IWCF Review Questions from 2014

Shuttle Valves

- Isolate pressurized control fluid between pods
- Allow pulling pods without losing BOP control fluid

SPM valves only operate in the active pod

A read-back signal is sent to surface from downstream of the regulator in the pod after pressure has been supplied to a function

The Pilot System is a closed, dead end system

Pilot fluid = potable water, glycol, bactericide and corrosion inhibitors

Memory Function : Previous position of BOP function before being put into BLOCK

Master Control Valve on an air-operated remote BOP activates the **air** circuit

Proximity switches for the BOP remote panel lights are located on the accumulator

Maximum pressure for charging pumps to start (API RP 53) is when the accumulator pressure has decreased to 90 % of operating pressure

Manipulator Valves

- In BLOCK, pressure is vented from line previously pressured
- BLOCK position is used to troubleshoot hydraulic control lines
- Used as a Pod Selector Valve on subsea hydraulic control system
- Not installed inside pod hose reels

When changing pump speeds with Choke Line Friction

- Start Up – Allow casing pressure to drop by Choke Line Friction
- Stop – Allow casing pressure to increase by Choke Line Friction

Closing time for subsea BOPs

- Rams = 45 seconds
- Annular = 60 seconds

Maximum Allowable Pressure on annulus gauge when starting kill operation = MAASP – CLF

Never bleed off from the drill pipe.

Increases the risk of exceeding the MAASP during well control event

- Long open hole section
- Large volume influx
- Small difference between Formation Breakdown Pressure and Mud Hydrostatic Pressure

H2S $\rightarrow$ High pH

Reservoir Capacity (API RP 53) : 2 x Useable accumulator volume

Test BOP (API RP 53)

- After changing out BOP components
- After setting a casing string

Accumulator gauge problem -- Hydro-electric pressure switch issue
Manifold gauge problem -- Pressure regulator issue

Standpipe pressure is lower than pump pressure due to the hydrostatic pressure of the mud in the standpipe

Dynamic Pressure Loss = Slow Circulating Rate Pressure

Good operating practices while drilling top hole with shallow gas :

- Circulate while POOH
- Circulate while picking up to make a connection
- Drill a pilot hole
- Maintain mud weight as low as possible
- Drill with controlled ROP to prevent losses while drilling top hole,

Slow Circulating Rate Pressure considerations :

- Gas handling capacity of MGS

Mud-Gas Separator :

- Blow through – Unloading – Loss of mud seal – Mud leg
- Pressure build up – Vent line diameter and length
- Overload – Vent line diameter and length

Valve arrangement on drilling spool

- Inside = Manual
- Outside = Hydraulic

Maintain SIDPP constant to maintain constant Bottom Hole Pressure

Chokes are operated by **AIR** from the remote choke operating panel

Wait & Weight method provides lower pressure at the shoe if
Drill String Volume < Open Hole Volume

Monitor pit volume during a well kill operation to determine :

- Amount of gas expansion
- If lost circulation occurred

If a large surface line volume is not taken into account :

- Following the pressure schedule results in a Bottom Hole Pressure that is too low
- Total time to kill the well will be longer

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1) What must be true for barrier test charts and documents ?

Test document shall record test pressure and its duration.
Test document should record the type of test to be conducted.

2) When a well barrier element fails, according to API Spec 53

Tightening, repair or any other work can be done only after verification that all **pressures have been released**.
All parties must agree there is **no potential for trapped pressure**.

3) Calculate pressure safety margin at the shoe (MAASP – SICP)

4) Calculate initial dynamic casing pressure at the kill rate. (SICP – CLF)

5) What is the first action that should be taken after connecting the OPEN and CLOSE hydraulic lines to the stack?

Function test all items on the stack

6) What would the hydraulic pressure in the ram opening lines between the hydraulic BOP control unit and the BOP stack normally be while drilling?

1500 psi

7) A long series of electric logs will be carried out in a well with limited overbalance value. What is the safest action to perform?

The correct rams for the riser/lubricator are installed and pressure tested.

8) What is an advantages of having a weep hole on a ram type BOP?

To show that the **primary ram shaft seal** is leaking.

9) The following statements about annular BOPs are correct :

They will allow reciprocating or rotating of the drill string while maintaining a seal against well bore pressure.

They can require a variable hydraulic closing pressure according to the test to be carried out.

They are a means of secondary well control.

