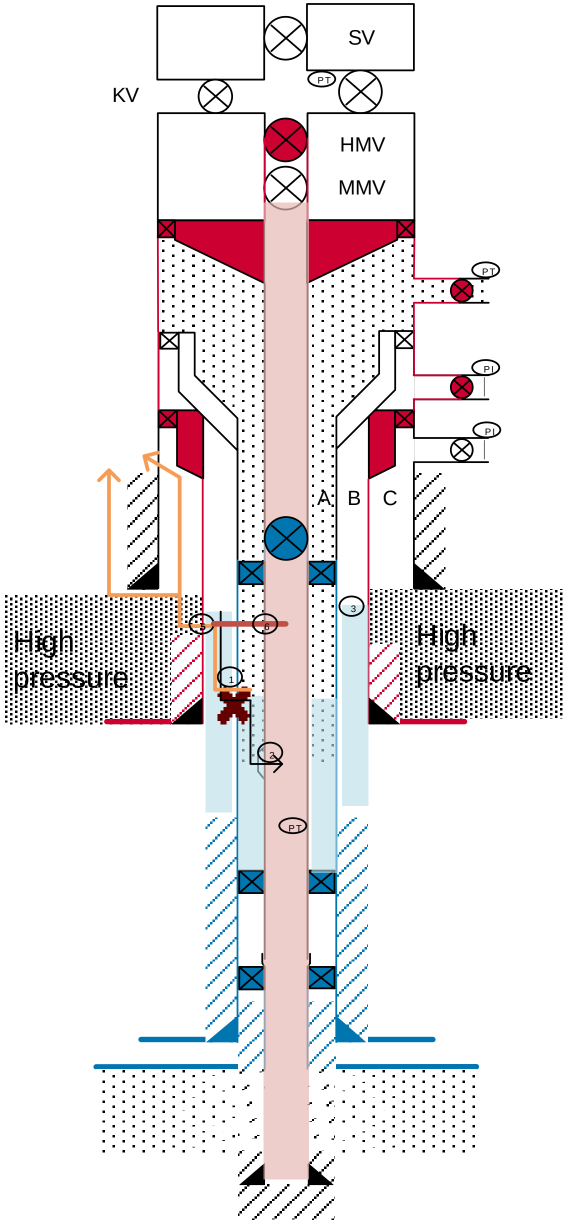
Collapse risk in gas lift wells

Offshore Norge Well Integrity Seminar 1st of October 2024

Collapse risk in gas lifted wells

- **Initial event: leak occurring in production casing (leak in primary gaslift and well barrier)**
- Drainage of liquid column leads to reduced pressure inside intermediate csg string
- Pore pressure and formations stress loads acting outside intermediate casing
  - Possibly exceedance of collapse pressure rating in part of intermediate string if not designed for vacuum in B-annulus
- RISK: A collapse of intermediate casing may result in
  - leakage of intermediate casing and subsequent failure of gas lift barriers
    - Release of gas lift gas on outside of well
  - Point load on production csg and tubing causing failure of well barriers
    - Release of gaslift gas and thereafter blowout on outside of well

