# INDUSTRY STANDARD NO. 43

# Surface BOP

**26 April 2016**

## Inhoud

NOGEPA
NETHERLANDS OIL AND GAS EXPLORATION AND PRODUCTION ASSOCIATION

# Document Control Sheet

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This document will be controlled in accordance with the NOGEPA Industry Standard No. 80 on Standards and Document Control.

## Terms and definitions

| | |
|---|---|
| Safety & Environmental Critical Element (SECE) | means such part of an installation and its design (including computer programs) or any part thereof, the failure of which would cause or contribute substantially to, or a purpose of which is to prevent, or limit the effect of, a major accident. |
| Working Pressure | means the pressure that a component could be safely subjected to during the full range of normal operations. |
| Factory Acceptance Test Pressure (FAT) | means 1.5 x maximum working pressure, if not otherwise specified in applied codes and standards. The acceptance test pressure needs to be done when put into first service and after a major repair. |
| Test Pressure | means the pressure to which BOP's are periodically tested. The test pressure will be determined by the well program and not exceed the maximum working pressure of the wellhead. |
| Pore Pressure | means the amount of pressure that is being exerted into the borehole by fluids or gases within the formation that has been penetrated. |
| Bottom Hole Pressure (BHP) | means the sum of all the pressures acting on the bottom hole; typically the surface pressure plus the force exerted by the column(s) of fluid in the wellbore. |

## Abbreviations

| | |
|---|---|
| API | American Petroleum Institute |
| BOP | Blow Out Preventer |
| BR | Blind Rams |
| BSR | Blind Shear Rams |
| CL | Choke Line |
| CV | Check Valve |
| DICV or DIBPV | Drop In Check Valve or Drop In Back Pressure Valve |
| HCR-valve | Hydraulically Controlled Remote Operated Valve |
| HP | High Pressure |
| HPHT | High Pressure/High Temperature |
| $H_2S$ | Hydrogen Sulfide |
| HWDP | Heavy Weight Drill Pipe |
| IADC | International Association of Drilling Contractors |

| | |
|---|---|
| IBOP | Internal BOP |
| ICP | Independent Competent Person |
| ID | Inside Diameter |
| KL | Kill Line |
| MAASP | Maximum Allowable Annulus Surface Pressure |
| MEWHP | Maximum Expected Well Head Pressure |
| MGS | Mud Gas Separator |
| MOC | Manual Operated Choke |
| MPD | Managed Pressure Drilling |
| DMR | Dutch Mining Regulations |
| OD | Outside Diameter |
| OEM | Original Equipment Manufacturer |
| PCE | Pressure Control Equipment |
| PMS | Preventive Maintenance System |
| PR | Pipe Rams |
| ROC | Remote Operated Choke |
| SECE | Safety & Environmental Critical Element |
| SIMOPS | Simultaneous Operations |
| SIT | System Integration Test |
| SodM | State Supervision of Mines |
| SOP | Standard Operating Procedure |
| SPM | Strokes per Minute |
| UPS | Uninterrupted Power Supply |
| VBR | Variable Bore Rams |
| WCE | Well Control Equipment |
| WH | Wellhead |
| WP | Working Pressure |
| XO | Cross Over Sub |
| XT | Christmas Tree |

## Legal Requirements

| | |
|---|---|
| Offshore Safety Directive | |
| Mining Decree | |
| Mining Regulation | 8.3.1.2 8.3.1.3 8.3.1.4 8.3.1.5 8.3.1.6 8.3.1.7 8.3.1.8 8.3.1.9 8.3.1.10 8.3.1.11<br>8.3.2.1 8.3.2.2 8.3.2.3 8.3.2.4 8.3.2.5 8.3.2.6<br>8.3.3.1 8.3.3.2 8.3.4.1 |

## Related Standards

| | |
|---|---|
| API spec 6A | Specifications for, Wellhead and Xmas tree equipment |
| API S53 | Blow Out prevention equipment systems for drilling wells.<br>One of the major changes from RP53 to the present S53 is the communication between OEM and equipment owner (Drilling Contractor) on failure reporting. |
| API 16D | Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment |
| API RP 16E | Recommended Practice for Design of Control Systems for Drilling Well Control Equipment |
| API spec 12J | Specification for Oil and Gas separators |
| NACE MR 0175 | Materials in $H_2S$ containing environments in oil and gas production |

## Important Nomenclature used in this Standard

| In the context of this Standard and when so used to describe a method or practice: | |
|---|---|
| **'shall'** | means that such method or practice reflects a mandatory provision of law (in Dutch: *dwingend recht*). Such method or practice is mandatory for those who are the addressees of such provision (mostly the operators). A Standard can describe or quote, but not amend, mandatory provisions. When an operator in exceptional cases for technical, operational or HSE reasons cannot comply, exceptions shall be documented and reported, and risks mitigated. Please note that this does not release the operator from the obligation to comply with the law. * |
| **'should'** | means that such method or practice reflects a Good Operating Practice. An operator is generally expected to apply such method or practice, but a specific situation may require a specific alternative. In other words: the operator complies or explains, and documents the explanation. * |
| **'could'** | means that such method or practice is of an advisory nature or mentioned by way of example. An operator is not obliged to comply and is not obliged to explain if he does not comply. |
| * Please refer to paragraph 2.3 of Standard 80 (Standards and Document Control), for further explanation on an exception of a 'shall' provision, or on a comply-or-explain of a 'should' provision. | |

# 1. Executive Summary

The primary purpose of a BOP is to be able to close in a well on a kick and subsequently to control bottom-hole pressure during the well killing process. So the BOP stack shall be designed to contain the surface pressure of a well where the full mud volume has been evacuated. It also needs to be designed, to provide a large enough passage for all anticipated tool sizes.

