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Wellbore Stability Issues in Shales or Hydrate Bearing Sediments

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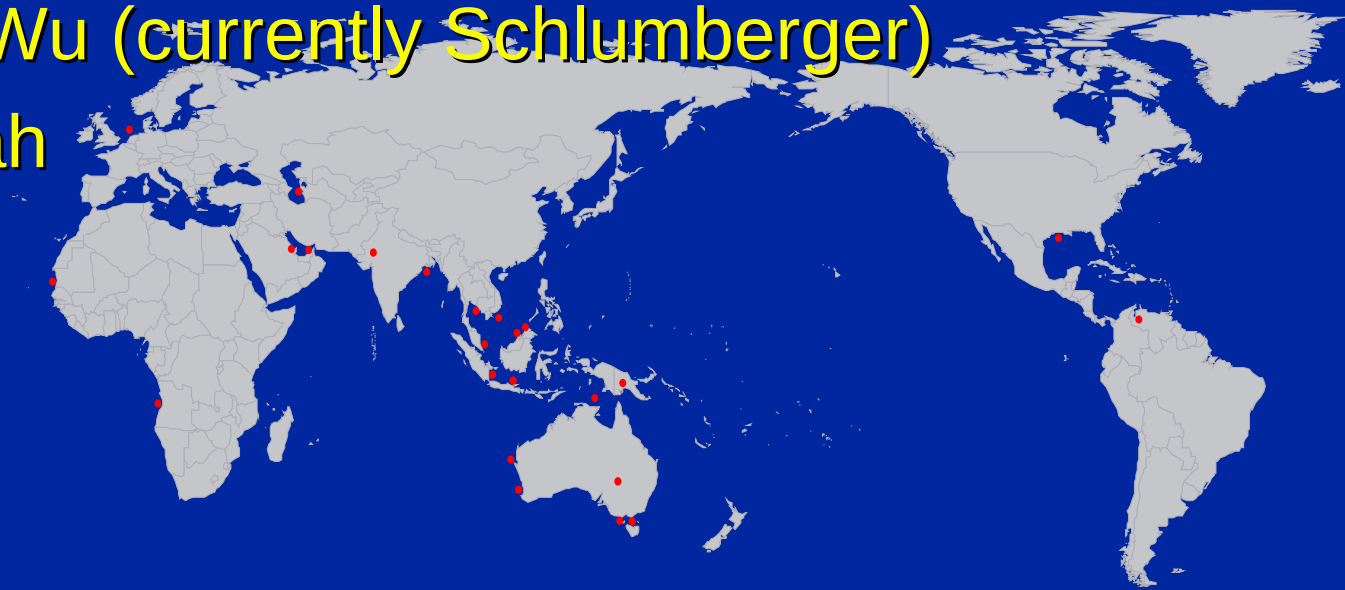


Outline

- When do we need Geomechanics?
- Consequences of wellbore instability
- Wellbore stability model data
- Wellbore stability in shale formations
  - Main processes
  - Modelling results
  - Key Messages
- Wellbore stability in hydrate bearing sediments
- Further challenges in Geomechanics

When do we need Geomechanics?

- Wellbore stability in difficult formations → loss of US$ 2 billions/yr
  - Shale formations → 90% of incidents

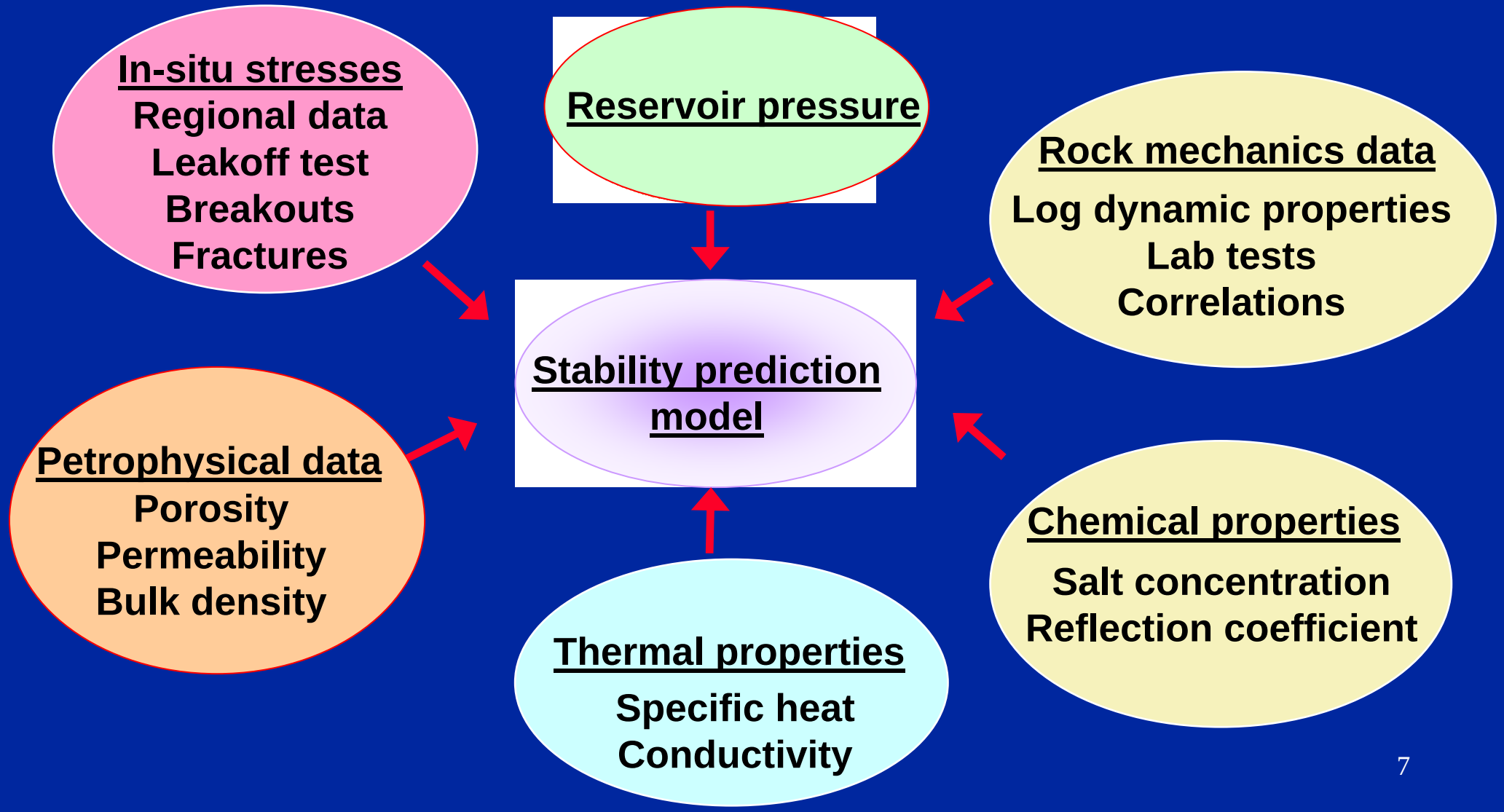
  - Hydrate bearing sediments (HBS)

  - Salt formations
  - HPHT reservoirs
  - Brown fields
- Sand production → US$ billions/yr
- Reservoir subsidence
- Fault seal analysis

