Drilling facilities
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Foreword

NORSOK (The competitive standing of the Norwegian offshore sector) is the industry initiative to add value, reduce cost and lead time and eliminate unnecessary activities in offshore field developments and operations.

The NORSOK standards are developed by the Norwegian petroleum industry as a part of the NORSOK initiative and supported by OLF (The Norwegian Oil Industry Association) and TBL (Federation of Norwegian Engineering Industries). NORSOK standards are administered and issued by SN (Standards Norway).

The purpose of NORSOK standards is to contribute to meet the NORSOK goals, e.g. by replacing individual oil company specifications and other industry guidelines and documents for use in existing and future petroleum industry developments.

The NORSOK standards make extensive references to international standards. Where relevant, the contents of a NORSOK standard will be used to provide input to the international standardisation process. Subject to implementation into international standards, the NORSOK standard will be withdrawn.

Annex A and C is informative and B is normative.

Introduction

The main objective of this NORSOK standard is to contribute to an optimization of the design of drilling facilities, their systems and equipment with respect to utilization, operational efficiency, life cycle cost and to promote sound HSE principles.

The standard can be utilized for modification of drilling facilities where only modified part need to be in compliance with this standard.

The standard may also be utilized for modular drilling facilities, workover and P&A rigs. In this case the datasheet in Annex C shall be adapted to fulfill the specific requirements.
1 Scope
This standard describes the functional requirements, design outline, installation and testing requirements for the drilling facilities and their systems and equipment on fixed installations and mobile offshore drilling units (MODUs).

Functional requirements will normally be based on:

Area of operation:
- Skagerrak and North Sea;
- the Norwegian Sea;
- Barents Sea, south of 72ºN;
- Barents Sea, north of 72ºN.

Area of utilization:
- rig for fixed installation operating in one field during lifetime;
- modular drilling rig;
- MODU.

Planned well operations:
- drilling wells;
- completion;
- well workovers;
- well interventions;
- well abandonment operations;
- 3rd party equipment and operations;
- simultaneous operations.

Environmental issues:
- amount of waste from drilling area;
- possibility to handle waste;
- drain systems.

Maintainability:
- online support;
- replacement of 3rd party equipment;
- access;
- back-up.

Interfaces:
- interface towards facility/unit equipment and systems;
- interface to 3rd party equipment.

The design outline is meant to encourage:
- safe design and lay-out;
- robust and efficient facilities/systems;
- separation of various areas and systems/equipment;
- working environment.

Design of facility require:
- verified layout by design review;
- all relevant operation conditions/situations included;
- interface between all relevant functions with adequate capacity included.
Minimum testing requirements are:
- factory acceptance test (FAT);
- commissioning test;
- acceptance/integration test based on complete verification of equipment and systems/sub systems as operated under normal conditions.

2 Normative and informative references

The following standards include provisions and guidelines which, through reference in this text, constitute provisions and guidelines of this NORSOK standard. Latest issue of the references shall be used unless otherwise agreed. Other recognized standards may be used provided it can be shown that they meet the requirements of the referenced standards.

2.1 Normative references

<table>
<thead>
<tr>
<th>Standard</th>
<th>Description</th>
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<tr>
<td>ANSI B 31.3</td>
<td>Process Piping</td>
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<tr>
<td>API RP 14 C</td>
<td>Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms</td>
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<td>API RP 2R</td>
<td>Marine Riser</td>
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<td>API Spec 4F</td>
<td>Drilling and Well Servicing Structures</td>
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<td>API Spec 7</td>
<td>Rotary Drilling Equipment (replace with ISO 10424 when issued)</td>
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<tr>
<td>API Spec 8C</td>
<td>Specification for Drilling and Production Hoisting Equipment (replace with ISO 13535 when issued)</td>
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<td>API Spec 9A</td>
<td>Specification for Wire Rope</td>
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<td>API RP 13C</td>
<td>ISO 13501 (modified), Recommended Practice on Drilling Fluids Processing Equipment Evaluation</td>
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<td>API Spec 6A</td>
<td>Specification for Wellhead and Christmas Tree Equipment</td>
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<tr>
<td>API Spec 16A</td>
<td>Specification for Drill Through Equipment (replace with ISO 13533 when issued)</td>
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<td>API Spec 16C</td>
<td>Choke and Kill System</td>
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<tr>
<td>API Spec 16D</td>
<td>Specification for Control Systems for Drilling Well Control Equipment</td>
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<tr>
<td>API RP 16E</td>
<td>Recommended Practice for Design of Control Systems for Drilling Well Control Equipment</td>
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<tr>
<td>ANSI/API 16J</td>
<td>Comparison of Marine Drilling Riser Analyses</td>
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<tr>
<td>API RP 16Q</td>
<td>Recommended Practice for Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems (replace with ISO 13624 when issued)</td>
</tr>
<tr>
<td>API Standard 53</td>
<td>Blowout Prevention Equipment Systems for Drilling Wells</td>
</tr>
<tr>
<td>ASME VIII</td>
<td>Div. 1 and Div. 2, Pressure Vessel Code</td>
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<tr>
<td>BS 5500</td>
<td>Pressure vessels, accumulators and piping systems</td>
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<td>ISO 1000</td>
<td>SI units and recommendations for the use of their multiples of certain other units</td>
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<tr>
<td>ISO 15663-1</td>
<td>Life cycling costing – Part 1: Methodology</td>
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<tr>
<td>ISO 15663-2</td>
<td>Life-cycling costing – Part 2: Guidance on application of methodology and calculation methods</td>
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<tr>
<td>ISO 15663-3</td>
<td>Life cycling costing – Part 3: Implementation guidelines</td>
</tr>
<tr>
<td>ISO 10423</td>
<td>Petroleum and natural gas industries – Drilling and production equipment – Wellhead and christmas tree equipment</td>
</tr>
<tr>
<td>NACE MR-0175</td>
<td>For sour service</td>
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<tr>
<td>NORSOK D-SR 007</td>
<td>Well testing system</td>
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</tbody>
</table>
2.2 Informative references

None.

3 Terms, definitions and abbreviations

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

3.1 Terms and definitions

3.1.1 competent person
as defined in the EC Directives for Supply of Machinery

3.1.2 drilling facilities
structures containing systems, equipment and utilities required for drilling operations

3.2 Abbreviations

ACS anti-collision (zone management) system
AWD analysis while drilling
BHA bottom hole assembly
BOP blow-out preventer.
CCTV closed circuit television
CPU central processing unit
DCDA drilling control and data acquisition system
DCS drilling control system
DSC drill string compensator
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>DSM</td>
<td>drilling support module</td>
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<tr>
<td>DES</td>
<td>drilling equipment structure</td>
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<tr>
<td>ESD</td>
<td>emergency shutdown system</td>
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<tr>
<td>FAT</td>
<td>factory acceptance test</td>
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<tr>
<td>HMI</td>
<td>human machine interface</td>
</tr>
<tr>
<td>HP/HT</td>
<td>high pressure/high temperature</td>
</tr>
<tr>
<td>HVAC</td>
<td>heating, ventilation and air conditioning</td>
</tr>
<tr>
<td>I/O</td>
<td>input/output</td>
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<tr>
<td>KEMS</td>
<td>kinetic energy measuring system</td>
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<tr>
<td>LAT</td>
<td>lowest astronomical tide</td>
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<td>LCC</td>
<td>life cycle cost</td>
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<tr>
<td>LER</td>
<td>local equipment room</td>
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<tr>
<td>LIR</td>
<td>local instrument room</td>
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<tr>
<td>LMRP</td>
<td>lower marine riser package</td>
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<tr>
<td>MD</td>
<td>measured depth</td>
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<td>MEWHP</td>
<td>maximum expected wellhead pressure</td>
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<td>ML</td>
<td>mud logging</td>
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<tr>
<td>MODU</td>
<td>mobile offshore drilling unit*</td>
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<tr>
<td>MPD</td>
<td>managed pressure drilling</td>
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<tr>
<td>MTBF</td>
<td>mean time between failure</td>
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<tr>
<td>MTTR</td>
<td>mean time to repair</td>
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<tr>
<td>MWD</td>
<td>measurement while drilling</td>
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<tr>
<td>NACE</td>
<td>National Association of Corrosion Engineers</td>
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<tr>
<td>MSL</td>
<td>mean sea level</td>
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<tr>
<td>NPD</td>
<td>Norwegian Petroleum Directorate</td>
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<tr>
<td>P&amp;A</td>
<td>plug and abandon</td>
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<tr>
<td>PL</td>
<td>point load</td>
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<tr>
<td>PLC</td>
<td>programmable logic controller</td>
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<tr>
<td>PV</td>
<td>pressure vessel</td>
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<tr>
<td>RPM</td>
<td>revolutions per minute</td>
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<tr>
<td>SG</td>
<td>specific gravity</td>
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<tr>
<td>SI</td>
<td>Système International d'Unités</td>
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<tr>
<td>TSV</td>
<td>tender support vessel</td>
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<tr>
<td>UBD</td>
<td>underbalanced drilling</td>
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<tr>
<td>UDL</td>
<td>uniform distributed load</td>
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<tr>
<td>VDU</td>
<td>visual display unit</td>
</tr>
<tr>
<td>WCI</td>
<td>wind shield index</td>
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</tbody>
</table>

*Requirements for MODU will also be applicable for floating production and drilling units
4 Deviations
The facility owner is responsible for any deviations from this NORSOK standard. The deviation process shall be in accordance with owner’s approved system for handling deviations.

5 General requirements

5.1 Introduction
The drilling facilities shall be designed, built and equipped in compliance with applicable regulations, this standard and other industry recognised standards such as those from API, ANSI, ASME, BS, ISO, NACE, NORSOK and TBK referenced in clause 2 above. Materials shall be selected according to NORSOK M-001 and piping and valves according to NORSOK L-001.

Any modular or none standard rig not built to a specific facility shall be subject to studies with regards to HSE requirements, layout, interfaces and well parameters at the actual location for use.

The drilling facilities shall be designed to allow for easy and safe operation and maintenance, with adequate manning levels.

Complexity of the systems and equipment shall be kept as low as possible.

5.2 Design outline
An overall objective is that the design shall ensure that no single failure in drilling and well activities shall entail any life threatening situation for the involved personnel, or significant damage to material and the environment. This applies both to operational errors and to failure in connection with equipment used directly in operations, as well as equipment with auxiliary functions.

The operational objectives will constitute the basis for definition and revision of the acceptance criteria for risk in connection with drilling and well activities, and for the choice of risk reducing measures.

System and equipment shall be protected against potential excessive loads and pressure. Control system for vital well and safety functions shall in addition be protected against potential damage, fire and explosions.

Safety systems are to provide two independent levels of protection to prevent or minimise the effects of a single malfunction or fault in the process equipment and piping system, including their controls. The two levels of protection are to be provided by functionally different types of safety devices to reduce the probability for common cause failures.

All equipment shall be located to ensure safe operation and, if located in hazardous areas, shall be suitably protected for installation in such areas.

The facilities shall be designed to minimise risks of personnel injuries, environmental hazards and economic loss.

A full operability study shall be carried out based on all activities planned for. Pipe and material handling shall be evaluated for DES in all well slot positions.

Typical drilling/completion program may be utilized as supporting document. OLF 081 shall be utilized for pipe handling study. Studies with regards to change of equipment, additional equipment and refurbishment shall include all adjacent areas that may affect the functionality.

5.3 Classification
Two different ranges of drilling facilities, systems and equipment have been defined in Annex C in order to assist specification and standardisation of drilling rigs. This standardisation is optional for modular drilling facilities or P&A rigs.

NORSOK I – wells up to approximately 6,500 m MD
NORSOK II – wells up to approximately 10,000 m MD

For drilling rigs to be classified as NORSOK I or II, the design of the rig shall comply with the provisions stipulated in Annex C.

Deviations or exemption for Annex C shall be prepared, approved and documented by rig owner.
5.4 Life cycle cost and regularity

Regularity requirements shall be defined prior to detailed design, based on availability (MTBF/MTTR) and service intervals. The service activities shall not interfere with the drilling activities. The service intervals shall reflect the MTBF. LCC shall be defined for all vital parts in the drilling facilities.

5.5 Process and ambient conditions

The drilling facilities shall be selected/designed to operate under ambient conditions prevalent in the intended area of operation.

- Ambient conditions for structure and machinery shall be based on relevant meteocean data.
- Operation under cold climatic conditions requires special attention with regards to ambient conditions (icing, WCI, etc.).
- Modular rigs shall be compatible with characteristics for platform/vessel.
- Facilities for deep water and/or HP/HT wells shall be designed for such services.

5.6 Testing requirements

The various vendors shall present a test procedure, including acceptance criteria, prior to the FAT for their equipment, system or sub-system. Mechanical completion shall be completed prior to testing. The commissioning procedures shall describe all tests to be carried out during the platform commissioning and start-up phase for the equipment as a stand-alone unit. The procedure context may be reviewed and approved by the owner/user of the systems.

The drilling package shall be tested and accepted as a complete system, with all subsystems integrated. Loads and I/O shall be simulated and recorded if a full scale test is not possible.

A complete integration test of the drilling package is recommended to reveal any showstoppers or bottlenecks in any of the systems working together.

During platform commissioning and start-up, the various drilling systems including instruments shall be utilised to verify the sensor data.

5.7 Simultaneous operations

It shall be possible to perform overhaul and maintenance work and testing of BOPs and x-mas trees on test stumps while normal drill floor operations are on-going.

The design shall allow for optimum simultaneous drilling, production, maintenance and well intervention operations where applicable.

If simultaneous drilling and well intervention are required in area covered by the drill floor envelope and access is not obtained through conventional well bay design, an alternative base design shall be used.

For drilling facilities with dual derrick design, the design, layout and equipment shall allow for preparation as well as for optimum simultaneous drilling, well maintenance and well intervention operations.

5.8 Layout requirements

5.8.1 General

The layout of systems, equipment and operating/control stations, lay down and store areas shall be based on the thorough design review, risk analysis, operability studies in combination with proven oilfield experience.

Interfaces to other part of the facility, e.g. topside shall be arranged for in the early engineering phase.

All work areas in connection with drilling activities shall be arranged to ensure the safety of personnel and operations, working environment and pollution control.

The layout of the drilling facilities shall give due consideration to areas that may be exposed to dropped objects, especially in connection with maintenance and material and equipment handling.

Areas that shall be unmanned during various operations shall be defined early in the project. It shall be possible to move to/from the various operator stations during operation.
The layout shall ensure that maintenance and service can be carried out in a safe and ergonomically efficient way.

5.8.2 Material handling

The layout and design of the drilling facilities shall enable safe and efficient transport, handling and storage of materials and tubular. A material handling and storage study shall be performed. For pipe handling reference is made to 5.2.

An operability study based on all activities planned shall be carried out early in the project typically including:

- receiving equipment on-board;
- skidding;
- hook-up 3rd party equipment;
- swarf handling;
- cuttings handling;
- slurry injection;
- wire line operation;
- coiled tubing operation;
- snubbing operation;
- MPD/UBD;
- building BHA drill string;
- running BOP and riser;
- drilling;
- running casing;
- cementing;
- completion;
- well intervention;
- down hole control lines;
- down hole cables;
- slip ring handling.

5.8.3 Workshops, stores, offices and services

Workshops for welders, electricians, instrument engineers, hydraulic engineers and mechanics with necessary equipment shall be available, and be located in areas with relevant classifications. For fixed installations the workshops should be considered to be part of the platform facilities (i.e. share the use of platform workshops).

There shall be sufficient dry and heated stores for drilling equipment, in-hole equipment and spare parts as well as lifting appliance etc. Relevant transportation/handling facilities shall be provided.

The drilling offices shall have easy access to all areas of the drilling facilities, especially the drill floor.

A study with regards to need of offices and work stations shall be carried out in the early engineering phase.

AWD equipment/workstation shall be located close to the drill floor and mud treatment plant, or there shall be utilities for sending signals onshore to drilling centre as specified by operator.

