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"Sharing To Be Better“

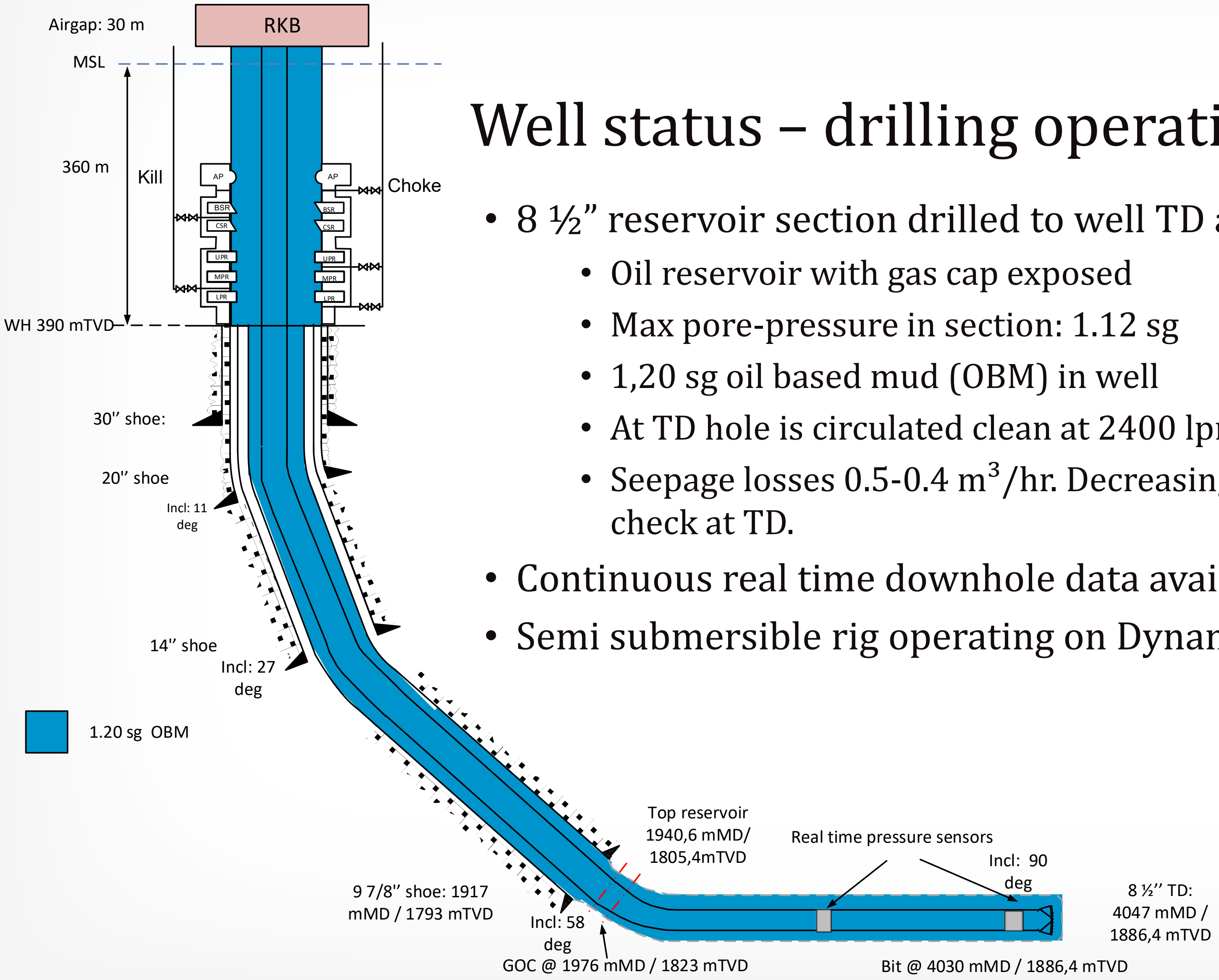
No 22

Serious (yellow) well control incident -

Influx during displacement operation

Well status – drilling operations

- 8 ½” reservoir section drilled to well TD at 4047 mMD
    - Oil reservoir with gas cap exposed
    - Max pore-pressure in section: 1.12 sg
    - 1,20 sg oil based mud (OBM) in well
    - At TD hole is circulated clean at 2400 lpm, ECD 1.53-1.54 sg.
    - Seepage losses 0.5-0.4 m^3/hr. Decreasing to 0.3 m^3/hr after prolonged flow-check at TD.
- Continuous real time downhole data available (wired drill pipe)
- Semi submersible rig operating on Dynamic Positioning (DP)