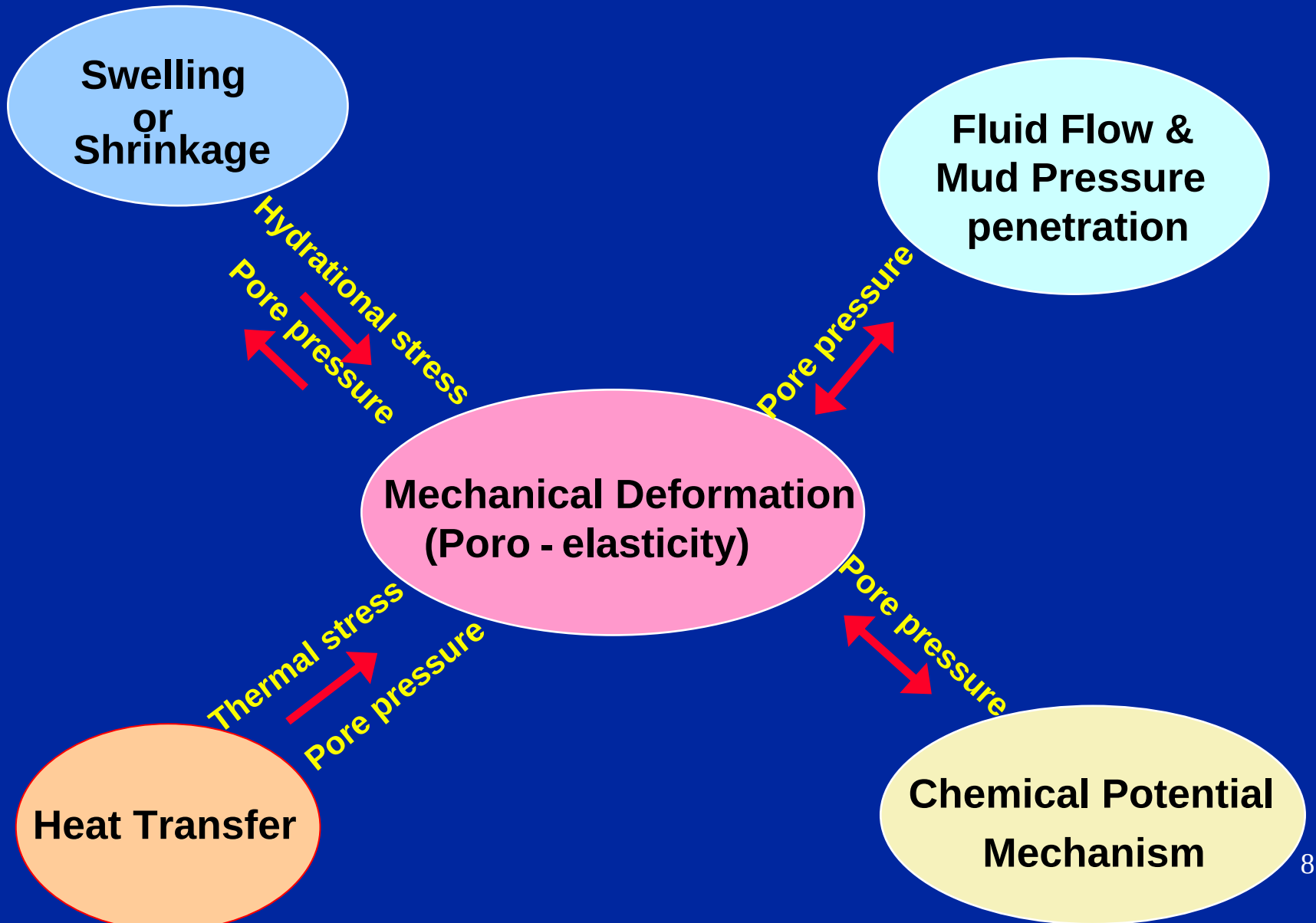
Consequences of wellbore instability

- Sloughing or caving
- Packoffs, blowouts, or mud losses
- Increased mud treatment cost
- Stuck pipe and loss of equipment
- Side tracks or well abandonment

Wellbore stability model data



Processes affecting wellbore stability in shale formations when using water based mud



shales

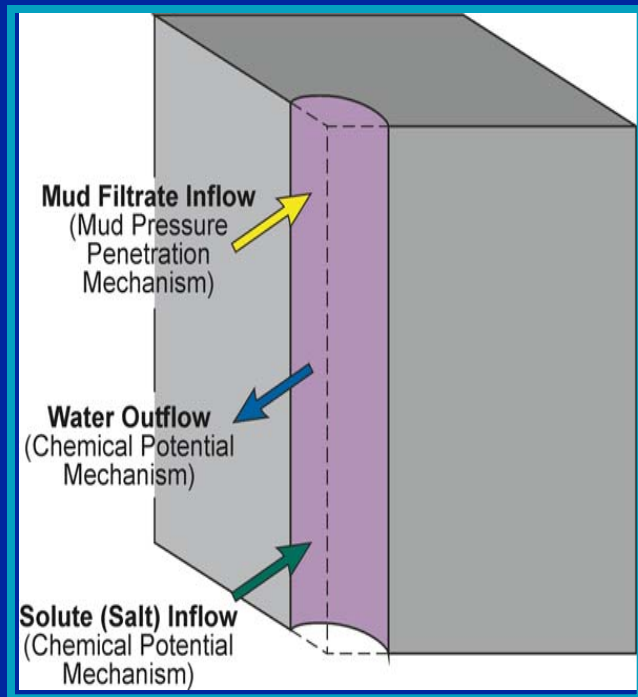
Mud pressure penetration mechanism

Overbalance drilling conditions mean

- Mud filtrate (viscosity, adhesion and density) will invade the formation
- Reduction of differential pressure leads to reduction of the mechanical support to the wellbore wall
- To ensure high breakthrough pressure
  - Optimize drilling mud properties
  - Consider the formation pore size distribution

Chemical potential mechanism

- Shales have fine pores and (-) charges, they act as a semi-permeable membrane
- Ideal semi-permeable membranes permit flow of water but not salt ions (osmosis)
- The chemical potential controls direction of flow
  - The chemical potential of a fluid = F (dissolved ion concentration)
  - Water flows from low to high salt concentration
- The membrane can be non-ideal or leaky



shales

Heat transport mechanism

- The drilling mud and formation differ in temperature
  - Geothermal gradient: the drilling mud is cooling the bottom and heating the top of the wellbore
- Heating the formation → thermal expansion of formation & pore fluid: thermal stresses develop.
- Pore fluid & formation have different coefficients of thermal expansion → pore pressure increases.
- Hydraulic and thermal diffusivities are different leading to pressure build-up.
- Other effects on drilling mud characteristics….

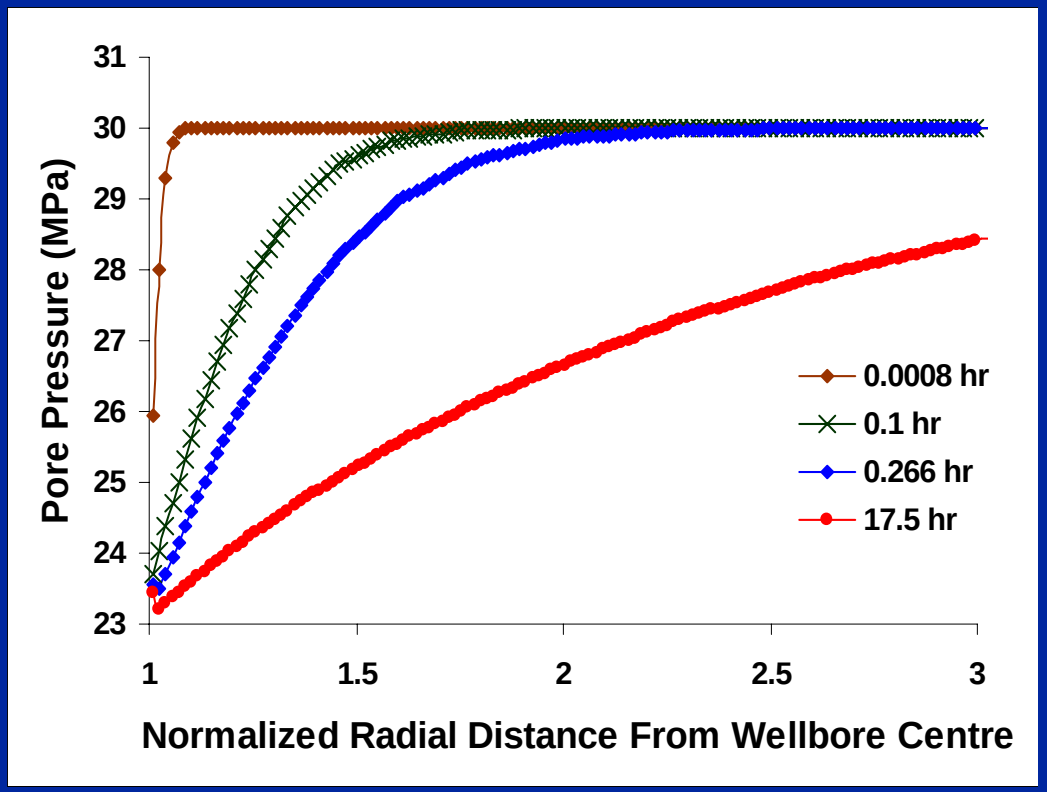
Swelling mechanism

- Reactive shales + non-inhibitive muds → pore pressure increase & adsorption of water
- This leads to hydrational strain=swelling or hydrational stresses & a possible shear failure
- Water is reactive with shales, low viscosity, high wetting characteristics i.e., non-inhibitive
- Inhibitive water based mud with low wetting characteristics reduces the risk of wellbore instability

Modelling results: mud chemical composition

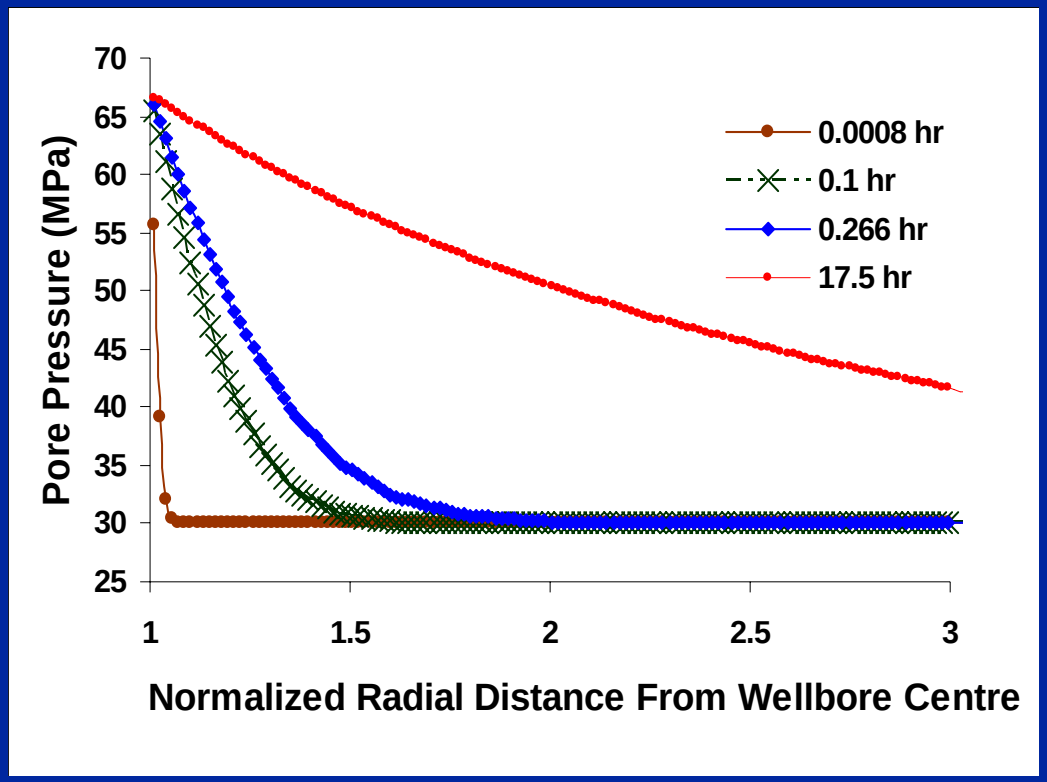
Drilling mud has 20% higher salt concentration