Key elements are to assure that all well operations, both onshore in the Netherlands and offshore on the Dutch Continental Shelf, shall use Pressure Control Equipment that is suitable for the program to be executed, taking into consideration the specific well conditions to be encountered. Equipment should be certified and tested according to this Industry Standard 43.

This NOGEPA Industry Standard 43 addresses various requirements for assuring control of a well by the Operator. The Standard is either based on mandatory legislation, based on the relevant articles of the Dutch Mining Regulations or international standards such as API S53.

Documentation and reporting requirements are defined and agreed with various parties.

Efficient and effective well control depends much on the soundness of the well design, construction quality and competence of Personnel.

Note:

This is the first issue. In order to keep it current, i.e. reflect changes in regulations, industry practices and experience, international standards, technologies, and documentation requirements, this Standard 43 should be reviewed once every 3 years or sooner, if required.

# 2. Scope and application

## 2.1 Scope

The scope of this Standard is restricted to:

- The Netherlands and the Dutch Continental Shelf; and
- Well Operations as defined in the Offshore Safety Directive, in essence those well operations that inherently carry significant risks. For Standard 43 we will limit to Drilling Operations and Well Services Operations using a BOP, where the XT has been removed.

*Note 1: API S53 does not address workover, well services or interventions.*

*Note 2: Exceptional wells (such as HPHT wells) will require additional consideration and prior consultation with SodM .*

## 2.2 Application

Standard 43 will be applicable both onshore and offshore. It applies to both drilling a new well, workover operations and well decommissioning with a rig or a workover unit when the XT is not installed on the well.

# 3. Drilling Pressure Control Equipment

The drilling pressure control equipment can be split into three parts:

3.1 Blow out preventer on the well with kill and choke-lines and choke manifold.
3.2 The BOP control system
3.3 The auxiliary equipment, going from equipment to shut off the internal pipe flow to equipment to handle the influx downstream of the choke manifold

All these items should be compatible with all of the other elements of the Drilling Pressure Control System.

## 3.1 Blow Out Preventer System

Blow out preventer, kill & choke-lines plus choke manifold.

### 3.1.1 Blow Out Preventer Selection

Drilling BOP's shall adhere to Mining Regulations

A documented risk assessment shall be made for a BOP stack to identify the configuration that is required; This assessment shall include tapered strings, casings, completion equipment, test tools etc.;

BOP Configuration: API S53 shall be used as the recognized industry standard practice for BOP systems. Refer to separate section in annex I: Drilling BOP Configurations.

BOP system selected shall be based on maximum anticipated surface pressure (API S53 & MR 8.3.1.3.3).

BOP rating, ram/annular configuration and test pressure is derived from the well design.

Annular preventers having a lower WP than ram preventers are acceptable.

### 3.1.2 Ram hang-off capacity

Pipe Rams Hang-off capacity shall be within the operating limits for all drill strings.

VBR hang-off capacity should be checked (refer to manufacturer data), as it is lower than the hang-off capacity of standard pipe-rams.

### 3.1.3 Ram Locking Devices

All ram type preventers shall be fitted with mechanical ram locking devices.

Locking devices are designed to block any ram in a closed position in the case of a severe situation (Heavy Drill Pipe string hung on BOP ram, high pressure in the well, etc.)

Surface BOP stacks should be pressure tested with ram locking screws tightened and test closing lines bled off during the initial test. This test can also be performed on the stump.

When the rams do not have an incorporated ram locking device, the lock closing device shall be kept at close reach from the BOP stack, ready to lock the rams when required.

### 3.1.4 Connections of Choke & Kill lines

Choke and kill lines are normally connected to side outlets above the lower most rams. The side outlets below the lower most rams should only be used in exceptional circumstances.

See also API S53 sections 7.2.3.2.3. and 7.2.3.2.10.

The reason for using these outlets only as a last resort is that the BOP outlet below the lowermost ram is a potential single point of failure. If washed out, there is no other means to secure the well.

The outlets below the lower rams shall be equipped with two valves and a flange each. One of the flanges shall be equipped with a needle valve and a pressure gauge.

The hook-up of choke and kill lines to the lower outlets is optional. Arrangements should be in place so that if needed they can be hooked-up in short time.

There should always be a provision to monitor the annular pressure below the lower most rams.

Choke and Kill systems should be designed, manufactured and installed in accordance with API 16C.

Lines and manifold should be designed for dynamic loads and rigidly fastened against vibrations. Flexible KL and CL high-pressure hoses longer than 4 meter and valve assemblies at BOP outlets should be supported, to avoid the weak point initiated by the heavy weight of valves and flexible hoses.

When two gate valves exist on an outlet, the valve closest to the well bore is considered as a master valve to be used only in the event of repair on the outer valve. Consequently, on a "normally closed" line, the downstream valve is the only valve closed.

### 3.1.5 Kill Lines (KL)

- There shall be at least one KL
- KL shall at least have a 2” ID;
- Each KL shall be equipped with two full bore valves
- When there are two KLs present, they may have a common part.
- On a KL "CHICKSAN" type lines and swivel joints are acceptable.
- The KL shall be equipped with a non-return valve

The KL should not be used as a fill-up line.