A mud laboratory including a workbench or desk and cabinet for storage of chemicals with adequate extraction/HVAC shall be located close to the mud pits, and be connected to the required utility systems including drains.

5.8.4 Completions and intervention equipment

Sufficient space shall be provided for equipment and operations for completion and intervention equipment such as slick and braided wire line, electric logging, coiled tubing, snubbing, well completion, work over and well testing.
All necessary utilities with adequate capacity shall be available close to the specific equipment, including necessary safety systems and temporary communications equipment.

5.9 Drilling power systems

Electric power shall consist of
- main power for essential and non-essential drilling systems and lighting,
- emergency power for emergency drilling systems,
- UPS (no-break) for low voltage emergency consumers,
- UPS for drilling instrument systems.

The drilling power system integrity shall be based on risk assessment and ensure that systems or part of systems are available to handle any unforeseen well control situations. Minimum requirements to the power generation system shall be as listed in 5.10 to 5.12.2

5.10 Emergency power

It shall be identified which system that requires supply directly from emergency power. These systems or part of systems shall be possible to operate independently from control systems that are not connected to UPS (no-break). Typical consumers will be:
- electric pump for well control equipment/system;
- pump(s) for circulating drilling fluid at identified rate;
- transfer pump(s) for drilling fluid;
- 1 x 100 % HVAC in LER/LIR required for maintaining overpressure or vent out gas;
- other consumers as listed in NORSOK S-001.

It shall be possible to safely terminate an ongoing cement job.

5.11 Main power failure

It shall be possible to supply essential drilling consumers from an additional power course in case of main power failure, either from an essential generator or an emergency generator. The power shall be sufficient to facilitate the following operations, not simultaneously but in relevant combinations:
- move tubulars at limited speed;
- rotate drill string at limited rpm/torque;
- operation of pipe handling equipment at limited speed.

It shall not be possible to connect alternative power supply in case the local equipment room is shut down due to gas, smoke or fire.

It shall be possible to activate the alternative power for essential consumers within 30 minutes.

5.12 UPS power

5.12.1 UPS (no-break)

The following systems shall be powered by UPS (no-break) supply and be Ex/ATEX certified for all components:
- well control system;
- consumers listed in NORSOK S-001;
- other critical systems/functions identified critical during shutdown.

5.12.2 UPS

The following systems shall preferably be powered from UPS supply that is connected to ESD system and will be available to the point where none EX equipment has to be isolated:
- servers;
- controllers (PLCs);
6 Drilling systems

6.1 General
Some of the systems hereunder described may be spread over more than one area, e.g. high pressure mud system will occur in DES and DSM.

6.2 Drilling equipment structure

6.2.1 General
The drilling equipment structure (DES) consists of substructure, drill floor, derrick/hoisting structure, mast, access ladders, walkways, work platforms and associated equipment within the area.

6.2.2 Special requirements for fixed drilling installations
The DES shall be capable of skidding between well slots with full setback with drill pipe and drill collars alternative stored string of casing, unless otherwise specified.

Drag chain shall be used for hoses and cables. Bending radius shall not exceed minimum requirement for any cables or hoses.

The DES shall be designed to withstand ambient conditions for planned area of operation and withstand unlimited operations with regards to hook load, setback load, and rotary load for wind speed up to 30 m/s, 10 minutes mean 10 metres above MSL unless otherwise specified. Earthquake conditions and platform accelerations shall be considered where applicable.

6.2.3 Special requirements for MODU
Storage for risers (drilling, work over) and slip joint in use shall be provided, including service area for same.

A handling system shall be available for marine risers (slick joints and joints with flotation), work over riser, slip joint, riser pup joints and riser accessories.

6.2.4 Functional requirements
The system shall be designed to and capable of handling tubulars and heavy well control equipment such as, but not limited to, in an efficient way:

- drill strings;
- casing strings;
- conductors;
- risers and associated equipment;
- BOP stacks and x-mas trees;
- marine risers where applicable;
- equipment for MPD and/or UBD if specified.

The system design shall allow for performing wire line work, electric logging, coiled tubing and snubbing unit operations from the drill floor, considering space, height, equipment handling and access to the equipment and weather protection.

Space and utilities for MPD/UBD shall be arranged for if specified by operator.

Access in connection with operation and maintenance of equipment shall be catered for by suitable and safe access from deck or installed work/access platforms.
6.3 Derrick/mast

6.3.1 General
The derrick/mast or hoisting structure shall be designed to withstand the forces imposed by installed equipment, operational loads and adequate environmental conditions.

6.3.2 Functional requirements
Access in connection with operation, maintenance and inspection of equipment shall be catered for by suitable and safe access from deck or installed work platforms. In addition there shall be access and facilities provided for change out of heavy equipment.

Work platforms in derricks shall be adequately equipped with hand rails and safety devices, lift, stairs or ladders for safe access.

Lubrication points with difficult access such as sheaves etc. shall be routed to an easy accessible area.

It shall be provided sufficient number of hang off points of required capacity underneath water table or similar platform for hang off line(s) for travelling assembly, manual rig tongs, winches, wire line, umbilical sheaves and tubing/cable for completion. All hang off points shall be certified.

A study based on planned operational requirements and load applied by rented equipment such as wire line unit etc. shall be carried out to decide number, size and capacity of hang off points.

Dedicated cabinet for tools, safety harness, lubricants etc. shall be located as required for work in height.

6.4 Drill floor

6.4.1 General
The drill floor shall in relevant areas be designed for dropped objects protection, i.e. to withstand the impact from a falling 9 1/2” drill collar stand from a height of 1,5 m. Mouse hole shall be designed to withstand maximum impact load based on type of tubular.

A dropped object study shall be performed to verify that manned areas such as driller’s cabin can withstand the impact of any falling objects with regards to pipe and material handling.

Restricted areas (red zone) shall be defined early in the project.

Access to operator stations such as driller’s cabin, winch control panels and others shall be available without crossing “red marked” areas.

The outline of drill floor shall take into consideration space for all planned operations including well intervention and completion operation (spools for tubing/wire).

Elevation of drill floor shall be taken into consideration with regards to material handling.

Noisy equipment such as draw work shall be installed in an area not manned during normal operation e.g. on a mezzanine above rig floor or similar.

Work areas within drill floor shall be covered with non-skid material.

The setback area shall be covered with a material which prevents tool joint damage.

A heavy tool store with designated lay down area for crane handling shall be provided. Efficient and safe handling of tools between the tool store and the drill floor shall be given due consideration. Material handling to/from landing shall be arranged without entering the red zone.

Material handling of equipment from well centre such as subs, bit, slips etc., shall be included.

Drilling subs and inside drill pipe BOP etc. to be stored easy accessible in dedicated sub racks at the drill floor.

Drill floor shall have capacity to store the complete drill string during casing and completion work if nothing else is specified by operator.

Optional casing racking capacity should be considered by owner.
6.5 Substructure

6.5.1 General

The substructure shall be designed to form an adequate foundation for the derrick/mast or hoisting structure and the drill floor, and provide required elevations and handling space as applicable.

The substructure shall be designed to withstand all combined loads from derrick/mast or hoisting structure and drill floor with full loadings as specified above, BOP handling loads, as well as equipment installed in the substructure itself.

Elevation of substructure shall allow for gravity return of drilling fluid from overflow process tanks back to mud pits.

Necessary additional elevation/space for MPD equipment shall be taken into consideration.

Access platforms or work basket shall be available for maintenance of equipment.

6.6 Hoisting and rotary systems

6.6.1 General

This subclause describes the requirements to hoisting and rotary systems including equipment such as:

- draw work/hoisting system;
- crown block/drill string compensator/structural parts of compensators;
- travelling block/yoke;
- drilling hook/adapter;
- top drive;
- guide dollsies;
- drill line spool and anchor;
- rotary table.

6.6.2 Functional requirements

The draw work/hoisting system shall be equipped with an emergency stop device which in the event of main brake/hydraulic/electrical system failure shall have the capability to stop the movement. The emergency stop device shall be readily identified and easily accessible.

Kinetic energy and travelling assembly monitoring as well as crown- and floor saver shall be provided.

It shall be possible to lower the load in case of failure in control system or loss of power. One brake system shall be dedicated for emergency/park function.

Drill line spool shall have mechanical drive device.

Deadline anchor shall be of rotating type.

It shall be possible to suspend the travelling assembly independent of the hoisting system. Safe access for slip and cut of the drill line shall be provided.

The top drive shall be fitted with a removable plug on top for wire-line work through the opening. A suitable and pressure tested wire line lubricator for such work to be available on-board. This will also apply for traveling yoke for cylinder rigs.

It shall be possible to rotate and lock the rotary table from the driller’s cabin. Rotary table shall be operated independent with regards to the top drive.

Rotary table/bushings shall facilitate space for down hole control lines and wire line simultaneous with operating drill string and slips.

6.6.3 Special requirements for MODU

Rotary table opening consideration shall be addressed relevant to such as marine riser size, completion, subsea equipment and MPD equipment etc. Bushings to be of split type.
6.7 Motion compensating and tensioning systems

6.7.1 General

This paragraph describes the overall requirements for motion compensating and tensioning equipment and systems.

The systems may include:
- marine riser tensioners (incl. direct acting tensioner/in-line tensioner);
- surface BOP/riser tensioner;
- guideline tensioners;
- pod line tensioners;
- idler sheaves (where applicable);
- drill string compensator, active and passive;
- active heave compensating draw works;
- surface test tree frames build-in compensator;
- pressure vessels;
- control panels;
- high pressure compressors or hydraulic power packs;
- CCTV camera winch (where applicable).

6.7.2 Functional requirements

6.7.2.1 Jack-up conductor/riser tensioner

Surface conductor and riser tensioners are required on jack-up rigs when drilling in free standing mode and on subsea template. The tensioner shall have individual hydraulic supply. The system shall maintain required tension with minimum failure on one of the cylinders.

6.7.2.2 Marine riser tensioner

Marine riser tensioners shall be designed to have a combined tension capability to keep the specified riser length for the rigs specified water depth, filled with mud specified to project specific gravity requirements in tension, and with enough over-pull to lift the riser and the LMRP with sufficient speed in the event of an emergency unlatch situation.

Required number of tensioners and combined tensioner force is subject to actual MODUs water depth capability, and defined in each case.

Two types of marine riser tensioners are commonly used on MODUs:

1. The wire line tensioners with cylinders/pistons, sheaves and ropes attached to and acting on a support ring fitted on the riser slip joint.
2. Direct acting tensioners (DAT) or in-line tensioner with cylinders/pistons suspended in the drill floor structure are attached to and acting directly on the support ring fitted on the riser slip joint.

The tensioners should be installed in pairs acting opposite to each other and are connected to a high pressure accumulator bank. The hydraulic oil in the system is preferable pressurized by nitrogen at a pressure to deliver required tension on the marine riser.

The hydraulic fluid used in the tensioning system shall be biodegradable, fire resistant water based or water/glycol based fluids.

The number of PVs, and the flow area of piping shall be sufficient to where the tensioning activity can take place at a rate corresponding to the MODUs motion characteristics, and without a detrimental tension load fluctuation.

It shall be possible to isolate part of the PVs as well as controlling the pressure from the driller’s position to adjust number of vessels and the operating pressure with regards to compensation tension variation.
All PVs and pressure containing parts that can be closed off shall be protected by pressure safety relieve valve venting to atmosphere with one exception. The rod side of the tensioning cylinder is protected by a relief valve function in the shut-off valve and if over pressurized, it shall vent back to the accumulator.

The riser tensioner systems shall be designed with a Riser Anti-Recoil System (RARS) that is controlling the upward movement of the tensioner’s pistons to a pre-set speed depending of operation and possible system and riser failure.

A proportionally shut off valve shall be installed in the piping between each cylinder and the accumulator bank. The valve together with a piston measuring system for speed and position and a programmable control system are the main components of the RARS.

The RARS shall gradually shut off the hydraulic supply to the cylinders and thereby reduce the retraction speed in the event of LMRP disconnect, riser, tension wire or cylinder failure to eliminate or minimize the effect of riser recoil.

An alarm system indicating any malfunction to the driller shall be part of the riser tensioning system.

6.7.2.3 Guideline and pod line tensioner
4 each guideline tensioners and 2 each podline tensioners are normally required unless BOP is of guideline less design.
Applied tension forces should act symmetrically around the well centre.

6.7.2.4 Drill string compensator (DSC)
Drill string compensator shall be passive with active compensating mode design.
Compensating type draw work may be used. Requirement for a back-up system shall be evaluated for both alternatives.
It should be possible to compensate the subsea BOP stack heave motion at 0,9 m/s peak speed.
The compensating system shall be design such that no un-intentional locking occurs.
It shall be possible to isolate part of the PVs from the driller’s position to facilitate smooth operation with regards to controlling low weight on the string (for example setting of wear bushing and seal assembly).

6.8 Pipe handling systems
6.8.1 General
The pipe handling systems include:
- vertical pipe handling systems;
- horizontal pipe handling system;
- horizontal to vertical pipe handling system;
- finger board;
- belly board;
- mouse hole.
All necessary equipment for manual pipe handling shall be included.

6.8.2 Functional requirements
The pipe handling shall be remotely operated and fulfill the requirements as described in OLF 081. Areas with no admittance during normal operation shall be mapped out in the design outline and location of operator stations placed accordingly.
It shall be possible to move pipe handling equipment to a safe position in case of failure and continue operation to the degree that is possible manually. It shall be possible to lower top drive and secure well.
System for transporting pipe between pipe deck and rig floor (conveyor or similar) shall have additional feasibility to transport risers, drill bits, x-overs, subs and other down hole equipment as described in OLF 081.
6.9 Drillers cabin

6.9.1 General

The driller’s cabin shall have necessary space and of ergonomic design to full fill requirements to working environment, safe operation and escape way leading to safe area.

Operators view to drill floor, derrick, hoisting structure, mast and V-door shall be without obstructions. Cameras with monitors can be used as compensating measure for the derrick, pipe handling equipment and mast if necessary.

2 x 100 % HVAC shall be utilized if pressurized safe equipment in cabin is chosen.

Control panels shall be easily accessible. Monitors shall be easy to read without disturbing the view out of cabin.

6.9.2 Functional Requirements

The driller’s cabin shall include the number of workstations as required to operate equipment. A study including all activities performed by personnel located in the driller’s cabin shall be carried out. It shall be ensured that none of the operators are overloaded in any of the operations.

Operation of 3rd party equipment such as casing tong shall be available from driller’s cabin as required

Lighting shall be sufficient and possible to adjust to operators need.

Operators view shall be protected against direct sunlight and a wiper window/washer system shall be included

Communication and talk-back system shall be included.

Additional room in connection to driller’s cabin with workstations for other personnel including printer facilities shall be included if specified by owner.

For detailed instrument requirement references are made to 6.45 Drilling control systems (DCS).

For detailed well control equipment references are made to 6.35 Well control system.

6.10 Work winches

6.10.1 General

Work winches shall be installed in DES. Operational studies shall be performed to ensure that capacity, type, number of winches and location is sufficient for all planned work.

Lifting device(s) shall be available in case of loss of power for handling equipment required for securing the well.

6.10.2 Functional requirements

Remote control of winches shall be available by means of radio control or other technical device where relevant.

6.11 Man rider winches

6.11.1 General

DES shall be designed such that use of man rider winches is minimized during normal operation and maintenance.

Man rider winches to be approved type and certified for offshore use.

6.11.2 Functional requirements

Operational studies shall ensure that number of winces and location is sufficient for possible work where access by means of man riding can be required.
6.12 BOP handling equipment

6.12.1 General requirements
A system for safe storing, lifting and transport of BOP shall be installed in the substructure (and or cellar deck).

6.12.2 Functional requirements
BOP handling system shall be capable of handling BOP between positions for drilling, testing/parking and area for transport. Lifting and handling facilities shall be available for disassemble/assemble BOP stack. Adequate means shall be available for handling of components. Capacity for these arrangements shall be based on heaviest single lift necessary required for repair work and be available in all locations defined for the BOP.

