MAWP of the discharge line at maximum inlet pressure.

If the maximum discharge pressure cannot exceed 70 % of the MAWP of the discharge line at maximum inlet pressure, a single PSH and PSL may be provided to shut down the compressor.

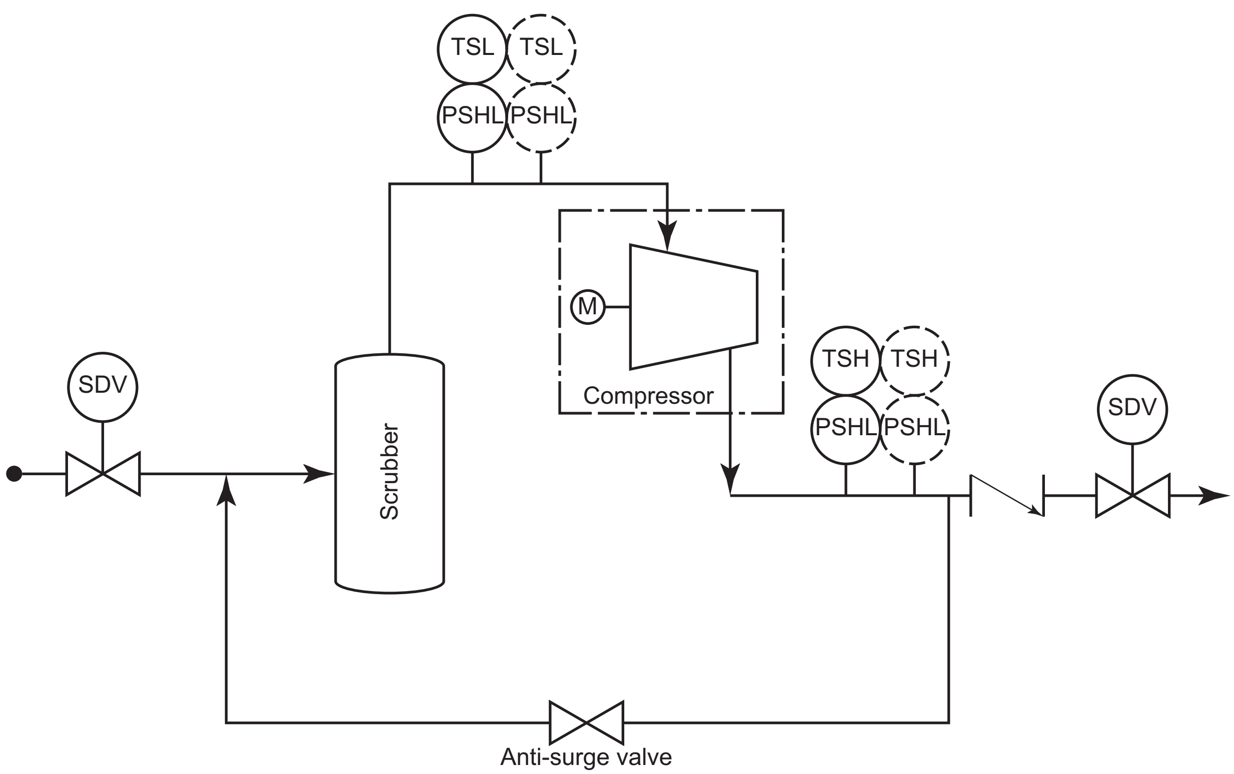


**Figure A.9—Recommended Safety Devices for a Typical Subsea Compressor**

**Table A.13—SAT–Compressors**

| Undesirable Event | Cause | Detectable Abnormal Condition at Component |
|---|---|---|
| Overpressure (suction) | Excess inflow<br>Failure of suction pressure control system<br>Compressor or driver malfunction<br>Chemical injection | High pressure |
| Overpressure (discharge) | Blocked or restricted discharge line<br>Excess back pressure<br>High inlet pressure<br>Overspeed<br>Chemical injection | High pressure |
| Under pressure (suction) | Withdrawals exceed inflow<br>Thermal contraction<br>Pressure control system failure<br>Blocked or restricted suction line | Low pressure |
| Leak | Deterioration<br>Erosion<br>Corrosion<br>Seal failure<br>Vibration | Low pressure |
| Loss of containment | Deterioration<br>Erosion<br>Corrosion<br>Impact damage<br>Seal failure<br>Connector failure<br>Vibration | Low pressure |
| High temperature | Compressor valve failure<br>Cooler failure<br>Excess compression ratio<br>Insufficient flow leading to a surge | High temperature |
| Low Temperature | Joule-Thomson cooling | Low Temperature |

### A.8.2.4 Check Valves

A check valve should be provided in each final discharge line to minimize backflow.

### A.8.2.5 Temperature Safety Devices

Dual TSHs shall be provided on all subsea compressor discharges to shut off process inflow to the compressor if the maximum discharge temperature can exceed the maximum design temperature of the equipment.

Dual TSLs shall be provided on the compressor inlet to shut off process inflow to the compressor if the minimum temperature is less than the design temperature of the equipment.

### A.8.2.6 Shutdown Devices

SDVs shall be located upstream and downstream of the subsea compressor. All SDVs should be actuated by a signal from the ESD system and by any abnormal pressure or temperature condition.

**Table A.14—SAC–Compressors**

| |
|---|
| a. Pressure Safety High (PSH)—Suction<br>1. Dual PSHs are installed.<br>2. Each input source is protected by a set of dual PSHs that will also protect the compressor. |
| b. Pressure Safety High (PSH)—Discharge<br>1. Dual PSHs are installed.<br>2. Compressor is protected by a dual set of downstream PSHs located upstream of any cooler that cannot be isolated from the compressor.<br>3. If the compressor is a kinetic energy type compressor and the maximum discharge pressure cannot exceed 70 % of MAWP of discharge line then a single PSH on the discharge line is installed. |
| c. Pressure Safety Low (PSL)—Suction<br>1. Dual PSLs installed.<br>2. Each input source is protected by a dual set of PSLs that will also protect the compressor.<br>3. System is fully rated for under pressure. |
| d. Pressure Safety Low (PSL)—Discharge<br>1. Dual PSLs are installed.<br>2. Compressor is protected by a dual set of downstream PSLs that cannot be isolated from the compressor. |
| e. Check Valve—Final Discharge<br>1. Check valve installed. |
| f. Temperature Safety High (TSH)<br>1. Dual set of TSHs are installed on the discharge line. |
| g. Temperature Safety Low (TSL)<br>1. Design system for minimum temperature.<br>2. Dual set of TSLs are installed on the suction line. |
| h. Shutdown Valve (SDV)<br>1. SDVs installed. |

## A.8.3 Safety Device Location

### A.8.3.1 Pressure Safety Devices

The PSHs and PSLs should be located on each suction line as close to the compressor as is practical, and on each discharge line upstream of the check valve and any block valve.