### 3.1.6 Choke Lines (CL)

- Choke lines shall be as straight as possible;
  flow targets or fluid cushions shall be used at short radius bends and 90 degree elbows and Tees;
- There should preferably be two CLs on a BOP configuration;
- On BOP stacks rated 10K and above CL should have at least a 3'' ID;
  For lower pressure ratings 2 inch is acceptable;
- Two full-bore valves shall be installed on each CL;
  One of these two valves shall be remotely operated;
- The two CLs should be independently connected to the choke manifold and should be fully isolated from the other CL by at least two valves;
- Swivel joints are not allowed on CL;
- Choke lines should be in accordance with API S53, which states that for 3000 psi WP and above they should be either flanged or have hub/clamp connections;

### 3.1.7 Choke Manifold

When the choke manifold and the stand pipe manifold are connected, there is a pressure rating risk, which should be properly evaluated and mitigation measures have to be in place.

Two valves of the same pressure rating as the choke manifold plus a check-valve should be installed in the connecting line between stand-pipe and choke manifold.

Requirements of the choke manifold:

- The choke manifold shall have at least the same WP rating as the BOP up to (and including) the chokes;
- The minimum size for choke manifold equipment 10K and above should be 3 inches (API S53 6.2.3.2a) ;
- With two CLs, two independent pressure sensors should be available on each line and be completely isolated from the other by at least two valves;
- All chokes shall discharge directly into a target flange;
- The choke manifold bypass line should be at least equal in diameter to the choke line;
- The buffer chamber should provide direct exits to the return mud system, the degasser and further to a safe area, away from the rig (onshore) or overboard line (offshore); all exits shall have the same WP rating as the downstream part of the choke manifold;
- Two gate valves with the choke manifold WP rating shall be installed directly upstream of each choke;
- At least one gate valve with the choke manifold WP rating shall be installed downstream of each choke but ahead of the buffer chamber;

- A bypass line with two gate valves should be provided from the CL to the buffer chamber without passing through the chokes. This line should have the same working pressure as the BOP stack up to the buffer chamber;
- The choke manifold configuration shall allow for re-routing of flow (No potential single point failure) without interrupting the well control operation. A split buffer tank is recommended, with a possibility to isolate a failure and to direct the flow to the poor boy degasser;
- Casing/drill pipe pressure gauges should be installed at the choke manifold;
- For BOP stacks > 10.000 psi WP, a connection to allow Glycol injection to prevent the formation of hydrates should be present (API S53 6.2.2.13);
- For BOP stacks < 10.000 psi WP, an injection port could be installed;

### 3.1.8 Remote Operated Choke (ROC) Manifold and Control Panel

A minimum of two chokes shall be installed on choke manifold systems one of which is remotely operated;

The remote control panel should be installed near the driller's position. It should include:

- Casing and drill pipe pressure gauges;
- A pump SPM and total strokes counter;
- Choke position monitor for each ROC;
- Back-pressure reading of the "Poor-boy" degasser visible at the remote control panel;

The automatic MAASP feature should not be allowed on the ROC panel. It should be possible to check that the maximum allowable annulus pressure is not exceeded.

The ROC should be equipped with an emergency backup system in the event of primary energy supply shut down or failure (hand pump and/or nitrogen).

All control panel instrumentation should remain available in case of primary energy supply failure. (UPS or hooked up to emergency generator)

The calibration of the various gauges (including these of the mud logging company) and their sensitivity to low pressures should be verified yearly.

All valves and chokes of the choke manifold shall be easily accessible.

### 3.1.9 Stripping

Stripping operations are normally performed with the annular preventer and consequently, the installation of a stripping bottle on annular preventers is recommended.

Spacer spools **could** be used to allow additional space between preventers to facilitate stripping and hang-off operations.

The pipe-rams should be positioned such that ram to ram stripping is possible.

### 3.1.10 Shear Capability

The shear rams shall be able to shear the heaviest drill pipe in use, against the maximum anticipated shut-in well pressure and be able to hold this pressure from below. This test **could** be performed in a suitable workshop.

Any identified well-specific risks associated with the use of BOP equipment and systems shall be mitigated and/or managed through the development of specific guidelines, operating procedures and a thorough risk assessment.

A documented risk assessment should be carried out on any identified “non-shearable” scenario. Mitigation procedures should be put in place. Also these identified situations should be clearly written in the drilling program. All rig teams should be familiar with the procedure.

Spacer spools could be used to provide additional space between preventers to allow hang-off and shear operations.

It is important to understand the effects of increasing wellbore pressure and its impact on the capability of shearing the drill pipe with a closed annular preventer. For this reason, it is important to understand the equipment design, their application and the string in the wellbore and the BOP control system in use.

Using the shear rams
In the configuration that the shear rams are installed between the annular and pipe ram, the annular should be opened as soon as possible after closing the pipe ram and to remove the well pressure and reduce the closing force (pressure required) to shear.

The shear tests should be performed under atmospheric pressure conditions, with further calculation modelling able to show that shearing can be accomplished at maximum anticipated well pressure.

The shear-test report should be available (electronically accessible) on site.

The pressure test from below after shearing should be carried out at the rated working pressure of the stack.

This test should have to be repeated when a major modification has been made. (either to shear-rams and/or use of heavier drill pipe)

## 3.2 BOP Control System

Back-up Systems (use of failsafe/auto function). Fail safe pressure regulators should be in use on the hydraulic control unit manifold.

