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Process system design

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Foreword

NORSOK P-002:2023 was adopted as NORSOK Standard and published 2023-01-03.

NORSOK P-002:2023 superseeds NORSOK P-002:2014.

NORSOK is an acronym for the competitive position of the Norwegian continental shelf and comprise petroleum industry standards in Norway. The collaboration initiative in 1993 between the authorities and the petroleum industry initiated the development of NORSOK standards.

Reducing the project execution time and developing and operating cost for petroleum installations on the Norwegian shelf was the target.

The intention for the Petroleum industry is to develop and use standards providing good technical and cost effective solutions to ensure that the petroleum resources are exploited and managed in the best possible way by the industry and the authorities. The industry will actively contribute to the development and use of international standards in the global market.

The NORSOK standards shall:

- bridge the gap based on experiences from the Norwegian continental shelf where the international standards are unsatisfactorily;
- replace oil company specifications where possible;
- be available as references for the authorities' regulations;
- be cost effective; and
- promote the Norwegian sector as an attractive area for investments and activities.

Developing new NORSOK standards and regular maintenance of existing standards shall contribute to maintain the competitiveness both nationally and internationally for the Norwegian petroleum industry.

The NORSOK standards are developed by experts from the Norwegian petroleum industry and approved according to the consensus principles as laid down by the guidelines given in NORSOK A-001 directive.

The NORSOK standards are owned by Offshore Norge, the Federation of Norwegian Industries and the Norwegian Shipowners' Association. They are managed and published by Standards Norway.

Introduction

The development of this document is primarily based on proven technology, but it does not preclude the use of new technology. The system design clauses are based on the most frequently used systems, but this does not imply that alternatives may not be used (for example dehydration by use of glycol is covered, but not the use of molecular sieves or other means).

The following changes have been made to this document:

- The document has been updated to reflect current industry practice and relevant international standards.
- Methodology for line-sizing of gas and two-phase flow has been updated.
- Added notes and examples.

The system numbers used in this document are those defined in NORSOK Z-DP-002 [\[1\]](#).

Process system design

1 Scope

This document provides requirements for the following aspects of topside process piping and equipment design on offshore production facilities:

- design pressure and temperature;
- process safety system design;
- line sizing;
- system and equipment isolation;
- insulation and heat tracing.

These criteria are applicable for all processes, process support and utility systems.

Additionally this document defines the minimum functional requirements for process systems on an offshore installation. The document includes a number of recommendations to give additional guidance for the system design.

2 Normative references

The following referenced documents contain text which fully or in part is part of the requirements in the document. For dated references, only the edition cited applies. For undated references, the latest edition of the cited document applies (including amendments).

NORSOK L-002:2016, *Piping system layout, design and structural analysis*

NORSOK L-003, *Piping details*

NORSOK M-001, *Materials selection*

NORSOK M-004, *Piping and equipment insulation*

NORSOK S-001:2020, *Technical safety*

NORSOK S-002, *Working environment*

NORSOK S-003, *Environmental care*

NS-EN 1473, *Installation and equipment for liquefied natural gas — Design of onshore installations*

NS-EN ISO 4126, *Safety devices for protection against excessive pressure*

NS-EN ISO 10418, *Petroleum and natural gas industries — Offshore production installations — Process safety systems*

NS-EN ISO 12241, *Thermal insulation for building equipment and industrial installations — Calculation rules*

NS-EN ISO 13702, *Petroleum and natural gas industries — Control and migration of fires and explosions on offshore production installations — Requirements and guidelines.*

NS-EN ISO 13703, *Petroleum and natural gas industries — Design and installation of piping systems on offshore production platforms*

NS-EN ISO 28300, *Petroleum, petrochemical and natural gas industries — Venting of atmospheric and low-pressure storage tanks*

NEK IEC 61508, *Functional safety of electrical/electronic/programmable electronic safety related systems*

NEK IEC 61511 (All parts), *Functional safety — Safety instrumented systems for the process industry sector*

NEK IEC 61882, *Hazard and operability studies (HAZOP studies) — Application guide*

NORSOK H-002, *Sanitary systems*

NORSOK I-001, *Field instrumentation*

API RP 14C, *Analysis, Design, Installation and Testing of Basic Surface Safety Systems on Offshore Production Platforms*

API RP 170, *Recommended Practice for Subsea High Integrity Pressure Protection Systems*

API Std 17F, *Specification for Subsea Production Control Systems*

API Std 520, *Sizing, Selection and Installation of Pressure-relieving Devices in Refineries*

API Std 521:2020, *Pressure-relieving and Depressuring Systems*

API std 537, *Flare Details for Petroleum, Petrochemical, and Natural Gas Industries*

3 Terms and definitions

For the purposes of this document the following terms, definitions and abbreviations apply.