For testing BOP, handling equipment shall be able to position the BOP where it is possible to hook up the umbilicals and install test pipe.

6.12.3 Special requirements for MODU
For MODUs an adequate guiding system shall be available for safe lifting, handling and securing of the BOP or part hereof during inspection, overhaul and maintenance.

It shall be possible to safely skid the BOP or part hereof out to open deck for handling by rig crane to/from supply vessel. Sea fastening of the BOP or part of same shall be possible in dedicated storing locations.

6.13 X-mas tree handling equipment

6.13.1 General
X-mas tree handling system shall be capable of handling x-mas trees between dedicated landing for offshore crane and place of storing and testing prior to installation

Layout and equipment shall ensure safe handling onboard.

6.13.2 Special requirements for MODU
It shall be possible to assemble and pressure/function test the X-mas tree with running and control prior to installation.

6.14 Work baskets

6.14.1 General
Work baskets may be installed for service and maintenance purpose.
Drill floor work basket(s) shall be included in the zone management system.
Work basket(s) shall be parked in dedicated cradle to prevent incidents in case of leak in the hydraulic supply loop.

6.14.2 Functional requirements
Manual lowering for safe evacuation shall be included

6.15 Pipe doping machine

6.15.1 General
A system for cleaning, drying and doping of drill pipe shall be installed. The system can be independent or part of the pipe handling/rotary equipment.

6.15.2 Functional requirements
Dope shall preferably be possible to apply to pin and box.
6.16 Remote operated slips and elevator

6.16.1 General
An integrated system for control of remote operated slips and elevator shall be installed.

6.16.2 Functional requirements
Interlock system shall be installed to prevent system from operator failure.

6.17 Hydraulic easy-torque, tong post and rig tong balancing system

6.17.1 General
Remote operated easy-torques shall be installed. Position of cat heads shall be outlined for safest operation of rig tongs.
A tong lift system shall be provided.

6.17.2 Functional requirements
The minimum functional requirements shall be included:
- capable for all rig tong operations;
- capable of break over torqued pipe;
- adjustment of pull force;
- readout of make-up and break-out torque in driller cabin.

6.18 DES hydraulic power pack

6.18.1 General
The hydraulic power pack shall have capacity to supply all machines that under normal operation works simultaneously, plus 40 % spare. Filters shall be installed on the inlet and discharge end.

6.18.2 Functional requirements
The hydraulic power pack design shall be able to maintain operation with regards to ESD as long as required by the consumers.
Additional requirement for 40 % overcapacity is not applicable for main lifting hoisting on cylinder rigs as long as the reliability study proves otherwise.
Separate reservoir tanks shall be considered if multiple pressure system is used.
System for surveillance, filtration and sampling shall be considered.
Filtration on high pressure side of pumps shall be considered.
Hydraulic systems shall be designed such that dangerous hydraulic fluid does not go to sea, e.g. use of environmental friendly fluid.

6.19 Drilling support module

6.19.1 General
The drilling support module (DSM) shall be designed for safe handling, treating and storing of liquid fluid, bulk, sacks, big bag and liquid additives.
Systems within DSM module will normally include:
- bulk systems;
- mud mixing and storage systems;
- high pressure mud system;
- mud treatment system;
cement system.

6.19.2 Functional requirements
The DSM and systems shall be able to handle, treat and store water/oil based drilling and completion fluids etc. or as required for the planned operations.

Special considerations shall be taken with regards to fume, dust, noise and vibration. Mud tanks and return line from well to be enclosed to avoid evaporation of the returning fluid.

Material handling with regards to overhaul and maintenance of heavy machinery shall be given due considerations.

A study to identify manual operated valves shall be carried out to secure a safe operation without risk of failure. Automated/remote operated systems shall be possible to operate manually in case of failure in control system or power source.

Due consideration should be given to operation, maintenance and replacement of valves.

Special precaution such as double barriers shall be taken to avoid environmental spillage. It shall be possible to verify closed/open position of the valves at all time.

Systems shall be controlled from a mud operator work station or local control panel.

Special requirements for cement bulk system is described in 6.32.

Tank top review shall be carried out with regards to instruments location, pipe work, hatches and ladders.

6.20 Bulk systems

6.20.1 General
The bulk system shall be designed to receive, store and deliver required volume of bulk material to the mud and cementing system.

The system usually comprise of the following main items:

- dry bulk storage tanks;
- bulk tank ventilation/regeneration system;
- bulk transfer and dosing system;
- loading stations;
- field instruments;
- surge tanks;
- secondary storage mud tanks;
- base oil tank;
- drill water tank;
- brine/completion fluid.

6.21 Dry bulk

6.21.1 Functional requirements
The dry bulk system shall be designed to store and transfer barite, bentonite and cement. The storage and transfer capacity shall be as described in Annex C or as specified by owner.

Provisions shall be made for sampling.

The dry bulk storage tanks shall be equipped with safety valves or rupture discs. Rupture discs may only be used on bulk storage tanks in open areas. For dry bulk storage tanks in enclosed areas, full open safety valves shall be used, and ventilated (through pipes) to open areas. Such enclosed areas shall similarly be ventilated to avoid pressure build-up in the event of a fracture or leakage in the piping for the air supply system.
All dry bulk tanks shall include weight or volume measurement and a high level alarm. Provision for manual measurement shall be available. Dry bulk tanks shall be installed with both local and remote pressure indication.

All tanks shall be provided with canvas and air fluffing system to prevent settling of bulk material. The design shall enable total emptying of tanks (maximum 1.5 % rest). The design shall also allow for easy access to all valves, instrumentation and access to interior of tanks including ladders if needed. It shall be possible to safely isolate individual tanks or section of the system for maintenance purposes.

Transfer of dry bulk between storage tanks and back loading to supply boat shall be mandatory. Cement and the barite/bentonite systems shall be separate. A removable crossover to be installed in special instances shall be provided, e.g. in case of mixing and pumping of a barite plug with the cement pump. Rock catchers are recommended in the lines from loading hoses.

All dry bulk lines (including ventilation lines) shall be designed and built with emphasis on low flow resistance, shortest distance (minimum length) and as few bends as possible. All bends in the transfer lines shall be a minimum of 5 times the diameter. This is to avoid pressure loss and material build up in pipes. Extra quick connection points for purge air may be installed as needed in the bulk lines. Long lines or bends will require possibility to dismantle part of line as required. Vent line outlet shall be routed away from HVAC inlets and manned areas.

All vent lines shall go through dust cyclones with dust collector tank, or similar. It shall be possible to recover bulk from dust collector. Each type of dry bulk material shall have dedicated dust collector.

The dry bulk storage tanks, surge tanks and dust collecting system shall have the same design pressure and shall be able to handle the maximum transfer capacities.

Special attention shall be taken with regards to dryer capacity for bulk air supply. Air supply shall be sufficient to transport amount of dry bulk in accordance with Annex C. The Air supply system shall take into consideration required supply in case with loss of compressor(s).

6.22 Liquid bulk

6.22.1 Functional requirements

Transfer systems with dedicated redundant pumps, manifolds and by-passes with necessary valves for the liquid bulk in each storage tank are required. The systems shall be designed to transfer the relevant liquid bulk with specified SG and capacity, to the various liquid bulk tanks according to Annex C.

Mud and completion fluid storage tanks including piping shall be separated.

It shall only be possible to fill dedicated base oil and brine tanks from their dedicated filling lines from the loading stations, this to avoid contamination from other fluids.

All pumps, valves, packing’s and equipment to be compatible with the relevant liquid to be stored and transported.

Other relevant functional requirements for liquid bulk are described in 6.24 Mud mixing and storage system.

6.23 Loading stations

6.23.1 Functional requirements

Provisions shall be made for sampling at the loading stations.

Dedicated loading hose are required for:

- barite/bentonite;
- cement;
- fresh water/drill water;
- potable water.

Dedicated loading hoses with valves to avoid spills are required for:

- liquid mud;
It shall be possible to back load bulk material to supply boat and drain loading hoses prior to disconnecting.

Mechanical reels shall be installed to protect hoses from damage/wear and reduce risk for spillage.

Hoses shall be equipped with floating elements (floating hoses).

### 6.24 Mud mixing and storage system

#### 6.24.1 General

The mud mixing and storage system shall be designed to perform all planned operations without any risk for spillage or release of dust or fume for the operators or environment.

System capacity shall be as described in Annex C if not specified by operator. See also API RP 13C.

Layout of mud mixing and storage area including landing area shall be designed for safe material handling by means of forklift, or other handling equipment.

The system may comprise the following main items, and is subject to individual selection:

- mud tanks(s);
- base oil tanks(s);
- completion fluid storage tank(s);
- mud mixing and suction tanks;
- pill/slug tanks;
- chemical mixing tank;
- caustic mixing unit;
- chemical dosing unit;
- agitators;
- shear mixing units;
- transfer and mixing pumps;
- valves and piping;
- suction- transfer- and mixing manifolds;
- mixing system, bulk (liquid and dry), and sack cutter/big bag;
- dry bulk/powder distribution conveyor;
- dry bulk/powder lifting screw;
- high rate mixer;
- field instruments.

#### 6.24.2 Functional requirements

The total capacity of the mud including storage volume and bulk to be mixed to the required specific gravity shall in general be sufficient to replace 100 % of any hole volume including the riser if applicable. If the required volume exceeds the available volume then necessary measures shall be taken in order to meet the requirements.

All tanks to be equipped with agitators with sufficient turnover rate to prevent settling of mud. For the base oil/mineral/synthetic oil based mud storage tanks and the brine storage tank, the agitation can be performed by pumps to give sufficient turnover rate if applicable.

Agitators to be suspended in the tank top with free shaft end. To improve agitation, baffles may be installed around agitator blades.

All tanks shall be designed to avoid "corners and pockets" that causes solid material build-up. Stiffeners, pipe work or other obstructions inside the tanks shall be avoided. The tanks shall have sloping bottoms.
towards both the suction and the drain manifold to secure complete emptying of same. An automatic tank cleaning system shall be installed.

The mud tanks shall be completely covered including an extract system, and have raised or bounded access/inspection hatches. Necessary facilities for the rescue of personnel shall be included and available in all of the tank top areas. Apparatus to collect samples of the mud shall be arranged without the need of opening lids or hatches.

Equalizer valve with sufficient capacity shall be arranged for between active tanks.

As a minimum shearing facilities shall be installed in the active tank(s) and reserve tank(s). Low-pressure shearing devise can be used supplementary.

The high rate mixer shall be installed in the active mud system and in at least one reserve tank.

All tanks for liquids shall be equipped with sensors in accordance with Annex B.

Minimum two separate mixing lines shall be available simultaneously to facilitate the mixing of dry bulk materials, powder additives and liquid additive in both the active and storage system. The manifolds to and from the mud tanks shall be arranged to perform transfer simultaneously with mixing. Arrangement for pre-mixing shall be available.

It shall be possible to transfer mud from all tanks to supply vessel.

The mud mixers shall be arranged in a way, or be of a type that prevents overflow by the accidental stoppage of the mixing pump(s). Precaution shall also be taken to prevent overflowing the mud mixer due to the incorrect operation of valves or pumps.

When sizing the low pressure pumps due consideration shall be given to optimize suction lines with regards to length, size and bends. The design should also take into consideration that most of the mud mixers are sensitive to the outlet back pressure, and that drilling fluid quite often accidentally exceed the specified limits for viscosity.

A specific gravity (S.G) measurement device shall be installed upstream the mixer. Provision shall be installed for calibrating measurement device.

Arrangement for handling powder in sacks/big bags/tanks shall be provided with regards to:
- storage;
- transportation;
- ergonomics;
- dust free handling;
- mixing system;
- empty sack/big bag disposals/tank return.

The mixing system shall be designed for a dust and fume free atmosphere in manned areas.

A lump crusher installed on the big bag unit is recommended.

Distribution conveyor/screw shall be designed for the actual powder and chemicals as specified by owner. Special precaution shall be taken with regards to slope and length.

There shall be provisions to load one of the surge tanks directly from a supply vessel with exception of cement surge tank. For other relevant functional requirements, refer to 6.21 Dry bulk.

Each and every tank and pump shall have the possibility to be isolated from the system during maintenance.

A central operator work station for remote operation of the mud mix, bulk and storage systems shall be included, unless satisfactory working environment is ensured by other means. Remote operator station shall include necessary process data and alarms. Automated control systems are preferred.

6.24.3 Special requirements for MODU

Different mud mixing and storage capacities may apply. Rigs movement shall be considered when choosing tank locations and instrumentation.
6.25 High pressure mud system

6.25.1 General

The high pressure (HP) mud system will normally involve several modules, e.g. pump system in DSM and manifold in DES.

The HP mud system shall be designed to deliver mud and/or various liquids to the well via the drill floor stand pipe and well bay, mud pits (s) via high pressure shear guns etc.

The HP well circulation (active) system shall be redundant in case of possible failure of pumps and valves.

The system should comprise of the following items:
- high pressure mud pumps;
- discharge manifold and lines;
- drive motors;
- pulsation dampener (suction and discharge);
- pop off safety valves;
- super charge pumps;
- strainers;
- local control panel;
- field instruments;
- utility systems;
- liner spray system;
- lube oil system;
- cooling systems;
- kicker hose on discharge line;
- vibration dampeners;
- bleed off line;
- high pressure piping;
- standpipe manifold;
- standpipe;
- rotary hose;
- cement pump (if used for emergency circulation).

6.25.2 Functional requirements

The high pressure mud system shall be capable of delivering drilling and completion fluid at rate and pressure as specified in Annex C if not otherwise specified by owner. The system shall be designed for continuous service.

Pressure bleed-off line for each pump shall be provided. Possibility for flushing the bleed-off lines should be included.

It shall be possible to isolate strainers for safe inspection and cleaning of same.

The discharge lines from the pop off safety valves shall be straight and self-drained into the active mud system. Rupture disc type pop off valve shall be avoided. Special precaution shall be taken with regards to access to and replacement of the pop off safety valves.

Work platforms and monorails or similar lifting equipment shall be available for transport and overhaul of heavy equipment such as electrical motors, crank shaft, fluid ends, pistons, liners and valves etc.

If a HP mud pump is intended used for shearing, the system shall be operated independently of the high pressure pumping to the well.

Booster line for riser circulation to be considered.
The suction lines shall be as short and straight as possible. A back wash system is required for removing of possible barite/possible settlement in the pipes due to limited dimension and/or crooked and long suction lines.

The HP mud pumps and charge pumps shall be operated from the driller’s cabin. There shall in addition be a local control panel for each pump to be used for maintenance. Activation of these panels shall be controlled from driller’s cabin.

Read back of SPM and pump pressure shall be arranged for in the drillers control panel, (DCDA) in addition to local display of same.

The mud stand pipe should be arranged with outlet, valve and connection for possible hook up of a hose to top of the drill pipe when hung off in the rotary table. The mud stand pipe shall have a pressure bleed off facility via a manual choke valve to the flow line return ditch.

The valves in the mud stand pipe should be arranged for easy access for operation and maintenance. Provision for reverse circulation shall be available.

The stand pipe with rotary hose to be arranged so there is no risk of interference with structure or equipment in the derrick or mast even in strong wind. The hose shall be hanging straight off the goose neck onto the top drive and secured in both ends. Special precaution shall be taken with regards to hose bending radius.

Connections for necessary probes etc. for MWD signals shall be provided for in the stand-pipe manifold. Pressure feedback from the stand pipe manifold shall be provided to the choke and kill remote panel and the drillers control panel.

6.26 Mud treatment system

6.26.1 General

The mud treatment system shall be designed to perform all planned operations without any risk for spillage or exposure to hazardous substances for personnel.

System capacity shall be as described in Annex C if not specified by owner.

The system may comprise of the following main items, and is subject to individual selection:

- mud return flow line;
- distribution system to shakers;
- shale shakers as required;
- mud return system from shakers;
- de-gassers as required;
- mud treatment tanks;
- control system and work station as required for the entire mud treatment system.