Tests to be performed on the hydraulic control unit:

### 3.2.1 **Depletion Test -** (with all pumps isolated)

- To confirm the actual useable volume of the accumulators to supply hydraulic power to the BOP, in case of complete black-out;
- To check the residual pressure after carrying out the tests as per Mining Regulations;
- To check the time required to restore pressure after a full depletion test;
- To check the working condition and correct set-up of the “low pressure alarm”;

### 3.2.2 **Emergency Test -** (with all bottle banks isolated at the Hydraulic Control Unit )

- The objective is to ensure that each independent pumping system (electric and/or air) should be able to close the Annular preventer within 2 minutes. (When accumulator banks can’t supply BOP fluid);

### 3.2.3 Initial Test

Both Depletion test and Emergency test shall be carried out upon first installation of the BOP’s on the well or after repairs.

An overall hydraulic control unit and accumulator pressure and function test shall be performed at first installation of the BOP on the well and after any major repair of the accumulator system.

### 3.2.4 Regular Tests

RAM function tests shall be carried out weekly.

A hydraulic control unit and accumulator function test shall be performed every three weeks.

Accumulator Capacity: Dutch Mining Regulations are more stringent than API 53 S and shall be complied with.

BOP accumulator close – open condition for all functions, (including hydraulically operated choke line and kill line valves) and subsequently again the closing of the annular preventer, referred to in Article 8.3.1.4.1.a, plus one of the following two functions: pipe-ram from Article 8.3.1.4.1.b or the BSR mentioned in Article 8.3.1.4.1.c.
The remaining accumulator pressure should be 200psi over pre-charge.
The test shall be carried out at the start of any new well and at least every 3 weeks thereafter.

*Note that there is a significant difference in the amount of hydraulic fluid consumed between option MBR 8.3.1.4.1.b and option 8.3.1.4.1.c., explained by the large bore cylinder or booster of the BSR. Best practice is to operate the BSR or simulate the BSR by closing and opening the pipe-ram. Because the BSR with either large bore or with booster cylinders use twice more fluid than standard rams.*

### 3.2.5 Lay-out of accumulator banks

These accumulators should be split into at least four bottle banks of equal capacity, isolated by manual valves. (API S53 6.3.10.4)

### 3.2.6 Control Units and Control Panels

- The hydraulic control unit with the master control panel shall be located in an easily accessible safe non-hazardous area, protected against dropped objects and fire;
- The hydraulic control unit shall meet the classification requirements for the area in which it is installed;
- The hydraulic control unit should have a by-pass valve (by-passing the manifold pressure regulator) to allow sending the full pressure of accumulators to the manifold piping;

Onshore, it shall be installed at a safe distance from the wellhead on the escape way;

Communication between control unit, panels and BOP should be based on hard wired technology. Wi-Fi transmission should be forbidden. Fluid storage capacity at the hydraulic control unit should be at least twice the usable volume of the accumulators.

### 3.2.7 Pumping System

The BOP control system should contain two distinct pumping systems, each driven by independent power sources, comprising at least:

- Either 1 electrical driven pump system plus 1 air powered pump system;
- Or 2 electrical driven pumps systems, supplied by strictly independent electric networks (engine room, bus bar, transformer, distribution boxes, cables);
- In all cases, at least one electrical driven pump should be powered by the emergency generator;
- Air driven pumps should be capable of charging the accumulators to full system working pressure with a 75 psi (0.52 MPa) minimum air pressure supply;
- The cumulative output capacity of the pump systems should be designed to charge the full accumulator system from pre-charge pressure to the rated pressure of the accumulator in less than 15 minutes;
- With the loss of one pump system or one power system, the remaining pump system should have the capacity to charge from pre-charge pressure to the rated pressure of the full accumulator system in less than 30 minutes;
- Each pumping system should be designed, independently of the other source and with the accumulators isolated from service, to close the annular preventer on the smallest drill pipe with correct sealing pressure and open the hydraulic choke valve in less than 2 minutes;
- Electric driven pumps should start automatically when pressure in the accumulator drops below 90% of the maximum operating pressure. Air driven pumps at 80% of maximum operating pressure; (API S53, 6.3.5.7)

- The same hydraulic pump system **could** be used to provide control fluid to BOP stack and diverter system;

### 3.2.8 BOP Activation Panel Locations

- For offshore and land operations, control panels shall be located both on the rig floor and at a safe location (a minimum of two independent control panels shall be in place);
- Each control panel shall clearly show “open” and “closed” positions on a visual display in line with the BOP stack installed. It shall be adequately protected against fluid splashes and dropped objects;
- A "Think first" flap should be set as a precaution over each BR or BSR push-button on each control panel;

### 3.2.9 Emergency Back-up Systems for BOP control system

- In case of an air supplied control panel an Emergency Air Supply shall be available ;
- An Emergency Electric Power Supply shall be available to operate the BOP control system, when of the electrical type, and should last for 24 hours. Electric power shall be supplied to all electric control panels. MBR Article 8.3.1.5;
- Any remotely operated valve or choke should be equipped with an emergency back-up power source or a manual override (API S53 6.2.2.20);

### 3.2.10 BOP Activation Mechanism Rules

The BOP control system should be capable of closing:

- A ram BOP within 30 seconds;
- An annular BOP smaller than 18 ¾ inches nominal bore within 30 seconds;
- An annular BOP of 18 ¾ inches nominal bore and larger within 45 seconds;
- Choke and kill valves (either open or close) in less than the minimum observed ram BOP closing response time;

The persons expected to respond in an emergency situation shall be suitably trained and participate in BOP activation tests.