3.1

shall (requirement)

expression in the content of a document conveying objectively verifiable criteria to be fulfilled and from which no deviation is permitted if compliance with the document is to be claimed

Note 1 to entry: Requirements are expressed using the verbal forms specified in ISO/IEC Directives, Part 2 clause 7.2 Table 3.

3.2

should (recommendation)

expression in the content of a document conveying a suggested possible choice or course of action deemed to be particularly suitable without necessarily mentioning or excluding others

Note 1 to entry: Recommendations are expressed using the verbal forms specified in ISO/IEC Directives, Part 2 clause 7.3 Table 4.

Note 2 to entry: In the negative form, a recommendation is the expression that a suggested possible choice or course of action is not preferred but it is not prohibited.

3.3

may (permission)

expression in the content of a document conveying consent or liberty (or opportunity) to do something

Note 1 to entry: Permissions are expressed using the verbal forms specified in ISO/IEC Directives, Part 2 clause 7.3 Table 4.

3.4

can (possibility and capability)

1: expression in the content of a document conveying expected or conceivable material, physical or causal outcome

2: expression in the content of a document conveying the ability, fitness, or quality necessary to do or achieve a specified thing

Note 1 to entry: Possibility and capability is expressed using the verbal forms specified in in ISO/IEC Directives, Part 2 clause 7.5 Table 6.

3.5

design

form and function

3.6

design pressure

pressure, together with the design temperature, used to determine the minimum permissible thickness or physical characteristic of each component as determined by the design rules of the pressure design code

3.7

maximum operating pressure

maximum pressure including plant operation at unstable conditions

Note 1 to entry: Unstable conditions include start-up/shutdown, control requirements and process upsets.

3.8

maximum operating temperature

maximum temperature including plant operation at unstable conditions

Note 1 to entry: Unstable conditions include start-up, shutdown, control requirements and process upsets.

3.9

minimum operating temperature

minimum temperature including plant operation at unstable conditions

Note 1 to entry: Unstable conditions include start-up, shutdown and depressurizing.

3.10

operating pressure

pressure during normal operation, including normal variations

3.11

operating temperature

temperature during normal operation, including normal variations

3.12

settle out pressure

equalized pressure after a compressor shutdown

3.13

shut-in pressure

pressure for pumps and compressors determined by the curves for a “no flow” situation

EXAMPLE Blocked outlet.

3.14**primary side**

main process fluid or main utility fluid

Note 1 to entry: Term used for heat exchangers.

3.15**secondary side**

utility fluid or secondary process fluid

Note 1 to entry: Term used for heat exchangers.

4 Abbreviations

ASV	antisurge valve
AVIFF	avoidance of vibration induced fatigue failure
BTEX	benzene, toluene, ethylbenzene and xylene
CIP	cleaning in place
CCR	central control room
CMR	carcinogenic, mutagenic, or toxic for reproduction
CS	carbon steel
EI	Energy Institute
ESD	emergency shutdown
GRP	glass fibre reinforced polyester
HAZOP	hazard and operability
ID	internal diameter
LAHH	level alarm high high (trip level)
LALL	level alarm low low (trip level)
LO	locked open
LOF	likelihood of failure
MAAP	maximum allowable accumulated pressure
MEG	mono ethylene glycol
NGL	natural gas liquids
NLL	normal liquid level
NPSH	net positive suction head
PAH	pressure alarm high
PAHH	pressure alarm high high (trip pressure)
PCHE	printed circuit heat exchanger
PCV	pressure control valve
PSD	process shutdown
PRV	pressure-relief valve
SIF	safety instrumented function
SS	stainless steel
WHRU	waste heat recovery unit

5 Design pressure and temperature**5.1 General**

Where pressure relief devices are used, set points for these shall be in accordance with the design code applied for the components in the system.

5.2 Design pressure

5.2.1 Maximum design pressure

For systems protected by a PRV, the criteria in [Table 1](#) should be applied unless the PRV manufacturer guarantees that use of other margins is acceptable.

NOTE The minimum margin is defined to avoid unintentional PRV opening.

The relation between high trip pressure and maximum operating pressure is given in [Figure 1](#).