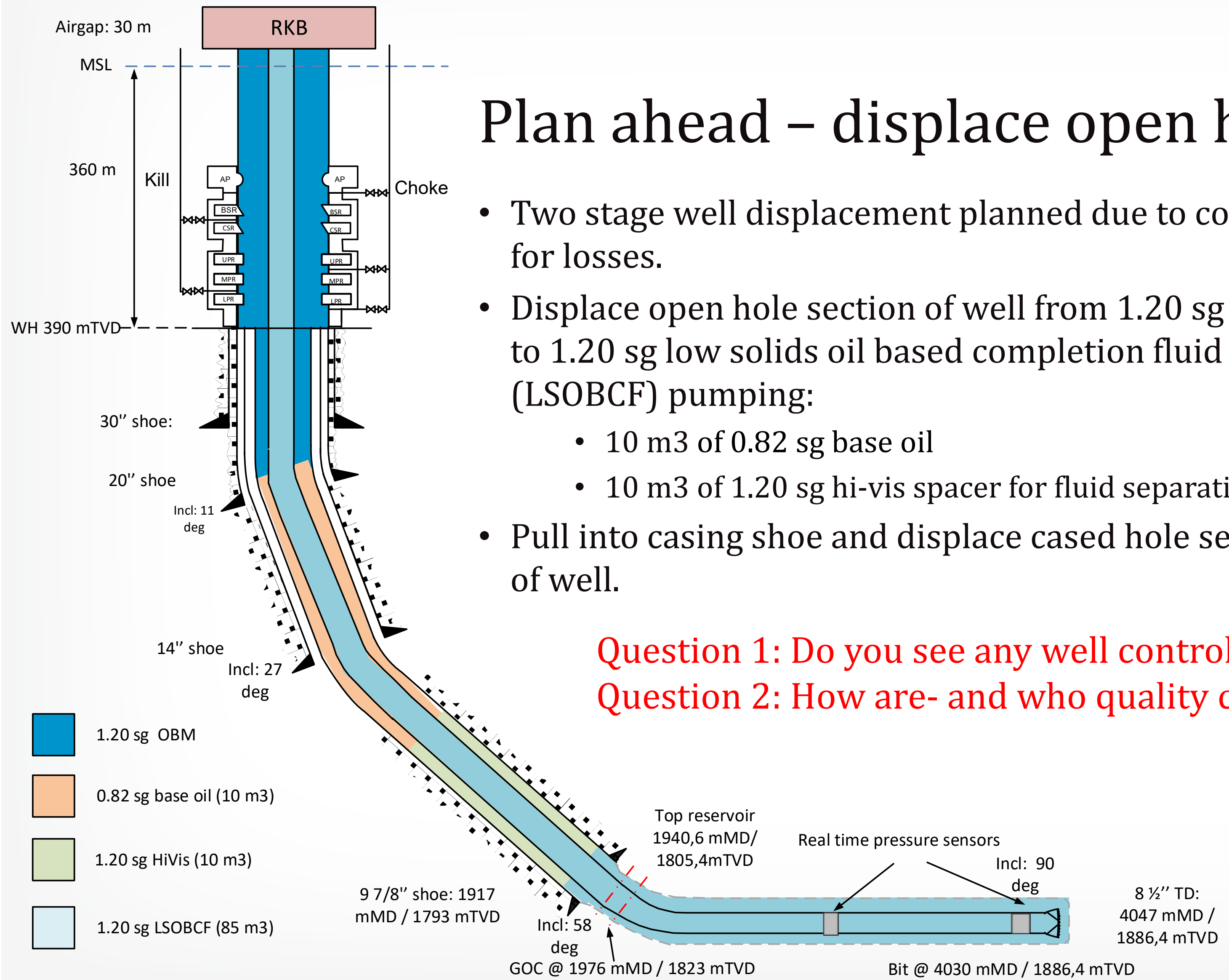
Plan ahead – displace open hole section

- Two stage well displacement planned due to concern for losses.
- Displace open hole section of well from 1.20 sg OBM to 1.20 sg low solids oil based completion fluid (LSOBCF) pumping:
  - 10 m3 of 0.82 sg base oil
  - 10 m3 of 1.20 sg hi-vis spacer for fluid separation.
- Pull into casing shoe and displace cased hole section of well.

Description from Detailed Operational Procedure (DOP)