### 3.2.11 BOP Control Lines

- All BOP control lines & cables should be protected and be fire resistant. Rigid piping or fire-resistant high-pressure flexible hoses with external steel wrapped protection (Coflexip type or equivalent) with a working pressure at least equal to the accumulator rating pressure should be used. The hoses should have an improved resistance to fire and an improved durability. Sharp bends on hoses should be avoided. The nominal diameter should be 1’’ minimum, so as to reduce pressure losses and consequently BOP functions closing time;
- For annular preventers a minimum diameter of 1.5” is recommended. Key is here that the annular preventer should close within 30 seconds. Ensure unrestricted flow;

- All rigid and flexible lines between the control system and the BOP should meet the fire test requirements of API 16D, including end connections. (700°C during 5 min) WP should be equal to the operating pressure of the control system (3.000 psi);
- All control system interconnecting piping and hoses should be protected from damage during operations;
- The various lines operating the BOP functions should be clearly identified;
- Maintenance and testing of control lines should be covered in the drilling contractors Planned Maintenance System (PMS);
- Upon initial installation of the BOP's on the well the full BOP control system manifold, hoses and BOP chambers should be pressure tested to 3000psi.
- The control system of the Annular Preventer should be tested up to a **reduced value** of 1500 to 2000 psi, depending on Manufacturer's specifications.

*Note: Quick connectors could be used on the control hoses, if they are of the fail-safe (open) type.*

## 3.3 Auxiliary Pressure Control Items

The auxiliary pressure equipment ranges from equipment to shut off the internal flow from the drill pipe to equipment handling the influx downstream of the choke manifold.

### 3.3.1 Inside BOP Systems

As part of the Top drive, there should be two IBOP safety valves:

- The remotely operated upper safety valve. This valve should be closed first if necessary;
- The manually operated lower safety valve. This valve allows installation of the circulating head or of the drop-in check valve in the drill string under pressure;
- Both the lower and upper IBOP valves should have as a minimum the same pressure rating as the BOP stack;

*Note: Equipment should be available on rig-floor to allow stripping operations in all hole sizes.*

### 3.3.2 Rig Floor Safety Valves

In case of kick event during tripping, it should be necessary to secure the drill string with a full-bore safety valve and it may be required to run back to bottom, possibly using the stripping method. In this case after having installed & closed the full-bore safety valve, a Gray valve non return-valve should be put on top of the safety valve and the full-bore opened again.

One drill pipe full opening safety valve (ex. Kelly valve) and one check valve (Gray valve) shall be permanently kept on the drill floor ready to be used and installed into the drill string.

They shall be stored at a specific safe spot on the rig floor, easily accessible, prepared with proper lifting handles for easy and rapid installation by the crew.

Rig floor safety valves should fit all sizes of drill pipes, HWDP and drill-collars in use.

All drill string safety valves should be pressure tested as follows:

- At BOP working pressure at rig acceptance and each time a new component is put into service;
- With the BOP's periodic 3 weekly pressure tests;

All drill string safety valves and HP pumping system components should be function tested each week.

It is recommended to have dedicated test subs and bench for testing the drill string safety valves.

#### 3.3.3 Mud Gas Separator

The MGS is designed to provide the effective separation of the mud and gas circulated from the well through the choke manifold, when evacuating a kick.

It is recommended to pay special attention to this equipment when selecting a rig, particularly for HP or HP/HT wells and in case there is expected a presence of $H_2S$. The design and specifications of such equipment should comply with API S53.

The contractor should supply operating performance and limitations of its MGS, the efficiency and performance of which are extremely dependent of their sizing and configuration.

The MGS **could** be vertical (the most popular is also called a "poor boy de-gasser"), cyclonic or horizontal.

Each drilling or work-over rig should be provided with an atmospheric Mud Gas Separator. Minimum requirements are:

- Adequate seal height;
- The MGS should be designed in such a way that the mud seal will not drain by itself;
- Adequate nominal pipe for gas vent line;
- A low range pressure gauge (0-20 psig) on the MGS with read-out at choke control panel;
- Compatibility requirements for $H_2S$;
- The MGS should be able to handle a large quantity of solids (or weighting materials). The design should minimize the risks of plugging, settling and erosion;
- The MGS should be sufficiently anchored in place and adequately braced to prevent movement of both the separator and lines;
- The main function of the siphon breaker is to avoid emptying the MGS into the active mud system. When a siphon breaker on the mud seal is required by design, it should not be tied up into the vent line;

Recommendations:

1. Have a “hotline” in place to safely refill and re-establish the liquid seal after a blow-through.
2. Install an inspection hatch on the MGS body.
3. Take measures to avoid internal corrosion.
4. Carry out yearly inspections, measuring wall thickness.

### 3.3.4 Vent line / Mud seal configuration

- Whatever the design, the operating pressure within the separator is determined by the gas pressure loss through the vent line.
- The head of fluid (mud seal) should at least have the capability to hold back this pressure in order to prevent any gas blow-through to the shaker room.
- Vent line should be routed to a safe place, for offshore rigs this **could** be to the crown block or overboard line. For onshore rigs carefully calculated vent locations should be determined.
- For pressure losses purpose, the vent line design should be as straight as possible with any bends as smooth as possible. There should not be any valves present in the line.
  Only rigid hard piping should be used.