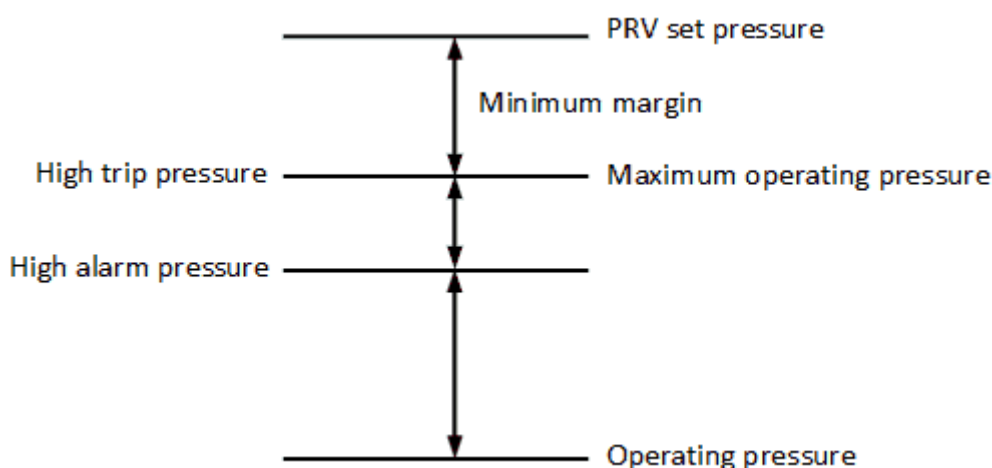


Figure 1 — Pressure relations

Table 1 — Design pressure criteria for pressurised systems

<i>Maximum operating pressure (barg)</i>	<i>Design pressure (barg)</i>
0-35	Maximum operating pressure +3,5 bar
35-70	Maximum operating pressure +10 %
70-200	Maximum operating pressure +8,5 % but minimum 7 bar and maximum 10 bar
200 +	Maximum operating pressure + 5 %

NOTE 2 The limitations in [Table 1](#) are given to ensure proper operation of the PRV. As shown in [API Std 521:2020](#), valves will begin to simmer at around 98 % of set pressure and reseal at about 92 % of set pressure. The guidelines above will be correct if PAHH is taken as maximum operating pressure giving some conservatism to PAH. System dynamics can require more conservatism.

When rupture disks are applied, sufficient margin shall be included to:

- prevent unintentional disk ruptures, i.e. margin between the disk set pressure and the operating pressure;
- ensure system pressure protection, i.e. margin between the disk set pressure and the maximum accumulated overpressure.

The use of double rupture disks in series to avoid variations in pressure in the flare system affecting the effective set pressure for the (first) rupture disk should be considered.

NOTE 3 Reference is made to relevant pressure relieving design codes for further guidance.

When accurate information is unavailable, the shut-in pressure for centrifugal compressors should be determined as the maximum operating suction pressure +1,3 times the normal head developed by the compressor, to include for pressure rise at surge condition and maximum speed. The maximum operating

suction pressure for a compressor shall in this case be determined by the high trip pressure from upstream separators or compressors.

When accurate information is unavailable, the maximum operating pressure (shut-in pressure) for centrifugal pumps should be determined as the suction pressure at relieving conditions +1,25 times the normal differential pressure developed by the pump.

Care should be taken not to define higher design pressure than required when it affects the selection of material and pressure class rating.

Water-hammer pressure surge shall be considered in system design.

To minimise the requirements for process relief (full flow) the design pressure should be kept identical for systems with almost identical operating pressures.

For piping, occasional variations in the pressure above the design pressure is permissible in some design codes. This shall be subject to due consideration of all aspects in the relevant piping design code. The effects of such variations shall be determined by the designer to be safe over the service life of the piping system.

Atmospheric tanks shall as a minimum be designed to be liquid filled to the highest point of the overflow line, and with an overpressure of 0,07 bar.

If the overflow line can be blocked or have reversed flow (e.g. during loading) the atmospheric tank shall be designed for a liquid filled vent line up to the goose neck.

NOTE Reference is made to [NS-EN ISO 28300](#) or [API 2000 \[2\]](#) for further guidance.

For flare knock out drums, the design pressure may be equal to the pressure at maximum relief rate.

NOTE It is recommended to add a margin to the maximum operating pressure in the design phase to account for increase due to uncertainties.

5.2.2 Minimum design pressure

For equipment where cooling or condensing vapours (e.g. after steam-out of vessels), drainage or pump out may lead to less than atmospheric pressure, the equipment shall be designed for full vacuum or protected by vacuum relief.

NOTE Reference is made to [API Std 521:2020](#) for further guidance.

5.3 Design temperature

5.3.1 General

The guidelines given in this standard for temperature are based on operation in the Norwegian sector.

Consideration should be taken that the equipment or system may be constructed or used elsewhere and that higher temperatures may be experienced due to solar radiation.

Consideration should also be taken for the possibility of higher temperatures during flare operation.

5.3.2 Maximum design temperature

Where the maximum operating temperature can be determined accurately, this temperature should be used as maximum design temperature, without adding a safety margin.