Lack of independent barriers



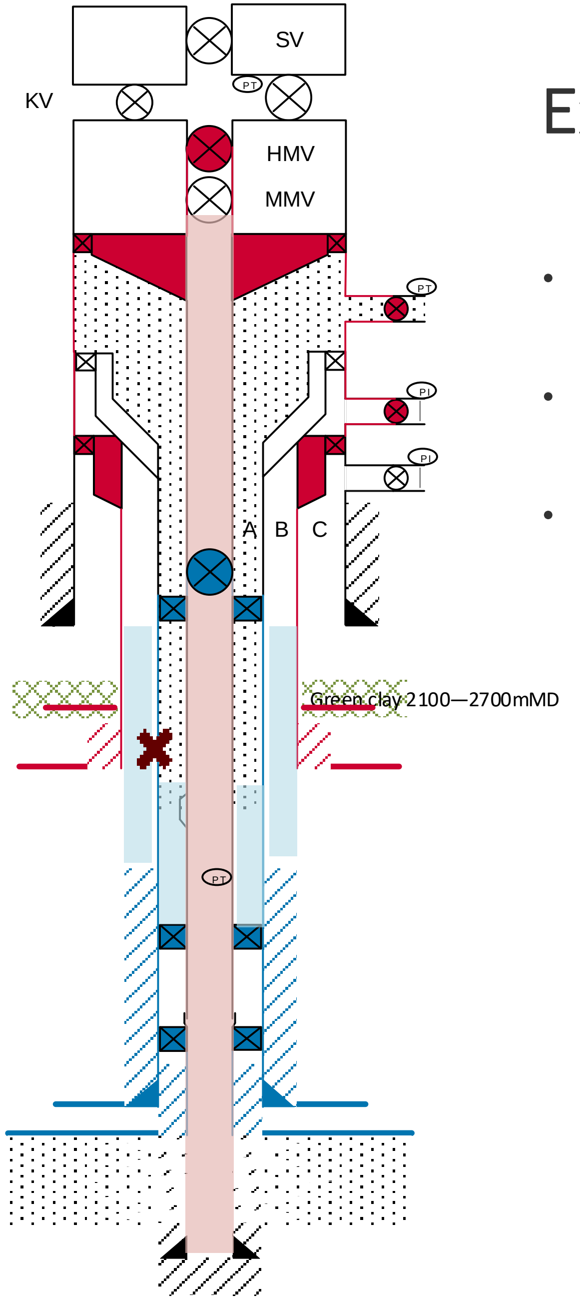
Open

NORSOK D-010 - some relevant well barrier selection and construction principles (chapter 5.2.3.2)

The well barrier envelope shall consist of qualified WBEs, and be designed and constructed with the capability to:

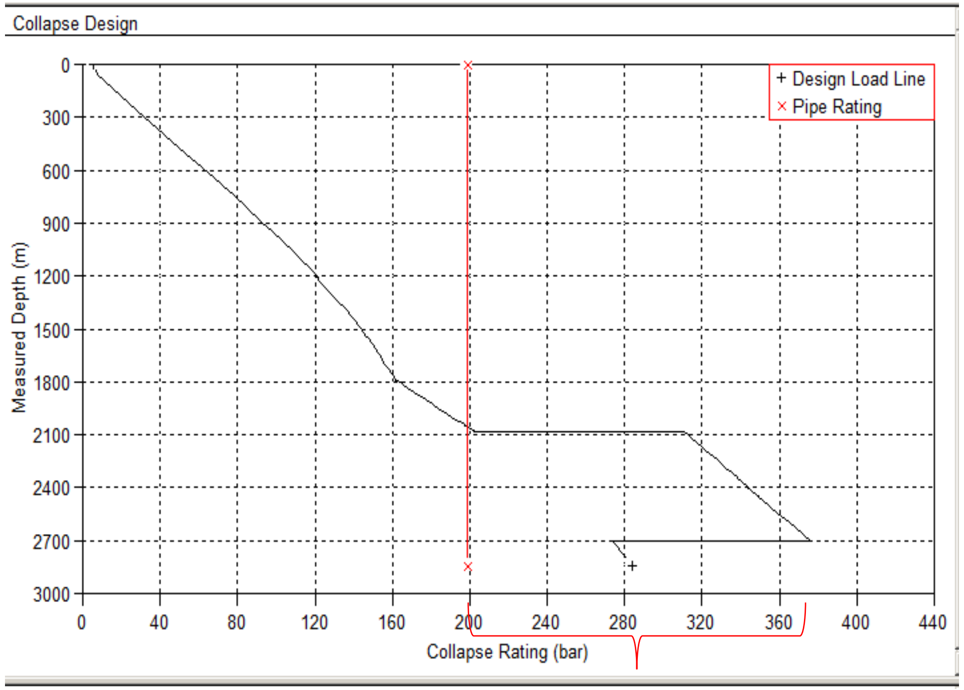
- a) withstand the maximum differential pressure and temperature it can be exposed to (accounting for depletion or injection regimes in adjacent wells);
- c) ensure that no single failure of a well barrier or WBE can lead to uncontrolled release of formation fluids and well fluids throughout the life cycle of a well;
- f) be independent of other well barrier envelopes and avoid having common WBEs to the extent possible.