### 3.3.5 Mechanical Type Degasser

- A mechanical type degasser should be used to remove entrained gas bubbles by vacuum extraction from the drilling fluid, that are too small to be removed by the poor boy degasser;
- The drilling fluid discharge line from the poor boy separator should be placed as closely as possible to the inlet of the mechanical type degasser;

# 4. Record Keeping WCE & Personnel

Since Well Control Equipment is of prime importance to assure the safe drilling of all wells, both Drilling Contractor and Operator should pay close attention to all aspects of the Well Control subject. Qualified personnel matter as much as equipment in this domain.

## 4.1 Certification & traceability

- All WCE should be manufactured by an OEM (Original Equipment Manufacturer) holding a valid API monogram;
- All individual WCE elements (from API connection to API connection) & replacement parts should consist of components manufactured by the same OEM FAT and SIT required ;
- For all WCE equipment a full history log (manufacturers record book) should be present on site; (Examples of WCE elements are: single or double ram preventers, annular preventers, gate valves, connectors, HP risers, double studded adaptors, etc...)
- It is the Operator's Drilling and Completion Supervisor's responsibility to periodically verify that the WCE log is available and up to date;

Original certification package (manufacturers record book) by the OEM (holding a valid API monogram) should contain:

- API manufacturing documentation;
- NACE certification including raw material traceability;
- Full traceability of WCE and spare parts;
- Re-certification package and inspection reports required after repair or change of equipment;
- Periodic inspection reports by OEM or OEM approved 3rd party;

This full history log should ensure that the manufacturer's BOP operating manual is adhered to and no non authorized alterations/modifications have been made.

## 4.2 Management of Change

- Any changes made to WCE elements should be in line with OEM specifications;
- Any modification to the functionality and operability of the BOP stack or the BOP control system should be performed with the formal agreement of the OEM;

## 4.3 Capability to know the position of Tool Joints

A space-out drawing for the BOP stack should be available at the driller's position complete with all distances from Kelly Bushing to the RAM positions and BOP test plug seat.

## 4.4 BOP Maintenance & Testing

All WCE shall be overhauled and tested by the OEM or an OEM approved 3rd party:

- Once every 5 years or sooner when indicated by OEM;
- In case of damage/failure (e.g. after stripping);

Such inspections and tests shall be duly recorded and documented.

All WCE should be covered by the drilling contractor Preventive Maintenance System, which should include as a minimum the following points:

- Dates of maintenance, technical reasons, spares part number, etc... should be recorded;
- A clean out and visual inspection of bag preventer packer, rams, ram cavities, make-up torque of flange and connectors and verification of pre-charge pressures in accumulators should be carried out prior to each well or during "between wells maintenance" when batch drilling;
- Storage conditions should adhere to the manufacturer's recommendations. Rubber goods **may** be damaged from exposure to high temperature and sun light;

The notion of redundancy for a BOP and its control system is complex. Therefore the following guide lines should be understood:

## 4.5 Functionality

The functionality of a BOP encompasses all ultimate functions to be performed by a BOP, i.e. closure of PR, BSR, Annular preventer, opening of HCR or kill and choke valves, etc.

For example, if a BOP is fitted with 3 PR instead of 2 PR, the 3rd PR **could** be considered as a supplemental PR and a loss of it would not impair the overall functionality of the BOP.

## 4.6 Operability

The operability is the ability of the control system to operate all BOP functions. Depending on the type of control system, there might be several means to operate a BOP function with the control system.

Any time during operations with a BOP, 100% functionality should be met. If a pressure test or a functional test fails (indicating that a specific function is lost), the operation should be stopped, the well secured and the well control equipment repaired, before continuation of the operation.

Daily system checks: It is normal operating practice to perform daily checks of control panel pressures and system fluid levels.

## 4.7 Function-testing of BOP

All WCE shall be function tested at the nominal control system WP to ensure their good working condition and the level of redundancy.

When performing a function test on a BOP, the control panel used, the opening and closing volumes (if a flow-meter is available) and response times of all tested functions shall be monitored and logged.

The exact BOP closing time for each function shall be recorded at the rig acceptance.

When in operation, all well control equipment (rams, bag preventer, remote and manual valves and chokes of BOP and choke manifold, IBOP valves) shall be function tested once a week.

Exception: where this is not possible due to operational circumstances the function test shall be done at first opportunity.

The main and remote control panels shall be used alternately.

When performing a pressure test, a function test is considered as having been performed.

## 4.8 Pressure Testing Procedures

A full pressure test (FAT) to 1.5 x working pressure should be performed in an OEM approved workshop after any over-haul or repair of the BOP.

Upon first installation on the well the BOPs shall be pressure tested to full working pressure or to maximum rated wellhead pressure. The annular preventer may be pressure tested to 70% of its full working pressure. This pressure could also be done on the stump except the lower connection.

All BOP functions should be fully pressure tested at least every 3 weeks to maximum anticipated wellhead pressure for the operations executed in the period until the next BOP test. For all tests the volume of test fluid should be carefully recorded.

In case of special circumstances the Mining Regulations offer the possibility to apply for exemption.

Following bonnet seal replacement or changing of rams in the field, the BOP stack should be tested to full working pressure or to maximum rated wellhead pressure.

A pressure test should be considered satisfactory if the recorded pressure has stabilized for 10 minutes at the pressure test value with a pressure drop of less than 5%, limited to 300 psi.

## 4.9 Programmed Maintenance System

The drilling contractors PMS should include the BOP maintenance sequence. PMS should be validated.

All primary and back-up systems should be included in the PMS. MBR Article 8.3.2.6.

A recordable history of repair and modification on safety and environmental critical elements (SECE’s) should be maintained.

Maintenance of SECE’s should be subject to annual audits.