NOTE A high temperature shut down function, in accordance with [NS-EN ISO 10418](#) or [API RP 14C](#), can limit the maximum operating temperature.

EXAMPLE This can apply to the use of reservoir temperature as maximum design temperature for platform inlet facilities.

Where the maximum operating temperature cannot be determined accurately, the maximum design temperature should be determined by adding 30 °C to the normal operating temperature.

For equipment operating at ambient conditions, the maximum design temperature should be limited to 50 °C in the Norwegian sector.

NOTE *A high temperature shut down function, in accordance with [NS-EN ISO 10418](#) or [API RP 14C](#), can limit the maximum operating temperature.*

Care should be taken not to define higher design temperature than required as it may affect the selection of material, pressure class rating and layout.

Vessels and instruments subject to steam-out shall be designed for coincidental temperature and pressure during steam-out operation.

Specific recommendations for individual systems are included in the system design [Clause 12](#) to [Clause 35](#).

5.3.3 Minimum design temperature

The minimum design temperature determines the requirements to the low temperature characteristics of the material, and shall be the most stringent of the following:

- minimum operating temperature (obtained during normal operation, start-up, shutdown or process upsets) with a margin of 5 °C;
- minimum ambient temperature, the lowest temperature should be based on available weather data, and safety factors should be selected based on the quality of such weather data;
- minimum temperature occurring during depressurising with a margin of 5 °C, the temperature calculations shall as a minimum include heat transfer between fluid and vessel, and the most conservative starting conditions for depressurising shall be used including the following considerations as a minimum:
 - cool down to minimum ambient temperature after shut-in at PRV set pressure and corresponding temperature (including reduction in pressure during cool down);
 - conditions during a start-up operation following a depressurisation;
 - minimum operating temperature and maximum operating pressure.

The minimum design temperature may be limited by initiating depressurisation at a higher temperature than the minimum ambient temperature.

If implemented, this shall be subject to project owner approval, and be addressed in documentation for operation.

The minimum design temperature may be limited by delaying start-up (to heat the system prior to start-up).

If implemented, this shall be subject to project owner approval, and be addressed in documentation for operation.

6 General system design

6.1 Design for minimum impact of facility movement

Design criteria for floating installations shall take into account movements and accelerations under which the process facility is required to operate. Any limitations shall be specified in the engineering documentation.

6.2 Material selection

To ensure correct material selection all chemical components and their concentrations in the fluid in all services shall be specified.

NOTE Certain chemicals (e.g. methanol) are aggressive against gasket materials and titanium and require special considerations, see [NORSOK M-001](#).

6.3 Maintenance and isolation

It shall be possible to isolate pumps and clean the suction strainer without draining upstream tank/vessels.

Provision shall be made for withdrawal of sump pumps during operation of the system without loss of blanket or purge gas and minimizing liquid flashing to atmosphere, e.g. by use of a well inside the tank.

Bypass piping may be installed across heaters, coolers, filters and coalescers.

Utility stations shall be located to enable flushing of all drip trays and mechanical equipment.

All equipment subjected to inspection/maintenance shall have provision for drainage and venting and suitable utility connection(s) for cleaning purpose prior to opening of equipment. The need for isolation, draining and cleaning facilities (steam out cleaning, nitrogen purging, CIP etc) should be considered in design to avoid health risks due to hydrocarbon exposure to personnel, e.g. benzene (a CMR substance).

NOTE Glycol contactor and regeneration systems are prone to accumulation of CMR substances (such as BTEX and Mercury).

6.4 Monitoring

Instrumentation to enable condition-based monitoring shall be provided. Remote monitoring is an option to enable automatic and remote condition monitoring.

7 Safety requirements

7.1 Objectives

The goal of process safety system design is:

- to protect personnel, the environment, and the facility from risks caused by the production process;
- to prevent the release of hydrocarbons or high pressure or toxic fluids from the process, and to minimize the adverse effects of such releases if they occur;
- to shut in the process or affected part of the process to stop the flow of hydrocarbons to a leak or overflow if it occurs;
- to prevent ignition of released hydrocarbons;
- to shut in the process in the event of a fire;
- to prevent undesirable events that could cause the release of hydrocarbons from equipment other than that in which the event occurs.

These objectives are met by a combination of the process safety functions (Process Shutdown System (PSD) and secondary safety devices) and Emergency Shutdown System (ESD), which shall be independent of each other.

NOTE ESD requirements are specified in [NORSOK S-001:2020](#).