### A.8.3.2 Check Valves

A check valve should be located on each compressor unit's final discharge line to minimize backflow.

### A.8.3.3 Temperature Safety Devices

Dual TSHs should be located in the discharge piping of each compressor or as close as practical to the compressor.

Dual TSLs should be located in the suction piping of each compressor or as close as practical to the compressor.

#### A.8.3.4 Shutdown Devices

SDVs should be located on each process in-flow line so that the compressor can be isolated from all input sources. SDVs should be located on the discharge line.

## A.9 Gas Lift

### A.9.1 Description

Gas lift is one of several processes used to artificially lift produced fluids from wells, flowlines, and risers where there is insufficient reservoir pressure to produce the well.

The gas lift supply system requirements described in API 14C applies to the gas lift supply system located on the facility. For subsea production purposes, gas lift is currently divided into three methods:

a) gas lift of subsea flowlines, risers, and manifolds via an external gas lift line or umbilical;

b) gas lift of subsea well(s) through the casing string via an external gas lift line or umbilical; and

c) gas lift of risers via a gas lift line or coil tubing contained within the riser.

#### A.9.1.1 General Safety Considerations for All Gas Lift Systems

General safety considerations for all gas lift systems include the following.

a) The MAWP of the gas lift injection line shall be rated greater than or equal to the system into which it is injecting.

b) A GLSDV shall be installed and meet the same requirements as the BSDV. This includes meeting the requirements of API 6A, API 6AV1, API 6FA, and being pressure rated for the MAWP.

c) The GLSDV should close anytime the BSDV closes and in approximately the same amount of time as the BSDV.

d) A gas lift isolation valve (GLIV) shall be installed at or as near to the injection location as is practical. The GLIV shall be an actuated, fail closed valve, and meet the design requirements of API 6A and API 6AV1.

e) Activation of the gas lift riser PSHL should close the:

   1) GLSDV and GLIV

   2) USV

   3) SCSSV

NOTE These requirements apply to all three methods of gas lift mentioned above.

### A.9.2 Safety Analysis for Gas Lift of Subsea Flowlines, Risers, and Manifolds via an External Gas Lift Line or Umbilical

#### A.9.2.1 Description

These are safety considerations for gas lift lines which intersect the subsea flowline, riser, or manifold via an external gas lift line or umbilical. The required safety systems for gas lift of the subsea flowline, riser, or manifold via an external gas lift line or umbilical are not necessarily the same as the following:

— a gas lift through the casing string via an external gas lift line or umbilical;

— a gas lift of risers via a gas lift line or coil tubing contained within the risers.

Refer to Figure A.10 and Figure A.11.

### A.9.2.2 Safety Analysis

#### A.9.2.2.1 Safety Analysis Table

The SAT for gas lift of subsea flowlines, risers, and manifolds is presented in Table A.15. The undesirable events that can affect a gas lift injection line are overpressure, loss of containment, leak, and low temperature.

#### A.9.2.2.2 Safety Analysis Checklist

Table A.16 presents the SAC for gas lift of subsea flowlines, risers, and manifolds.

#### A.9.2.2.3 Pressure Safety Devices

Pressure protection is usually provided by a PSHL on the injection source, such as a compressor or pump, to shut off inflow. If the PSHL also protects the gas lift injection line or other equipment, these devices are not required on the injection line.