Equipment malfunctions or failures should be reported in writing to the OEM.

Pressure gauges should be subject to annual calibration. Pressure gauges should bear a test date.

## 4.10 Training, Certification & Drills

The proficiency of drill crews to operate the well control equipment is as important as the operational condition of the equipment. Refer to API 59.

### Training:

IWCF BOP operating & maintenance training course (latest edition) should be obligatory for tool-pushers, tour-pushers, drillers and assistant drillers. (every 2 years)

Drilling Contractors should assure regular training for the rig crews on operation and maintenance of BOP systems.

It is recommended having personnel from assistant driller to senior tool-pusher to attend once every two years a scenario based well control training.

### Drills:

BOP shut in drills shall be held on a weekly basis and shall involve the persons expected to respond in an emergency situation. It shall involve each drill crew onboard.

Prior to drill out of the production casing a choke drill should be performed. Well control start-up and shut-in exercises should be done with some pressure applied in the well, up to a controlled closing of the Remote Operated Choke, keeping a pre-determined amount of pressure trapped. It is recommended to carry out this drill with each drill crew onboard.

# Annex I Drilling BOP Configurations

(Reference – IADC BOP Arrangement Considerations)

The primary purpose of a BOP is to be able to close in a well on a kick and subsequently to control bottom-hole pressure during the well killing process. So the BOP stack should be designed to contain the surface pressure of a well where the full mud volume has been evacuated. It also needs to be designed to provide large enough passage for all anticipated tool sizes.

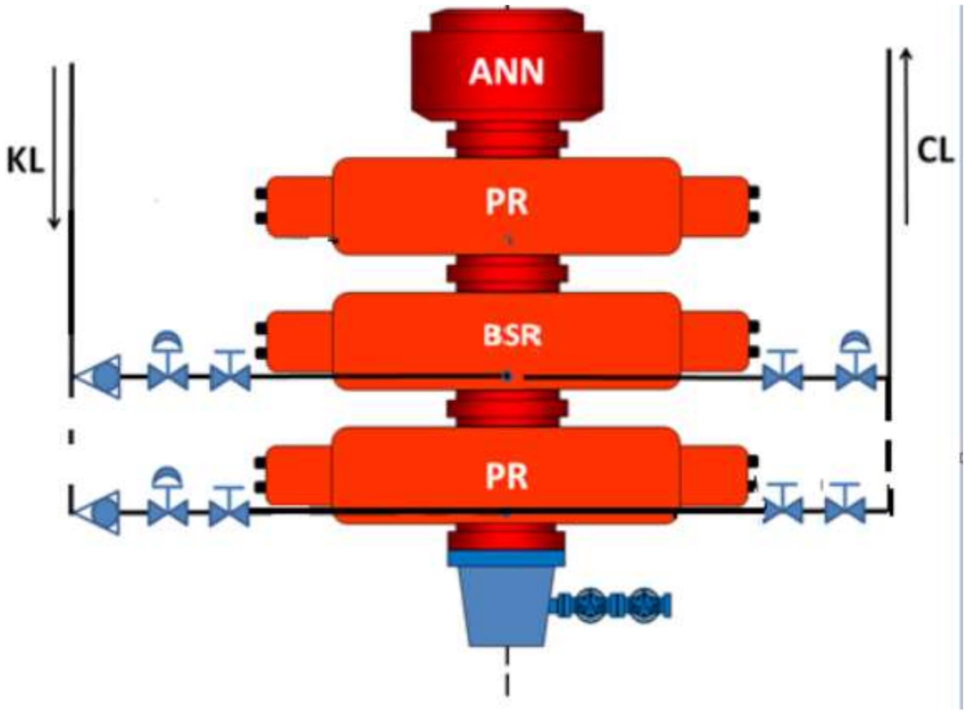
BOP Configurations are often determined by Company Policy and should also take into account any Regulatory Authority requirements. Other site specific considerations may include weight, size and flexibility.

There are no "best" standard stack arrangements, but the following configuration are most commonly used for surface installed BOP stacks in The Netherlands.

Of fundamental importance is the placement of the blind/shear rams in a 3 ram surface BOP stack. The acceptable positions of the blind/shear rams are:

- Either in the second position from the top, where the blind/shear rams can act as a master valve for the re-pair or change out of the pipe-rams above it;
- Or in the very top position, where the closed BSR seals off the full BOP stack;