Mud weight 45 MPa



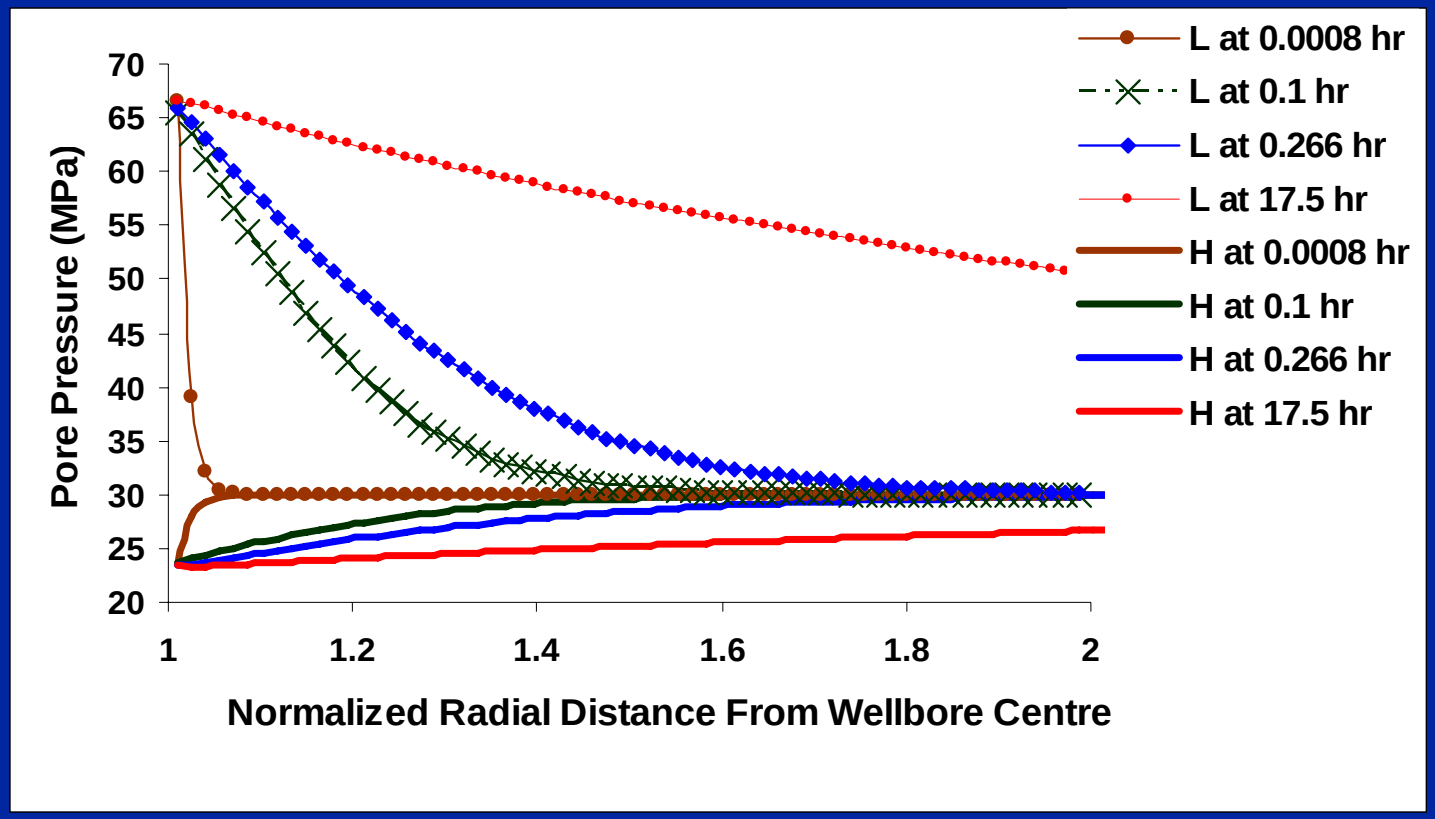
Drilling mud has 20% lower salt concentration

Mud weight 45 MPa



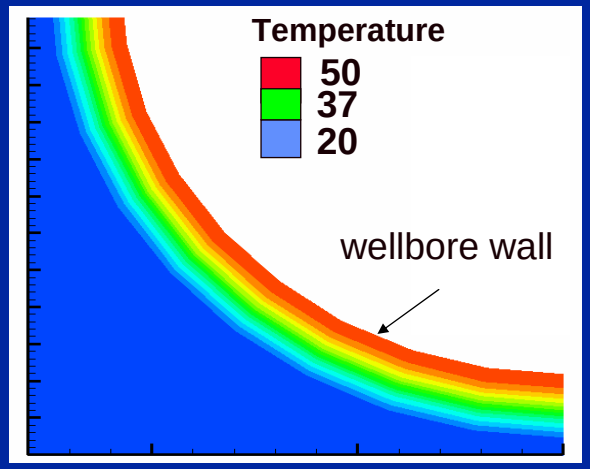
Comparison between high and low salt concentration mud