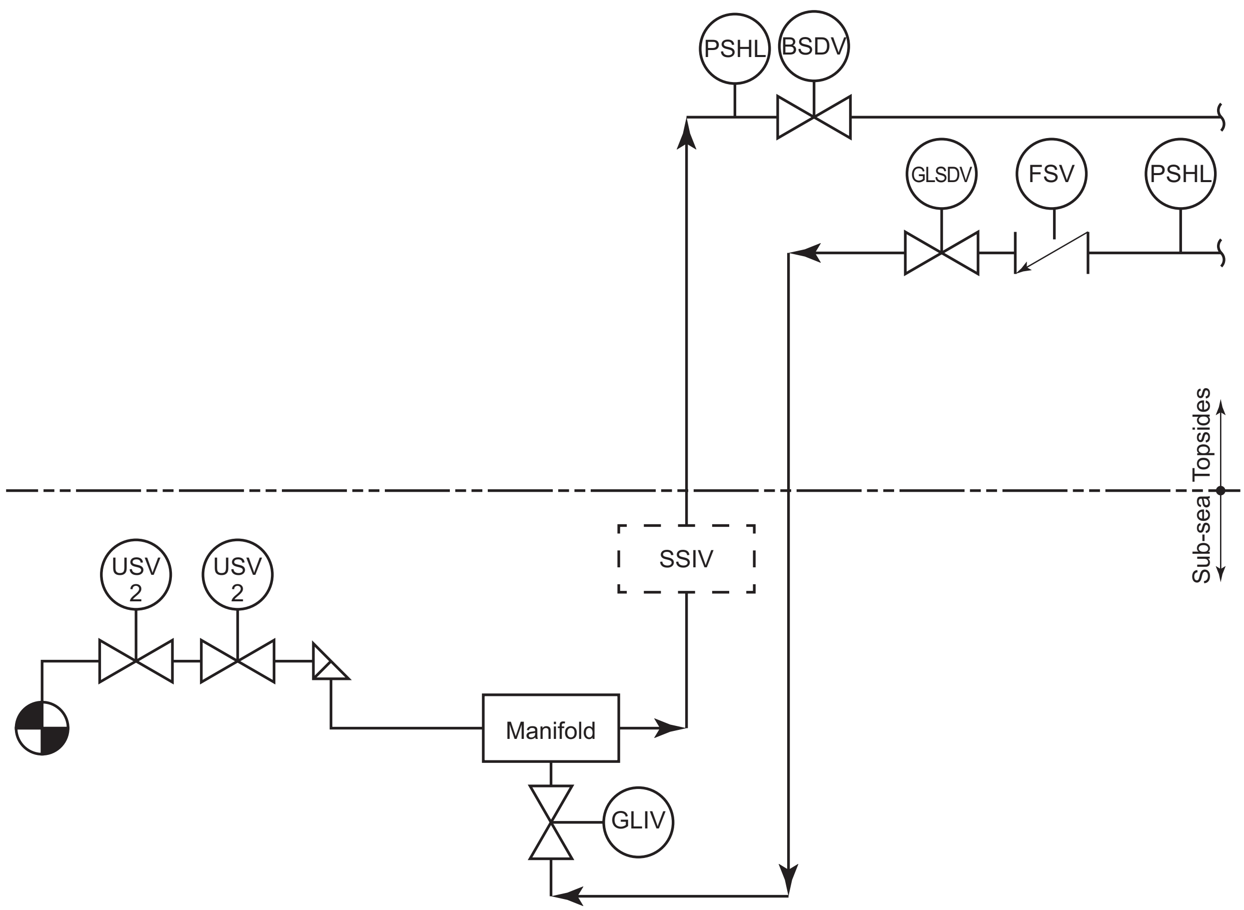


**Figure A.10—Recommended Safety Devices and Subsea Isolation for Gas Lifting a Manifold via an External Gas Lift Line**

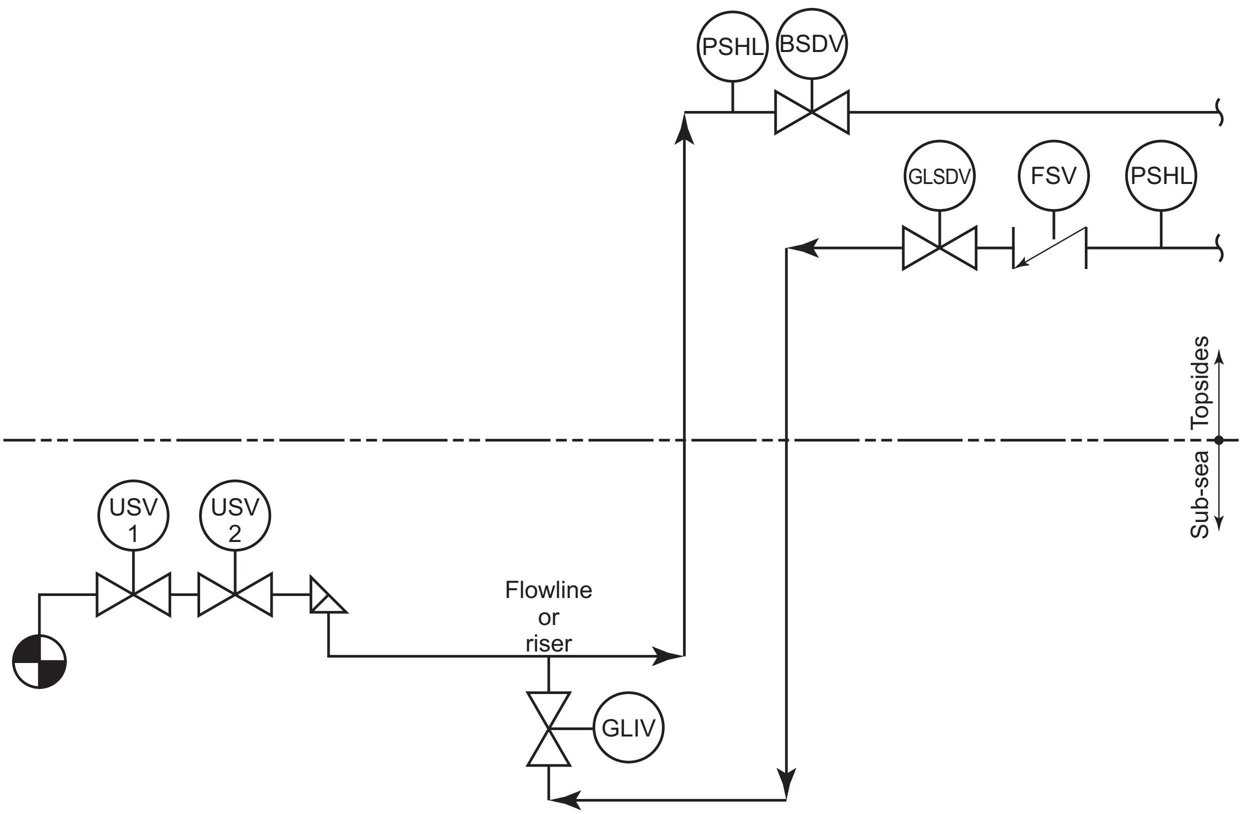


**Figure A.11—Recommended Safety Devices and Subsea Isolation for Gas Lifting a Subsea Flowline or Riser via an External Gas Lift Line**

**Table A.15—SAT–Gas Lift of Subsea Flowlines, Risers, and Manifolds via an External Gas Lift Line or Umbilical**

| Undesirable Event | Cause | Detectable Abnormal Condition at Component |
|---|---|---|
| Overpressure | Blocked or restricted outlet<br>Hydrate plug<br>Upstream control failure<br>Plugged formation<br>Chemical injection | High pressure |
| Loss of containment | Deterioration<br>Erosion<br>Corrosion<br>Impact damage<br>Seal failure<br>Connector failure<br>Vibration | Low pressure |
| Leak | Deterioration<br>Erosion<br>Corrosion<br>Seal failure<br>Vibration | Low pressure |
| Low temperature | Joule-Thomson cooling | Low temperature |

**Table A.16—SAC–Gas Lift of Subsea Flowlines, Risers, and Manifolds via an External Gas Lift Line or Umbilical**

| |
|---|
| a. Pressure Safety High (PSH)<br>1. PSH installed.<br>2. Line and equipment are protected by an upstream PSH. |
| b. Pressure Safety Low (PSL)<br>1. PSL installed.<br>2. Line and equipment are protected by an upstream PSL. |
| c. Pressure Safety Valve (PSV)<br>1. PSV installed.<br>2. Line and equipment have a MAWP greater than or equal to the maximum pressure that can be imposed by the injection source.<br>3. Line and equipment are protected by an upstream PSV. |
| d. Gas Lift Shutdown Valve (GLSDV)<br>1. GLSDV installed. |
| e. Subsea Isolation<br>1. GLIV installed. |
| f. Flow Safety Valve (FSV) (Topsides)<br>1. Check valve installed. |

The gas lift injection line shall have a pressure rating greater than or equal to the system into which it is injecting.

If the gas lift system source pressure is higher than the design pressure of the system into which it is injecting, pressure protection (PSV) shall be provided in accordance with API 14C upstream of the GLSDV.

#### A.9.2.2.4 Temperature Safety Devices

A TSL shall be provided if the minimum temperature is less than the design temperature of the equipment.