"The final BOP Configuration is jointly selected by operator and drilling contractor. Best practice in The Netherlands is for the operator together with the drilling contractor to critically review the BOP arrangement and risk assess the configuration for the entire planned operation."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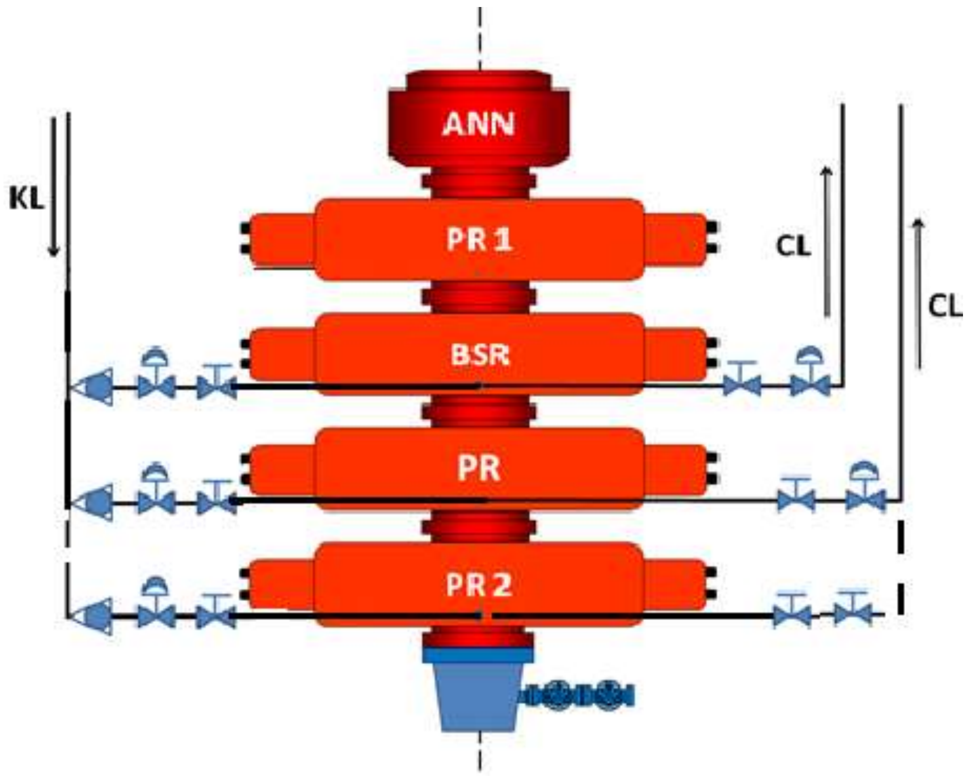
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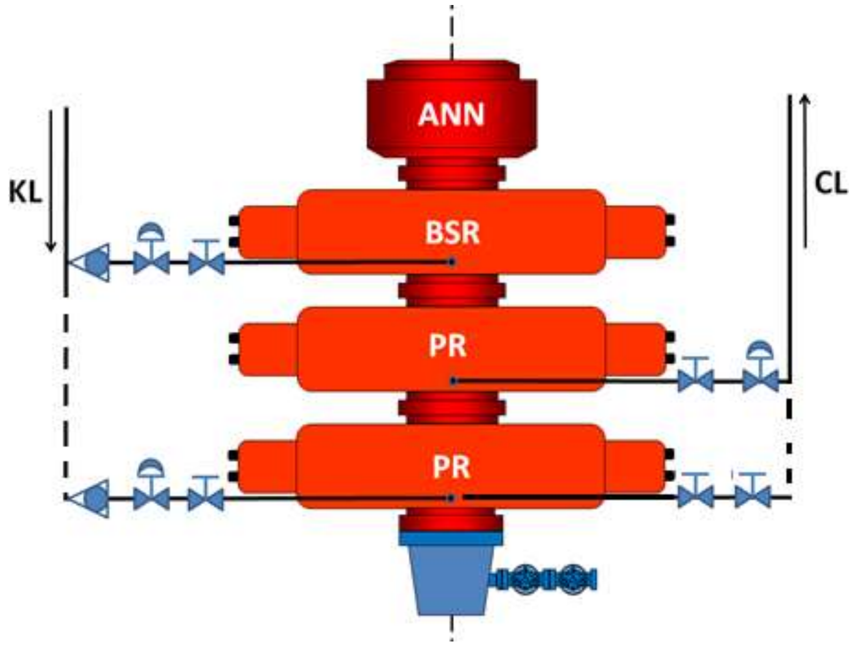
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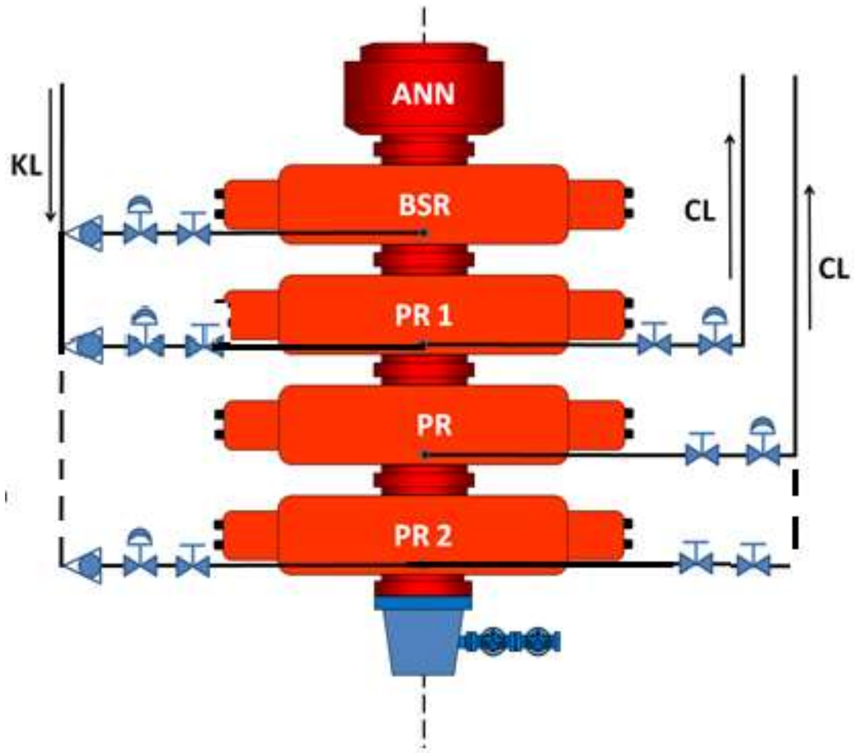
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