This means in practical terms that intermediate casing in gas lifted wells should consider external pressure such as pore pressure from formation and loads from creeping formation into casing with full internal evacuation



Example well

- Collapsed/creeping green clay observed. 13 3/8» casing ovalized and appr 28% wall loss observed on log before side-track
- Loads from green clay may cause collapse of 13 3/8» casing once dP above casing in green clay area becomes too high
- Wellcat simulations showed that dP becomes too high once liquid level in B-annulus drops below 250m (casing wear not accounted for)

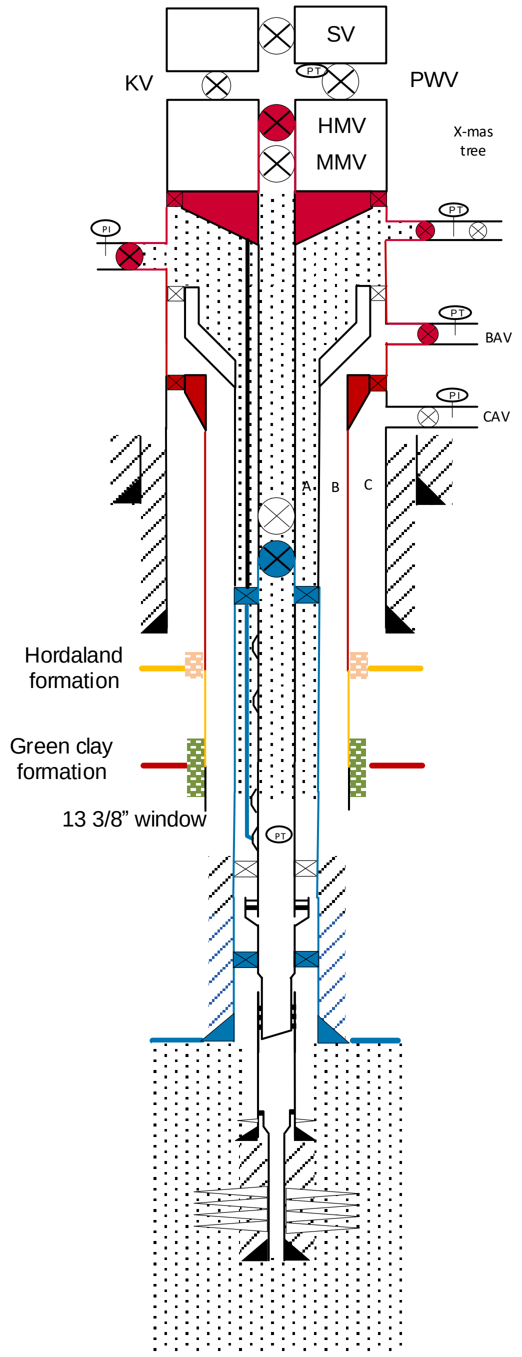


Fully evacuated B-annulus – loads exceeded with 180 bar, not accounted for wall loss

Solution

- Log identified other isolating formation above green clay (Hordaland)
  - Dilemma: Needed to include formation loads also for these formations
    - Only green clay had been included in original simulation, but experience show collapsed formation up to surface casing shoe which needed to be included as loads

  - Able to identify isolating formation not exceeding collapse load under evacuated B-annulus and redefine well barriers above potential collapse areas with evacuated B-annulus