Mud weight 45 MPa

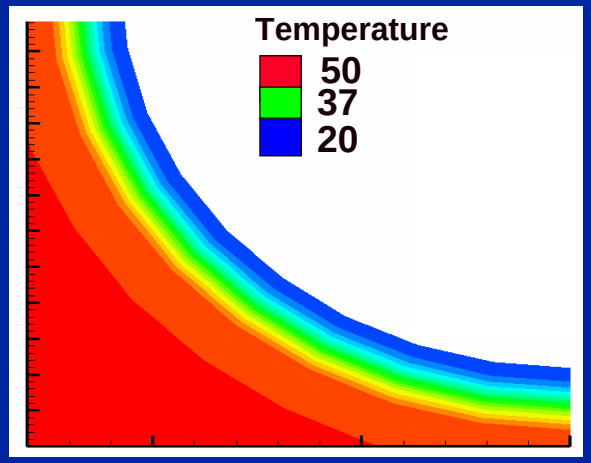


Modelling results: mud temperature

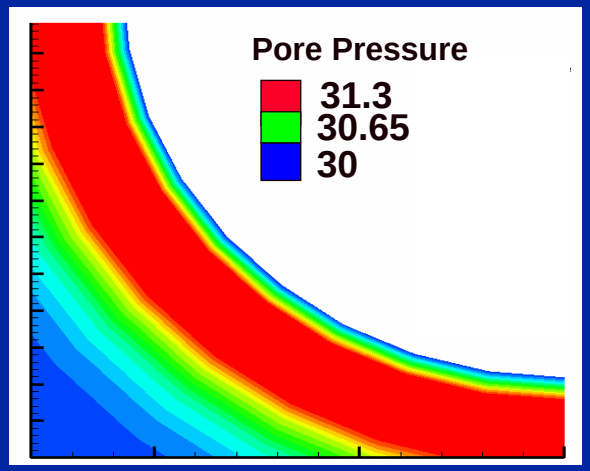
Hot mud

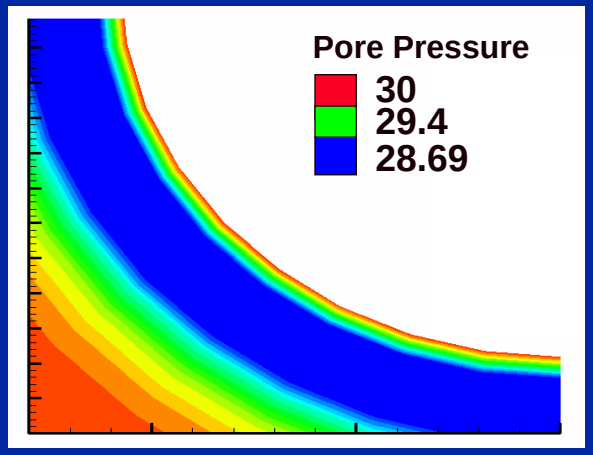


Cold mud



Temperature (ºc) contours



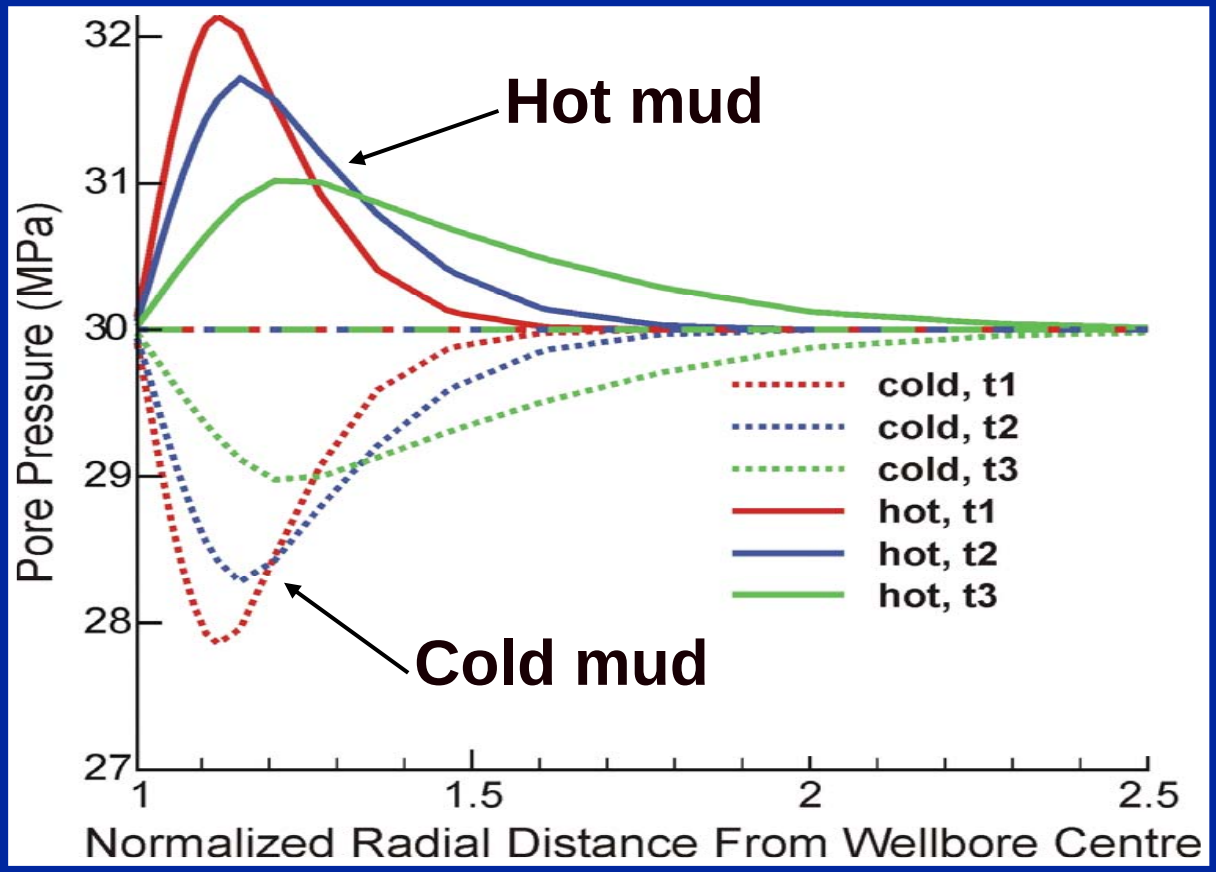


Pressure (MPa) contours

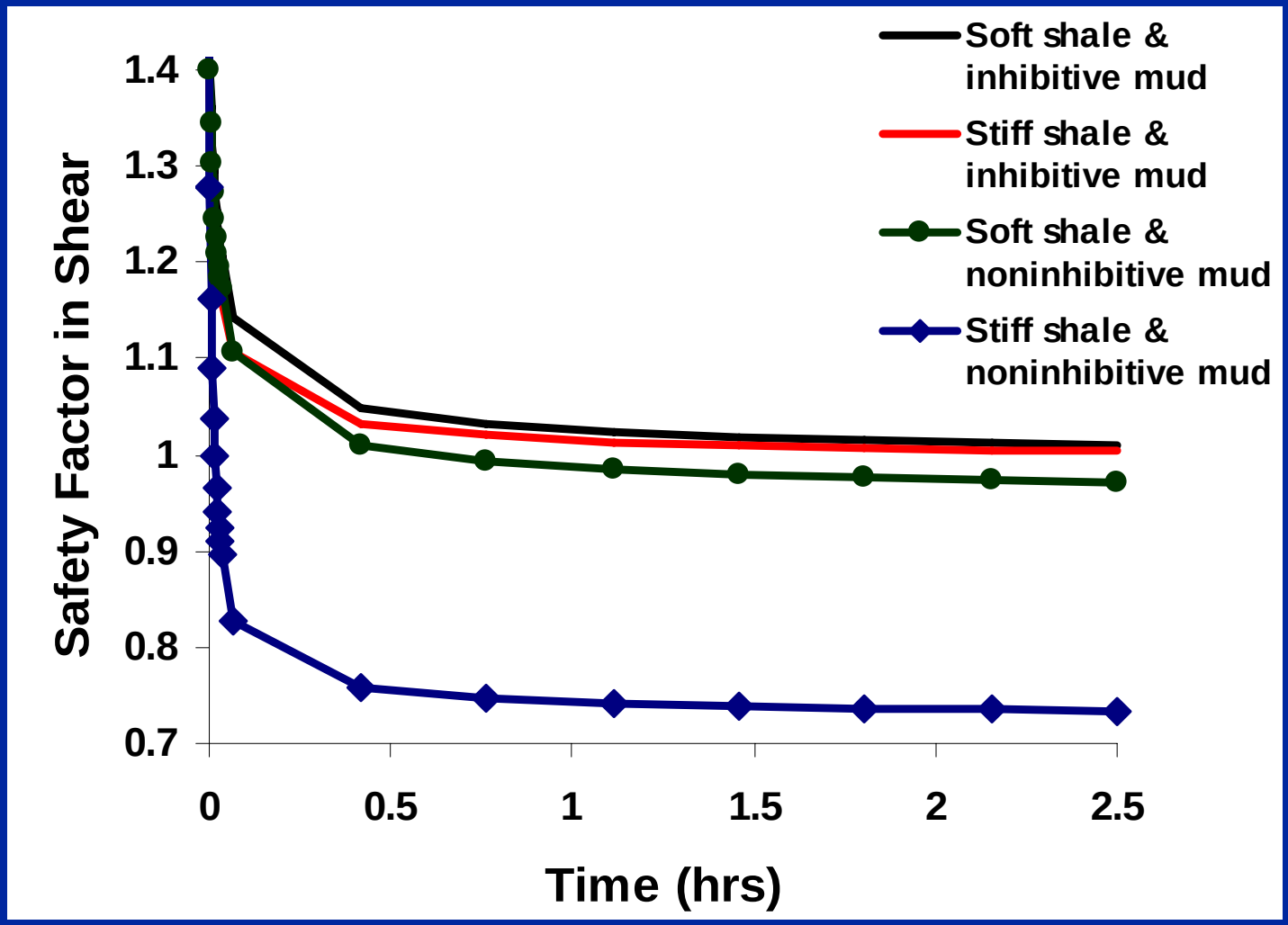
Modelling results: mud temperature

Pore Pressure evolution

Pressure change due to 30º (heating or cooling) > 2 MPa



Modelling results: swelling shales



Swelling is significant when non-inhibitive mud is used with highly stiff reactive shales

shales

Key Messages

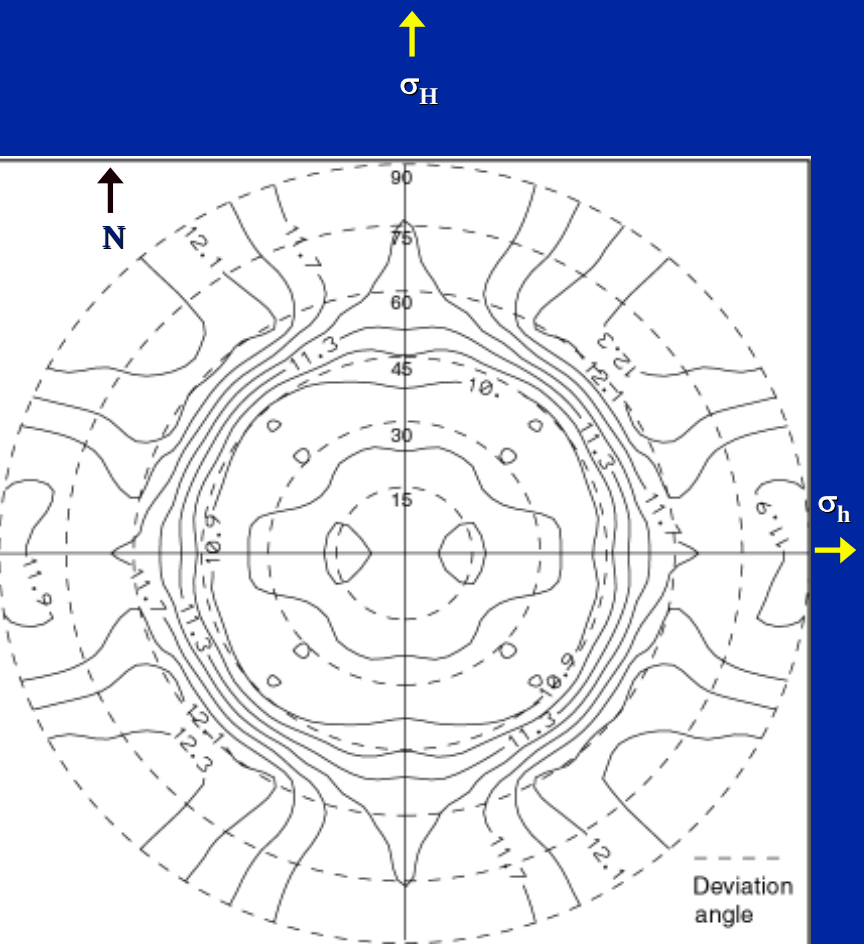
Careful design of water base drilling fluids is needed to control PP and SF evolution