7.2 Safety analysis

The following systems shall be designed in accordance with [NS-EN ISO 10418](#) or [API RP 14C](#) and the shutdown functions shall be realised in the PSD system:

- all hydrocarbon containing systems in wellhead and main process (system 13, 20 to 39, except 34);
- flare (system 43);
- oily water treatment (system 44) including injection of produced water (system 29);
- fuel gas (system 45);
- methanol/MEG injection (system 46);
- hazardous open drain (system 56);
- closed drain (system 57);
- jet fuel (system 61);
- diesel oil (system 62).

Design in accordance with [NS-EN ISO 10418](#) or [API RP 14C](#) shall also be considered for other systems that involve hazards due to:

- flammability/flash point;
- temperature;
- pressure;
- volatility;
- toxicity;
- fluid content/volume.

7.3 Hazard and operability

HAZOP studies shall be carried out in accordance with [NEK IEC 61882](#).

HAZOP shall as a minimum include the systems covered by [NS-EN ISO 10418](#) or [API RP 14C](#) as defined in [7.2](#) including equipment packages and non-hazardous open drain (system 56). Additional systems and equipment packages may require a HAZOP analysis. The HAZOP team shall be as small as possible consistent with the relevant technical and operating skills and experience being available. The number of participants shall be limited to ensure an efficient HAZOP process.

For description of roles and responsibilities, including the requirement for an independent study leader, [NEK IEC 61882](#) shall apply.

The documentation shall be in accordance with requirement in [NEK IEC 61882](#).

7.4 Overpressure protection

7.4.1 General

Overpressure protection shall be in accordance with the recommendations in [NS-EN ISO 10418](#) or [API RP 14C](#), for systems as defined in [7.2](#).

All scenarios as described in [API Std 521:2020](#) shall be covered.

A risk based design approach shall not be used to eliminate any of these standard scenarios.

The existence of other credible scenarios shall be evaluated.

Instrumented secondary pressure protection systems may be used, as covered in [7.4.3](#).

7.4.2 Pressure relief devices

Location of pressure relief devices and design of inlet and outlet piping should be in accordance with [NS-EN ISO 4126](#), [API Std 521:2020](#) and [API Std 520](#).

Design of pilot operated relief valves used in dirty service (typically well-stream and hydrate forming fluids) shall include compensatory measures due to the risk of clogging impulse lines and/or the pilot.

For pumps with internal pressure relief capability, a dedicated external relief device shall be installed if the internal relief device is not designed and located such that maintenance and testing is possible.

7.4.3 Safety instrumented secondary pressure protection systems

Mechanically based pressure protection systems (e.g. PRV) shall be the preferred solution for secondary pressure protection.

Use of safety instrumented secondary pressure protection systems shall be based on acceptance criteria for overall system integrity, and be limited to the following applications:

- as a replacement for PRV to protect gas pipeline systems where the use of PRV would entail high material cost and for production flowline where full pressure rating would be impractical;
- as a means to reduce the relief design rate by avoiding simultaneous flaring from parallel equipment/equipment trains. In this application, the instrumented barrier shall protect the flare system only, and it shall not be used to reduce the required capacity of PRV(s);
- as a means to reduce the relief design rate where multiple feeds are routed into the same equipment. The available relief capacity for overpressure protection of the equipment/piping shall as a minimum accommodate the rate caused by failure to shut off the largest feed;

NOTE Higher relief capacity can be required, e.g. allowance for multiple feed shut off failures in order to obtain compliance with risk tolerance criteria.

- to protect wells from overpressure from MEG or chemical injection where use of PRV is demonstrated and documented to be impracticable.

The reduced relief rate shall be accommodated within the flare system capacity. For new build, the capacity should be limited to design pressure. Similarly, flare radiation for this relief rate should meet the radiation criteria in [API Std 521:2020](#).

Acceptance criteria for frequency of rupture of the protected equipment and piping as defined in [NORSOK S-001:2020](#), project owner risk acceptance criteria or risk acceptance criteria given by design code shall be applied. Safety instrumented secondary pressure protection systems shall be designed in accordance with [NEK IEC 61508](#), [NEK IEC 61511 \(All parts\)](#), [API RP 170](#) and [API Std 521:2020 Annex E](#).

Norwegian Oil and Gas guideline 070 [\[3\]](#) may be used as guidance in the application of [NEK IEC 61508](#) and [NEK IEC 61511 \(All parts\)](#) standards.

Special consideration shall be given to the design of the safety instrumented system due to the potential for erosion problems, hydrate formation, fluid viscosity, wax content, etc. Common mode failures (e.g. loss of heat tracing), shall be considered.

7.4.4 Safety instrumented functions

Safety instrumented functions (PSD functions) should be designed to keep process within design limits without assistance of secondary barrier. Exceptions may be acceptable if response time is not achievable.

For safety instrumented functions protecting against high/low level, the response time should be so that the level in the separator is kept within safe levels and within the range of the level instrument.