Work scope:

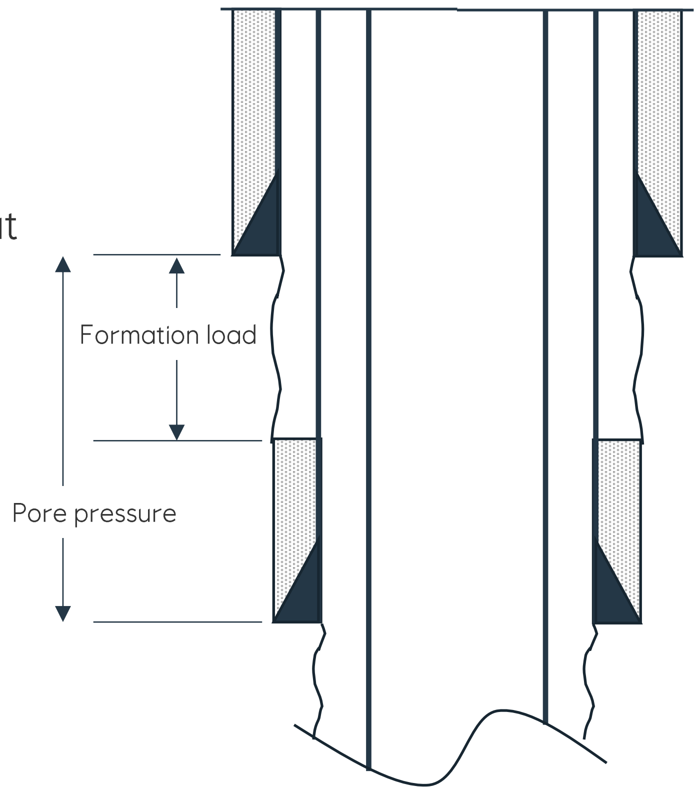
1. Collect information and evaluate well design for the identified wells
2. Propose specific acceptance criteria approved in relevant disciplines
3. Well specific evaluation of well design and barriers
4. If needed:
   - Propose compensating measures for monitoring and control of liquid level / pressure in annulus for each well
   - Assist with documentation for dispensations
     - Status / facts
     - Compensating measures

Screening of wells

Screening of intermediate casing's collapse capacity vs pore pressure and formation loads was performed for gas lift wells in operation

The wells were divided in the following categories:

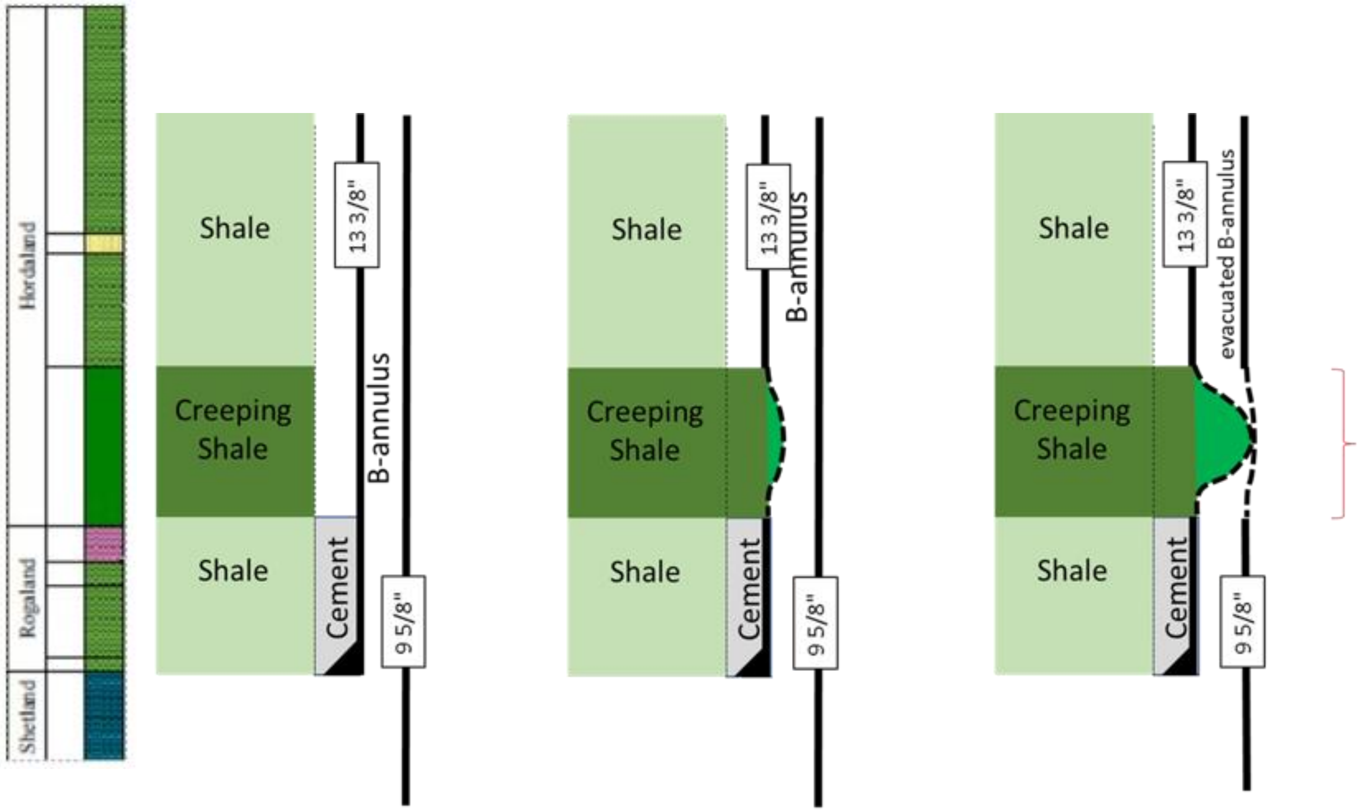
- wells according to requirements - OK
- wells only failing on formation load
- wells fail to fulfill minimum collapse design factor of 1.1 against pore pressure, but design factor is greater than 1.0
    - Casing wear not yet considered
- Plugged wells or A-annulus liquid filled - OK
- **Wells failing on pore pressure (design factor < 1.0)**



Learning:

In general wells with 13 5/8" or 14" intermediate casing were OK

Problem description for creeping formation – Initial hypothesis



1.
Initial state after well construction

2.
Production phase with creeping shale bonding to 13 3/8" casing

3.
Production phase – evacuated B-annulus

Area with creeping formation

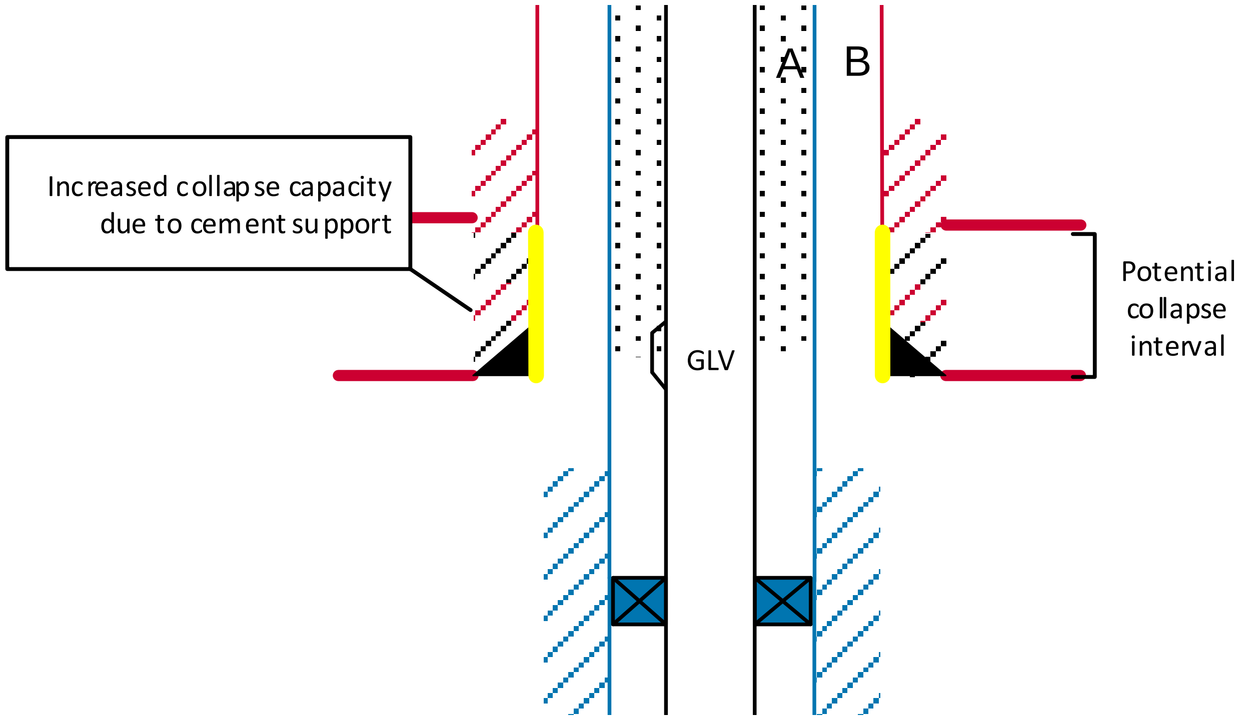
Conclusion from independent formation creep studies

- Formation creep will be almost uniform during the creeping process, such that the gap between casing and formation is small enough to give sufficient support when formation is contacting casing on other side
- Significant increased casing collapse capacity (appr twice capacity) in areas where either formation or casing cement supports casing
- Pore pressure will be the dominant load (after barite has settled out of mud), not formation load

Wells only failing on formation load now concluded as OK

Cement and formation barrier assessment used to identify wells with either:

- Good casing cement and sufficient sigma min shallower than potential collapse area
- Barrier qualified formation bonding above potential collapse area
- Good casing cement or formation bond increasing collapse capacity in area with potential collapse



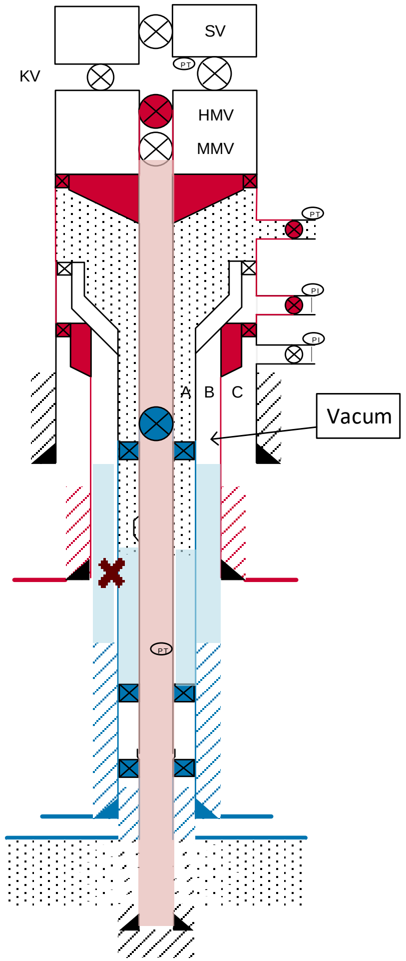
B-annulus drainage behavior and calculation results

- **Worst case dP above casing occur during drainage phase of B-annulus** (before gas is entering B-annulus)
  - Provided A-annulus is not bled further down after drainage phase