Drilling fluid pressure = 45 MPa Formation Pressure =30 MPa	Time=0.0025 hour		Time=0.1 hour	
Drilling Fluid	Pressure	Safety Factor	Pressure	Safety Factor
Water	33.37	1.36	42.39	1.07
→ Low filtrate invasion	31.25	1.42	38.05	1.19
Lower salt concentration than the formation	36.55	1.28	54.42	0.76
→ Higher salt concentration than the formation	29.80	1.48	25	1.60
Hot water	38.33	1.25	43.71	1.02
→ Cold water	28.41	1.48	41.07	1.11
Cold-low filtrate invasion-higher salt concentration than formation	23.76	1.62	23.2	1.72

Results at 5% well radius inside the formation

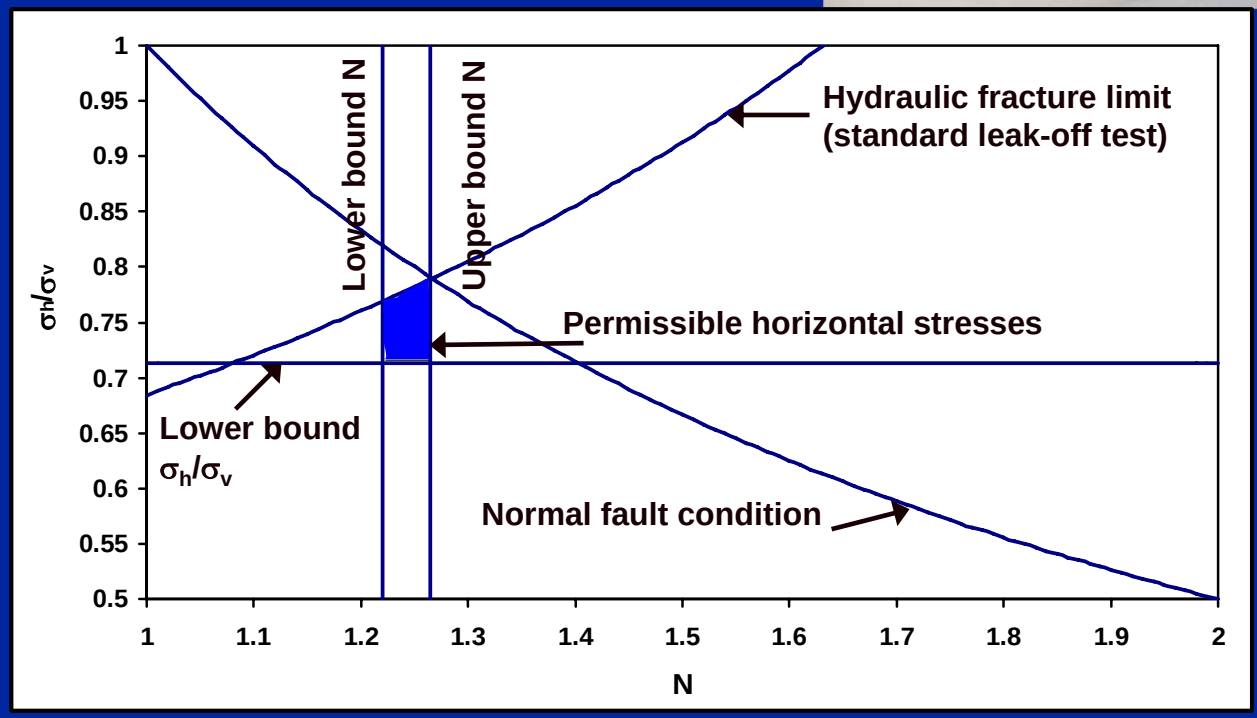
Drillers' wellbore stability tool

Mud weight vs. well orientation



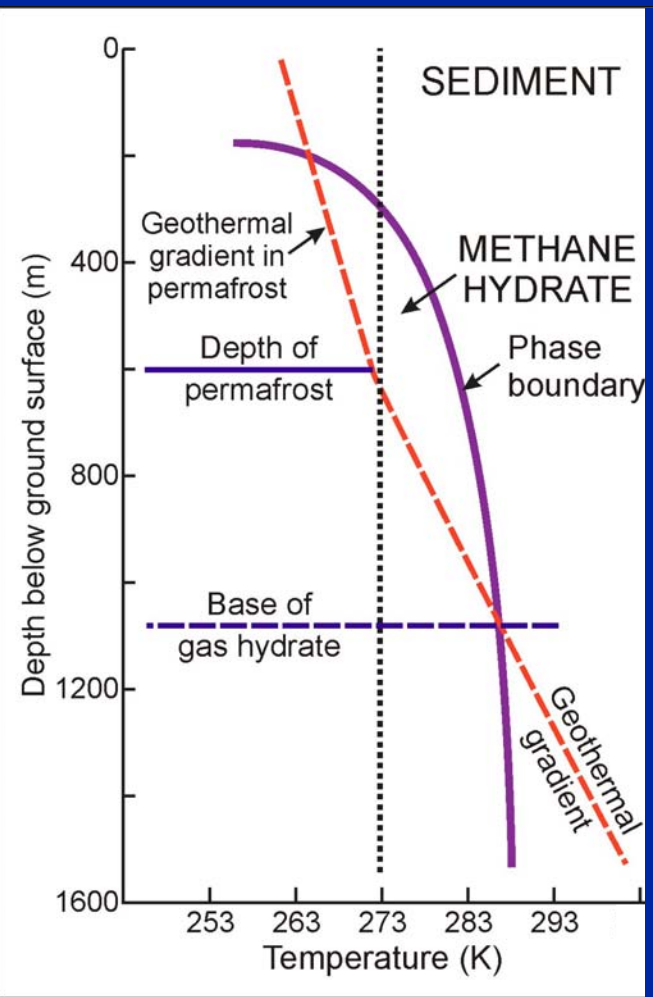
High pressure triaxial cell

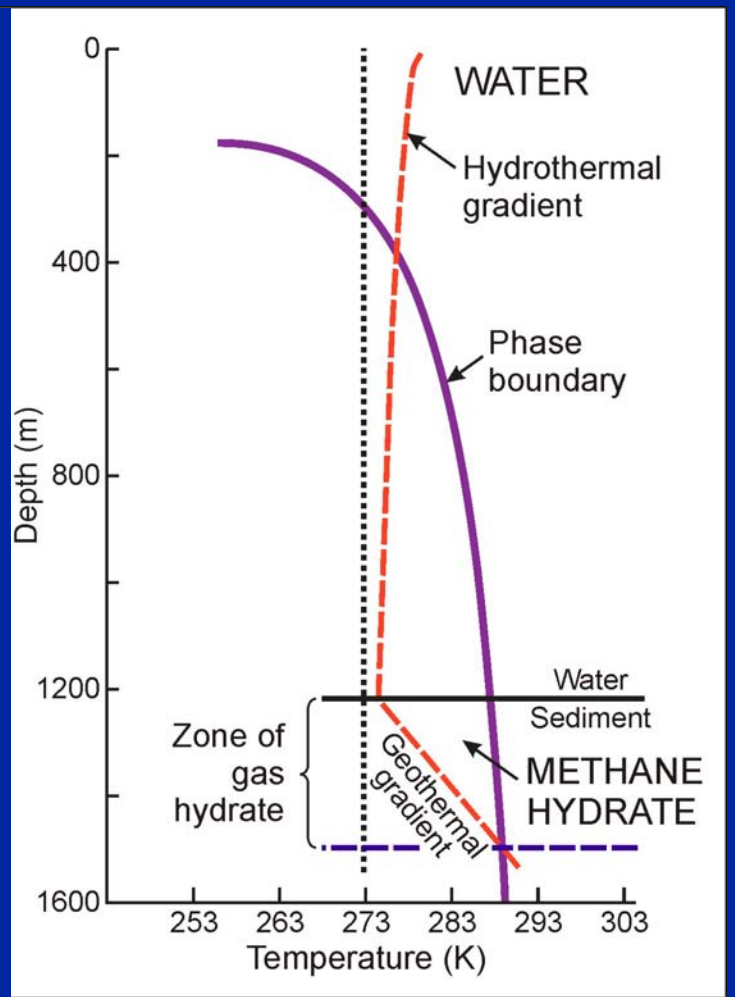
In-situ stress bounds



What are hydrates and why are hydrate bearing sediments (HBS) important ?