Instrumentation with input to PSD, ESD or other autonomous protection systems shall be regarded as safety critical.

A system shall be established and maintained in order to ensure that manual valves in impulse lines are secured in open position.

7.5 Check valves

When two check valves are installed in series to limit relief rate through PRV due to reverse flow from a high pressure source, these shall be regularly tested for leakage rate. If a positive displacement pump is used and it prevents backflow, this may replace one of the two check valves.

The design shall cater for the testing of each check valve. For more guidance, see [API Std 521:2020](#).

If credit is taken for check valves in determining required relief flow, the check valves shall be tagged, defined as safety critical and included in a maintenance program.

7.6 Piping

Hydrocarbon piping through non-hazardous area should be avoided. Where this is unavoidable, the pipes shall be welded and the use of flanges (e.g. for connection to turbine fuel gas) minimised.

8 Line sizing criteria

8.1 General

When sizing piping, the following constraints shall be addressed:

- required capacity/available driving pressure;
- flow induced forces;
- noise/vibration;
- pressure surges;
- material degradation (erosion, corrosion and cavitation);
- liquid accumulation/slug flow;
- sand accumulation.

Line sizing criteria in this clause below shall be adhered to for design of new installations.

For modification of existing installations, additional considerations shall be given to life cycle cost, and increased velocity or pressure drop may be accepted if mechanical integrity can be documented, e.g. $\rho v^2 > 200000 \text{ kg/ms}^2$ for a line in the flare system.

Sizing of lines should be in accordance with [NS-EN ISO 13703](#).

8.2 Permissible pipe sizes

A minimum pipe size of DN 50 (2 in) should be used for all process, process support and utility piping.

NOTE Minimum pipe size is necessary to ensure adequate mechanical integrity, particularly for connections to vessels.

Smaller piping can be used where protection or support is provided to withstand human activity and where small volume flows make the use of small piping a requirement.

Minimum size for the sewage and open drain header shall be DN 100 (4 in) and sub-headers DN 80 (3 in).

Overflow from atmospheric tanks shall as a minimum be equal to the largest inlet pipe.

Tubing may be used for air, hydraulic oil and other non-combustible/non-hazardous fluids.

8.3 Pipe roughness

For all calculations of pressure drop, the following pipe roughness values should be used:

- Carbon steel (CS) non-corroded: 0,05 mm;
- Carbon steel (CS) corroded: 0,5 mm;
- Stainless steel (SS): 0,05 mm;
- Titanium and Cu-Ni: 0,05 mm;
- Glass fibre reinforced polyester (GRP): 0,02 mm;
- Polyethylene, PVC: 0,005 mm;
- flexible hose: vendor to be consulted.

NOTE As a rough estimation, ID/20 mm can be used (ID is the internal diameter in inches) for steel carcass and 0,005 mm for plastic coating

8.4 Sizing of liquid lines

8.4.1 Velocity limitations

The velocities shall be kept low enough to prevent problems with erosion, water-hammer pressure surges, noise, vibration and reaction forces.

Potential velocity limitations due to coating or use of chemicals, such as corrosion inhibitor, shall be accounted for. The material discipline should be consulted for advice.

Table 2 — Recommended maximum velocities for sizing of liquid lines

Fluid	Maximum velocities (m/s)			
	CS	SS/Titanium	CuNi ^d	GRP
Liquids	6	^b	3	6
Liquids with sand ^e	5	7	NA	6
Liquids with large quantities of mud or silt ^e	4	4	NA	NA
Untreated seawater	3	7 ^a	3 ^b	6
Deoxygenated seawater	6	^c	3	6
^a See clause 8.4.6 for limitations in fire water systems. ^b For pipe less than DN 200 (8 in), see BS MA-18 [4] for maximum velocity limitations. ^c For stainless steels and titanium the maximum velocity is limited by system design (available pressure drop/reaction forces). 7 m/s may be used as a typical starting value for sizing. ^d Minimum velocity for CuNi is 1,0 m/s. Maximum allowable velocity is between 6 m/s and 10 m/s depending duration and frequency of operation. ^e Minimum velocity for liquids with sand should be in accordance with NS-EN ISO 13703.				

8.4.2 Centrifugal pump suction and discharge lines

The suction piping shall be sized based on NPSH requirements.

Maximum velocity from Table 2 and the following maximum pressure drops should be used:

- sub-cooled liquids: 0,25 bar/100 m;
- boiling liquids: 0,05 bar/100 m.

The fluid temperature shall be at least 15 °C below the fluid boiling point temperature to allow sizing based on the criterion for sub-cooled liquids.

The maximum velocity in the discharge piping is given in Table 2.