#### A.9.2.2.5 Gas Lift Shut Down Valve (GLSDV)

A GLSDV shall be installed in accordance with requirements for the BSDV per API 14C.

#### A.9.2.2.6 Subsea Isolation

A fail-safe GLIV shall be installed at the point of intersection of the gas lift line and subsea flowline, riser, or manifold. The GLIV shall close with the GLSDV.

#### A.9.2.2.7 Check Valve

A check valve should be installed at the top of the riser to prevent backflow.

### A.9.2.3 Safety Device Location

#### A.9.2.3.1 Pressure Safety Devices

The PSHL should be located upstream (inboard) of the GLSDV and check valve at the top of the gas lift riser or umbilical. The sensing point should be on top of a horizontal run or in a vertical run. The PSV, if utilized, should be located so that it cannot be isolated from any portion of the injection line.

#### A.9.2.3.2 Temperature Safety Devices

If required, the TSL should be located in a position to sense the low temperature.

#### A.9.2.3.3 Gas Lift Shut Down Valve

The GLSDV shall be located in accordance with requirements for the BSDV per API 14C.

#### A.9.2.3.4 Subsea Isolation

A GLIV should be located at or as near the injection location as is practical so that the entire line is protected from backflow.

#### A.9.2.3.5 Check Valves

A check valve should be installed on the gas lift supply line on the facility upstream (in board) of the GLSDV to prevent back flow. Refer to API 14C.

## A.9.3 Gas Lift of Subsea Well(s) through the Casing String via an External Gas Lift Line

### A.9.3.1 Description

These are safety considerations for gas lift through the casing string. The required safety systems for gas lift through the casing string are not necessarily the same as for gas lift of the subsea flowline, riser, or manifold via an external gas lift line or umbilical or for gas lift of risers via a gas lift line or coil tubing contained within the risers. Refer to Figure A.12.

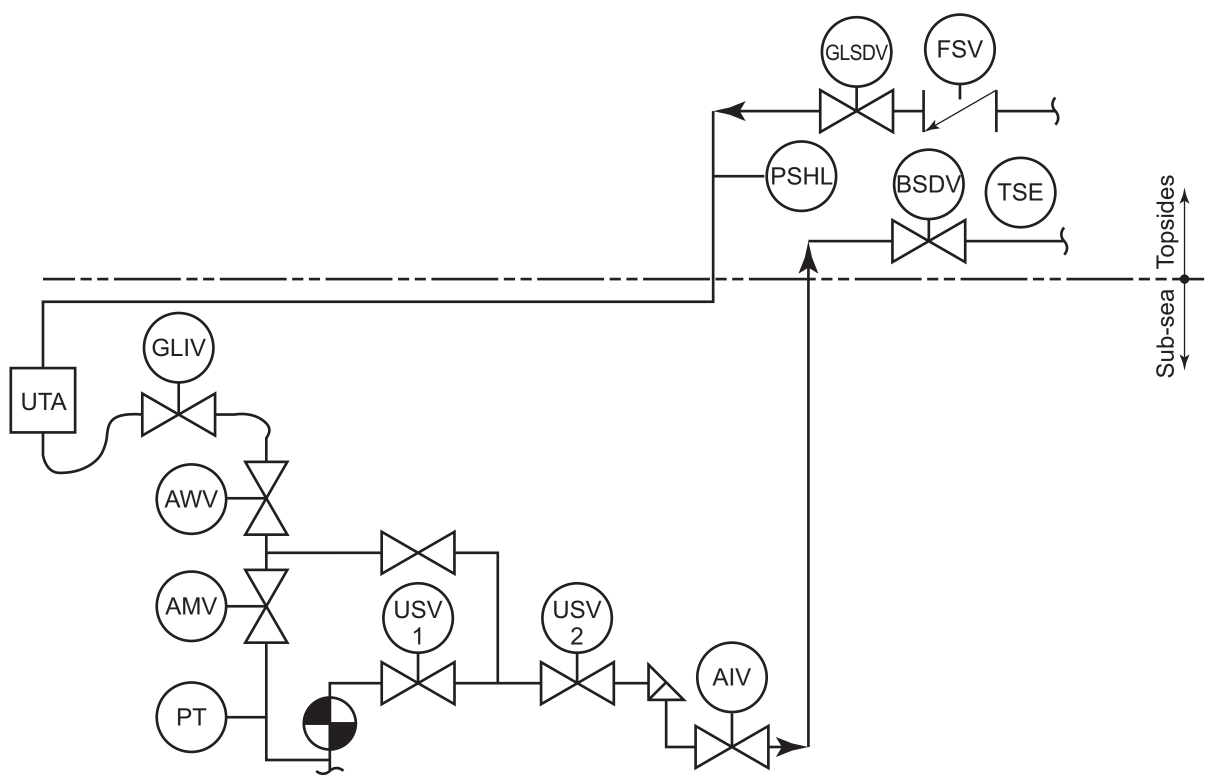


**Figure A.12—Recommended Safety Devices for Gas Lifting a Subsea Well through the Casing String via an External Gas Lift Line**

### A.9.3.2 Safety Analysis

#### A.9.3.2.1 Safety Analysis Table

The SAT for gas lift through the casing is presented in Table A.17. The undesirable events that can affect a gas lift injection line are overpressure, loss of containment, leak, and low temperature.

#### A.9.3.2.2 Safety Analysis Checklist

Table A.18 presents the SAC for gas lift through the casing string.

**Table A.17—SAT–Gas Lift of Subsea Well(s) through the Casing String via an External Gas Lift Line**

| Undesirable Event | Cause | Detectable Abnormal Condition at Component |
|---|---|---|
| Overpressure | Blocked or restricted outlet<br>Hydrate plug<br>Upstream control failure<br>Plugged formation | High pressure |
| Loss of containment | Deterioration<br>Erosion<br>Corrosion<br>Impact damage<br>Seal failure<br>Connector failure<br>Vibration | Low pressure |
| Leak | Deterioration<br>Erosion<br>Corrosion<br>Seal failure<br>Vibration | Low pressure |
| Low temperature | Joule-Thomson cooling | Low temperature |

**Table A.18—SAC–Gas Lift of Subsea Well(s) through the Casing String via an External Gas Lift Line**

| |
|---|
| a. Pressure Safety High (PSH)<br>1. PSH installed.<br>2. Line and equipment are protected by an upstream PSH. |
| b. Pressure Safety Low (PSL)<br>1. PSL installed.<br>2. Line and equipment are protected by an upstream PSL. |
| c. Pressure Safety Valve (PSV)<br>1. PSV installed.<br>2. Line and equipment have a MAWP greater than or equal to the maximum pressure that can be imposed by the injection source.<br>3. Line and equipment are protected by an upstream PSV. |
| d. Gas Lift Shutdown Valve (GLSDV)<br>1. GLSDV installed. |
| e. Dual Barrier<br>1. Two SDVs installed. One valve designated the GLIV.<br>2. GLIV and check valve installed. |
| f. Flow Safety Valve (FSV) (Topsides)<br>1. Check valve installed. |

#### A.9.3.2.3 Pressure Safety Devices

Pressure protection is usually provided by a PSHL on the injection source, such as a compressor or pump, to shut off inflow. If the PSHL also protects the gas lift injection line or other equipment, these devices are not required on the injection line.