Hydrate stability domain





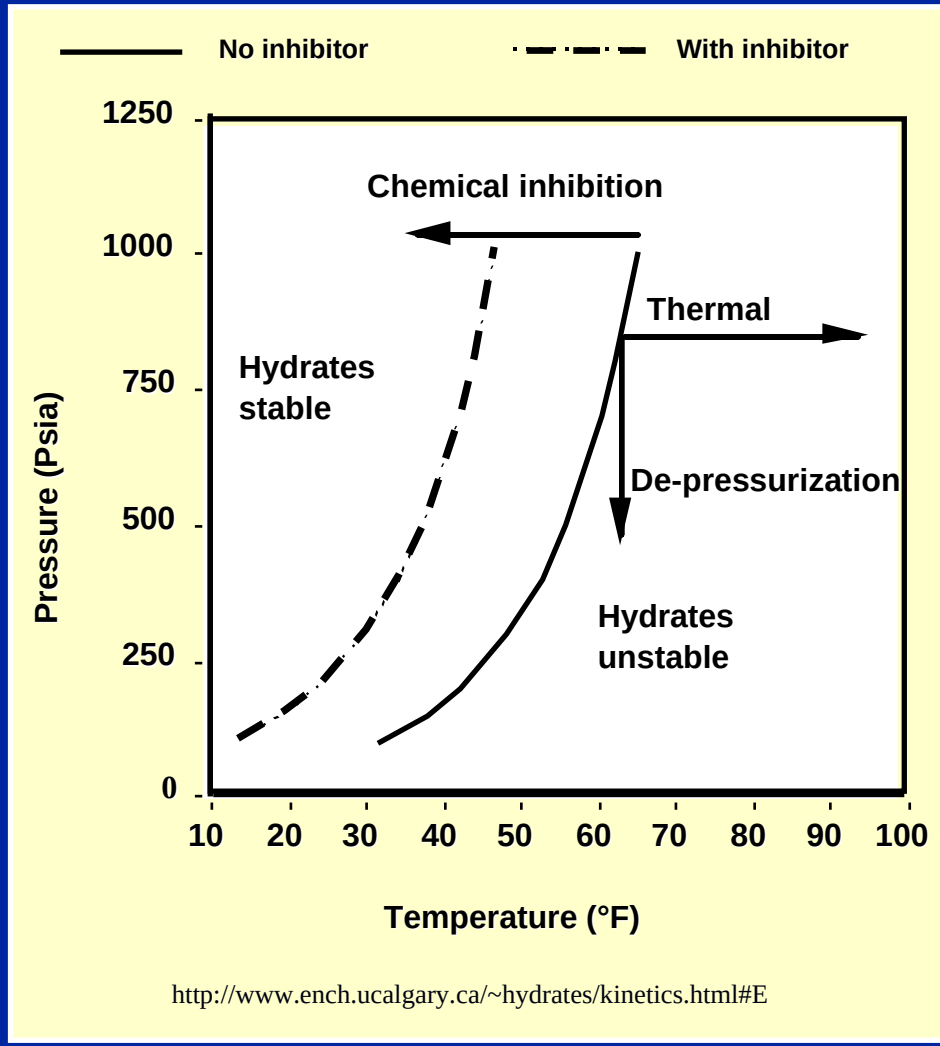
Hydrates are

- Source of energy
- Way to transport natural gas
- Geohazard
- Climate change
- Drilling hazard
- Problem in flow assurance

Hydrates on sea bed (USGS)

Hydrate stability domain

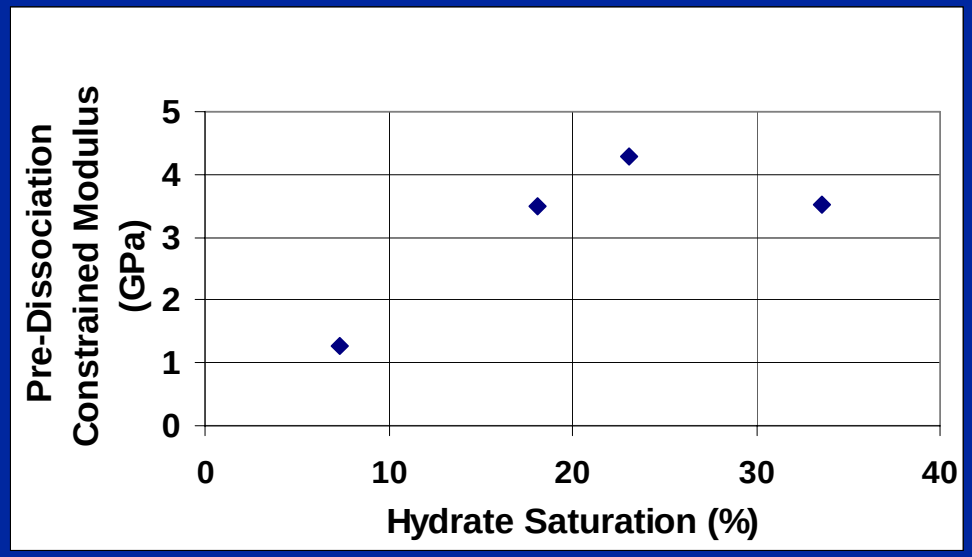
- Depressurization
- Thermal stimulation
- Chemicals affect hydrate stability:
  - Thermodynamic inhibitors (salts, alcohols, glycols) can inhibit hydrate formation in the mud
  - Kinetic additives (eg lecithin + poly N-vinyl pyrrolidone (PVP)) stabilize hydrates in the formation



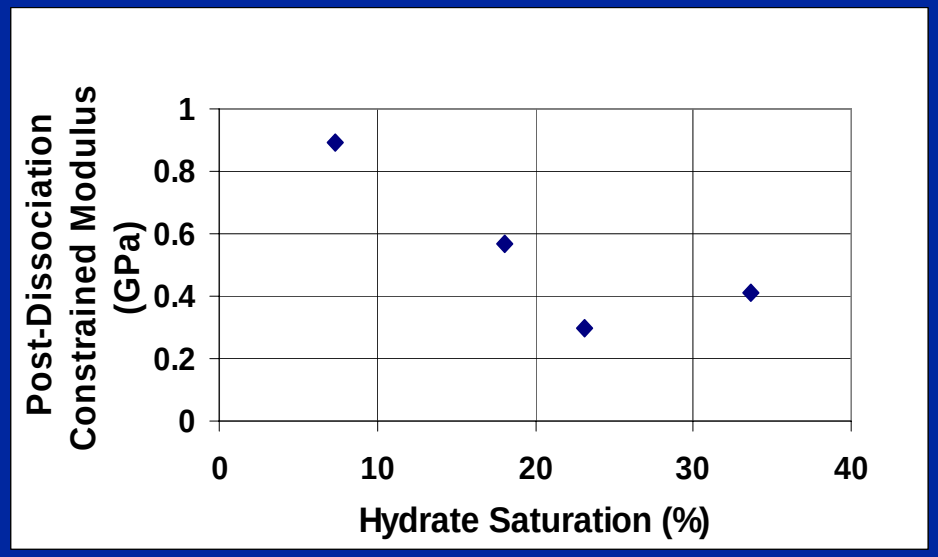
Constrained modulus of HBS

Results of confined compression tests on natural gas hydrate bearing silica sands (In collaboration with Heriot-Watt University)

Pre-dissociation (with hydrates stable) constrained modulus dependence on hydrate saturation



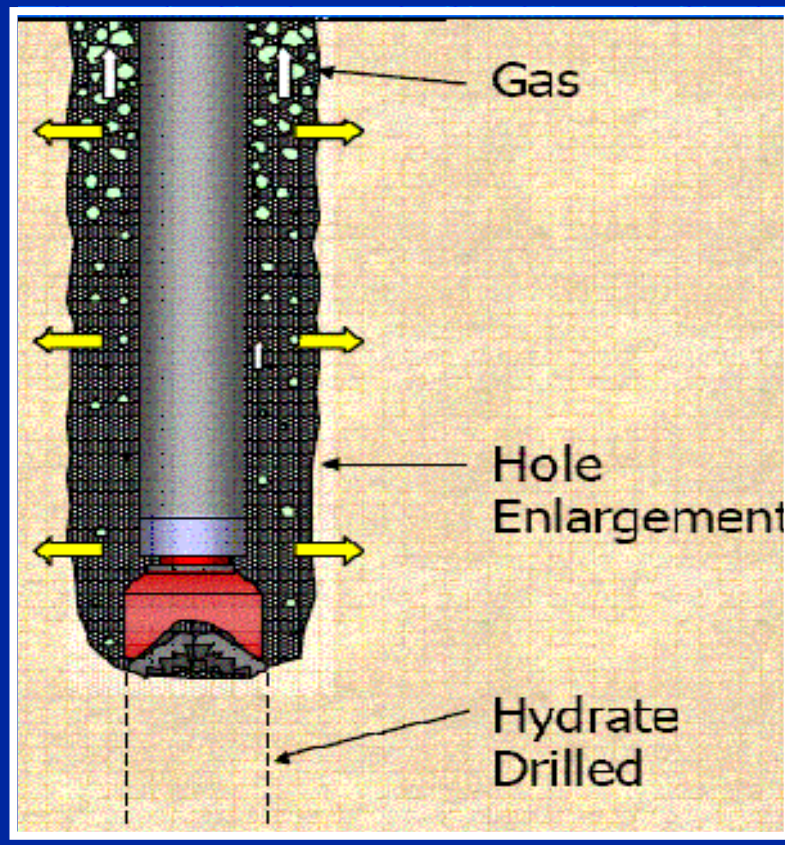
Post-dissociation (after hydrates dissociated) constrained modulus dependence on hydrate saturation



HBS well control problems

- Hydrates are sensitive to the drilling mud:
  - Pressure
  - Temperature
  - Chemical composition