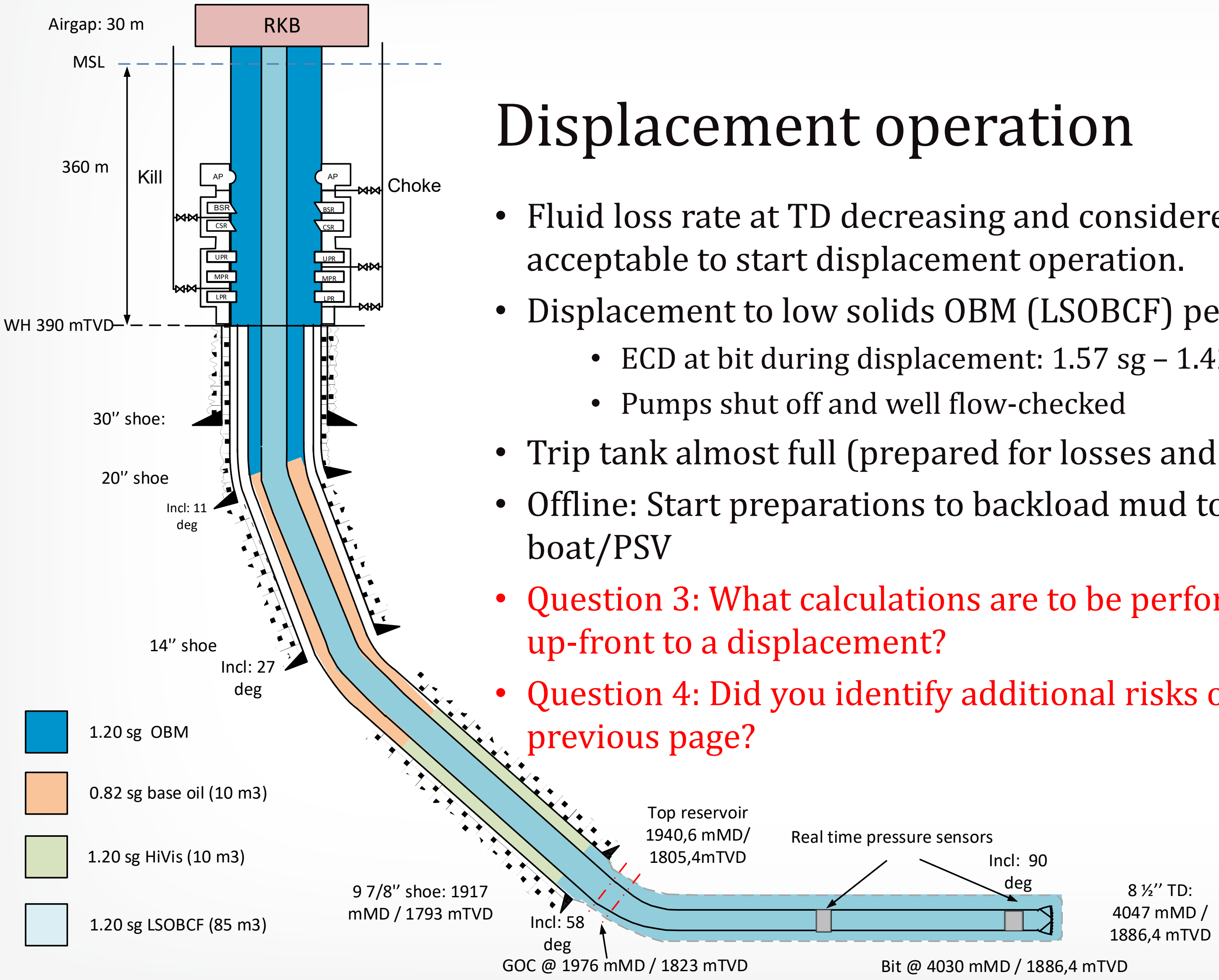
25. Displace OH to 1.20 sg LSOBCF according to mud engineer displacement program.
    - Stay within max ECD confirmed by XLOT
    - Expect rapid increase in ECD
      - Careful as 1.20 sg LSOBCF enters open hole with bit on bottom
    - Pump total of 1x OH volume + 10 %

Question 1: Do you see any well control risks with the planned operations?
Question 2: How are- and who quality checks the displacement plans?



Displacement operation

- Fluid loss rate at TD decreasing and considered acceptable to start displacement operation.
- Displacement to low solids OBM (LSOBCF) performed
  - ECD at bit during displacement: 1.57 sg – 1.42 sg
  - Pumps shut off and well flow-checked
- Trip tank almost full (prepared for losses and POOH)
- Offline: Start preparations to backload mud to boat/PSV
- Question 3: What calculations are to be performed up-front to a displacement?
- Question 4: Did you identify additional risks on previous page?



Communicated well control risks:

HSE
- Losses
  - High ECD during drilling
  - High ECD during displacement to LSOBCF (rheology)

Risk and mitigation:
- Losses
  - High ECD while exiting shoe
  - XLOT performed

Risk and mitigation:
- Unable to stay within reservoir
  - reactively geosteer based on LWD
- Loss of data transfer
- Risk of losses
  1. Reduce MW, minimum 1.14 sg (no riser margin)
  2. If unable to cure losses, LCM is available on the rig

5.0-05 WI-PB	Losses while drilling 8 1/2" section	• Drilling through fault • High MW/ECD	HSE: • Loss of primary barrier TC: • Cement and redrill

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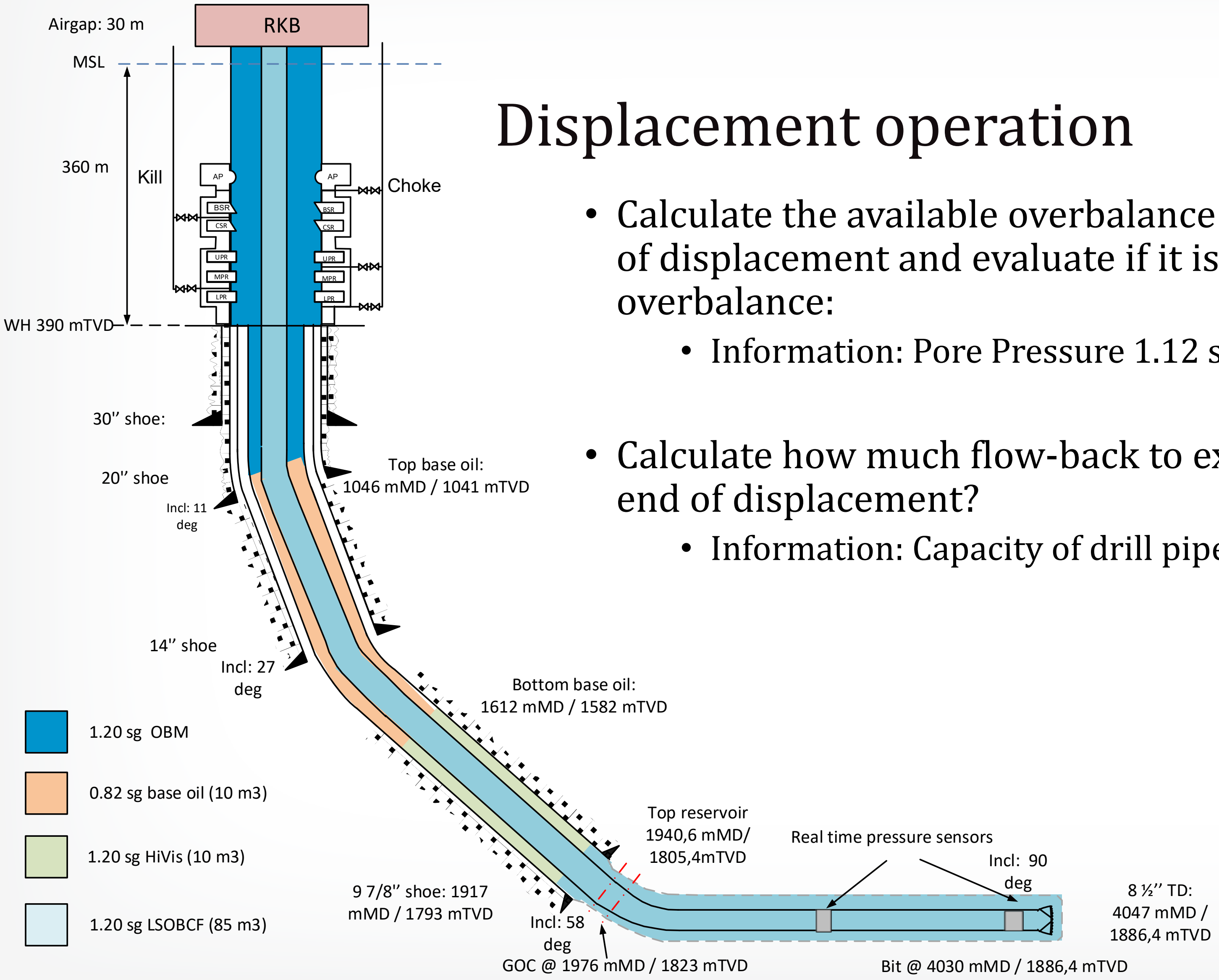
Displacement operation