The system may further have all, or parts of the following equipment incorporated:

- gumbo trap;
- sand trap;
- centrifuges with feeding pumps;
- desander(s);
- desilter(s);
- cuttings collecting system;
- cuttings disposal system;
- control cabin for shale shaker operator.

Consideration should be given to well completion fluids handling with regards to:

- flushing and cleaning of circulating system;
- extra equipment for filtering;
- special chemicals.
6.27  Solids control

6.27.1  Functional requirements

The drill cuttings shall primarily be removed by the shale shakers with the possibility to operate with coarse and fine mesh screens. Fines are to be removed by the centrifuge system if installed. The drill cuttings shall be gravity fed into a cuttings chute or to a conveyor system and thereafter to a cuttings handling system.

There shall be a local remote operated system to facilitate individual distribution to each shaker. The system shall include the possibility for by-passing and dumping. It shall be possible to isolate each shaker individually. The distribution system from the flow line to the shakers shall enable circulation without overflow at the rates and conditions shown in Annex C whenever drilling. Space and utilities for mud gas detector shall be included. Arrangement for installation of magnets shall be provided. It shall be possible to manually sample the mud.

The shale shakers shall be enclosed with mechanical extract allowing visual inspection and change of shaker screens. Shale shakers with variable speed and variable screen angle should be considered for an optimal versatility, and shaker screens of a wide range of mesh sizes should be available. Access and quick release for easy change of screens shall be provided.

All equipment located in the shaker room shall be designed for minimum maintenance during drilling.

A separate rack for spare screens shall be provided, in or close to the shaker room.

Screen washer connected to suitable drain shall be installed.

6.28  Centrifuges for fines control

6.28.1  Functional requirements

If centrifuges are installed, they shall be located with consideration of fines/barite transport. The centrifuges should be arranged such as to facilitate gravity feed of fines or weight material directly to the cutting chute, tank or conveyor. Discharge from oil based mud shall not be mixed with water.

Facilities for flushing the centrifuges with the relevant base fluid (water and base oil) after use shall be implemented.

Centrifuges with adjustable speed for both bowl and scroll are recommended for removing weighted materials and fines. Access for sampling point shall be provided.

6.29  Mud shaker tanks

6.29.1  Functional requirements

The mud return system shall collect clean mud from all shale shakers, and shall be equipped with required number of outlets to the mud treatment tanks. Adjustable gates for wave slapping/isolating purposes are to be included.

The shaker tanks shall be completely covered, with a fume extraction system installed to remove any fume or pressure builds up. Access/inspection hatches shall be provided. Necessary facilities for rescue of personnel from the tanks shall be included. Automatic sampling to collect samples of the mud shall be arranged without the need of opening lids or hatches.

All tanks with exception of the sand trap shall include agitators necessary to prevent settling.

Gravity feed from mud treatment tanks to active/reserve mud system are recommended.

Special precaution shall be taken with regards to design and size of sand trap and drain valve.

All tanks shall be designed with sloped bottom towards outlet nozzle and provided with permanent tank cleaning system.

Design and layout of tank top(s) shall ensure installation and maintenance of level measurement instruments with minimum interference with regards to stiffeners, pipe work or other obstructions.

Regarding process requirements, see API RP 13C Ch. 7 Practical operation guidelines.
6.30 Vacuum de-gasser

6.30.1 Functional requirements
The mud de-gasser system shall be designed to handle the maximum design flow rate.
The degasser shall separate gas from the mud, and the vent shall be routed to a safe area for gas discharge.

6.31 Control system

6.31.1 Functional requirements
The equipment and control system shall be arranged such as to minimise manual operation.
The treatment system shall be operated from a control station. The control station may be located by the shakers or in a separate office/cabin with direct or CCTV view of the shakers.
A combined control room, sound proofed and ergonomically laid out shall be arranged for cement and mud system operations.

6.31.2 Special requirements for MODU
The effect of rig motion shall be taken into consideration when designing the mud distribution system to the shaker.

6.32 Cementing system

6.32.1 General
The cementing system shall be designed to perform operations such as mixing and pumping of cement slurries used in the formation of well bores, pressure testing of well head equipment and well control system, well circulation, well killing and bull heading without risk of spillage or exposure to hazard substances for personnel.
Hence the cement pumps shall be rated to above expected pressure necessary to control the well in a kick situation as well as in emergency.
The system should normally comprise of the following main items:
- cement pumps;
- transmissions;
- prime movers (diesel or electric);
- mixing unit;
- liquid additive proportioning and storage system;
- emergency start system;
- local control station;
- tank, dry cement;
- manifold and valves with a minimum of two outlets (high pressure);
- pressure safety valve;
- centrifugal pumps;
- diesel day tank where applicable;
- data acquisition and transfer system for critical data;
- operator control cabin.

6.32.2 Functional requirements
On installations where a diesel driven cementing unit is classified as emergency circulating pump for well control, mud supply shall be provided for during platform main power failure. On installations where electric driven cementing unit is classified as emergency circulating pump for well control, an alternative power source for the cementing unit and mud supply shall be provided.
The cement unit shall be readily available for start-up within short time during critical phases in the on-going well operation. Diesel driven cement pump shall have a dedicated start air receiver with adequate capacity for safe start-up of same.

Electric power required for operating diesel driven units shall be available.

The cement unit should in addition to the local control, preferable be remote operated from a dedicated operators control cabin with direct view to same or it shall be possible to monitor vital parts of the unit by TV cameras.

As a minimum the operation of necessary functions for pressure testing, continuous circulation of mud etc. shall take place from a suitable control facility at a safe distance from the high pressure equipment.

Cement storage tanks should be installed with a regulating discharge valve and be placed as close to the cement unit as possible to reduce risk of plugging lines.

The cement unit shall be connected to a data registration and acquisition system. As a minimum the following data shall be recorded during mixing and pumping operations:
- specific gravity;
- pump pressure;
- pump rates;
- cumulative volume pumped.

The cement unit shall be located with emphasis on easy access for operation, maintenance and provision for change out of engine, transmission, pump parts and entire unit.

Facilities for cleaning the unit shall be available and contaminated wash water shall be collected as for other dirty liquid disposal.

6.33 Pipe deck and landing areas

6.33.1 General

Pipe deck and lay down areas shall be designed such that all crane operations can be performed without risk for personnel safety or damage to equipment or structure.

Illumination shall not disturb the crane operator view.

Pipe deck shall be protected from wind and sea as far as possible. Personnel working on the pipe deck shall be provided with a shelter for warm-up and light maintenance.

Dedicated area for proper storing of slings and lifting equipment shall be provided.

Pipe deck shall be designed with arrangements for barrier of relevant areas. The barrier arrangement shall be evaluated and planned in the study phase in connection with crane operations, pressure testing, or otherwise.

Safe access between pipe deck and drill floor shall be considered.

A special arrangement to control swinging crane loads shall be considered. Such an arrangement can be a “bumper”/wall made of hard wood.

6.33.2 Functional requirements for pipe deck

Offshore cranes shall cover the entire pipe deck area including V-door and the operator shall have unrestricted view from the cabin or the operator station.

Pipe handling shall handle pipe in accordance with requirements in OLF 081.

Arrangement for transporting items between pipe deck and drill floor such as drill bits, subs, pup joints, x-overs, spiders and slips etc. shall be provided for.

An operational study shall be performed to size and dimension the deck for storing, handling and deliver tubular to the drill floor. The study shall take into consideration normal amount of all sizes of risers, conductors, drill collars, HWDP, drill pipe, stub collars, pups and assembled BHA, long baskets etc. relevant for the rig design In addition the study shall also include adequate space for perforating guns.

The study shall be based on planned operational size of rig, ref. Annex C.
Layout of area and dimension of deck as well as handling for coiled tubing and snubbing equipment should if relevant be included in the study.

Elevation of pipe deck vs. drill floor shall be considered when the pipe handling system is designed and/or chosen. It is recommended to keep this elevation to a minimum.

Pipe storage height shall be kept to a level which enables safe handling.

The support beams shall be covered with hard wood or similar to avoid metal to metal noise and protect tubulars for damage. The required stanchions shall be removable and locked in place when installed and be of adequate strength and height.

### 6.33.3 Functional requirements for landing areas

Landing areas shall be arranged in connection with:
- drilling tool store on drill floor;
- equipment/spare part stores and workshops;
- sack store;
- shaker room;
- outside rooms that require handling of heavy equipment;
- X-mas tree.

Landing areas shall
- as far as possible be prepared for mechanical handling system or use of forklift,
- be clearly marked with load limitation (UDL/PL),
- be provided with bumpers and guides, and
- be equipped with access barriers.

### 6.34 Moon pool area

#### 6.34.1 General

This subclause is applicable for semisubmersible MODUs and floating production installation with drilling facilities and subsea BOP system.

#### 6.34.2 Functional requirements

The moon pool area includes:
- moon pool;
- subsea BOP storage and handling system;
- BOP running/retrieving guiding systems;
- BOP umbilicals and riser hose connection systems;
- riser suspension, riser and guideline tensioning equipment;
- BOP test and maintenance facilities;
- BOP sea fastening system;
- base plate trolley;
- subsea X-mas tree/subsea equipment stack-up and test area, if applicable;
- subsea X-mas tree/subsea equipment handling, skidding, sea fastening and guiding system, if applicable.

The moon pool shall be sized as required for running/retrieving and guiding of the BOP and for running and guiding of X-mas tree and subsea modules as required.

Further it shall be sized to ensure that the riser can stay connected with an up to 10 degrees angle at upper flex joint, without clashes between any part of the riser, tensioning equipment, support ring, hoses and umbilicals and moon pool structure, guiding structures or handling equipment.
The BOP storage area shall have sufficient access platforms or other means to access the BOP and its parts where maintenance may be required without having to climb on the BOP stack and to avoid use of standby vessel.

Efficient and safe handling systems for all BOP components shall be available for all elevations in stack-up areas.

It shall be possible to replace the seal ring and inspect the seal surfaces on the stack and the LMRP connectors without the need for working under a hanging load.

Sea fastening arrangement for the BOP shall be provided.

In order to avoid personnel working over open sea in moon pool, the following equipment shall be present:

- hydraulic operation of slip joint locking device;
- support ring with integrated choke/kill/booster/mux connections;
- “cherry pickers” covering all operations in moon the pool area.

If applicable the moon pool area shall include area and facilities for stack up of X-mas. The storage/stack-up area shall facilitate full access for safe handling, stacking and sea fastening of XMT and associated equipment.

Skidding/transport system shall enable XMT stack-up assembly to be correct orientated prior to being run.

6.35 Well control system

6.35.1 General

This subclause describes the mechanical well control equipment, control systems and associated equipment. The well control system shall comprise of the following equipment:

- BOPs – single or dual BOP system as required;
- choke and kill system;
- mud gas separator (poor boy);
- diverter system;
- riser system;
- wellhead connectors;
- test stump(s)
- control systems;
- trip tank system;
- stripping tank system.

The BOP system shall furthermore be connected to a choke manifold and de-gasser system.

The well control system may be designed to various working pressure categories:

- 2000 psi/138 bar;
- 3000 psi/207 bar;
- 5000 psi/345 bar;
- 10000 psi/7689 bar;
- 15000 psi/1035 bar (HPHT class);
- 20000 psi/1379 bar (ultra HPHT class).

6.35.2 Special requirements for MODU

During drilling with the blowout preventer located on the seabed, the following equipment and systems shall be incorporated:

- diverter system;
- marine riser system with kill, choke and booster lines;
- integrated support ring;
It shall be posted an actual schematic of the choke manifold, the stand pipe manifold and the BOP stack configuration with actual measures for space out etc. next to the well shut-in and control procedure in the driller’s cabin and elsewhere if needed.

6.35.3 Functional requirements for blow out preventer (BOP)

The surface BOP system shall as a minimum consist of:
- one (1) annular preventer;
- one (1) shear and seal ram preventer;
- two (2) pipe ram preventers;
- minimum one (1) choke line outlet;
- minimum one (1) kill line outlet;
- one (1) wellhead coupling or connector;
- minimum two manual gate valves;
- minimum two remote hydraulic operated gate valves.

The subsea BOP system shall as a minimum consist of:
- one (1) annular preventer;
- one (1) shear and seal ram preventer;
- three (3) pipe ram preventers;
- minimum two (2) choke line outlet;
- minimum two (2) kill line outlet;
- four (4) kill failsafe close valves;
- four (4) choke failsafe close valves.

Consideration of additional valve/ram and arrangements shall be given based on operational requirements and a risk assessment.

Dual pipe rams are required for dual completion i.e. when two strings are run simultaneously in a live well.

The internal diameter and pressure rating of the BOP components are to be specified to suit the intended operation.

Consideration shall be given to H2S protection on complete system.

Consideration shall be given to line ring gasket grooves with corrosion resistant alloy such as nickel alloy, stainless steel or alternative inlay.

The pipe rams shall be dimensioned for size and hang off capacity to suit the actual tubular drill pipe string. Consideration for use of variable type pipe rams should be given for tapered and special work strings.

Choke and kill outlet valves on the BOP shall be fitted as close as possible to the BOP.

A minimum of two valves shall be installed on each outlet.

It shall be documented that the shear/seal ram can shear the adequate weight and grade of the following:
- drill pipe;
- tubing;
- landing string and/or shear subs;
- wire line;
- CT.

Or a combination of these and any other specified tools, and seal the well bore thereafter.

If this cannot be documented a qualification test shall be performed and documented.

Consideration for full BOP bore shear capability or pipe/tubular/wire centralizing blades/rams should be given.
All shearing operations shall be achievable within 90 % of available hydraulic system pressure at the expected maximum wellhead pressure.

Shear and pipe ram preventers shall be fitted with a mechanical locking device securing the rams in closed position. The locking device shall be incorporated into the main piston function or remotely activated from the BOP control panel.

Exposed parts of the well control system shall to necessary degree be protected to withstand heat in connection with fires and force from external loads and possible explosion.

Testing of the BOP stack and well control system shall be documented with suitable recorders for both low pressure and high pressure. Testing shall be possible in a safe and efficient manner on dedicated test stump(s).

The position of the choke and kill line outlets shall be arranged so that circulation for well control can be carried out with the drill string suspended in the BOP and the shear ram(s) closed.

It shall be possible to bullhead the well when the string is hung off in the BOP and cut by shear rams.

It shall be possible to suspend the drill string below the shear ram prior to a shear operation ensuring that any upset or tool joints are clear of the shear ram.

Consideration should also be given to allow for stripping in and out of the hole in a sound and safe manner.

Addition of an outlet below the lowermost pipe ram may be considered. This outlet can be used as a kill line and the last resort to regain well control in a well control situation.

6.35.4 Special requirements for MODU

Subsea BOPs for MODUs normally comprise of the following main components:

− wellhead connector;
− BOP stack;
− LMRP with control pods;
− ROV intervention panel.

The LMRP shall be connected to the BOP stack by means of a remotely controlled hydraulic connector.

The LMRP shall incorporate the disconnectable choke and kill stabs and the pods for the BOP Control system and alternative ROV stabs.

It shall be documented that the LMRP can be safely disconnected and reconnected (without having to pull same to surface) at a given angle without equipment damage.

Testing of BOPs at the surface shall be possible with the LMRP connected to the BOP and the control system connected.

Each of the Choke and Kill outlets on the BOP stack shall be fitted with two gate valves arranged in series and installed close to the BOP. The valves shall be protected against damage from external loads.

The size of the choke and kill outlets/inlets and piping shall be adequate for the maximum expected circulation rate when in use during operation and in well control situations.

All of the gate valves shall be hydraulically operated and of remote control type. The valves shall be of the "fail assist" closing type, and shall be capable of closing under dynamic flow conditions, preferable sequenced with the outer valves closing prior the inner valves. For valves requiring hydraulic assist for closing, activation should be automatic when loss of surface control and/or hydraulic fluid.

The wellhead connector shall be hydraulically operated, and be remotely controlled.

Where relevant, operation of the wellhead connector shall be possible to operate only from the main HPU panel or hose reel and shall be possible to lock/secure to avoid unintended operation.