Developed calculator to calculate the **minimum A-annulus WH pressure needed** to avoid critical drainage of B-annulus or too low B-annulus support pressure

Measure for wells where a casing collapse may cause failure of both barriers:

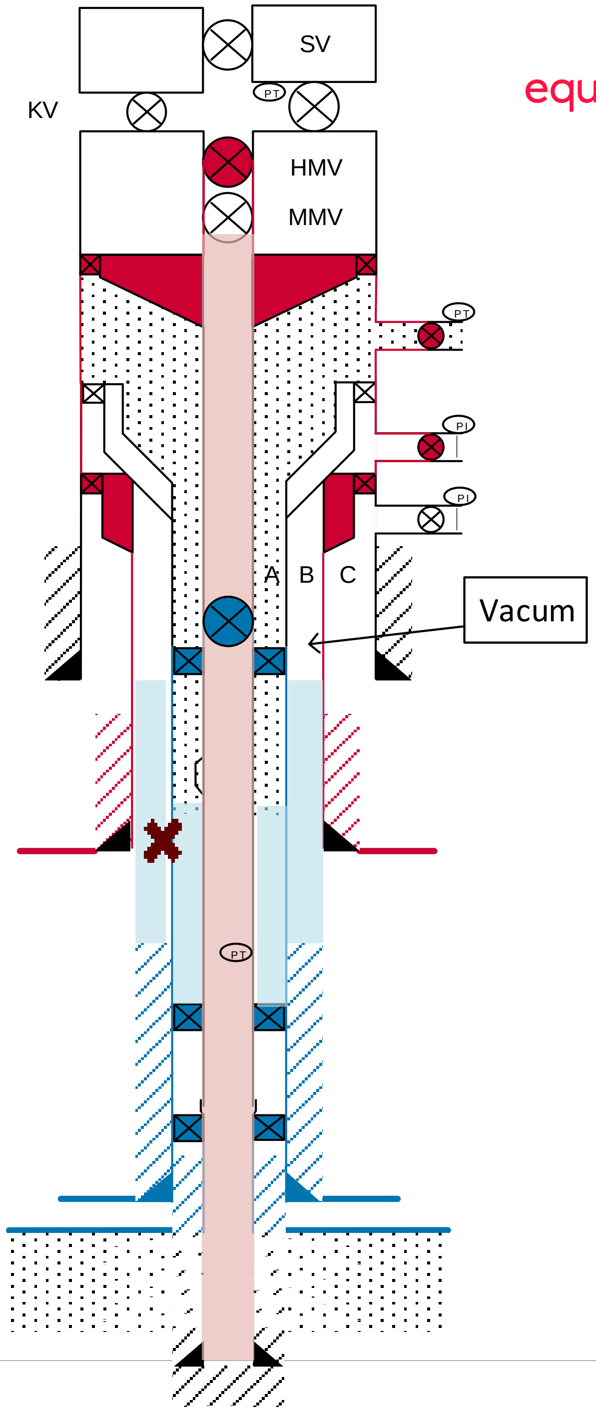
- Keep A-annulus pressure sufficiently higher than the calculated A-annulus limit to eliminate casing collapse risk



Exercise

- How can we assure that the needed A-annulus pressure is always maintained high enough?