- Calculate the available overbalance towards the reservoir at end of displacement and evaluate if it is sufficient to maintain overbalance:
    - Information: Pore Pressure 1.12 sg EMW

- Calculate how much flow-back to expect due to u-tube pressure at end of displacement?
    - Information: Capacity of drill pipe 12.9 l/m

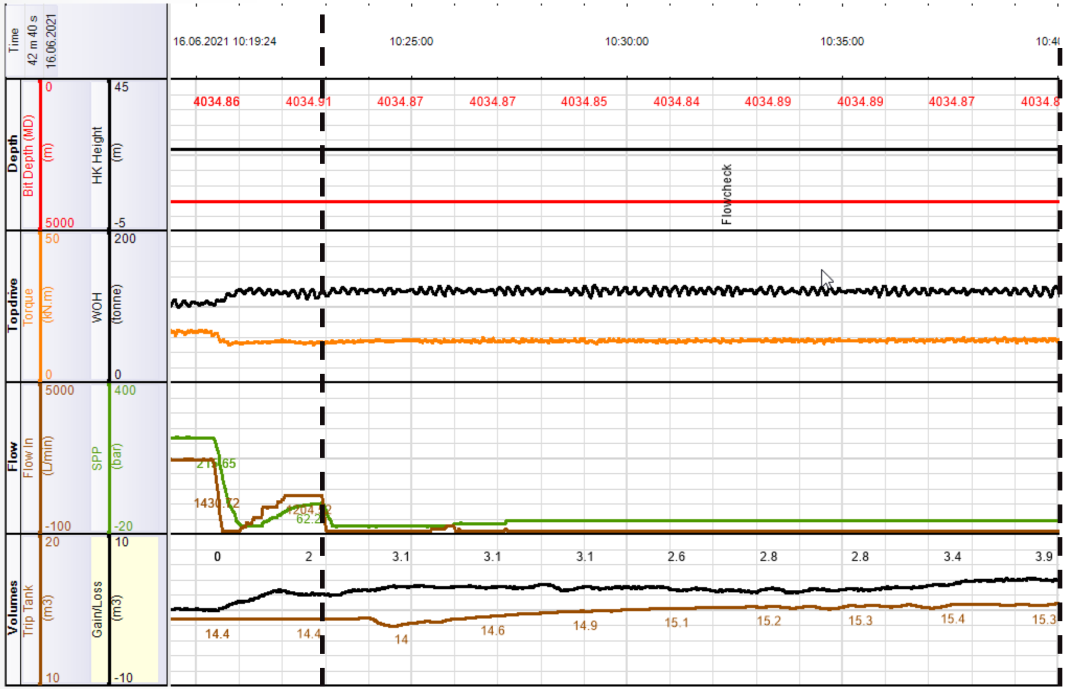


Flow check after displacement 1/4

10:23 Pump shut-off – line over to TT.

10:23 - 10:30
Flow back due to u-tube pressure

10:30 – 10:40
Flow-checking well



The theoretical backflow due to u-tube pressure is 2.2 m3 (not known/calculated prior to flow-check by crew).

Be aware that the trip tank was not lined up immediately.

- Question 5: Is the flowback due to u-tube as expected?
- Question 6: Good flow-check or would you have extended it?