For DP operated vessels, an additional shear ram that can shear casings and drill pipe tool joints or other heavy walled pipe with expected maximum wellhead pressure, shall be installed.
DP operated vessels shall have emergency quick disconnect (EQD) systems in accordance with the relevant DP class requirements. The EQD system shall incorporate an automatic sequence that ensures the following minimum operations:

- close and shear one shear ram;
- disconnect LMRP;
- close and seal one shear ram.

### 6.36 Choke and kill system

#### 6.36.1 General

The choke manifold shall as a minimum include 3 chokes. Minimum two shall allow for remote control, and minimum one for manual operation.

Consideration shall be evaluated with regards to an additional fixed choke.

Operation of remote controlled chokes shall take place from a suitable panel at the driller’s position, which shall at least indicate:

- drill string pressure;
- choke manifold pressure;
- choke position indicators;
- strokes/volume pumped;
- drilling fluid pump rate;
- mud gas separator pressure monitoring.

In the case of manually operated chokes, the drill string pressure and the choke manifold pressure shall be displayed on or close to the manifold enabling pressure monitoring during choke operation.

Choke and kill manifold including lines and valves shall be designed according to operational requirements. System flow bore size should be uniform to the extent possible.

Consideration shall be given to line ring gasket grooves with corrosion resistant alloy such as nickel alloy, stainless steel or alternative inlay.

The manifold should also be fitted with a connection facility for pressure gauge with low increment readings.

Lines/hoses between the BOP stack and the choke manifold system shall, together with their connections and valves on the high pressure side of the choke manifold, as a minimum have the same working pressure rating as the BOP stack.

The choke and kill manifold layout shall enable isolation upstream and downstream of individual chokes for repair/service while choke manifold is in operation.

The choke and kill manifold shall furthermore be fitted with a valve on each of the outlet/inlet pipes, so that lines to and from the manifold can be isolated safely.

Where different pressure zones interfaces in the manifold system, two valves arranged in series shall be installed.

Manifolds for 345 bar pressure rating or higher shall be equipped with at least two valves upstream and one valve downstream each of the chokes. The working pressure of the valves shall refer to the maximum working pressure of the choke manifold.

The choke and kill manifold shall be connected to a mud gas atmospheric separator (poor boy) of sufficient capacity.

Choke and kill manifold shall be connected to the burner booms and/or overboard lines using fixed piping arrangements.

It shall be possible to interconnect a minimum of one outlet from the choke manifold, and an outlet from the cement unit to the drilling fluid standpipe manifold.

Any connection from the cement manifold to either the choke manifold or standpipe manifold shall have a quick removable spool. A valve is not sufficient to ensure positive isolation.
The layout and design of choke manifold system shall be given due consideration to accessibility in order to enhance safety and working conditions during local operation and maintenance. Required lifting points and work platforms shall be incorporated for operations and maintenance.

6.36.2 Special requirements for MODU

For subsea BOP, all choke and kill lines hoses shall be of the flanged or clamped end connections.

6.37 Kill and choke downstream arrangement

6.37.1 Gas separation

The vent gases to an atmospheric mud/gas separator shall be conducted to at least 4 m above the top of the derrick/hoisting structure or to another safe area.

The atmospheric mud/gas separator and ventline shall be designed to withstand the pressure from 2.2 S.G. mud, or the S.G. the rig is designed to handle, to the top of the vent line. Vent line shall be minimum 254 mm (10”) diameter.

The mud gas separator shall in general have at least 3 m of liquid seal.

The mud gas separator shall have an arrangement for proper cleaning and inspection.

The mud gas separator pressure and temperature shall be monitored from control panel at the driller’s location. It shall be possible to maintain the liquid seal during a well control situation via a “hot loop”.

The mud gas separator shall not be connected to the diverter system.

The mud gas separator/mud discharge line should be routed directly to the header box upstream of the shale shakers where gas detection is present.

The mud gas separator/mud discharge line and the bleed off line from the stand pipe manifold should be routed to the flow line system before the branch to the trip tank system and directly to the header box upstream of the shale shakers where gas detection is present.

6.37.2 Well test equipment permanently installed on installations.

Dedicated area classified for well test equipment shall be provided for. Location and layout of the test equipment and control cabin shall be utilized to size and dimension the necessary deck area.

Test equipment (temporary or permanent) is covered in NORSOK D-SR 007. For safeguard of the surface test equipment, see API RP 14 C.

The high pressure well test line shall be adequately designed, sized and dimensioned for the anticipated type of fluid/gas, well flow and pressure. Safe access hooking up of the flexible hose to the test line shall be provided.

The test line shall have a section (spool-piece) near the drill floor that can be removed for installation of a data header.

The pipe from the drill floor to the well test area shall have the same pressure rating as the stand pipe and be as straight as possible and be terminated with a valve and hub or flanged connection.

The test area shall be bunded to prevent any oil spillage from spreading outside the dedicated process area with an adequate drain system.

Necessary utilities such as electrical power, fresh water, compressed air, steam in addition to PA system, ESD, fire water and/or deluge system and communication system to be provided.

The steam supply line in the test area shall have a non-return valve installed.

From the test area to the burner booms the following lines shall be installed:

- high pressure gas (gas from separator);
- low pressure gas (gas from tank or second stage separator);
- oil and condensate lines (from separator and tank);
- minimum 10” vent line to burner boom or 3 m below rig into a safe zone;
maximum design capacity shall be provided for each line.
The interconnected piping with valves, between test area and burner booms shall be permanently installed. A manifold shall be installed for each and every lines to direct the fluid and/or gas to the appropriate burner during testing.
The inlets should be connected to the test equipment by hub or flanged connections.
The piping shall be covered and protected with removable grating or floor plating for adequate access for inspection.
Where piping installations include a change of pressure rating ("spec break") the lower rated pipe shall be adequately protected against overpressure. Double isolation valves shall be installed where practicable.
The connections at the burner boom(s) end shall also be permanent with swivels or flex hoses for possible swing in of same.
Burner booms to be equipped with:
- HP gas line (extended beyond burner by 1,5 m);
- LP gas line (extended beyond burner by 1,5 m);
- oil and condensate line;
- propane pilot lines;
- compressed air line (not part of installation compressed air system);
- cooling water line (not part of the installation fire water system).
All line should preferable be self-drained so as to empty same after test operation.
The relevant lines shall have provision for pressure testing and internal treatment with anticorrosion liquid or similar.
The burner booms shall have sufficient length with burner heads at a safe distance from the unit and this distance shall be justified by means of heat intensity calculation.
Expected wind forces should be taken into consideration during design of the burner booms.
The booms shall have adequate foundation in the end for installation of burner head(s). Load on the foundation shall be at least the weight of the relevant burner head(s) to be installed but shall as a minimum be 1200 kg point load plus excess for additional hoses for cooling etc.
The burner air supply shall be completely independent from installation air system.
The burner(s) and boom(s) shall be equipped with a sufficient cooling and heat shielding system to prevent heat damage to the installation.
It shall be possible to ignite the burner(s) from a remote control facility on deck.
The burner boom shall have adequate walkway with handrails.
Swinging of the burner boom(s) from rest to operating position and back and securing of same shall be mechanically operated (preferably by remote operated hydraulic cylinders).

6.38 Diverter system

6.38.1 General
The diverter system shall include as follows (if applicable):
- diverter housing;
- element;
- inserts;
- piping arrangement.
The diverter shall have a suitable diverter piping/overboard lines arrangement leading to opposite sides of the installation.
Valve activation on these lines shall be remote and have remote position sensor verification.
The control system shall be designed in such a way that it is not possible to close in pressure when closing the diverter.

Locking system for diverter and housing shall not be able to release if diverter is closed.

The diverter housing shall normally incorporate:
- hydraulic lockdown system for diverter element and inserts;
- flow line arrangement for mud returns to treatment equipment and mud tanks;
- fill-up lines, (trip tank and mud system).

Flow line slope shall be minimum 3 degrees.

The overboard diverter line should have the following characteristics:
- minimum 12” inside diameter;
- as short as possible;
- termination minimum 4 m outside platform;
- minimum restrictions or bends;
- no quick connections;
- self-drained.

Line size should be considered based on calculations with regards to bends and obstructions.

The diverter system shall as a minimum be remotely operable from drillers position and main BOP control unit, and be able to close around relevant drill string dimensions.

6.38.2 Special requirements for MODU

A subsea diverter system shall not supersede the on board system.

Diverter for MODU shall include automatic activation of slip joint hydraulic packer when diverter is activated.

Flow line slope shall be minimum 6 degrees.

6.39 Trip tank system

A trip tank system of two tanks adequately sized shall be provided. Two level controls with drill floor operated interlock valves between tanks to ensure continuous volume control during tripping operation.

The trip tanks shall be located as close to the well centre/flow line as possible to improve response time for monitoring the flow into the tank. The return and fill up line should be arranged to minimize movements of the liquid surface to improve level reading accuracy.

The suction line should run direct to the trip tank pumps with necessary manifold/by-pass for alternating use of both trip tanks and with redundancy in case of pump failure.

Two independent reliable level measurement systems with display in the driller’s and at the mud logger’s cabin and as needed, shall be installed.

Access to the interior of the trip tank shall be provided for cleaning and overhaul/replacement of measuring devices etc. It shall be possible to fully drain the trip tank with the discharge routed to the appropriate drain system.

A stripping tank with a level measurement system as for the trip tank is recommended.

6.40 Riser system

6.40.1 General

Drilling risers will normally include one or more of the following:
- high pressure riser;
- low pressure riser.
High pressure risers shall as a minimum have the same pressure rating and internal diameter suited to the wellhead.

Consideration for a drain outlet on the high pressure riser lower connection should be made.

Low pressure risers shall as a minimum have the same pressure rating as the diverter system, and as a minimum have the same internal diameter as the relevant BOP.

6.40.2 Special requirements for MODU

Marine riser for MODU should include:

- marine riser;
- telescopic joint;
- flexible joints;
- gas handler located below telescopic joint in deep water wells (if considered relevant).

Marine risers shall be of minimum same internal diameter as the BOP stack plus sufficient radial clearance for running tools.

Marine risers shall as a minimum have a pressure rating and a tensile load rating in accordance with the water depth, tensile loads and mud weight the drilling unit is designed for.

Marine riser sections shall have choke and kill line extensions with quick stab connectors incorporated.

Consideration for remote stabbing/connection of Goose neck and other external line connections should be made.

A booster line should also be included.

Flexible joints with minimum 10 degree deflection shall be installed at the top of the telescopic joint and between the marine riser and LMRP. The flexible joints shall not separate if the flexible element fails.

A system for detecting leakages in the slip joint package shall be installed.

6.41 Test stumps

BOP test stump(s) shall be available for testing purposes in the BOP storage area.

They shall be of required type and pressure rating to suit the wellhead connector on actual BOP stack(s) and shall be fitted with valves and drain piping to slop tanks.

Means to prevent plugging the vent line should be fitted to the test stump bore.

The test stump should allow inspection/change of wellhead gasket and seal prep without being subject to hanging loads.

6.42 BOP control system

6.42.1 General

The BOP control system shall meet recommendations in OLF 070.

It shall be possible to activate the BOP from at least three locations on the facility:

- one activation panel at the driller’s position;
- independent activation panel in a safe accessible area;
- activated directly on the main unit.

Control panels shall clearly indicate (e.g. by means of lights for remote panel)

- whether the functions are in open or closed position,
- all activation panels shall indicate pressures (accumulator and manifold), and
- volume (flow meter reading) for the functions and operations performed.

Colour configuration shall follow API Spec 16D section 5.2.5.4 for subsea and dry BOPs.
The control panels shall be equipped with a securing device against unintentional operation of essential functions (e.g. shear ram, riser connection).

All electrical equipment related to activate the BOP/diverter shall be supplied by UPS and Ex proof.

The panels shall be equipped with alarms for:

- low accumulator pressure;
- loss of power supply;
- low levels of control fluid;
- low rig air pressure;
- low pilot pressure (if applicable).

Failure of one activation panel shall not effect activation from remaining panels.

The main BOP accumulator unit shall be located in a protected area in order to avoid exposure in the event of an uncontrolled well situation. Normally this will entail that the main BOP accumulator unit cannot be located on the drill floor.

Accumulator volumetric capacity, pressure requirements and BOP response time shall be in accordance with API Spec 16D.

Accumulators shall have sufficient pressure capacity (with charge pumps inactive) to enable cutting of all tubulars for the planned operation and sealing the BOP bore.

Alternatively a dedicated shear ram auxiliary pressure system (Shear boost system) may be installed to meet the minimum requirements to cut and seal the BOP bore as per requirements if the remaining accumulator pressure is not sufficient to enable cutting and sealing after having performed operations as described above.

Pressure regulators in the system shall remain unaffected in the event of loss of power supply, e.g. loss of compressed air.

For systems using a pneumatic pilot system, a backup nitrogen supply system shall be used in case of loss of air pressure.

6.42.2 Special requirements for MODU

Wellhead connector hydraulic control functions shall not be possible from BOP control panel. Hose reel wellhead connector control functions during drilling operations shall only be possible to activate from the main BOP control unit panel and the hose reel panel. Wellhead connector status shall be shown on all control panels (lights or similar). This requirement is not applicable to MUX control systems.

Remote activation panels shall, in addition to open and close functions also be capable of setting the function in “block”/“vent”.

With regard to floating offshore units with BOP located on subsea wellheads, there shall in addition be sufficient remaining pressure to enable the LMRP to be disconnected after completion of cutting requirements.

Considerations to sealing delay after cutting and LMRP disconnect should be given based on DP rig EQD sequence.

When calculating additional accumulator capacity for sub-sea BOPs, corrections shall be made for hydrostatic pressure of the relevant sea water column, as well as for sea temperature.

An independent acoustic or other equal control system shall be available when drilling with the BOP system installed on subsea wellhead.

This system shall as a minimum be able to operate:

- two pipe ram preventers;
- all shear ram preventers;
- marine riser connector;
- mini C&K connectors (if fitted).

The subsea acoustic accumulators shall have sufficient volume and pressure for the following functions:
− close pipe ram preventers;
− shear tubulars and seal the well bore;
− opening of the LMRP connector;
− open both mini C&K connectors (if fitted);
− plus 50 % remaining capacity based on above calculated functions.

The necessary hydrostatic water depth pressure for the operation in question shall be used as basis for calculating the capacity.

Full well bore pressure shall be used for volume calculations.

A portable acoustic system control panel unit (which can be handled by one person) shall be available for operation of the above mentioned functions in the event of evacuation from the platform. As a minimum, this unit shall be located at a pre-defined area with easy access for relevant personnel.

Consideration should be given to having two units available in primary and secondary life boats.

For all subsea BOP a dead man system shall be in place that automatically activates on loss of hydraulic, electric power to the pods and acoustic signals. Activation of the dead man system shall shear the tubular in place, and seal the well bore.

All seal areas for the control system exposed for seawater or well bore fluid shall be with non-corrosive inlay material.

### 6.43 High pressure/high temperature

#### 6.43.1 General

The current definition of high pressure or high temperature or both (HPHT) wells is as follows:

− when the wellhead shut-in pressure exceeds 690 bars;
− the bottom hole static temperature exceeds 150°C.

All of the relevant requirements for the drilling facilities and equipment set out in this NORSOK standard shall be met together with the requirements set forward in this subclause.

To cope with and manage HPHT wells it is mandatory that the drilling facility is adequately fitted out and all involved systems and equipment are certified and reliable and have the required capacity and necessary redundancy.

#### 6.43.2 Rig capacity

The drilling facilities shall minimum have adequate space and capacity in accordance with class II, reference to Annex C.

#### 6.43.3 General requirements

The drilling facilities shall have an early kick detection system.

The drilling facilities shall have the possibility to hook up a mud cooling system adequate for lowering the temperature of the returning mud from the well to an acceptable level.

#### 6.43.4 Functional requirements

The BOP preventers with associated well control system shall have a WP greater or equal to the ME WHP during the operational phase and as a minimum RWP of 1035 bar (15k psi).