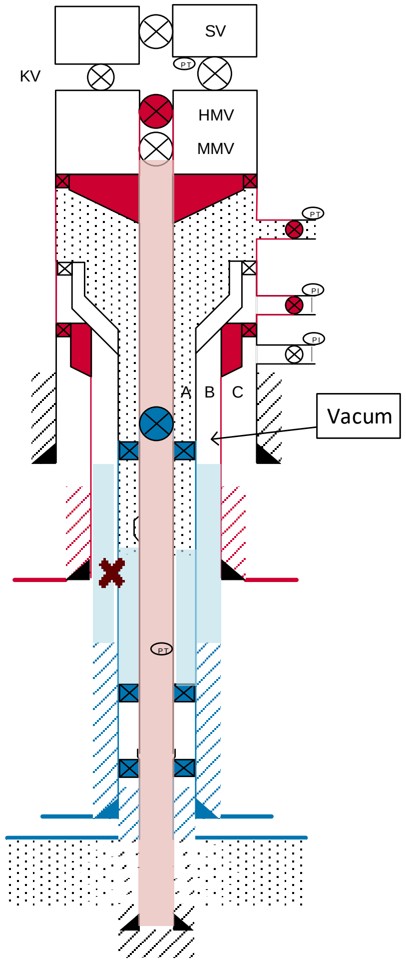
- What measures would you suggest to implement?



How to always maintain sufficiently high A-annulus pressure

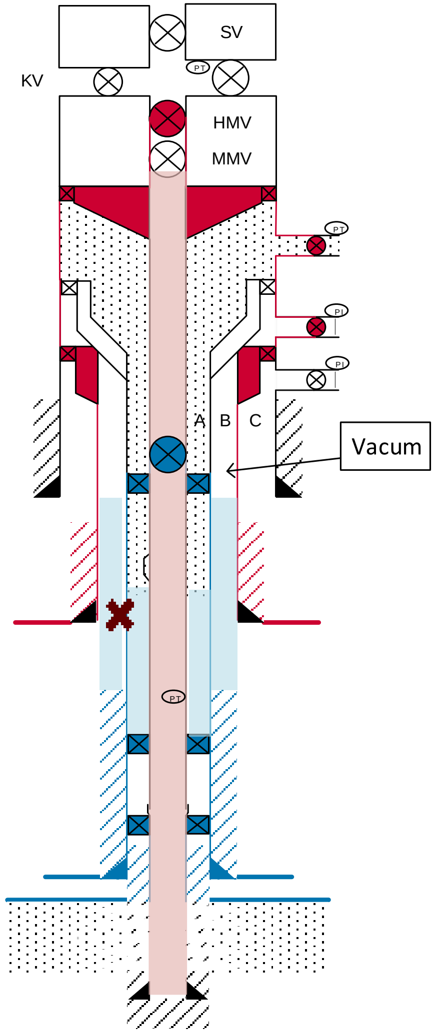
- Implement PALL on A-annulus WH transmitter shutting in annulus valve (and well)
  - avoid annulus pressure bled off, or topside leakage resulting in too low annulus pressure.
  - PAL and PALL > than A-annulus limit
- Maintain sufficiently high reservoir pressure / wellbore pressure at GLV depth
  - avoid too low A-annulus pressure, bled down through GLV when well is shut in
- Ensure A-annulus is actually monitored
  - Evaluate to implement a logic avoiding production without AV / AMV and ASV being in open position
- Verify packer fluid in A-annulus at correct depth when the calculated A-annulus limit is dependent on packer fluid not being deeper than GLV depth. Only relevant for wells with shallow GLV depth compared to possible production casing leakage depth between A- and B-annulus

- **If not possible to maintain A-annulus pressure, evaluate to liquid fill A-annulus and install dummy GLV**



Open

Additional recommended measures for all gas lifted platform wells with B-annulus access



- **Ensure liquid filled B-annulus** through PM program and **implement PAL/PALL** for early detection of possible drainage. The liquid will assure possibility to detect any drainage of B-annulus by drop in B-annulus pressure, not camouflaged by a gas pillow.
- Procedures and equipment for topping up or bleeding off B-annulus to be in place

- These measures will reduce the likelihood of undetected drainage of B-annulus
- Only collapse risk if leakage rate is bigger than top up capacity including response time. Most leaks start as small leaks.
- Recommended measure independent of identified shallower barrier or implemented A-annulus WH limits

equinor

Collapse risk in gas lift wells

Hilde Brandanger Haga
Advisor Well Technology Well system integrity