Flow check after displacement 2/4

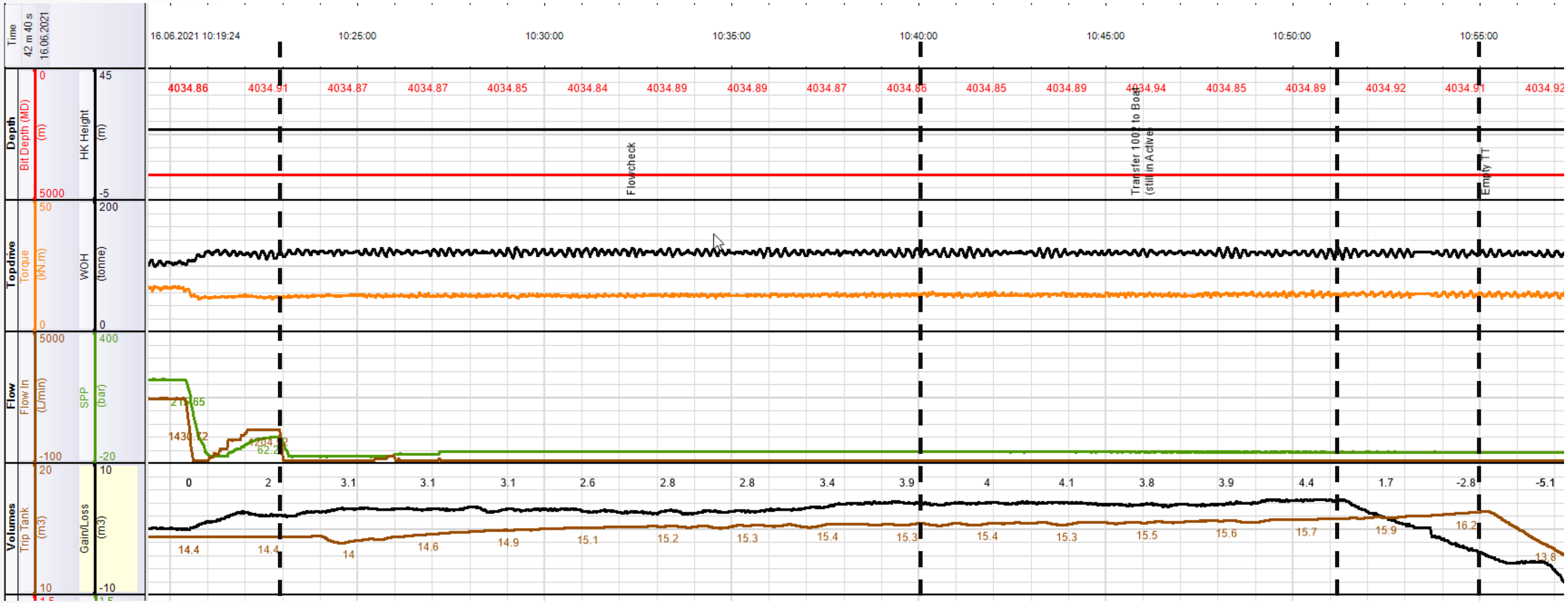
10:23 Pump shut-off – line over to TT.

10:23 - 10:30
Flow back due to u-tube pressure

10:30 – 10:40
Flow-checking well

10:51: Start off-load mud to boat / PSV

10:55: Decision to empty trip tank as it was close to full



- Question 7: What would you do if trip-tank was close to full in this scenario?
    - Empty TT, line over to 2nd TT (if available) or other?
- Question 8: What improvements to volume control do you see during the flow-check?

Flow check after displacement 3/4

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10:23 Pump shut-off – line over to TT.

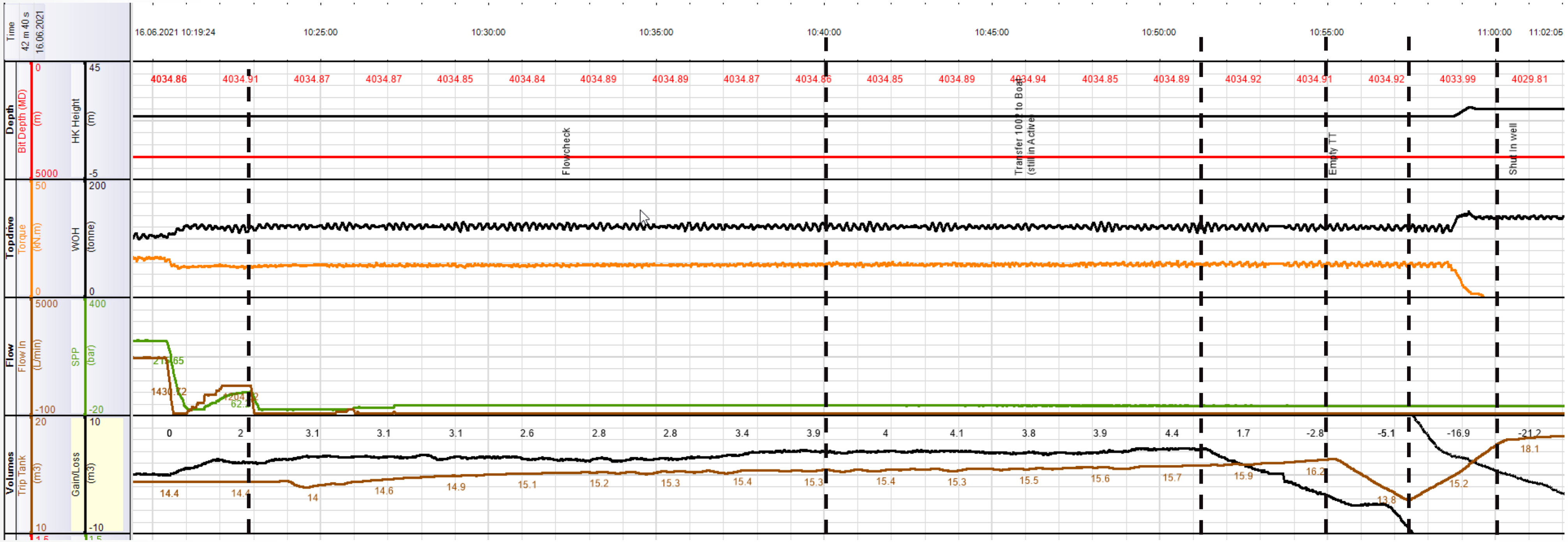
10:23 - 10:30
Flow back due to u-tube pressure

10:30 – 10:40
Flow-checking well

10:51: Start off-load mud to boat / PSV.