The annular preventers shall have a minimum RWP of 690 bar (10k psi).

The BOP stack shall be configured for the actual well to be drilled and preferable be fitted with a shear ram capable of shearing intermediate casing with actual grade and weight.

If two sizes of drill pipe are in use, additional sets of rams shall be considered if the VPR can’t handle the anticipated wellhead temperatures.

The BOP stack shall be fitted with minimum 3” ID choke and kill lines and with full bore fail-safe valves on each line of which at least one of each shall be remotely operated.
All ram packers/seals, bonnets, operating rod seals etc. exposed for drilling fluid shall be dressed with high temperature elastomers acc. original equipment manufacturer (OEM) recommendation, certified for continuous expected temperature peaks for minimum one hour in energized position.

The annular preventer’s element shall have as high temperature rating as possible and be compatible with the drilling fluid in use.

The choke and kill manifold shall be equipped with a minimum 127 mm (5”) overboard vent line, with a fail-safe open, remote operated valves in the line and preferably be automatic sequenced.

The material of the lines downstream of the choke and kill manifold to the mud gas separator shall be of low temperature rating down to -40°C or protected from freezing by appropriate means.

Isolation/separation valves for change of flow to choke in the manifold shall be remote operated from appropriate area.

All choke and kill lines and stabs, including flexible line hoses and the choke and kill manifold shall be dressed with HP and/or HT resistant WEBs/seals acc. OEM recommendation, certified for continuous expected temperature peaks for minimum one hour in energized position.

Flexible kill/choke line and kill hoses to be certified for HPHT and for the actual well and circulated fluid. Cement line and hoses to be certified for HP and for the actual well and circulated fluid.

Temperature and pressure sensors shall be installed in critical locations such as before and after the choke manifold and transmitted to the driller’s position.

The choke and kill manifold shall have provision for adequate injection of glycol up stream of the choke and a relevant sized glycol storage and an adequate rated injection system shall be available and hooked up to the manifold during the HPHT phase.

The cement/kill pump line pressure shall be displayed in the choke panel at the driller’s position.

The mud/ gas separator (MGS) shall at least have the capacity to meet the potential need for the well to be drilled, but in any case as minimum have throughput capacity of 10 MMscfd, not limited by blow-down capacity.

The MGS shall have a liquid seal of at least 6 m that shall be maintained by a “hot loop” system allowing continuous circulation of fresh mud from the pits.

A 0-1.5 bar scale pressure gauge shall be installed on the top of the MGS with read-back to the choke control panel.

The high rate mixer and the mixing pumps shall be capable to meet the actual requirement for the HPHT well to be drilled.

The packing in the kelly cock, inside BOP and drop-in dart valve shall be dressed with HP and/or HT resistant WEBs/seals acc. OEM recommendation, certified for continuous expected temperature peaks for minimum one hour in energized position.

A remote operated CCTV camera shall be installed in the shaker house viewing the shale shakers etc. and with display in the driller’s cabin.

In an emergency situation it shall be possible to transfer barite from the storage tank to the cement unit. The cement unit shall be capable to mix and pump a barite plug of at least 2.2 SG at adequate circulating rate and with a pressure of 1035 bar.

There shall be no direct feed of sea water to any of the mud pumps or to the trip tanks.

6.43.5 Special requirements for MODU

The rig’s variable deck load has at least to meet the actual requirement for the planned wells.

The BOP stack shall be equipped with an auto-shear function if full riser margin is not available, and be tested before the stack is deployed.

The BOP shall be equipped with two annular preventers.

It shall be possible to operate valves re-vital functions of the BOP control system from an intervention panel installed on the BOP stack, by a ROV in emergency situations:
− close pipe rams for the tubular in use*;
− close casing shear rams*;
− close shear/seal rams*;
− disconnect LMRP after the K&C connections are opened and stingers/pods are retracted.

*Closing of rams includes ram locks.

The capacity of the ROV pump or hot line for the actual functions shall be such that the closing time is acceptable for the various functions and the complete disconnect sequence.

The marine riser’s kill and choke lines shall be dressed with HPHT resistant WBEs seals and the LP fluid return system for SSWs according OEM recommendation.

6.44 Deep water operations

6.44.1 General

Deep water is defined in the NORSOK D-010 as water depth in access of 600 m.

Deep water may range from 600 m to 3000 m and ultra-deep water beyond this depth.

All of the relevant requirements for the drilling facilities and equipment set out in this NORSOK standard shall be met together with the requirements set forward in this chapter.

To cope with and manage wells in deep water it is mandatory that the drilling facilities is adequately fitted out for heavy and bulky equipment and have the necessary load- and deck capacity.

6.44.2 MODU capacity

The MODU design shall cater for sufficient VDL and adequate CoG for the operation in the water depth of the planned well(s) and the weather conditions in the area.

Consideration shall be made to the extra weight and length of equipment and time it take to land, disconnect, pull out and secure same by hanging off and/or laying down in adverse weather condition.

The MODU shall have adequate crane capacity, space and load capacity on deck to facilitate safe handling and proper storing of the marine riser system and completion equipment if relevant.

The liquid mud storage capacity shall be evaluated but at least meet actual capacity for the planned wells and shall in any case be minimum 130 % of the largest hole volume including riser.

6.44.3 General requirements

The drilling facilities shall be dimensioned for safe handling of heavy equipment as the marine riser system with handling equipment, from deck to the drill floor through the V-door. The hoisting equipment, substructure with rotary table shall have adequate capacity to handle and suspend the heavy equipment and long casing strings.

Detailed riser verification analysis shall be performed with actual well data (i.e. weather data, current profiles, rig characteristics etc.) and should be verified by a competent 3rd party body.

Parameters that affect the stress situation of the riser during operation should be systematically and frequently collected and assessed to provide an optimum rig position that minimizes the effects of static and dynamic loads.

6.44.4 Functional requirements

Dual pipe handling system should be evaluated with regards to operation efficiency and safety enable to handle casing in parallel to other tubular movement.

An additional bleed off line with two fail-safe valves on the BOP should be located below upper annular in order to handle trapped gas.

Dimension and strength of the marine riser system and riser tensioner system to be evaluated based on the actual water depth and operational area. The riser tensioning system shall be designed with an anti-recoil system to prevent riser damage during disconnection.
The kill and choke lines ID size shall be verified to give acceptable pressure loss to allow killing of the well at predefined kill rates. The kill and choke line size requirement increases proportional with water depth.

The need to utilize a multiplex BOP control system (electrical signals) to meet the BOP closing time requirements shall be evaluated. Multiplex or equivalent system shall be used in water depth exceeding 1500 m.

Installation of an additional booster line pump facilitating lifting out of drill cuttings in hole sections with low circulating rate, shall be considered.

A flex joint wear bushing should be installed to reduce excessive flex joint wear.

It shall be possible to monitor the shut-in casing pressure through the kill line when circulating out an influx by means of the work string/test tubing/tubing.

It shall be possible to monitor the BOP pressure and temperature (readable on surface via the multiplex system or other means).

Consideration shall be given for one choke outlet located below upper annular in order to handle trapped gas if two annular are installed.

For high potential gas wells a subsea diverter system or dump valve system should be evaluated to mitigate risk of gas-filled riser.

In ultra-deep water where large amount of gas charged drilling fluid could enter the riser before the BOP is closed, a specific riser gas handling system should be considered. The system includes an annular preventer installed in the riser string below the slip joint and a discharge line below the preventer directed to the choke manifold or to the surface diverter system.

It shall be possible through build in ports, to flush wellhead connector internal cavity with antifreeze liquid solution by using the BOP accumulator bottles or with a ROV system or other methods. One or more hydrate seals may in addition be added to the connectors.

Alternative to above is a “gas mat” that seals around the 30” conductor to divert any leaking gas away from the wellhead connector.

The marine riser should be fitted out with adequate deflectors to minimize the sea current force on same if relevant.

The marine riser system shall be fitted out with the following:
- sea current meter;
- riser inclination measurement devices along the riser;
- riser fill-up valve.

A ROV hot stab panel shall be mounted on the drilling BOP to operate the following functions:
- wellhead connector unlock;
- wellhead connector gasket release;
- wellhead connector glycol injection;
- BOP accumulator dump (unless the control system has this feature);
- close blind shear/seal ram (preferably the upper shear ram);
- close second shear ram (if fitted);
- close one set of pipe rams;
- activate ram locks if applicable.

A ROV hot stab panel shall be mounted on the LMRP to operate the following functions:
- LMRP disconnect;
- LMRP gasket release;
- LMRP accumulator dump (unless the control system has this feature).

No single failure or leakage of the above ROV functions shall affect other ROV or BOP control function.

The BOP and/or wellhead shall be fitted with a sonar system or similar for BOP landing/re-entry.
6.45 Drilling control systems (DCS)

6.45.1 General

The drilling control systems (DCS), is a common appellation for equipment and system required for display and storage of drilling data, alarm handling, process control and control of mechanical equipment and utilities.

This subclause describes:

- general functional requirements and principles for design of DCS;
- functional requirements for DCS;
- additional requirements for DCDA.

Drilling control functions associated with equipment is described beneath the equipment’s functional requirements paragraph.

Definitions used:

- **drilling control systems (DCS)**: generic term for drilling control systems, include instrumentation, e.g. DCDA, BOP, Cement, CRI, Mud Mix, ML, MWD etc.;
- **drilling control and data acquisition (DCDA)**: specific drilling control system mainly used by operators in drillers cabin and information with regards to drilling data for the entire drilling rig;
- **drilling control network (DCN)**: DCDA system’s control network (controller level);
- **drilling PC network (DCpN)**: DCDA system’s PC network;
- **DCDA operator workstation**: drillers chairs included operator screens;
- **DCDA operator terminals**: other workstation, e.g. toolpusher office, company man, maintenance office, etc.;
- **anti-collision (ACS)**: system as prevent collision between two moving drillfloor equipment. (Zone management system).

A topology of a typical DCS is shown in Annex A, where these expressions are used.

6.45.2 Philosophy and principles

The following functional requirements shall to the extent possible form the basis for the design, but not limited to:

- efficient and user friendly/intuitive HMI adapted to drilling application;
- high degree of remote and automatic control from control station;
- high degree of monitoring and diagnostic functionality;
- use of well-developed alarm and message system;
- efficient integration, distribution and sharing of vital information between different systems;
- remote diagnostic and support onshore;
- use of condition based maintenance on vulnerable machines and equipment;
- support for collaboration with remote operation centre.

The DCS shall be designed and realized according to the following principles:

- cost efficient solutions and a minimum total cost of ownership through system lifecycle (i.e. long lifetime components);
- efficient and safe maintenance and modifications;
- high degree of standardization;
- proven-in-use or qualified components;
- high degree of sub-system integration/interfacing into DCDA;
- high availability and reliability.

The DCS shall be designed to:

- identify developing faults (early fault detection);
- detect only true faults, and as few as possible false alarms (fault validation).
The DCS shall be designed with:
- IT security measures (e.g. local and remote access control, anti-virus protection, patching strategy);
- high degree of segregation (contribute to reducing the consequences of failures and on isolating failures to the failing equipment only).

The main concerns to take into consideration when deciding on how to define interface within the DCS are:
- safety, which means only negligible time delay on safety critical signals and a fail-safe system;
- availability, which means that the interface and number of interfaces chosen shall reduce the effects of single mode fails;
- efficiency, which means that the operator shall feel comfortable with respect to response times;
- cost that means investment cost should be compared to operation cost and cost of possible future expansions.

The drilling facilities should be designed with control cabins and adjacent local equipment rooms in several locations. Typically these may be located in the following areas:
- drill floor;
- mud return area;
- mud tanks and pump area;
- cement unit area;
- cuttings reinjection area;
- well completion area.

Dedicated operator stations should control and monitor all activities within each drilling process and utilities area and have user depending rights.

Typically user roles can be:
- driller;
- assistant driller;
- toolpusher;
- company man;
- maintenance office;
- electrician maintenance;
- mud;
- cutting/reinjection;
- cement;
- third party.

6.45.3 Functional requirements for DCS
The DCS shall be designed to be operative continuously without stop for planned maintenance/calibration etc. for minimum 6 months.

6.45.3.1 Operator interface
Each main operation working area shall have screen pictures specially designed for the purpose.

The operator interface (HMI) shall have uniform colour and symbols for process medium and process equipment, and have standardized graphical visualization and configuration, within each operator working area. When different system suppliers are selected effort should be made to standardized graphical visualization across different operator working area.

Information overload shall be avoided by keeping a calm layout with mostly low key colours, restricted use of audible and flashing presentation, and provide a clear presentation on screen.

The different operators/users shall have user rights depending on their work tasks.

Exact roles number and location may depend upon actual arrangements on each installation.
6.45.3.2 Alarm system

The DCS shall have an alarm system design based on YA 711 Principles for alarm system design.

6.45.3.2.1 Alarm objectives

The main objectives of an alarm system are:

− to warn the operator about a situation that is undesirable or unsafe;
− to serve as an event log.

To accomplish the above objectives, functions should be provided to:

− alert the operator about the existence of an alarm conditions;
− inform the operator about the priority and nature of the alarm;
− guide the operator response to the alarm;
− restrict the number of alarms to those which are essential;
− help analysing events.

The following operator tasks and actions should be supported by the alarm system:

− monitor and control the drilling process and equipment;
− perform corrective actions, the most important first;
− acknowledge alarms*;
− analyse alarms.

*Only possible for the relevant operator with control rights.

The alarm system should not be used for showing statuses and operator messages and alarm presentation shall not interfere with the display of process data.

6.45.3.2.2 Time synchronize

All DCSs with logging functionality (alarms, process, event, etc.) shall be time synchronized against a common central rig clock, minimum every 24 hours and maximum deviation shall not exceed 2 seconds. Logged information shall be time stamped in order to identify correct sequence of events.

6.45.4 Software

When powered up after loss of power, the total DCS shall automatically restart itself, including all internal system communication mechanisms without manual intervention. Power-up shall not cause spurious activation of outputs.

Software application, including default parameter values, shall reside in permanent memory and shall not be changed by power loss or system reset.

Scan rates for DCS shall be sufficient to ensure properly system behaviour.

The controller program shall be well documented for troubleshooting. Distinct guide texts and descriptions shall be implemented throughout the program for help to provide efficient troubleshooting for the controller supplier.

Standard supplier made function codes can be used and be “knowhow protected”. This code shall have version and revision control.

6.45.5 Segregation

Selection of components, separation of functions and network communications shall be used to the extent necessarily to achieve a reliable system with high availability.

There shall be segregation between the DCS and safety systems, i.e. fire and gas, shutdown systems, BOP system. No failure in the DCS shall influence the safety systems.

Where duplicated sensors are provided (ref. Annex B) and connected to the same controller, these shall as a minimum have separate I/O cards.
6.45.6 Fail-safe design
The DCS system shall be designed to be fail-safe in regard to failure of any element of the system, included:
- wiring fault (except redundant elements);
- communication failure;
- controller failure;
- power failure.

6.45.7 Interface
The communication interface between controllers and RIO/field instrumentation shall be based on open industrial standards, e.g. profibus DP.

The interface shall be optimized with regards to signal count and response times.

Standalone control safety systems such as BOP, choke and kill can be interfaced to the DCDA for visualization, alarm logging etc. The design of this interface shall ensure that no failure in the DCDA can interfere with the safety system controllers.

6.45.8 Additional space and capacity requirements
Spare space for I/O shall be at least 20 % at FAT for each signal type, included field terminations and space for additional hardware components.

Spare disk and memory capacity for controllers, computers and data acquisition system shall be at least 50 %.

This requirement applies for process control systems, e.g. mud control and not mechanical equipment, e.g. draw work.

6.45.9 Maintenance requirements
Standard components and accepted industry standards should be used to the extent possible to ease maintenance and spare part handling.

System design shall include diagnostics to identify faults in the entire instrument loop, including:
- servers/controller systems;
- I/O modules;
- sensor (dead, out of range, shorts and cable breaks).