As a guideline, a pressure drop of up to 0,9 bar/100 m may be used.

8.4.3 Reciprocating pump suction and discharge lines

For reciprocating pumps, the piping shall be sized based on NS-EN ISO 13703.

8.4.4 Control valve inlet lines liquid service

Control valve inlet lines shall be sized such that single phase liquid is maintained.

8.4.5 Liquid flowing by gravity

8.4.5.1 General

Lines flowing by gravity includes tank overflows, drains (sanitary, closed and open drains), and other lines where the liquid flows due to gravity forces instead of pressure difference.

Generally, for fixed installations, a minimum downward slope of 1:100 shall be used.

However, with mud or sand, the slope shall be at least 1:50.

On floating installations the slopes shall be evaluated according to planned installation trim.

Pipes that run full, and do not require a minimum downward slope to avoid particle deposition, shall be sized according to the total available static pressure head, and the maximum allowable velocities for liquid lines.

8.4.5.2 Near horizontal lines

Near horizontal pipes not running full shall be sized based on the maximum flow capacities as given in [Table 3](#).

Table 3 — Flow capacity – Near horizontal pipes

Diameter mm (in)	Liquid flow capacity (NOTE) m ³ /h	
	Slope 1:50	Slope 1:100
50 (2)	3,7	2,6
80 (3)	9,9	6,9
100 (4)	24	17
150 (6)	70	49
200 (8)	150	106
250 (10)	271	192
300 (12)	441	312
350 (14)	665	471
400 (16)	950	672

NOTE According to the Manning formula (see [\[5\]](#)) a pipe “filling degree” of 75 % is assumed.

The liquid in the entrance part of a near horizontal pipe needs some acceleration distance to reach fully established velocity. To reduce the entrance pressure loss, the inlet section should have increased diameter compared to [Table 3](#).

For the first ten pipe diameter length, the next larger pipe diameter in [Table 3](#) should be selected ending with an eccentric reducer.

8.4.5.3 Vertical lines

Vertical gravity lines with or without submerged outlets (e.g. so-called “dump caissons”) should be designed such that the Froude number is less than 0,7.

NOTE 1 Guidance on Froude number for design of vertical gravity lines with or without submerged outlets (e.g. so-called “dump caissons”) is: 0,3 for caisson sizes less than 12 inch nominal diameter; 0,5 for caisson sizes between 12 to 24 inch nominal diameter; 0,7 for caisson sizes larger than 24 inch nominal diameter. Introduction of bends and sloping pipes will reduce the capacity and more detailed flow analysis is recommended.

NOTE 2 Introduction of bends and sloping pipes will reduce the capacity and more detailed flow analysis is recommended. This is to avoid air entrainment and ensure undisturbed flow without pulsations.

$$Froude \text{ number} = \frac{V}{\sqrt{D \times g}} \quad (1)$$

where

V is the velocity assuming full pipe in m/s
 D is the pipe inner diameter in m
 g is the gravity constant in m/s²

A vent line shall be included from top of the vertical gravity line to prevent vacuum, flashing or pulsations. The vent line should be designed for an air/vapour volumetric flow-rate equal to the liquid volumetric flow through the vertical line and a pressure loss of maximum 0,005 bar. The vent line for vertical lines/caissons to sea, shall also be designed for the wave motion inside lines/caisson.

Liquid inlet to dump caissons should be tangential and sloped downwards.

Drainage of deluge water from drain boxes through vertical lines shall be sized on basis of 50 % of the available head (assuming the pipe running full of liquid) and not Froude number.

[Formula \(2\)](#), [Formula \(3\)](#) and [Formula \(4\)](#) can be used to determine the capacity.

$$Q = \frac{8855,8 \times D^{2,5}}{\sqrt{f}} \quad (2)$$

where

Q is the flow in m³/h
 f is the Moody friction factor
 D is the pipe inner diameter in m

The Moody friction factor for fully turbulent flow can be calculated by the Nikuradse formula, see [Formula \(3\)](#)

$$f = \frac{1}{\left[2 \log\left(\frac{D}{2k}\right) + 1,74\right]^2} \quad (3)$$

where

k is pipe roughness in m

The flow formula is based on setting 50 % of the available head equal to the piping friction loss, see [Formula \(4\)](#).

$$\rho \times g \times 0,5 \times L = \frac{f \times L \times \rho \times V^2}{D \times 2} \quad (4)$$

where

ρ is the density in kg/m³
 g is the gravity constant in m/s²
 L is the pipe length in m
 V is the velocity in m/s

8.4.6 Fire water

The line sizing of fire water lines shall be based on available system pressure and allowable flow velocities.