10) Cup type tester will be used

To test entire casing head, outlets and casing-to-wellhead seals

11) According to API Spec 53, the lower Kelly cock, upper Kelly cock, drill pipe safety valve and IBOP should be tested

Test to a pressure at least equal to the **maximum anticipated surface pressure**, but limited to the maximum rated pressure of the BOP stack in use.

12) According to API RP 59, the pressure that should be used to determine the rated working pressure of the ram-type BOP to be installed on the well is

The maximum anticipated surface pressure

13) Before running 7-inch casing with variable pipe rams (5 – 7 inch) already installed, it is not necessary to change over to 7-inch casing rams

14) The vacuum degasser should be used to remove gas from mud when Drilling and Circulating

24) Gauge Question : Pump rate is shown too high

Answer : Slow down the pump.

Following Question : What is next action

Answer : Close choke.

27) Poor cement job between 13-3/8” casing and 9-5/8” casing. Pressure observed in annulus between casing strings. What problems can develop ?

9-5/8 casing collapse; 13-3/8 casing burst; Breakdown of the formation at shoe

28) Calculate Initial Dynamic MAASP (MAASP – CLF)

29) Gauge Problem : Accumulator Pressure = 2,450 psi steady, Manifold Pressure = 2,450 psi, steady, Annular Pressure = 900 psi steady.

Problem : Leaking By-Pass valve

31) In a diverter operation, what is the weakest component in the system

Slip joint packer

IWCF Focus Questions

Always shear pipe with full system pressure (3,000 psi)

Minimum pressure allowed in accumulator bottles = 200 psi above recharge

Cameron Model D Annular Preventer

- Only annular preventer with weep hole
- Requires 1,500 psi to close
- Is not well bore pressure assist

CSO = Complete Shut Off

Weep hole on rams indicates the **rod shaft packing** is leaking

Pos-Lock – Only rams without self-feeding of elastomer function

Ring gasket compatible with 6 BX Flange = BX

Ring gaskets used with Face-to-Face flanges = BX

For the minimum closing pressure on a Hydril GL, connect secondary closing line to the closing chamber

For the minimum response time on a Hydril GL, connect the secondary closing line to the opening chamber

Most likely drill string position for swabbing - Off Bottom ~~At Shoe~~ ~~At BOP~~

Pit Gain is the only positive indicator of an influx in the horizontal section

The only time SICP can be read in a deviated well is when the influx moves into the vertical section of the well

There are no ABSOLUTES in IWCF well control. All or Never → False or No

Hydril MSP Diverter does not have a closing chamber

IWCF allows 70 psi over for drill pipe circulating pressure

Use **neoprene** element for **cold temperature** situations

Selector Valve has all middle positions blocked

Hydrates form in the choke

Inject methanol or glycol UPSTREAM of the choke to prevent hydrates

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1) The "emergency" ram shaft packing is leaking. What pressure can leak through ?

Well bore pressure

2) A well is 9,200 ft deep. The weight of the mud in the hole is 12.2 ppg. Before pulling out of the hole, a 20 bbl, 14.5 ppg heavy pill is pumped into the drill string followed by 10 bbl of 12.2 ppg mud. What is the difference in height between the fluid levels in the drill pipe and casing ?

3) While circulating a kick out of the well, a **washout** develops in the drill string. The choke is closed to compensate for the drop in drill pipe pressure. What is the effect on bottom hole pressure when the choke is closed ?

Increases

4) An influx is being circulated out of the well using the Driller's Method. ICP = 1,450 psi at 45 spm. The Driller increases the pump speed to 50 spm and the crill pipe pressure still reads 1,450 psi. What is the FIRST ACTION to take ?

Decrease the pump speed.

What is the SECOND ACTION to take ?

Close the choke

6) A semisubmersible is drilling surface hole with riser installed. Air gap = 80 ft. Water depth = 220 ft. RKB to Shoe = 600 ft. Sea water gradient = .44 psi/ft. Formation strength gradient = .641 psi/ft. What is the maximum allowable mud weight ?

a) 9.5 ppg
b) 9.2 ppg
c) 10.6 ppg
d) 12.3 ppg

How often should all operational components of the surface BOP stack equipment systems be functioned tested according to API RP 53 ?

At least once per week

What is the correct meaning of the terminology "primary seal" and "secondary seal" when used in connection with ram-type BOPs ?

Primary seal is the mechanical **ram shaft packing** alone. **Secondary** seal is **injected plastic packing** that activates an extra seal on the ram shaft in an emergency (if the primary seal is leaking).

Are all ram-type BOPs designed to open in a situation where rated working pressure is contained below the rams and the mud hydrostatic pressure to the flow line is above the rams (in a stripping situation) ?