All DCS including BOP and choke and kill system shall be delivered with maintenance software tools. Delivery shall include required licences.

6.45.10 Instrumentation testing and commission requirements
A FAT shall be carried out for all DCS deliveries.

The DCDA shall be tested as a complete system, with all subsystems integrated. Load and I/O shall be simulated.

The various vendors shall present a FAT procedure including acceptance criteria’s per item prior to the FAT for their system or sub-system.

In addition the various vendors shall present a commissioning procedure including acceptance criteria’s per item prior to the offshore commissioning for their system or sub-system. This procedure shall describe all tests to be carried out during the platform commissioning and start-up phase for the equipment as a stand-alone unit.

6.45.11 Additional functional requirements for DCDA system
These requirements are minimum requirements in addition to the general requirements for the DCS:
- operator interface;
- operator workstations;
− operator terminals and printer;
− drilling communication networks;
− interface to mechanical equipment controllers;
− interface to other systems;
− anti-collision system;
− drilling equipment emergency stop system.
Requirements for each item are described below paragraphs.
The DCDA shall integrate drilling instrumentation and include as minimum the following functionality for these instrumentations:
− real time data acquisition;
− data processing;
− display/monitoring;
− recording/storage;
− alarm handling;
− change in selected parameters.
Annex B shall be used as normative reference.
The DCDA system shall be prepared for online remote support and remote monitoring of drilling control signals, through a secure access solution.

6.45.12 Operator interface
6.45.12.1 DCDA VDU displays
The operator/HMI interface shall be designed for integration of the different control systems into a common HMI, to ensure consistency in user interface and visual design.
The DCDA shall have multiple-window display function to allow for several simultaneous displays including CCTV video (if specified).
The DCDA shall provide sufficient graphic displays to adequately cover all of the external process systems to be controlled and monitored by the system, in addition to the displays required for all mechanical equipment located on the drill floor (draw works, pipe handler, top drive etc.).
To obtain an efficient and user friendly display design the following applies:
− parameters that are influenced by a fault, including calculated ones, shall be marked to notify the operator;
− “help” messages for operator guideline shall be implemented for machinery controlled through the DCDA system.
The DCDA shall include all instrumentation for monitoring of the drilling process.
The table in Annex B shall be used as normative reference. The final list of the parameters shall be developed during detail design.
Units for all instruments not listed in annex B shall be in SI units.
The DCDA should have, but not be limited to, the following VDU picture displays:
− drilling operation (drilling, tripping, volumes, trends);
− drilling equipment (top drive, draw works, iron roughneck, pipe handling);
− display hierarchy for display navigation;
− CCTV displays*;
− power system – single line information;
− topology overview, showing communication status;
− alarm displays, inclusive alarm and message banner;
− DCDA system display for maintenance purposes;
anti-collision overview, included status override switches.

In addition shall DCDA when specified include displays of the appropriate Mud, BOP, choke control, CRI and cementing systems whereby the DCDA has only secondary control or monitoring function.

*If CCTV system is integrated in the DCDA system, the following shall be possible:

- to view and control CCTV from the DCDA operator work stations;
- to view CCTV from the DCDA relevant operator terminals;
- to view CCTV from onshore remote terminals.

There shall be an alarm banner in top of one of the multiple monitors and on operator terminal stations. The alarm banner shall announce the most critical alarm, i.e. the alarm with the highest priority last generated that is not yet acknowledged.

There shall be a message banner and message list showing information from equipment controller to guide the operator about reason for operational equipment restriction. Messages should be connected to operator commands.

The navigation bar should always be located on the bottom of one of the operator work station screens.

Navigation should also be possible

- through the keyboard/function-keys from the operator chair, and
- by clicking/pushing the different buttons in navigation display(s).

6.45.13 Data storage and validation

Data shall be validated and quality checked prior to presenting and logging.

Annex B details the minimum parameter requirements for logging of drilling and well activities.

The DCDA shall record and store data for minimum 200 days (or as specified in the project) with same frequency information sent on the DCN. When the storage media is filled up the logging function shall continue uninterrupted by newer records overwrite the oldest records.

See parameter list in Annex B for preferred units. Otherwise SI units shall be used for all logging.

Older data shall be available on off-line storage media. Off-line historical information shall be easily restorable and shall have export possibilities to excel.

When a systematic error or error condition (e.g. change or bit depth due to incorrect tally) necessitates editing of data, data recorded to the point of error shall not be overwritten.

6.45.14 Trending

Historical stored data shall be accessible and viewed in trend display.

A trend is a plot of the values of one parameter versus that of another parameter, usually “time” parameter.

It shall be possible to shown several process variables simultaneously in the same trend display for comparison and examination. Pen colour shall be changeable. Fixed trends where specific data are set up may be used in connection with a particular equipment or process.

Trend charts shall at least have possibilities to scroll, zoom, pause and jump to current time.

Scaling of the axis shall be possible including change of time span.

6.45.15 DCDA alarm and message system

All alarms for the operator shall be presented in a common alarm system which shall be a part of DCDA HMI. All subsystems interfacing with the DCDA system shall be integrated such that the operator has only one consistent alarm system to monitor and operate.

The DCDA alarm system shall have the following functionality:

- alarm grouping;
- alarm priority;
− distinct alarm presentation;
− different alarm colours;
− distinct alarm text;
− alarm sound.

These functionalities are described in more detailed below.

6.45.15.1 Alarm grouping

All alarms shall be filtered by the selected operation based on user login, operation mode and priority and presented to the operator as default alarm list. It shall be possible for the operator to reach all the other alarm lists by selection, e.g. sorted by equipment.

6.45.15.2 Alarm priority

Alarms shall be prioritised to guide the operator in his decision to select which alarm/abnormal situation to handle.

Alarms shall be prioritized according to the severity of consequences that could be avoided by corrective actions and the time available for successful corrective operator action.

Alarm priority shall keep at least three levels for DCDA system (low, medium, high).

Each project has to review all alarms and determine correct priority level. Cause of the increase in priority from low level to be described in final documentation.

6.45.16 Alarm visual presentation

The following information should be available for each alarm:

− priority;
− tag name;
− tag service description;
− timestamp (date and time alarm was generated);
− system;
− alarm description;
− alarm status (e.g. acknowledged/unacknowledged).

6.45.16.1 Alarm colour

Use of colour shall ensure an intuitive presentation to operator and uniquely present status and priority.

6.45.16.2 Alarm text

Every alarm text shall be distinct and self-explanatory.

6.45.16.3 Alarm sounds

Use of audible alarms shall be restricted to an absolute minimum. It shall be possible to silence the alarm sound from the operator chair. Silencing shall be independent from the acknowledgement of the alarm.

To maintain a safe and effective working environment in the drillers cabin, the alarm load shall be kept to a minimum. This means minimizing the alarm rate as well as the number of active alarms. It shall be possible to perform alarm performance analysis to monitor the alarm load situation.

6.45.16.4 Alarm and message lists

The DCDA system shall have alarm lists and message, which are available from all DCDA operator terminals. The lists shall be continuously updated.

The alarms shall be listed in chronological order and be time-stamped. The latest alarm/message/event shall be at top of the list.

The alarm/message lists should be sortable based on time, operation, system, status and priority.
The following lists should be available for a DCDA system:

- alarm list;
- alarm hidden list;
- alarm shelved list;
- historical alarm list*;
- message list;
- historical message list.

*Once the alarm is both acknowledged and normalized, it will be removed from the alarm list. It will be kept in the alarm history.

A historical alarm log shall exist for a minimum of 7 days electronically where all alarms and their change of status can be viewed in the system. Older data shall be available on off-line storage media. Off-line historical information shall be easily restorable and shall have export possibilities to an open spread sheet format. This information shall include messages, events and alarms and be sorted by time.

The system shall be set up to print out the alarm and message lists.

6.45.17 DCDA operator work stations

DCDA operator chairs in driller’s cabin shall be the main operator interface with the drilling process, drilling equipment and utility systems.

Driller will typically operate draw works, top drive, HP mud pumps and rotary table while assistant driller typically operates pipe handling equipment. A study shall ensure that work load for each operator is within acceptable limit with regards to machines operated in any work process.

Each operator chair shall be equipped with:

- emergency stop switch(s);
- swing ability with a good escape ability;
- minimum two screens in front against well center, operated by mouse and keyboard;
- multi-function touchpad/keypads;
- multi-function joystick with out of centre switch and multi-function top switch(es);
- alarm horn silence function;
- safe modus function (operator leaving chair etc.).

Drillers chair and assistant drillers chair shall have the same control and monitoring possibilities and act as backup in case of failure in one of the chairs.

6.45.18 DCDA command functions

Multi-function joystick and touchpads/keypads shall be the primary input devices for the operators. The most frequent used functions shall be located on the joystick switches. There shall be indication in the screen/touchpad picture showing current buttons/joystick configuration.

Command buttons should have at least the following indications: command status, field status and inhibition.

Time delay from the operator gives a command on the DCN until command feedback is received on keypad/touchpad should be negligible and not feel uncomfortable for the operator with respect to the systems response times. The response time should be less than 250 ms.

Joystick level (engagement) shall be shown on the screen/touchpad.

Multi-function configuration, within the same operator mode, should be avoided for elevator and slips operation.

Secondary functions can be performed on screen, by using mouse pointer together and/or keyboard, e.g. acknowledge of alarms, adjustment of operation parameter, alarm limits, etc.
6.45.19 DCDA operator terminals and printer

It shall be possible to log on to any DCDA operator terminal to get access to the operators’ pictures and privileges. Information in the systems should be open for all operators.

There shall as a minimum be DCDA operator terminals at the following locations:
- tool pusher office;
- company man office;
- maintenance office.

There shall be a printer available, which allows the trends to be plotted with differentiation of values (colour, line pattern, etc.).

6.45.20 Drilling communication networks

The DCDA system shall have a dedicated drilling control network (DCN) for drilling and well activities connecting controllers, servers, operator stations and other network components.

The DCN shall be fault tolerant (e.g. ring topology) and provide for information exchange between the connected components and based on well proven technology used for drilling applications.

The DCN architecture shall ensure that no single failure of a network component may affect the availability or control functions of controllers connected to other network components.

Network failures shall raise an alarm in the DCDA.

The DCN shall be defined early in the project such that drilling equipment supplied by others can be integrated. Requirement does not apply for 3rd party equipment.

The infrastructure shall support remote monitoring and access possibilities for diagnostics, down to controller level, from other locations on the facility and outside the facility, i.e. vendor’s offices.

Communication telegrams with fixed time rate shall be used for communication between controllers and shall include mechanisms to detect communication error and halted or missed processor execution. A failure in a controller or communication component may thus be detected by the remaining parts of the system and corresponding fail-safe actions taken.

The DCN shall support real time operation of drilling equipment and shall support minimum 100 ms update rates for information exchange between connected controllers and minimum 500 ms update rates to servers.

Communication between servers, third party company PCs, distributed DCDA operator terminals and printer(s) shall have dedicated networks (DPcN(s)) and be physically segregated from the DCN.

Servers/PCs connected directly to DCN, based on required functionality, shall have mechanism to reduce the risk of spreading malicious software into the DCN.

A network topology diagram for the DCS including all system components and interfaces to other systems shall be made available.

6.45.21 DCDA interface to mechanical equipment controllers

Mechanical equipment packages shall be integrated into the DCDA’s HMI.

The various equipment controllers shall be connected directly to the DCN. A gateway controller may be used when this is more convenient and appropriate.

The supplier of DCDA system should be responsible for:
- ensuring consistency in the user interface;
- ensuring the necessary design information related to the integration;
- ensuring proper communication through the DCN.

The mechanical equipment controller supplier should be responsible for:
- providing necessary design information related to HMI integration;
- equipment design and functionality.
The mechanical equipment package shall meet the following requirements:

- ensure proper machinery protection;
- avoid collision against fixed structure;
- use of fail-safe technology;
- activate alarms;
- present all analogue input values and corresponding fault bit at HMI screen for maintenance purpose;
- ensure diagnostic fault for analogue inputs;
- use separate card and fuses for duplicate I/O;
- message system to aid the operator with equipment operation;
- none alarms during normal start up or stop;
- ensure proper machinery behaviour during communication fault;
- prepared for interface with the anti-collision system;
- anti-collision override functionality;
- prepared for interlocks against other equipment.

Multiple alarms occurring at the same time should be avoided (e.g. by defining alarm sequences and dependencies between alarms).

Alarm grouping and priority shall be used to reduce operator overload.

It should be avoided to split control functions as automatic closed-loop control or control sequences between equipment controllers.

6.45.22 DCDA interface to other systems

The DCDA shall be designed to interface with all required drilling control systems and relevant rig control systems. Rig control systems typically include:

- dynamic positioning;
- heave;
- weather data;
- tanks on top sides.

The DCDA should typically be able to interface the following 3rd party systems for control and/or monitoring:

- cement unit;
- MWD/LWD;
- mud logging.

6.45.23 Anti-collision

The anti-collision (zone management) system shall be part of the DCDA system.

The anti-collision system shall avoid collision between any two moving pieces of equipment on drill floor and in the derrick. Collision with fixed structure is normally not included in the anti-collision system and should be taken care of by the individual machine control system.

Based on collected position data the anti-collision system shall be a “traffic coordinator”. The anti-collision system shall provide stop movement/permit movement signals or stop destinations to the equipment involved. Systems based solely on alarms (visible and audible) shall be avoided.

All relevant machine control systems should communicate with the anti-collision system through the DCN. Instrumentation for zone management system shall be installed for machines involved in the anti-collision. Involved equipment shall include measurement healthy signals.

The anti-collision system shall be designed to be fail-safe.

The system shall include override functions needed for special operation, e.g. fault situations, maintenance, casing operations, etc. activation of the override switch(s) shall be logged of the DCDA.
system and clearly informed to the operator. A reminder mechanism to prevent accidental long override should be implemented.

Typical equipment included in active anti-collision system:

− top drive extended and retracted*;
− draw works (top drive/block position)**;
− vertical pipe handling machine (VPH solution);
− pipe shuttle machine incl. horizontal pipe handling machine;
− iron roughneck, including mud bucket*;
− gantry crane;
− access basket*;
− V-door material handling crane*;
− drill floor manipulator arm*.

*Typically equipped with proximity switch for detection of specific position.

**KEMS logic in the draw works control system shall be used to stop downwards block movement against other machines. Crown and floor saver shall be included in the draw works control system.

Equipment stop based on anti-collision information shall be informed to the operator as an operator message and included in the historical message list.

Anti-collision overview display shall be implemented in the DCDA system.

6.45.24 Drilling equipment emergency stop system

This subclause describes only functional requirements for design of emergency stop system activated from operator work stations.

Requirements for local emergency stop and its design requirements for machinery equipment is not covered in this paragraph, but drilling equipment emergency stop system have to be integrated into that system.

A study shall be carried out to ensure safe operation with regards to the drilling emergency stop system. The study shall as a minimum include:

− Can layout/design of pushbuttons mislead the operator?
− Can stopping all machines controlled by one operator cause an uncontrolled operational situation?

The design should be based on an emergency stop philosophy document and by use of cause and effect diagram.

Typically, the emergency stop system for the drilling equipment consists of the following type of emergency stop buttons:

− for stopping moving equipment on drill floor;
− for stopping of mud pumps;
− for stopping specific equipment (local adjacent to the equipment).

The following functional requirements shall form the basis for the design, but not be limited to:

− the drilling control system shall integrate all equipment in an overall drill floor emergency stop system;
− the emergency stop circuits shall be hardwired to the respective cabinet or switchgear and be integrated into the equipment emergency stop circuit;
− one emergency stop button (several stations) shall stop all equipment movement on drill floor except heave compensating equipment. Shut off valve should be used to isolate involved hydraulic powered equipment;
− information about activation of all emergency stop buttons (each loop) included in this emergency stop system shall be available in the DCDA system;
− information about activation of local emergency stop circuits should have inputs to the equipment controller and be presented at the DCDA system through the equipment controllers HMI interface.
6.46 Machine – machine interlocks

An interlock system shall be implemented to achieve but not limited to the following:

− secure last grip on pipe (avoid unintentional drop of pipe or tubular, e.g. open slips/open elevator);
− avoid movement of pipe or tubular with machinery clamped on (e.g. hoisting with roughneck or pipe handler clamped on pipe);
− avoid rotating of pipe or tubular with equipment clamped on.