The pressure drop to the large deluge systems shall be calculated on basis of the most unfavourable pipe routing to those systems.

In the ring main pipe-work the flow velocity shall not exceed the velocity as given in [Table 2](#).

Upstream the deluge skids, the flow velocities should not exceed 10 m/s.

Some areas may require velocities higher than 10 m/s in order to hydraulically balance the systems, which is acceptable, provided the reaction force within the system does not cause excessive stress in the pipe work or the supports.

8.4.7 Oily water systems

Where retaining the size of oil droplets in the water is crucial, this can be achieved by providing low flow velocities.

Typically the velocity should not exceed 3 m/s. This should also be considered in selection of fittings and instruments in these lines to avoid shearing of oil droplets.

8.5 Sizing of gas lines

8.5.1 General

When sizing gas lines the sizing criteria is a compromise between the maximum velocity (see 8.5.2) and allowable pressure drop (see 8.5.3). The compromise is driven by installation cost, power for compressors and noise. Piping with gas at the dew-point and/or with some droplets shall be designed as gas lines.

8.5.2 Maximum velocities

In lines where pressure drop is not critical, gas velocity shall not exceed limits which may create noise or vibrations problems.

For streams having a gas volume fraction above 99 %, all normally flowing pipes with velocities of 25 m/s or higher shall be subject to vibration screening.

EXAMPLE A recognised method for vibration screening of piping is Energy Institute's Guidelines for the avoidance of vibration induced fatigue failure in process pipework (AVIFF) [6].

Anti-surge lines shall be considered normally flowing pipes.

The fluid viscosity factor (FVF) for gas flow is defined in [Formula \(5\)](#).

$$FVF = \frac{\sqrt{\mu_{gas}}}{\sqrt{10^{-3}}} \quad (5)$$

where

μ_{gas} is dynamic viscosity [Pa·s].

Calculated LOF (likelihood of failure) should be < 0,5 according to selected support arrangement. However, this is not always possible due to geometry and thermal expansion of piping arrangements. In such cases, LOF values up to 1 may be acceptable. Prior to completed support design, medium category stiffness may be assumed.

NOTE Improved stiffness of piping support arrangement and increased pipe wall thickness might reduce LOF.

In order to avoid excessive dispersion of noise in lines connected to pressure control valves, the valve manufacturer shall be consulted.

If solid particles are present, special attention shall be given to particle erosion.

8.5.3 Recommended pressure drop

Where pressure drop is critical the guidelines in [Table 4](#) should be used.

The pressure drop should be prorated between the operating pressures given.

NOTE The pressure drop is considered critical when:

- the cost increase due to additional power requirement is larger than the potential cost savings due to reduced pipe diameter;
- it results in unacceptable liquid drop out in suction lines between scrubber and compressor suction, inlet lines to turbo expanders and contactors, etc.

Table 4 — Recommended pressure drop for single phase gas process lines.

Operating pressure (barg)	Pressure drop (bar/100 m)
0 to 35	0,001 to 0,11
35 to 138	0,11 to 0,27
over 138	P/500 ^a
^a P is operating pressure in barg.	

8.6 Sizing of two phase/multiphase lines

8.6.1 General

Wellhead flow-lines, production manifolds, process headers and other lines made of steel and transporting two-phase or multiphase flow, have a velocity limitation.

When determining the maximum allowable velocity, factors such as piping geometry, well-stream composition, sand particle (or proppant) contamination and the material choice for the line shall be considered.

For two phase/multiphase streams with gas volume fraction (GVF) below 99 %, all piping subject to mixture velocities of 10 m/s or higher shall undertake vibration screening according to Energy Institute's guideline for AVIFF in process pipework, using fluid viscosity factor (FVF) = 1 for GVF less than 0,88.

Calculated LOF (likelihood of failure) should be < 0,5 with the selected support arrangement.

Improved stiffness of piping support arrangement can reduce LOF. However this is not always possible due to geometry and thermal expansion of piping arrangements. In such cases, LOF values up to 1 may be acceptable.

If no piping support information is available medium support arrangement should be used.

NOTE Alternative remedies for vibration problems identified by FIV screening:

- increase the line size to reduce velocity;
- increase the pipe wall thickness for pipe robustness.

This is typically relevant downstream flashing control valves.

Velocities above 30 m/s should be avoided.

For GVF between 0,88 and 0,99 (low liquid fraction - typically wet gas production), FVF shall be estimated as given in [Formula \(6\)](#):

$$FVF = -27,882 \times GVF^2 + 45,545 \times GVF - 17,495 \quad (6)$$

NOTE Equation represents a curve fit for FVF between GVF 0,88 and 0,99.

When sizing two- or multiphase lines, unstable flow and slugging shall be considered.