The gas lift injection line shall have a pressure rating greater than or equal to the system into which it is injecting.

If the gas lift system source pressure is higher than the design pressure of the system into which it is injecting, pressure protection (i.e. a PSV) shall be provided in accordance with API 14C upstream of the GLSDV.

#### A.9.3.2.4 Temperature Safety Devices

A TSL shall be provided if the minimum temperature is less than the design temperature of the equipment.

#### A.9.3.2.5 Gas Lift Shut Down Valve

A GLSDV shall be installed in accordance with requirements for the BSDV per API 14C.

#### A.9.3.2.6 Dual Barriers

Dual barriers shall be installed near the point of intersection of the gas lift line and subsea tree. One of these valves shall be designated the GLIV and provide the dual function of containing annular pressure and shutting off the gas lift supply gas. Most subsea trees or tubing heads are equipped with an annulus master valve (AMV) and annulus wing valve (AWV), which can be designated as the GLIV. The GLIV should close with the GLSDV.

The dual barriers should consist of one of the following combinations:

a) two remotely actuated SDVs (one designated the GLIV);

b) one check valve and one GLIV.

#### A.9.3.2.7 Check Valve

A check valve should be installed at the top of the riser to prevent backflow.

### A.9.3.3 Safety Device Location

#### A.9.3.3.1 Pressure Safety Devices

The PSHL should be located on the facility upstream (inboard) of the GLSDV and check valve at the top of the gas lift riser or umbilical. The sensing point should be on top of a horizontal run or in a vertical run. The PSV, if utilized, should be located so that it cannot be isolated from any portion of the injection line.

#### A.9.3.3.2 Temperature Safety Devices

If required, the TSL should be located in a position to sense the low temperature.

#### A.9.3.3.3 Gas Lift Shut Down Valve

The GLSDV shall be located in accordance with requirements for the BSDV per API 14C.

#### A.9.3.3.4 Dual Barriers

The two SDVs or SDV and check valve should be located at or as near the injection location as is practical so that the entire line is protected from backflow.

#### A.9.3.3.5 Check Valve

The check valve should be located on the gas lift supply line on the facility of each injection line, upstream (in board) of the GLSDV, to protect the entire line and prevent backflow.

## A.9.4 Gas Lift of Risers via a Gas Lift Line or Coil Tubing Contained within the Riser

### A.9.4.1 Description

These are safety considerations for gas lift lines or coil tubing that is contained within the riser. The required safety systems for gas lift lines or coil tubing that is contained within the riser are not necessarily the same as the following:

— gas lift of the subsea flowline, riser, or manifold via an external gas lift line or umbilical;

— gas lift through the casing string via an external gas lift line or umbilical.

Refer to Figure A.13.

The gas lift line or coil tubing shall be suspended via a flanged connection to a tubing head or similar device that meets the requirements of API 6A and is fire rated for 30 minutes.

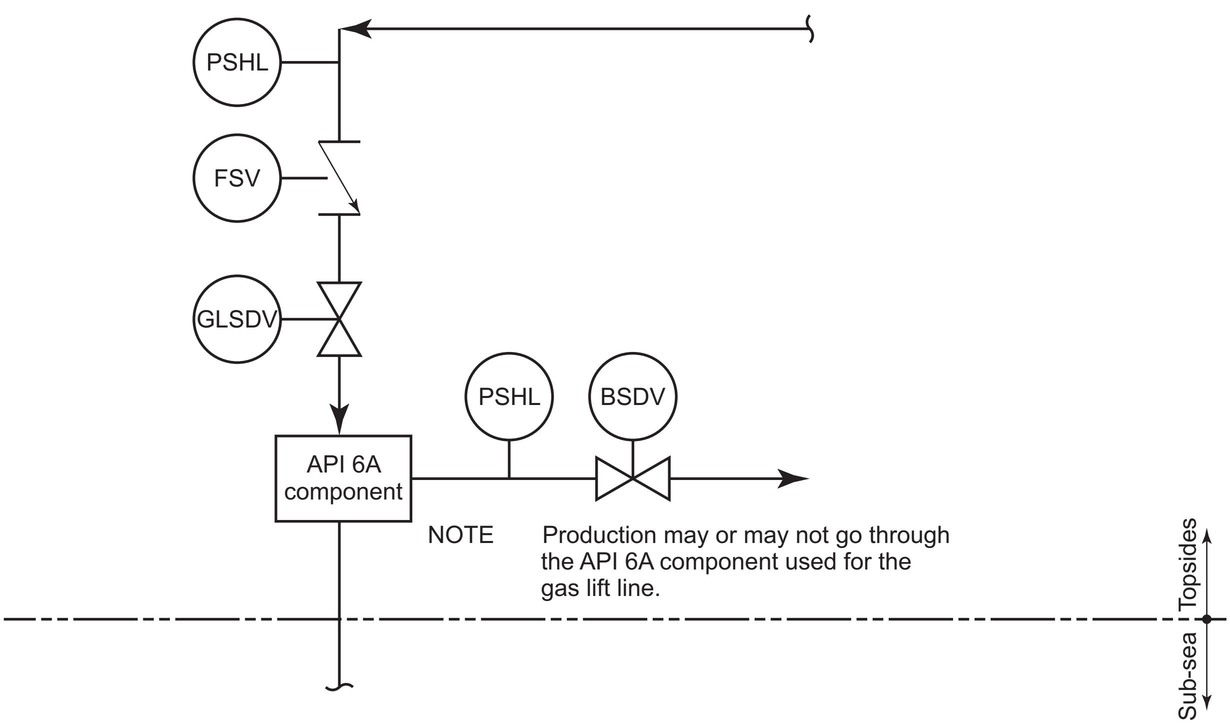


**Figure A.13—Recommended Safety Devices for Gas Lifting a Riser via Coil Tubing Contained within the Riser**

### A.9.4.2 Safety Analysis

#### A.9.4.2.1 Safety Analysis Table

The SAT for gas lift of risers via a gas lift line or coil tubing contained within the riser is presented in Table A.19. The undesirable events that can affect an injection line are overpressure, loss of containment, leak, and low temperature.