- Hydrate destabilization →
  - Drilling mud contamination with gas
    - ☞ Reduction of mud density
    - ☞ Change of mud rheology
  - Decrease of formation strength & loss of mud support → wellbore instability



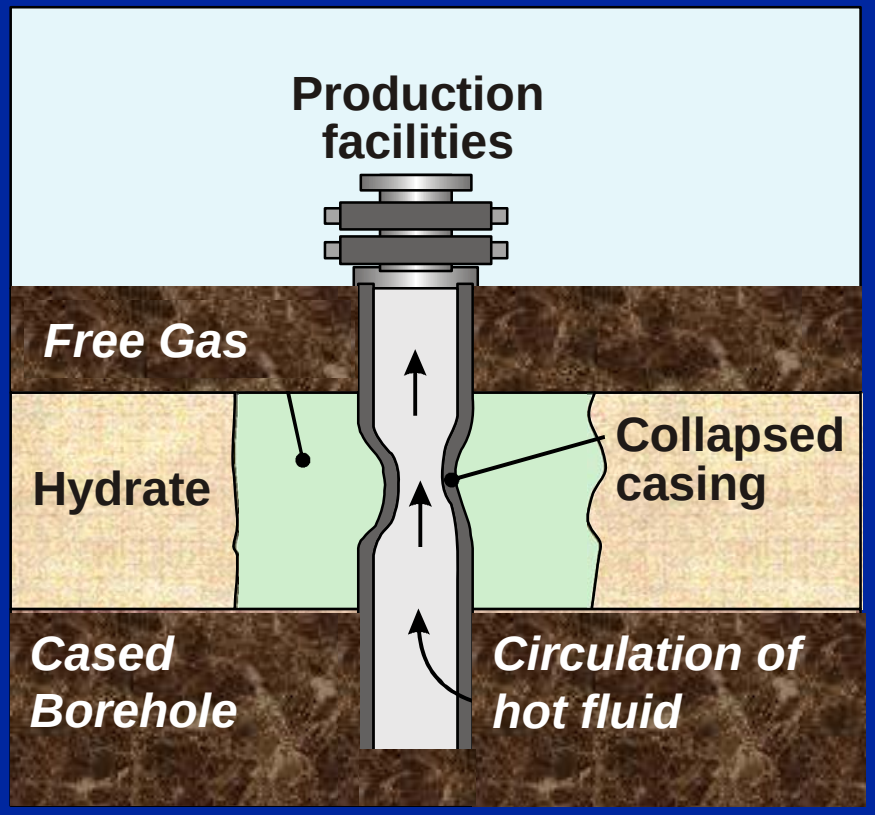
Gas hydrate-related drilling problems (Adapted from Maurer Engineering, Inc.)

HBS and casing integrity

During hydration of casing cement

During circulating of hotter drilling mud

→ Casing collapse

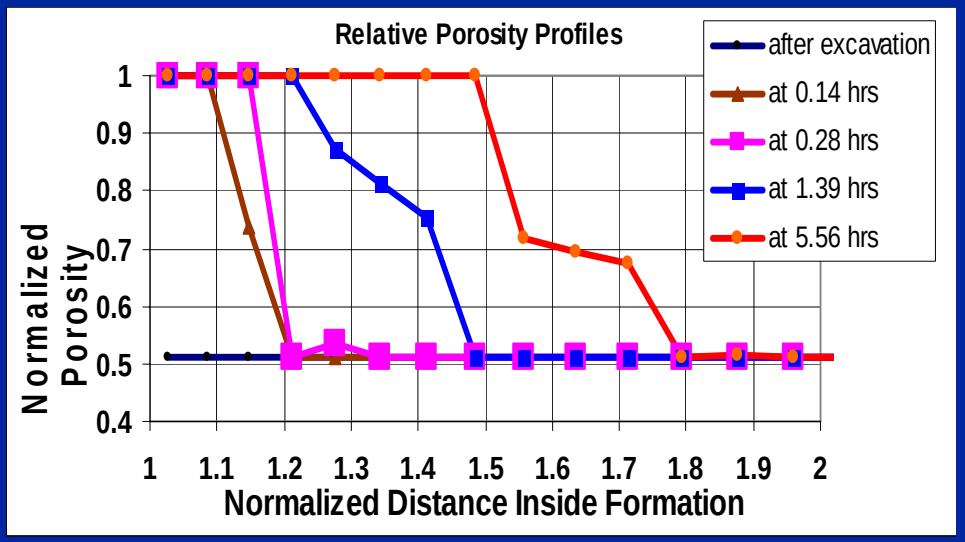


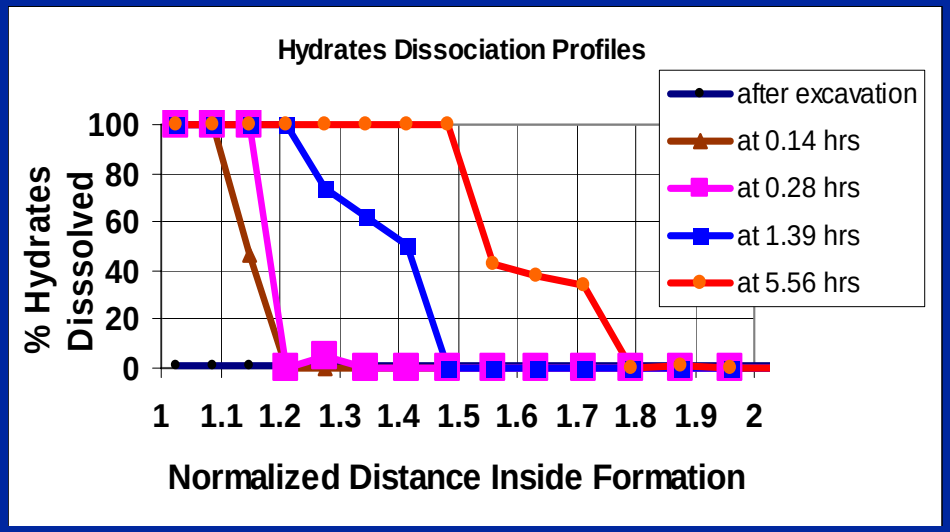
Gas hydrate-related casing problems (Adapted from Maurer Engineering, Inc.)

Wellbore stabilization strategies

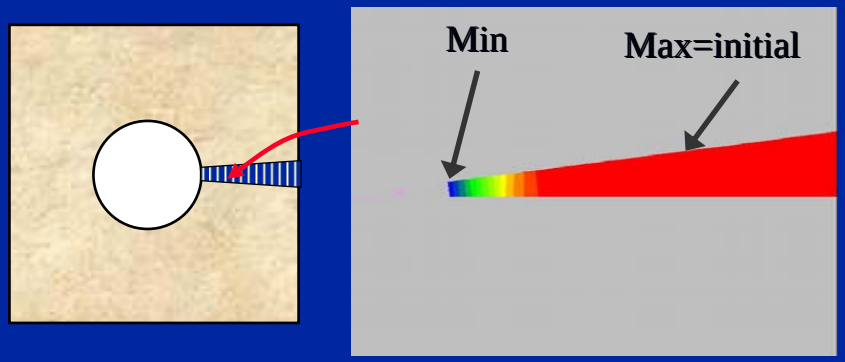
- Optimal design of the drilling mud to enhance hydrate stability (use kinetic additives e.g.: lecithin, etc.)
- Selection of casing cement with low hydration heat
- Use predictive modeling
  - Analyze stability of the wellbore formation using coupled mechanical-thermal-chemical/kinetic
  - Assess conductor integrity when circulating hot fluid through the hydrates zone.

Wellbore stability in HBS: heating the wellbore walls

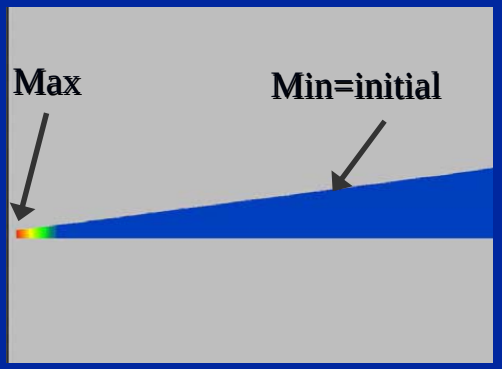




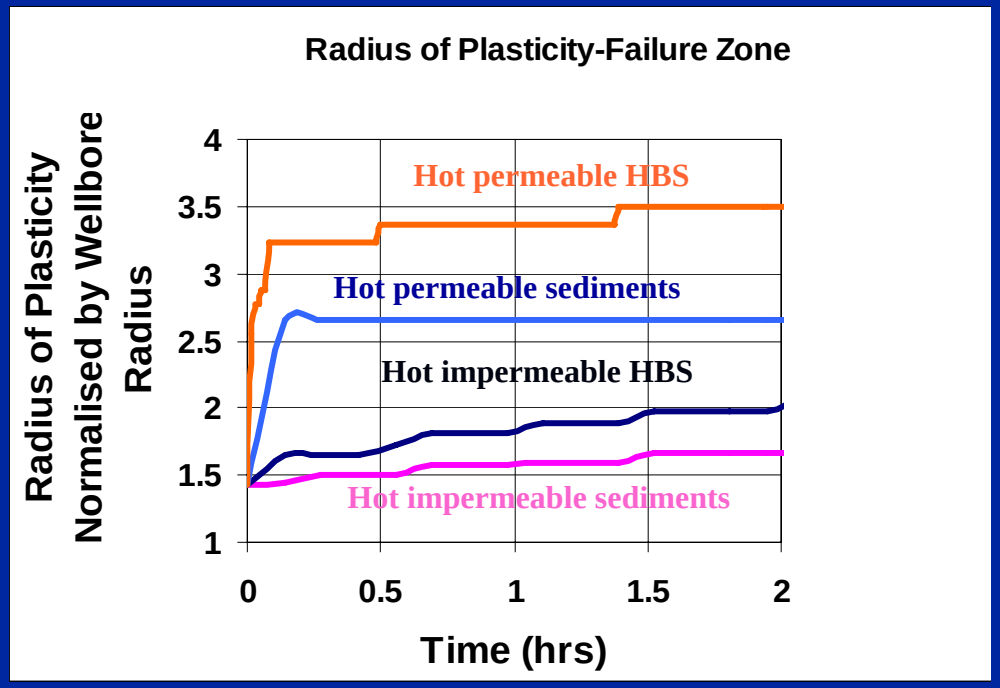
<u>Cohesion</u>: reduced in near wellbore region by hydrate melting