10:55: Need to empty trip tank as it is close to full

10:57: Back on trip-tank
11:00: Well shut-in on annular



- Prior to start emptying the trip tank the flowback from well was ~ 135 liters/min.
    - After spending just over 2 minutes to empty TT, the flowback rate had increased to 2100 liters/min.
- Question 9: What has happened?

Flow check after displacement 4/4

10:23 Pump shut-off – line over to TT.

10:23 - 10:30 Flow back due to u-tube pressure

10:30 – 10:40 Flow-checking well

10:51: Start off-load mud to boat / PSV.

10:55: Need to empty trip tank as it is close to full

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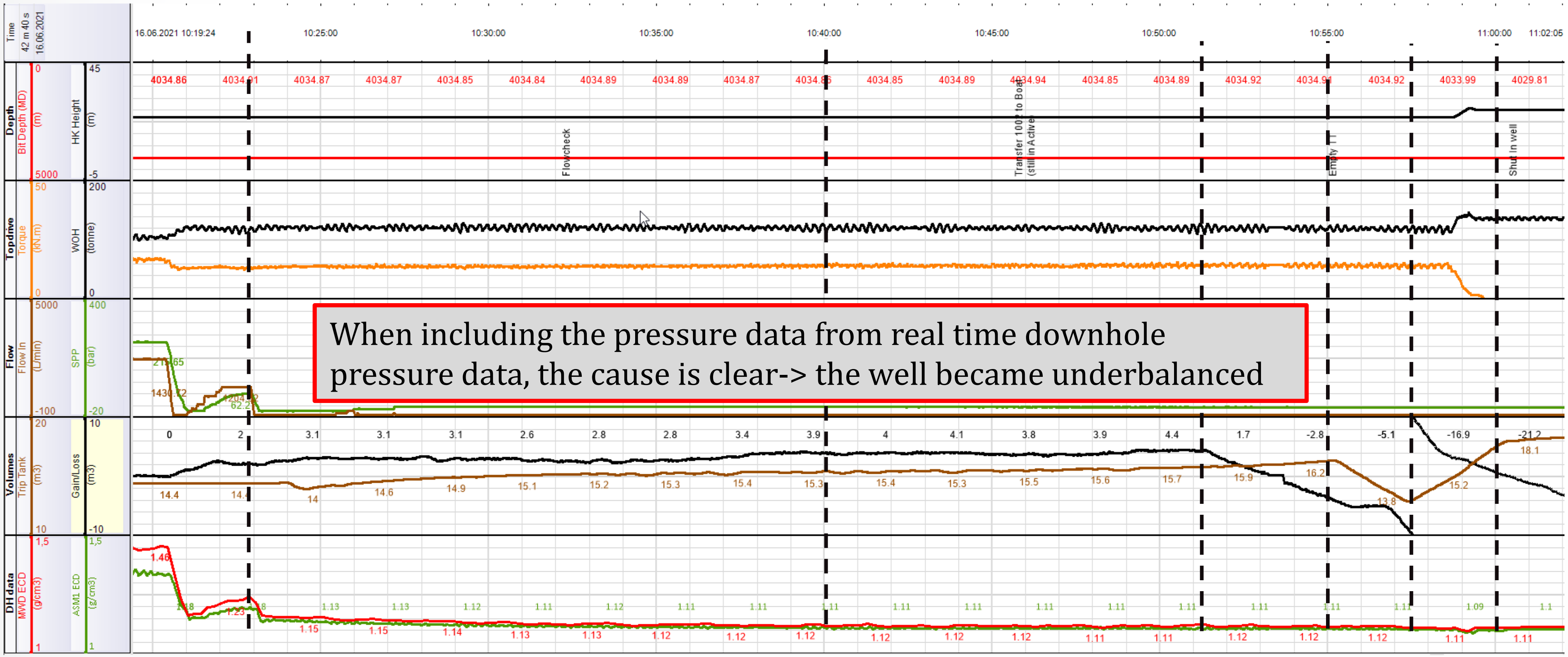


When including the pressure data from real time downhole pressure data, the cause is clear-> the well became underbalanced

Pore pressure 1,12 sg

- Question 10: How do you ensure that all available data from the well are being used?
- Question 11: How to avoid becoming complacent towards sufficient overbalance in upcoming plans?