**Table A.19—SAT–Gas Lift of Risers via a Gas Lift Line Contained within the Riser**

| Undesirable Event | Cause | Detectable Abnormal Condition at Component |
|---|---|---|
| Overpressure | Blocked or restricted outlet<br>Hydrate plug<br>Upstream control failure<br>Plugged formation | High pressure |
| Loss of containment | Deterioration<br>Erosion<br>Corrosion<br>Impact damage<br>Seal failure<br>Connector failure<br>Vibration | Low pressure |
| Leak | Deterioration<br>Erosion<br>Corrosion<br>Seal failure<br>Vibration | Low pressure |
| Low temperature | Joule-Thomson cooling | Low temperature |

#### A.9.4.2.2 Safety Analysis Checklist

The SAC for gas lift of risers via a gas lift line or coil tubing contained within the riser is presented in Table A.20.

**Table A.20—SAC–Gas Lift of Risers via a Gas Lift Line Contained within the Riser**

| |
|---|
| a. Pressure Safety High (PSH)<br>1. PSH installed.<br>2. Line and equipment are protected by an upstream PSH. |
| b. Pressure Safety Low (PSL)<br>1. PSL installed.<br>2. Line and equipment are protected by an upstream PSL. |
| c. Pressure Safety Valve (PSV)<br>1. PSV installed.<br>2. Line and equipment have a MAWP greater than or equal to the maximum pressure that can be imposed by the injection source.<br>3. Line and equipment are protected by an upstream PSV. |
| d. Gas Lift Shutdown Valve (GLSDV)<br>1. GLSDV installed. |
| e. Flow Safety Valve (FSV) (Topsides)<br>1. Check valve(s) installed. |

#### A.9.4.2.3 Pressure Safety Devices

Pressure protection is usually provided by a PSHL on the injection source, such as a compressor or pump, to shut off inflow. If the PSHL also protects the injection line or other equipment, pressure protection devices are not required on the injection line.

The gas lift injection line shall have a pressure rating greater than or equal to the system into which it is injecting.

If the gas lift system source pressure is higher than the design pressure of the system into which it is injecting, pressure protection (a PSV) shall be provided in accordance with API 14C upstream of the GLSDV.

#### A.9.4.2.4 Temperature Safety Devices

A TSL shall be provided if the minimum temperature is less than the design temperature of the equipment.

#### A.9.4.2.5 Gas Lift Shut Down Valve

A GLSDV shall be installed in accordance with requirements for the BSDV per API 14C.

#### A.9.4.2.6 Check Valve

A check valve should be provided on each gas lift injection line to minimize backflow.

### A.9.4.3 Safety Device Location

#### A.9.4.3.1 Pressure Safety Devices

The PSHL should be located upstream (inboard) of the GLSDV and check valve at the top of the gas lift riser or umbilical. The sensing point should be on top of a horizontal run or in a vertical run. The PSV, if utilized, should be located so that it cannot be isolated from any portion of the injection line.

#### A.9.4.3.2 Temperature Safety Devices

If required, the TSL should be located in a position to sense the low temperature.

#### A.9.4.3.3 Gas Lift Shut Down Valve

The GLSDV shall be located in accordance with requirements for the BSDV per API 14C.

#### A.9.4.3.4 Check Valve

A check valve should be installed on the gas lift supply line on the facility upstream (in board) of the GLSDV to prevent back flow.

## A.10 High Integrity Pressure Protection System

### A.10.1 Description

A HIPPS is designed to autonomously isolate downstream facilities from overpressure situations.

## A.10.2 Safety Analysis

### A.10.2.1 Safety Analysis Table

The SAT for HIPPS is presented in Table A.21. The undesirable events are overpressure, loss of containment, and leak.

**Table A.21—SAT–HIPPS**

| Undesirable Event | Cause | Detectable Abnormal Condition at Component |
|---|---|---|
| Overpressure | Blocked or restricted discharge line<br>Excess back pressure<br>High inlet pressure<br>Chemical injection | High pressure |
| Loss of Containment | Blocked or restricted discharge line<br>Excess back pressure<br>High inlet pressure<br>Chemical injection | High pressure |
| Leak | Deterioration<br>Erosion<br>Corrosion<br>Seal failure<br>Vibration | High pressure |

### A.10.2.2 Safety Analysis Checklist

The SAC for HIPPS is presented in Table A.22.

**Table A.22—SAC–HIPPS**

a. Pressure Safety High (PSH)
   1. PSH installed.

### A.10.2.3 Pressure Safety Devices

PSHs shall be provided on all HIPPS. Redundant PSHs shall be used to shut the HIPPS isolation valve(s) in the event of high pressure. The number and configuration of valves and sensors shall be installed per API 17O and to the required safety integrity level (SIL) rating.

### A.10.2.4 Shutdown Devices

The shutdown device(s) shall be located upstream of the pressure specification break.

## A.10.3 Safety Device Location

### A.10.3.1 Pressure Safety Devices

The PSHs should be located to sense the overpressure from the source and such that closing the HIPPS valves does not result in the pressure alarm being automatically reset.

### A.10.3.2 Shutdown Devices

One or more SDVs shall be installed to isolate the high pressure source from the lower pressure rating parts of the system.

## A.11 Subsea Isolation Valves

### A.11.1 Description

A subsea isolation valve (SSIV) is an ESD valve normally installed below the splash-zone, often on the seabed. An SSIV should be considered to reduce risk. The need for an SSIV should be determined by a HAZOP or other hazard analysis. The SSIV shall be fail close.

### A.11.2 Safety Analysis

#### A.11.2.1 Safety Analysis Table

The SAT for the SSIV is presented in Table A.23. The undesirable events that can affect a SSIV are overpressure, loss of containment, and leak.

**Table A.23—SAT–SSIV**

| Undesirable Event | Cause | Detectable Abnormal Condition at Component |
|---|---|---|
| Overpressure | Blocked or restricted outlet<br>Hydrate plug<br>Upstream control failure<br>Closed BSDV<br>Chemical injection<br>Thermal expansion | High pressure |
| Loss of containment | Deterioration<br>Erosion<br>Corrosion<br>Impact damage<br>Vibration<br>Seal failure<br>Connector failure | Low pressure |
| Leak | Deterioration<br>Erosion<br>Corrosion<br>Vibration<br>Seal failure | Low pressure |

#### A.11.2.2 Safety Analysis Checklist

The SAC for SSIV is presented in Table A.24.