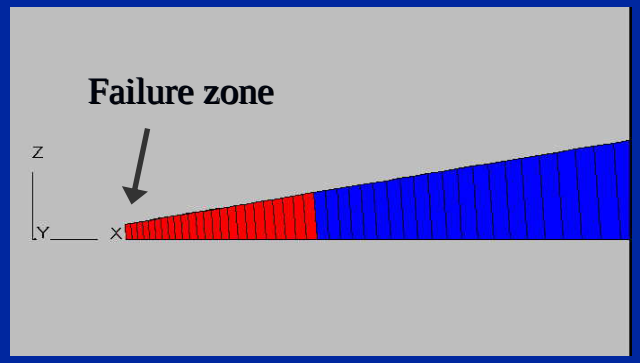
<u>Porosity</u>: increased in near wellbore region by hydrate melting



Key messages: stability of wellbores in HBS



Shear failure zone

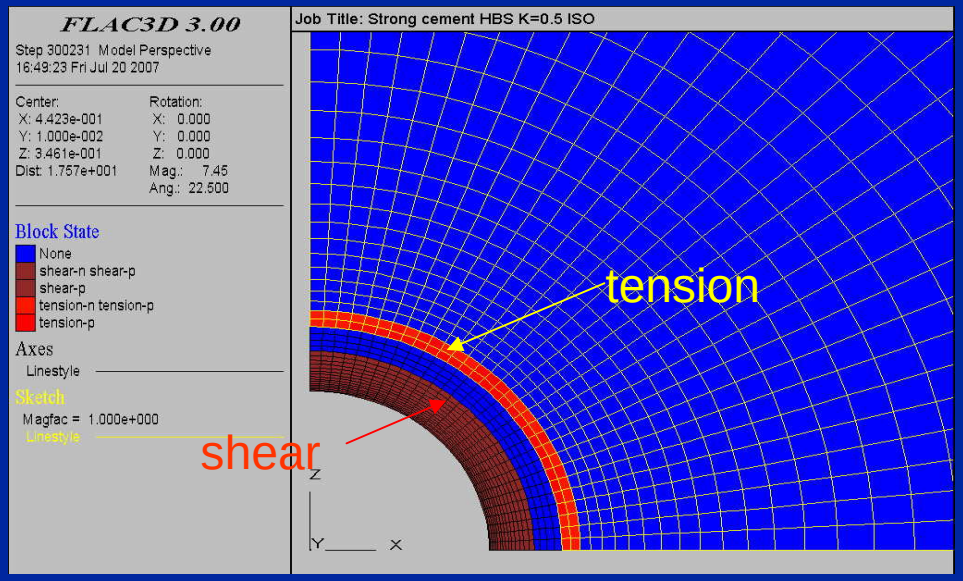


- Encountering hydrates in the sediments while drilling a wellbore can increase the size of the yield zone by 32%
- The importance of employing techniques to stabilize HBS in deep water drilling.

Casing Integrity in HBS: 20in API casing

Strong cement	
Thermal conductivity	0.66 $Wm^{-1}K^{-1}$
Modulus of elasticity	55.16 GPa
Poisson's ratio	0.4
cohesion	11.4 MPa
Friction angle	10º
Tensile strength	2.6 MPa
Weak cement	
Modulus of elasticity	0.4 GPa
Poisson's ratio	0.2
Cohesion	1.2 MPa.
Friction angle	10º
Tensile strength	0.379 MPa

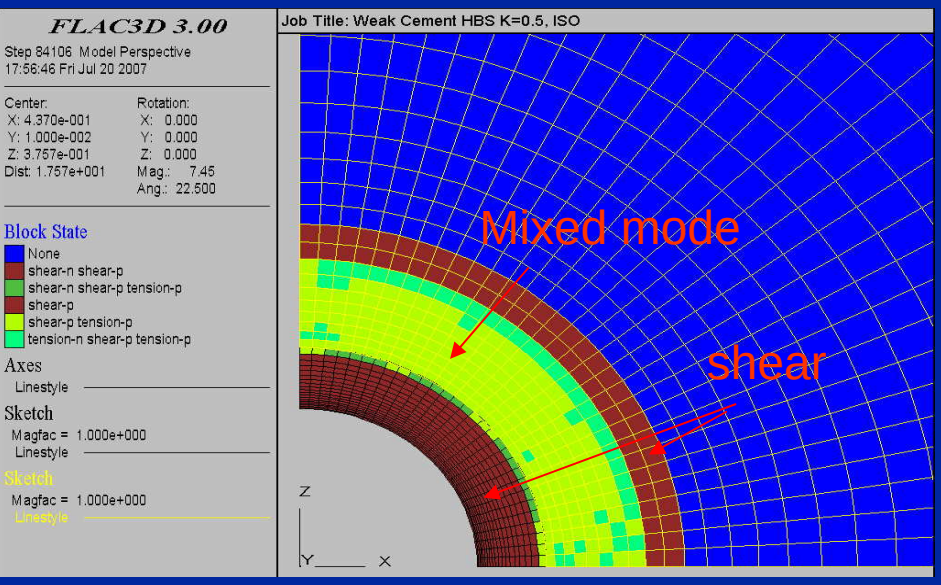
Strong cement



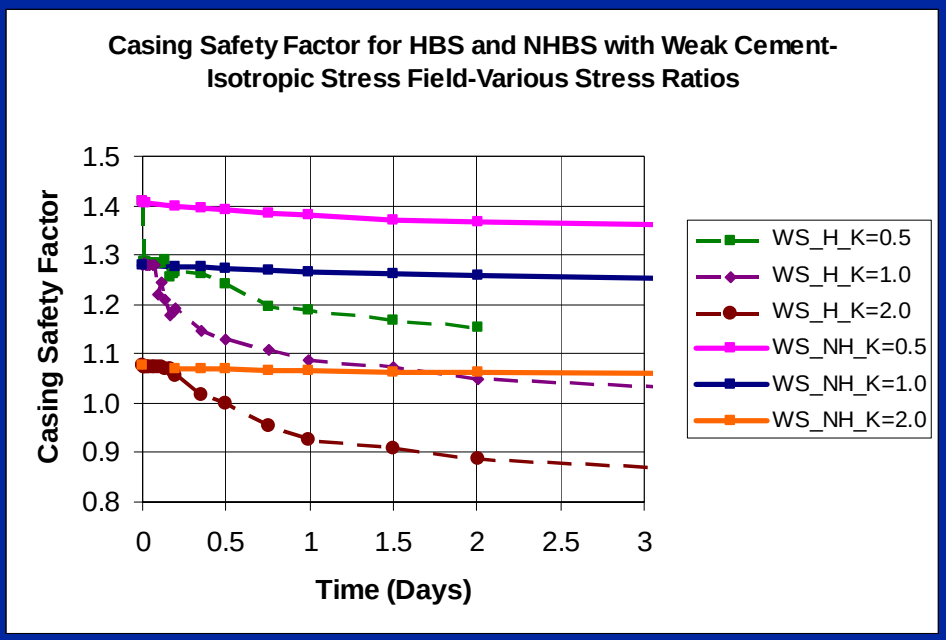
Progress of shear failure inside the strong cement and tension failure inside the HBS as the cement and the formation heat up 8.33 hrs after heat application to the casing. Isotropic stress field, K0=0.5

Results for 20in API casing

Weak cement



Shear failure of all the weak cement and further part of the HBS and a band of mixed mode: tension and shear failure develops at the boundary of the cement 15minutes after heat application to the casing. No change is observed at 8.33 hours. Isotropic stress field, K0=0.5.



Casing safety factors for a wellbore drilled in NHBS or HBS and cased with 0.635in casing using weak cement. The strength degradation resulting from hydrate dissociation in the HBS upon heating reduce the SF for all stress ratios considered. Note that cases with lower stress ratios K0 have higher SF than cases with higher K0.

Further challenges and future trends in Geomechanics

HPHT reservoirs	→ narrow or nonexistent mud window
Brown fields and tail production	→ sand & water production and management issues → formation strengthening issues
Rock properties measurements	→ cuttings instead of coring
Deep water drilling	→ one trip well