6.47 CCTV

A CCTV system shall be installed as necessary to give the operators visual control over equipment and processes. Cameras shall, where required be equipped with pan, zoom and tilt function.

A system for cleaning camera-glasses shall be included where required.

Monitors can be part of DCDA display or standalone. Typical locations for CCTV monitors will be:

− drillers cabin: cameras on drill floor, derrick, return line and shakers;
− shaker operator: cameras for control of shakers and mud distribution;
− mud control room: cameras for control of mud pump fluid end and mixing facilities;
− cement control room: cameras for control of slurry mixer;
− offices: access to view picture from all cameras.

CCTV monitor picture for drill floor equipment shall have time lag less than 250 ms.

Digital CCTV systems shall have a mechanism for detecting frozen picture.

6.48 Utilities

The drilling facility shall be equipped with HP water cleaning system and necessary hock-up for vacuum cleaning system.

All modules shall have facilities for supply of electric power for tools, pressurised air and water as required for the work.

Requirements for 3rd party utility stations shall be defined in pre-engineering. Utility stations shall as minimum include hook-up point for fire and gas, emergency shutdown, phone, electric power, connection of data transfer, compressed air, water and diesel.

Typical 3rd party units will be:

− mud logging unit;
− MWD;
− MPD;
− wire line unit;
− coiled tubing;
− snubbing unit;
− ROV;
− completion/WO unit;
− cuttings transport;
− swarf unit;
− casing tong;
− well testing equipment;
− workshop container.

6.49 Drilling waste management

6.49.1 General

A system for handling drilling waste from well shall be implemented, either for transportation to onshore or injection.
6.49.2 Functional requirements

The system shall be designed to transport all waste from shale shakers to chosen method of further safe disposal of drilling cuttings and waste from well cleanup.

A backup system shall be evaluated if injection system is chosen.

Storage and handling of skips shall be arranged such that spill to sea is avoided and handling can be carried out without risk of personnel injury.

Capacity shall be based on anticipated maximum volume (rate of penetration x hole size).
Annex A (informative)
Principal topology of a drilling control system
## Annex B (normative)

### Drilling parameter requirements

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<td>Audible alarm</td>
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<td>Display requirements</td>
<td>Meas Sys</td>
<td>Accuracy (%)</td>
<td>Response time (s)</td>
<td>Display (Y)</td>
<td>Data update (Y)</td>
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<td>58</td>
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<td>Viscosity in each active well</td>
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<td>m</td>
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<td>2.00%</td>
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<td>m</td>
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<td>m</td>
<td>0.05</td>
<td>2.00%</td>
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Annex C (informative)
Data sheet

The following data sheets are normative references for a typical NORSOK I and NORSOK II drilling facility.

Columns marked other shall be used where alternative requirements specified to meet specific requirements.
## Drilling facilities

<table>
<thead>
<tr>
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<td>Project:</td>
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<td>Document No:</td>
<td></td>
<td></td>
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<tr>
<td>Date and revision</td>
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### System/equipment

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<th>NORSOK I</th>
<th>NORSOK II</th>
<th>Other</th>
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<tbody>
<tr>
<td>System/equipment</td>
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<td></td>
</tr>
<tr>
<td>NORSOK I</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>NORSOK II</td>
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### Process conditions

#### Mud properties

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<tr>
<th></th>
<th>Density</th>
<th>Viscosity</th>
<th>Return temperature</th>
<th>Mud types</th>
<th>Injection slurry properties (if applicable)</th>
<th>Density</th>
<th>Grain size</th>
<th>Viscosity</th>
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<tr>
<td></td>
<td>2,2 SG</td>
<td>PV = 100 mPas</td>
<td>Minimum 50(^\circ) C</td>
<td>All</td>
<td>Density 0,80 – 1,60 SG</td>
<td>0,80 – 1,60 SG</td>
<td>90% &lt; 250 microns</td>
<td>PV &lt; 100 mPas</td>
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<tr>
<td></td>
<td>2,2 SG</td>
<td>PV = 100 mPas</td>
<td>Minimum 50(^\circ) C</td>
<td>All</td>
<td>Grain size 90% &lt; 250 microns</td>
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<tr>
<td></td>
<td></td>
<td>PV &lt; 100 mPas</td>
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<td>Viscosity PV &lt; 100 mPas</td>
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### Special requirements for MODU

#### Marine riser tensioner – maximum combined design load

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<tbody>
<tr>
<td>Individual tensioner capacity:</td>
<td>350 KN</td>
<td>350 KN</td>
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<tr>
<td>Tensioner stroke length:</td>
<td>15,2 m (50 ft)</td>
<td>15,2 m (50 ft)</td>
</tr>
</tbody>
</table>

#### Guideline tensioner – maximum combined design load

- POD and guideline tensioner:
  - Individual tensioner capacity: 75 KN
  - Tensioner active work length: 12,2 m (40 ft)

#### Minimum drill string compensator:

- Individual tensioner capacity: 1900KN (200 mt)
- Stroke length: 7,6 m (25 ft)

### Hoisting and rotary systems

- Minimum draw work power: 1500 KW
- Lifting capacity: 4450 KN
- Lifting height – minimum: 32 m
- Lifting speed – minimum: 1 m/s
## System/equipment

<table>
<thead>
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<th>NORSOK I</th>
<th>NORSOK II</th>
<th>Other</th>
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<tr>
<td>Topdrive – minimum load rating</td>
<td>4450 KN</td>
<td>5785 KN</td>
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<tr>
<td>Topdrive rpm at maximum continuous torque – minimum</td>
<td>120 rpm</td>
<td>160 rpm</td>
<td></td>
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<tr>
<td>Topdrive maximum continuous torque – minimum</td>
<td>60 KNm</td>
<td>80 KNm</td>
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<tr>
<td>Topdrive breakout torque – minimum</td>
<td>120 KNm</td>
<td>120 KNm</td>
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<tr>
<td>Topdrive makeup torque – minimum</td>
<td>80 KNm</td>
<td>80 KNm</td>
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<tr>
<td>Topdrive/rotary minimum speed at maximum torque</td>
<td>10 rpm</td>
<td>10 rpm</td>
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<tr>
<td>Topdrive/swivel maximum speed</td>
<td>220 rpm</td>
<td>220 rpm</td>
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<tr>
<td>Topdrive/swivel pressure rating</td>
<td>34,5 MPa</td>
<td>51,7 MPa</td>
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<tr>
<td>Rotary table - minimum internal diameter</td>
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<td>1,2573m (49,5&quot;)</td>
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<tr>
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<td>5785 KN</td>
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<tr>
<td>Rotary table speed</td>
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<tr>
<td>Rotary table torque</td>
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## Pipe handling system

**Vertical pipe handling system**
- Fingerboard capacity 5" to 5⅞" drill pipe | 120 stands | 190 stands |
- Fingerboard capacity 6¾ drill pipe | 100 stands | 130 stands |
- Fingerboard capacity 6" drill collar | 9 stands | 9 stands |
- Fingerboard capacity 8" drill collar | 9 stands | 9 stands |
- Fingerboard capacity 9½" drill collar | 9 stands | 9 stands |
- Total number of stands – proposed minimum | 238 stands | 338 stands |
- Lifting capacity - minimum | 95 KN | 95 KN |
- Minimum average tripping speed | 60 stands/h | 60 stands/h |

**Horizontal pipe handling system(s)**
- Tubular range handling capacity | 2 ¾" – 30" | 2 ¾" – 30" |
- Lifting capacity – minimum | 60KN | 60 KN |
- Handling capacity – tubulars per hour
  - 30" | 5 | 5 |
  - 20" | 10 | 10 |
  - 13¾" | 25 | 25 |
  - 9¾" | 35 | 35 |
  - 7" and smaller | 45 | 45 |

**Iron roughneck**
- Minimum tubular range | 3½" - 9½" | 3½" - 9½" |
- Make-up torque - minimum | 80 KN | 80 KN |
- Break-out torque – minimum | 120 KN | 120 KN |
## System/equipment

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<thead>
<tr>
<th>Associated equipment</th>
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<td>Man rider winches</td>
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## Bulk system

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<td>-40°C</td>
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## Mud mix and storage

| Minimum capacity unless otherwise specified               |          |           |       |

### Base fluid system

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### Primary mud system

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</tr>
<tr>
<td>Total volume: a) – e)</td>
<td>380m³</td>
<td>600m³</td>
<td></td>
</tr>
</tbody>
</table>

### Secondary mud system

<table>
<thead>
<tr>
<th>Mineral/synthetic oil based mud storage tank (if applicable)</th>
<th>350m³</th>
<th>450m³</th>
</tr>
</thead>
</table>

### Completion fluid system

<table>
<thead>
<tr>
<th>Brine storage tank (if applicable)</th>
<th>380m³</th>
<th>600m³</th>
</tr>
</thead>
</table>

### Additional systems

---
Cuttings slurry tank (if applicable) 60m³ 60m³
Drain tank 40m³ 40m³
Mud mix transfer pump 220m³/h 220m³/h

**Chemical dosing system**

| Feed rate dry powder: | 0.05 – 1.5m³/h | 0.05 – 1.5m³/h |
| Feed rate liquid: | 0.1 – 2.0m³/h | 0.1 – 2.0m³/h |

**System/equipment**

<table>
<thead>
<tr>
<th>Bulk dosing system</th>
<th>NORSOK I</th>
<th>NORSOK II</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>Feed rate bentonite</td>
<td>15 t/h</td>
<td>15 t/h</td>
<td></td>
</tr>
<tr>
<td>Feed rate barite</td>
<td>45 t/h</td>
<td>45 t/h</td>
<td></td>
</tr>
<tr>
<td>Mud mixer Powder</td>
<td>45 t/h (barite)</td>
<td>45 t/h (barite)</td>
<td></td>
</tr>
<tr>
<td>High rate mud mixer (if required). Required for HPHT Powder:</td>
<td>60 t/h (barite)</td>
<td>80 t/h (barite)</td>
<td></td>
</tr>
</tbody>
</table>

**High pressure mud system**

| Minimum number of HP and supercharger pumps | 2 | 3 |
| Design flow rate at given pressure: (continuous output at 85% of maximum capacity) | 300m³/h at 260 bar | 420m³/h at 345 bar |
| Maximum operating pressure | 345 bar | 517 bar |
| Required flow rate at maximum operating pressure (continuous output) | 210m³/h | 300m³/h |

**Mud treatment system**

| Maximum well return | 360m³/h | 500m³/h |
| Minimum shaker capacity | 360m³/h | 500m³/h |
| Degasser capacity | 360m³/h | 500m³/h |
| Centrifuge capacity (at 2.000 G and 1.5 SG) | 20m³/h | 20m³/h |
| Treatment tank volume, pr tank | 2-5m³ | 2-5m³ |
| Cuttings disposal system average capacity, if installed | 10m³/h | 10m³/h |
| Cuttings disposal system maximum capacity, if installed | 20m³/h | 20m³/h |
| Flow dimension | 16” | 16” |
| Flow capacity and screen size for typical hole size: | | |
| 17.5” section (mesh ≥ 60) | 320m³/h | 450m³/h |
| 12.25” section (mesh ≥ 100) | 210m³/h | 300m³/h |
| 8.5” section (mesh ≥ 150) | 135m³/h | 150m³/h |
| Completion fluids (mesh ≥ 200) | 190m³/h | 190m³/h |
| Gumbo trap – optional | | |
| Cuttings collection system – optional | | |
| Cuttings weight system – optional | | |
## Well control system

<table>
<thead>
<tr>
<th></th>
<th>NORSOK I</th>
<th>NORSOK II</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well control equipment pressure rating – minimum</td>
<td>345 barg</td>
<td>690 barg</td>
<td></td>
</tr>
<tr>
<td>BOP internal diameter – optional</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Number of rams – minimum</td>
<td>3</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>Ram size – optional</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Number of annular preventer(s) – minimum</td>
<td>1</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>System/equipment</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annular preventer(s) internal diameter</td>
<td>As for BOP</td>
<td>As for BOP</td>
<td></td>
</tr>
<tr>
<td>Annular preventer pressure rating – minimum</td>
<td>210 barg</td>
<td>345 barg</td>
<td></td>
</tr>
<tr>
<td>Number of choke/kill outlets – minimum</td>
<td>2</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>Choke and kill valve pressure rating – minimum</td>
<td>345 barg</td>
<td>690 barg</td>
<td></td>
</tr>
<tr>
<td>Trip tank capacity – minimum</td>
<td>2 x 5m³</td>
<td>2 x 5m³</td>
<td></td>
</tr>
<tr>
<td>Trip tank pump capacity</td>
<td>100m³/h</td>
<td>100m³/h</td>
<td></td>
</tr>
<tr>
<td>Accuracy of volume variation measurement</td>
<td>0.05m³</td>
<td>0.05m³</td>
<td></td>
</tr>
</tbody>
</table>

## Diverter

<table>
<thead>
<tr>
<th></th>
<th>NORSOK I</th>
<th>NORSOK II</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimum pressure rating</td>
<td>35 bar</td>
<td>35 bar</td>
<td></td>
</tr>
<tr>
<td>Minimum diverter line size</td>
<td>16&quot; (406mm)</td>
<td>16&quot; (406 mm)</td>
<td></td>
</tr>
<tr>
<td>Minimum flow line size</td>
<td>14&quot; (355mm)</td>
<td>16&quot; (406mm)</td>
<td></td>
</tr>
</tbody>
</table>

## Cementing system

<p>| | | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydraulic power</td>
<td>375 KW</td>
<td>600 KW</td>
<td></td>
</tr>
<tr>
<td>Maximum working pressure</td>
<td>690 bar</td>
<td>1035 bar</td>
<td></td>
</tr>
<tr>
<td>Number of pumps</td>
<td>2</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>Maximum continues flow rate at:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>345 barg</td>
<td>28,6 m³/h</td>
<td>40,2 m³/h</td>
<td></td>
</tr>
<tr>
<td>690 barg</td>
<td>14,3 m³/h</td>
<td>20,1 m³/h</td>
<td></td>
</tr>
<tr>
<td>1035 barg</td>
<td>NA</td>
<td>13,4 m³/h</td>
<td></td>
</tr>
<tr>
<td>Maximum intermittent (120 minutes) flow rate at:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>345 barg</td>
<td>34,3 m³/h</td>
<td>45,0 m³/h</td>
<td></td>
</tr>
<tr>
<td>690 barg</td>
<td>17,5 m³/h</td>
<td>24,0 m³/h</td>
<td></td>
</tr>
<tr>
<td>1035 barg</td>
<td>NA</td>
<td>14,0 m³/h</td>
<td></td>
</tr>
<tr>
<td>Slurry mixing capacity:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>maximum bulk rate</td>
<td>1,8mt/min</td>
<td>1,8mt/min</td>
<td></td>
</tr>
<tr>
<td>maximum mix water rate</td>
<td>90 m³/h</td>
<td>90 m³/h</td>
<td></td>
</tr>
<tr>
<td>mixing performance (density)</td>
<td>2.5</td>
<td>2.5</td>
<td></td>
</tr>
<tr>
<td>Data measurements</td>
<td>± 1% of FS</td>
<td>± 1% of FS</td>
<td></td>
</tr>
<tr>
<td>Emergency starting (diesel engines)</td>
<td>6 attempts at 10 s periods</td>
<td>6 attempts at 10 s periods</td>
<td></td>
</tr>
<tr>
<td>Diesel day tank capacity</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Emergency circulation: Number. of pumps required (i.e. 800 l/min at 203 barg)</td>
<td>Minimum 1</td>
<td>Minimum 1</td>
<td></td>
</tr>
</tbody>
</table>