**Table A.24—SAC–SSIV**

| |
|---|
| a. Subsea Isolation Valve (SSIV)<br>1. SSIV installed.<br>2. Risk analysis does not require an SSIV. |
| b. Pressure Safety High (PSH)<br>1. PSH installed.<br>2. Line and equipment are protected by an upstream PSH. |
| c. Pressure Safety Low (PSL)<br>1. PSL installed.<br>2. Line and equipment are protected by an upstream PSL. |

#### A.11.2.3 Pressure Safety Devices

Pressure sensor(s) should be provided upstream on all SSIVs. The sensors should be used to alarm in the event of high or low pressure. The topside PSHL associated with the riser may be used to shut down the SSIV.

#### A.11.2.4 Shutdown Devices

SSIV(s) shall be designed in accordance with API 6A, API 6AV1, and API 6AF.

### A.11.3 Safety Device Location

#### A.11.3.1 Pressure Safety Devices

The pressure sensor(s) should be located upstream of the SSIV.

#### A.11.3.2 Shutdown Devices

The shutdown device(s) shall be located below the splash zone or near the base of the riser at the seabed. For a deepwater installation, if an SSIV is positioned on the seafloor, it should be located beyond the touchdown point.

# Annex B
(normative)

## Support Systems

ESSs and other support systems provide a method of performing specific safety functions common to the entire facility and subsea system. The ESS includes ESD, fire detection, gas detection, ventilation, containment systems and sumps, and SCSSV systems. These are essential systems that provide a level of protection to the facility by initiating shut-in functions or reacting to minimize the consequences of released hydrocarbons.

Subsea installed shutdown valves and SCSSVs should shut-in when activated by a hard wired ESD signal from the topside ESD system. As a backup to this system, all subsea hydraulic power units (HPUs) shall be equipped with hydraulic dump valves for low pressure and high pressure systems that are connected to the ESD. This is applicable to electrohydraulic and direct hydraulic systems.

For all electric systems, these shall fail safe on loss of electrical power.

Refer to API 14C for additional information.

# Annex C
(normative)

# Testing and Reporting Procedures [2]

## C.1 General

Performance testing provides a practical method of confirming the system's ability to perform the design safety functions. On initial installation, tests shall be conducted to verify that the entire safety system, including every final shutdown valve or other final element, is designed and installed to provide proper response to abnormal conditions. Thereafter, periodic operational tests should be performed at least annually to substantiate the integrity of the entire system. Alternative procedures may be used as recommended by manufacturers or as determined through other assessments. A reporting method shall provide orderly accumulation of test data that can be used for operational analyses, reliability studies, asset integrity studies, and reports that may be required by regulatory agencies.

## C.2 Design and Installation Verification

### C.2.1 Purpose

Before a production system is placed in initial operation, the safety system should be thoroughly inspected and tested to verify that each device is installed, operable, performs its design function, and if applicable, is calibrated for the specific operating conditions.

When re-commissioning a facility after being shut in for 30 days or more, the production safety system sensors and final elements shall be verified for proper operation. This verification is to ensure that all sensors remain connected to the process and are functional and all final elements are properly connected and functional.

Where an addition or modification is made to the safety system, that portion of the added or modified system shall be completely inspected and tested to ensure functionality from sensor through logic and to confirm that the final element functions as required.

### C.2.2 Safety Analysis Function Evaluation Chart

The SAFE chart shown in API 14C provides a checklist for the initial design and installation verification. Each sensing device is listed in the column headed "Device I.D.", and its respective control function is indicated under the column headed "Function Performed." It must be determined that each safety device is operable and accomplishes the design control function within the prescribed time. This fact can be noted on the same SAFE Chart used for the topsides safety system. When all initiating devices have been tested and their "Function Performed" confirmed, the design and installation is verified.

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[2] The examples in this Annex are merely examples for illustration purposes only. [Each company should develop its own approach.] They are not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied for reliance on or any omissions from the information contained in this document.

Work sites and equipment operations may differ. Users are solely responsible for assessing their specific equipment and premises in determining the appropriateness of applying the requirements. At all times users should employ sound business, scientific, engineering, and judgment safety when using this RP.

## C.3 Safety System Testing

### C.3.1 Purpose

Safety systems shall be tested to verify that each sensing device operates within specified limits and the control circuit performs its shutdown function as specified. Testing is required to maintain the reliability of the safety system. Test intervals may be shortened to maintain the reliability of the system.

### C.3.2 Frequency

Safety devices and systems should be tested at the intervals recommended below. All safety devices shall be tested at least annually if not listed below. The recommended test frequencies do not supersede the testing requirements called for in C.2.1 when the safety system is initially installed or modified.

Alternative test intervals may be established based on field experience, operator's policy or governmental regulations. In order to establish an alternative test interval beyond the frequency recommended herein or outside of those dictated by governmental regulations, the alternative test interval should verify device reliability greater than or equal to the reliability demonstrated by the recommended/required test frequency. The following parameters should be verified and documented in order to justify use of such a test interval.

— A statistical analysis of the test history of the specific devices to develop a device failure probability or conversely, device reliability, and should likewise define the optimum test frequency to ensure device repeatability.

— A comprehensive historical testing record for each device to support the statistical analysis. The historical records should be maintained in a database that records and reports the results of the device testing and inspection.

— A monitoring program based on the results of the statistical analysis to establish acceptance criteria for devices in this program as well as methods to continuously monitor, review, and update test results to verify that the established level of device reliability is maintained.

Test intervals include the following:

a) Monthly (once each calendar month, not to exceed 6 weeks):

   1) GLSDV, WISDV, and GISDV;

   2) ESD (logic test).

NOTE Refer to API 14C testing requirements for a BSDV.

b) Quarterly (every third calendar month, not to exceed 120 days):

   1) Primary USV;

NOTE The primary USV serves as USV1 (as depicted in Figure A.1, Figure A.2, and Figure A.3) until USV1 fails to test or fails to meet the allowable leakage rate; the USV2 then becomes the primary USV.

   2) GLIV;

   3) PSH and PSL;

   4) LSH and LSL;

   5) ESD (function test).