Kick behaviour 1/2

- Question 12: How much safety margin/time left to shut-in well before hydrocarbons could have been above BOP and inside marine riser?
  - Measured kick-size: 8,7 m^3
  - Annular volume from top reservoir to BOP: 30 m3

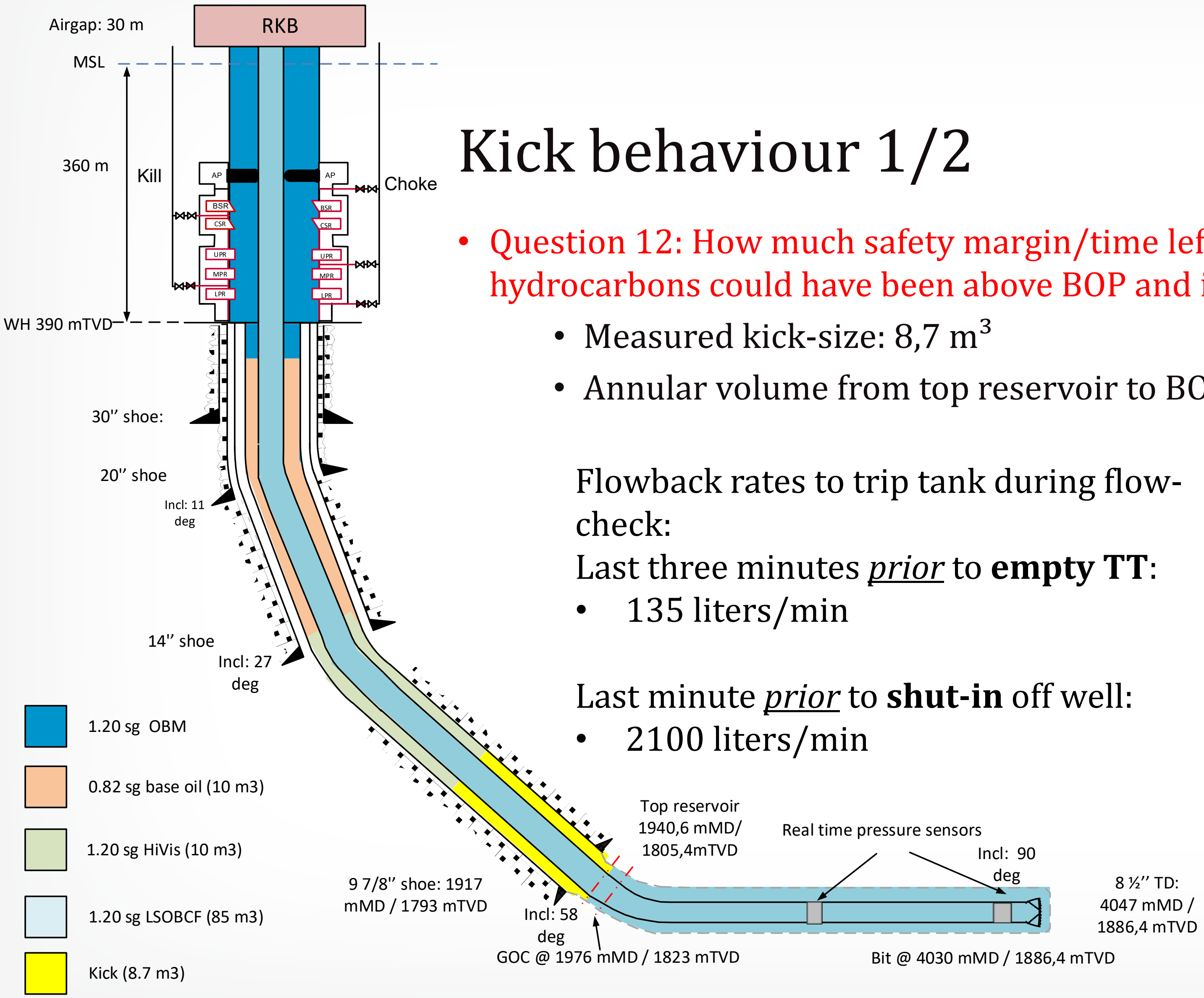
Flowback rates to trip tank during flow-check:

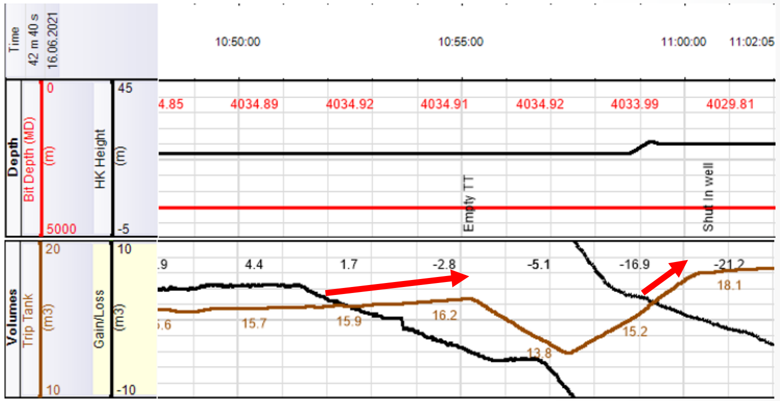
Last three minutes *prior* to **empty TT**:

- 135 liters/min

Last minute *prior* to **shut-in** off well:

- 2100 liters/min





Kick behaviour 2/2

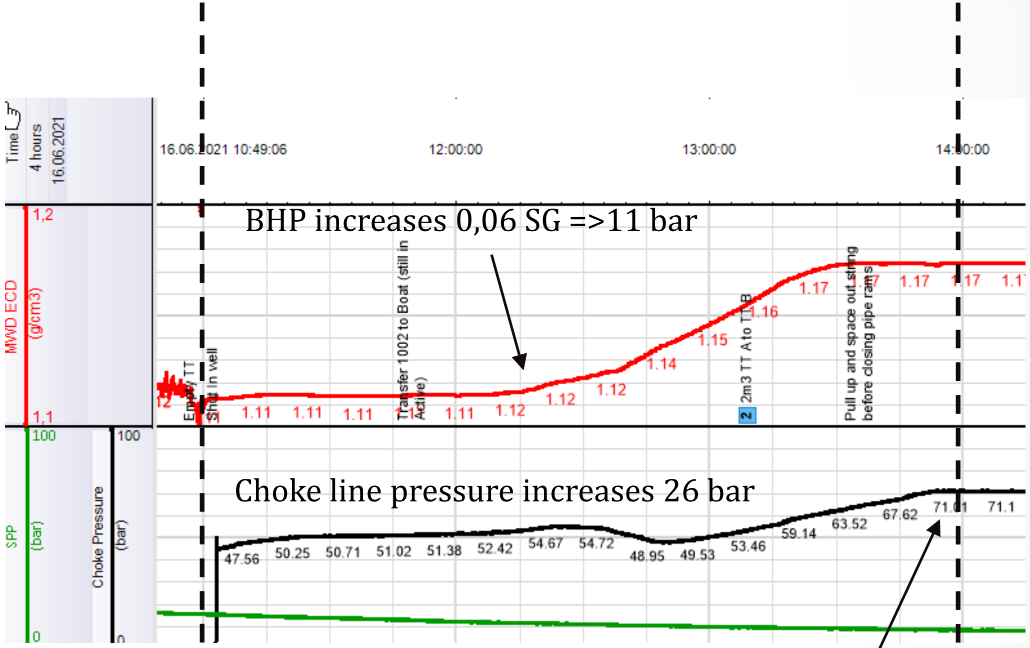
- Based on last observed rate of influx the safety margin for hydrocarbons above BOP was “maximum” 10 minutes, probably lower due to increasing kick-intensity.

- Question 13: Why do the BHP and choke/kill line pressures increase before stabilizing ~3 hrs after well was shut-in?
  - Shut-in casing pressure: 45 bar
  - MAASP: 114 bar (w/1.20 sg mud)

- Question 14: Can you estimate the density of the influx?
  - Choke/kill line length: 390 m,
  - Total volume in kill/choke line 5 m3, i.e. less than kick-volume.

11:00: Well shut-in on annular

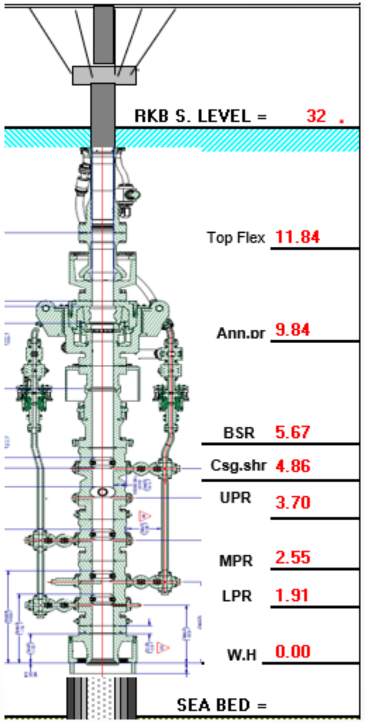
14:00: Pressures stabilized



Stabilized pressure at choke/kill: 71 bar
Stabilized pressure at wellhead: 78 bar

Space out considerations

- At initial shut-in, the space-out of drill pipe tool joint was positioned for successful seal with annular preventer.
- When evaluating contingency plans it was identified that the tool joint was located 0,5 m above casing shear ram.
  - 5 7/8" tool joint not available/included in BOP shear-matrix
  - Indications of it being shearable when compared to similar OD tool joints.
- Question 15: Would you proceed with the kill operation with this knowledge/space out?



Normalisation and handling the influx

- Large volume of gas kick taken into well.
  - Gas continued to migrate up well and up choke/kill lines after well shut-in.
  - Based on differences in surface kill/choke and subsea wellhead pressures the calculated influx-density is 0.18 sg EMW.

- Drillers method 1st circulation chosen to circulate the influx out of well
  - It was decided to strip up pipe to increase safety distance from tool joint to casing shear ram prior to kill operation, but this improvement was done 5 hrs after shut-in.
  - Choke operator used the surface choke pressure reading as primary gauge when circulating (as pr. normal procedures).
  - Real time downhole pressure data was monitored and made available to choke operator as supporting data.
  - Question16: How would you have utilized the real time downhole data when circulating out a kick?

- Onshore well control response team mobilized to support offshore operations.
  - 24 hrs rotation established.

Learning and recommendations

Risk management, Management of Change (MoC) and organizational factors:

- Ensure proper QA/QC and compliance with MoC process.
    - Introduction of base oil was not part of Design of Service, unknown to key leading personnel and not discussed in Detailed Operational procedure (DOP) review.
- Include volumes and specify densities to be pumped in DOP.

Team and human factors:

- All communicated and experienced risks was related to losses. Potential information bias resulting in delaying the shut-in of the well -> lower threshold for shutting in well.
- Enable crew to utilize downhole pressure data when available.
    - Clarify the responsibilities and increase awareness of wired drill pipe data to strengthen operational barrier elements.

Well control

- Always calculate flow-back from u-tube and avoid flow-checking on full trip tank.
- Space out considerations