No

Pressure required to shear 1" coiled tubing = 3,000 psi

The body of a 10,000 psi ram is tested to 15,000 psi.

According to API RP 53, when should the pre-charge be measured on the accumulator bottles for a surface BOP installation ?

Prior to installation of each BOP stack on each well.

Where is the suction of the vacuum degasser located ?

Downstream of the mud-gas separator

On a surface BOP stack, the hydraulic valves are **NOT** designed to close automatically if the hydraulic pressure in the hydraulic lines to the valves is lost.

What must be true for barrier test charts and documents ?

The test document and chart must be signed by an authorized person.
BOP test pressures must be recorded on a pressure chart.

What must you do if a well barrier element fails a pressure test ?

Document the problems with the BOP equipment and the **actions** you took to correct the problem.

How should the manually operated and hydraulically operated kill line valves on the BOP be pressure-tested ?

From the pump side, with the check valve removed (so that pressure can be bled) off and the kill line vented.

What is the purpose of an inflow test ?

To check there is no communication from the formation through the casing, liner lap or cement plug.

If the Driller activated the ram close function and observed that the manifold pressure immediately decreased to zero, what should be done to close the pipe rams as quickly as possible ?

Activate the by-pass function.

When the annular BOP is closed on a subsea BOP from the Driller's electric BOP panel, what indicators confirm that the function has been carried out ?

a. Flow meter runs then stops after the required volume of flow.
b. Annular pilot pressure decreases then increases.
c. Annular read-back pressure decreases then increases.
d. Accumulator pressure decreases then increases.
e. Lights change.

Why is a master control valve fitted to the remote BOP control panel on the rig floor ?

To ensure that all BOP functions are "two hand" operated from the Driller's remote panel.

Well Barrier Envelope = All well barriers in the well.

"Dynamic" means to Subtract Choke Line Friction Pressure.

BOP Tests per API :

Initial = To Full Rated Working Pressure
Subsequent = To Maximum Anticipated Surface Pressure

Pressure Safety Margin at the Shoe = MAASP – SICP

During gas migration, the increase in BHP is the mud left behind.

Hard Shut-In	Soft Shut-In
Close BOP	Open HCR
Open HCR	Close BOP
	Close Choke

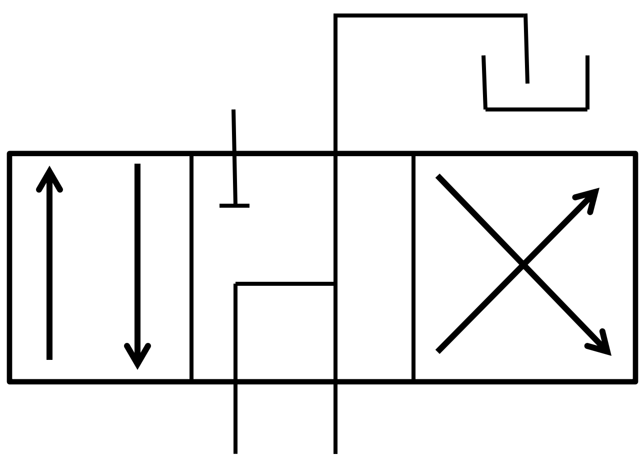
Tripping In ---- Displaced volume less than calculated ---- Losses

Dynamic drill pipe pressure = ICP

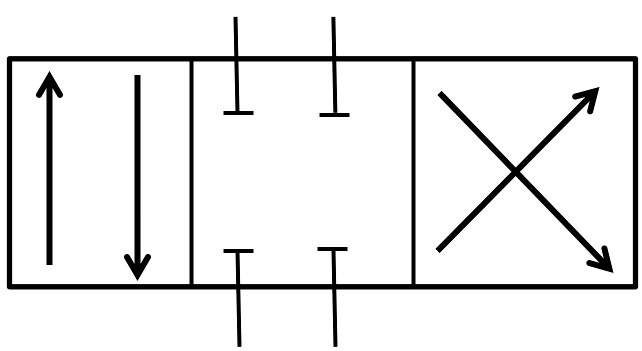
	Flanges	
	6 B	6 BX
Gaskets	R, RX	BX
	Gap	Face-to-Face
	5 K	10 K

With a saltwater kick, surface casing pressure is at its maximum value immediately after the well is shut in.

If pressures do not respond to opening the choke, this indicates a plugged choke.



3 Way, 4 Position Valve
Manipulator



3 Way, 4 Position Valve
Selector