NOTE Shut in at least one well during the ESD function test. If multiple wells are tied back to the same platform, a different well should be shut-in with each quarterly test.

c) Bi-annually (every six calendar months):

 1) SCSSV

 2) SSIV

d) Annually:

 1) logic solvers

 2) HPU dump valve

 3) check valve

e) Other—Refer to API 17O for testing requirements for HIPPS.

## C.3.3 Software

### C.3.3.1 General

When changes to the software are required, a functional verification of the change shall be performed. The impact of changes shall be assessed to determine scope of testing.

For SIL rated logic solvers, testing shall ensure that a change to a function does not affect other functions.

### C.3.3.2 Sensor Testing

Safety device tests should confirm that sensors properly detect the abnormal conditions and transmit a signal to the logic solver to perform specific shutdown functions.

All subsea safety related sensors should have a baseline test applied, at time of commissioning, to verify calibration. Sensor test methods include:

— performing hydrostatic testing;

— adjusting sensor set point.

Topside sensors within injection circuits shall be calibrated in accordance with standard topside instrumentation calibration cycles and procedures in API 14C.

To facilitate testing of a sensor, the trip function may be bypassed to prevent actual shutdown of the subsea system.

## C.3.4 Subsea Boosting

A subsea pump/compressor shutdown test shall be conducted as a part of commissioning. This test may be combined with testing of other safety system devices ESD function test. The test should verify the accuracy and operational performance of the sensors.

After any intervention or changes to the software affecting the subsea pump/compressor, a complete pump/compressor function test (including full shutdown) shall be conducted.

### C.3.5 Shutdown Valve and other Final Element Testing

Shutdown valves (including USVs, SCSSVs, SSIVs, HIPPS, HPU dump valves) and other final elements should be tested to ensure they receive the signal transmitted by the logic solver and perform their design function. Before testing a sensor, the final shutdown or control device activated by the sensor may be de-activated or bypassed to prevent actual shutdown of the facility. However, the entire shutdown or control circuit, including the final SDV or control device, should be tested per C.3.2 or at least annually.

### C.3.6 Logic Solvers

Logic solvers shall have all I/O tested annually. Application code or configuration for the logic solver shall be strictly controlled under a management of change (MOC) program.

### C.3.7 Auxiliary Devices

All auxiliary devices in the safety system between the sensing device and the SDV or other final element shall be tested at least annually to verify the integrity of the entire shutdown system. These devices, including master or intermediate panels, should be tested in addition to the sensing devices.

### C.3.8 Installation for Testing

Devices should be installed to accommodate regular and/or mandatory testing that will be required during production operations.

### C.3.9 Test Procedures

Testing of safety devices shall be performed. Individual operators shall be responsible for providing procedures for each system.

### C.3.10 Personnel Qualification

Only a competent person should perform testing of subsea safety systems. Individual operators shall establish requirements for qualification.

### C.3.11 Deficient Devices

A safety device that fails, malfunctions, or is otherwise found inoperable during the test procedure should be promptly re-placed, repaired, adjusted, calibrated, or a redundant device assigned as appropriate, and the failure documented in the test records. Until such action can be completed, the device should be clearly tagged on the human machine interface (HMI) as inoperable; a redundant device or equivalent surveillance shall be provided; the process component taken out of service, or the facility shut in.

### C.3.12 Test Tolerances

#### C.3.12.1 Safety Relief Valve

PSV set pressure tolerances are defined in API 14C.

#### C.3.12.2 Pressure Sensor High and Low

PSHL set pressure tolerances are defined in API 14C.

#### C.3.12.3 Level Safety High and Level Safety Low

LSH and LSL set tolerances are defined in API 14C.

#### C.3.12.4 Check Valve

Check valves defined as a barrier should be tested for leakage. If sustained liquid flow exceeds 400 cc/min. or gas flow exceeds 15 $ft^3$/min (0.4 $m^3$/min), the valve should be repaired or replaced.

#### C.3.12.5 Temperature Safety High and Low

TSHL set tolerances are defined in API 14C.

#### C.3.12.6 Boarding Shutdown Valves

BSDV, GLSDV, GISDV, and WISDV should be tested for leakage per API 14C.

#### C.3.12.7 Subsea Shutdown Valves

Subsea shutdown valves, including USVs, SCSSVs, and SSIVs should be tested for leakage. If sustained liquid flow exceeds 400 cc/min. or gas flow exceeds 15 $ft^3$/min (0.4 $m^3$/min), the valve should be repaired or replaced. The GLIV should be function tested per C.3.2, but does not need to meet a specific leak rate.

Shutdown valves used for chemical injection systems are not subject to the above testing requirements.

Refer to API 17O for testing of subsea HIPPS valves.

## C.4 Reporting Methods

### C.4.1 Purpose

Safety device test result records should be maintained in a manner that will enable the performance of operational analyses and equipment reliability studies, and help provide reports that are required by regulatory agencies. These records should document that standards and regulatory requirements are met.

### C.4.2 Test Information

The minimum test information for different safety devices is shown in Table C.1. Test results and operating conditions must be recorded to adequately assess the performance of safety devices.

### C.4.3 Deficient Devices

Records of deficient devices are essential for reliability analyses. As a minimum, the record should include the cause of the deficiency in addition to the data required in Table C.1.

**Table C.1—Safety Device Test Data**

| Data | ESD | LSH | LSL | PSH | PSL | SDV | SSIV | TSH | TSL | USV | HIPPS | SCSSV | FSV | GLIV | GLSDV | GISDV | WISDV |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Device Identification | X | X | X | X | X | X | X | X | X | X | X | X | X | X | X | X | X |
| Maximum W.P. | | | | X | X | X | X | | | X | X | X | X | X | X | X | X |
| Operating Range | | X | X | X | X | | | X | X | | X | | | | | | |
| Response Time | X | | | | | | | | | X | X | X | | X | X | X | X |
| Required Setting | | X | X | X | X | | | X | X | | X | | | | | | |
| Observed Setting | | X | X | X | X | | | X | X | | X | | | | | | |
| Adjusted Setting | | X | X | X | X | | | X | X | | X | | | | | | |
| Proper Operation | X | X | X | X | X | X | X | X | X | X | X | X | X | X | X | X | X |
| Proper Calibration | | X | X | X | X | | | X | X | | X | | | | | | |
| Leakage | | | | | | X | X | | | X | X | X | X | | X | X | X |
| Corrective Action if Required | X | X | X | X | X | X | X | X | X | X | X | X | X | X | X | X | X |

NOTE GLSDV, GISDV, and WISDV are equivalent to the BSDV. Refer to API 14C.

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