CO2 Storage Conference 2024

Advanced Numerical Modelling in Carbon Capture and Storage Well Design

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Axis

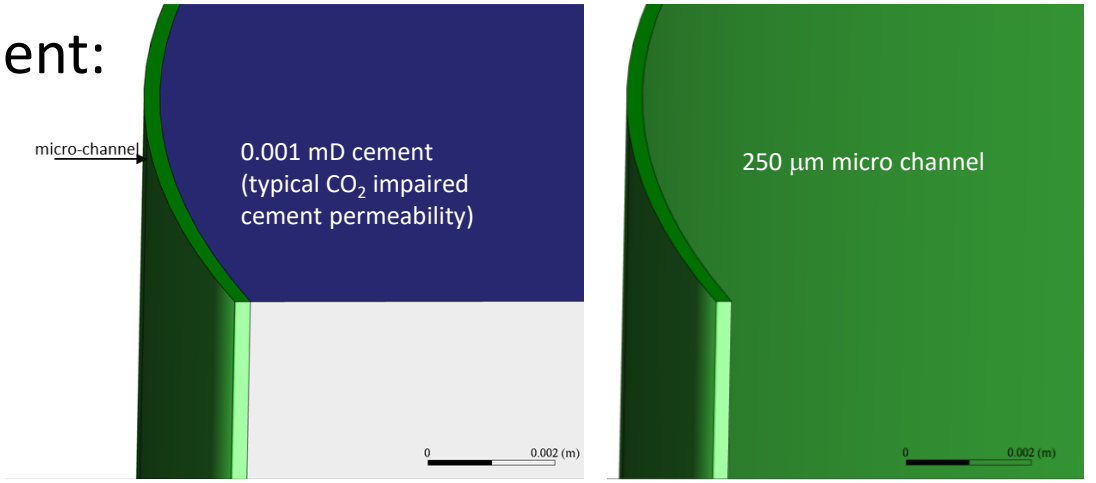
Or…..
An Ode to CCS Modelling!

Leak path modelling

Micro Channel & Cement

- Micro channel and Cement:

High confidence cement…..
Low confidence cement…..
Unlikely to be "good cement"
Very little chance of cement

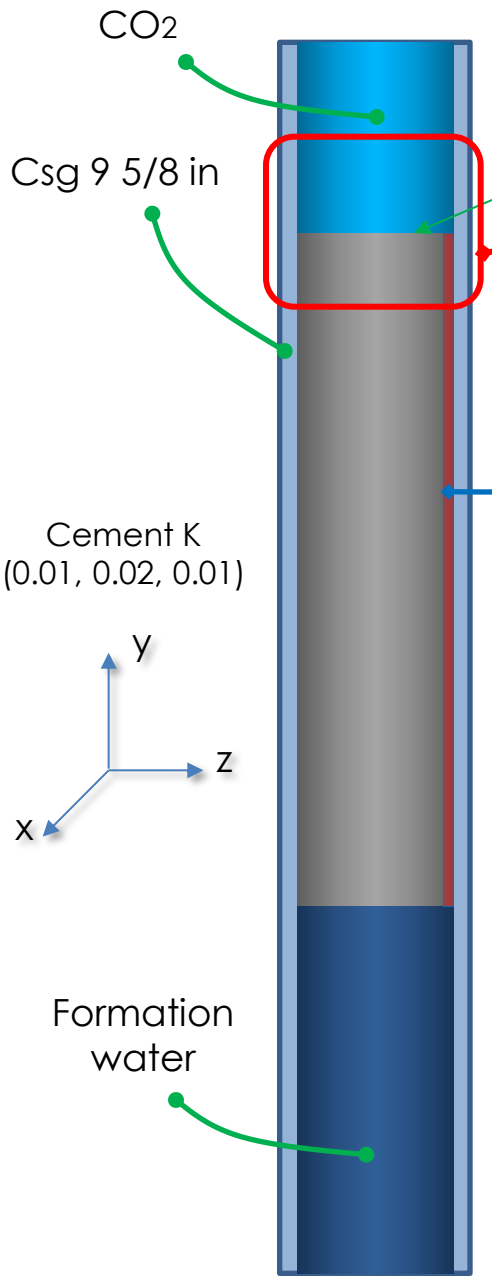


- The micro channel, at the sandface side, will dominate the flow compared to the low permeable cement
  - → model the different cement quality as different micro channel size and coverage

High confidence cement…..	modelled as 60 µm channel, 25% circumference
Low confidence cement…..	modelled as 125 µm channel, 50% circumference
Unlikely to be "good cement"	modelled as 250 µm channel, 100% circumference
Very little chance of cement	modelled as open space

Based on Herriot Watt University modelling assumptions in SPE 200608 (Table 4)

Flow along Cement Plug & Micro Annulus



P1 = PH = 2350 psi c

1654 m

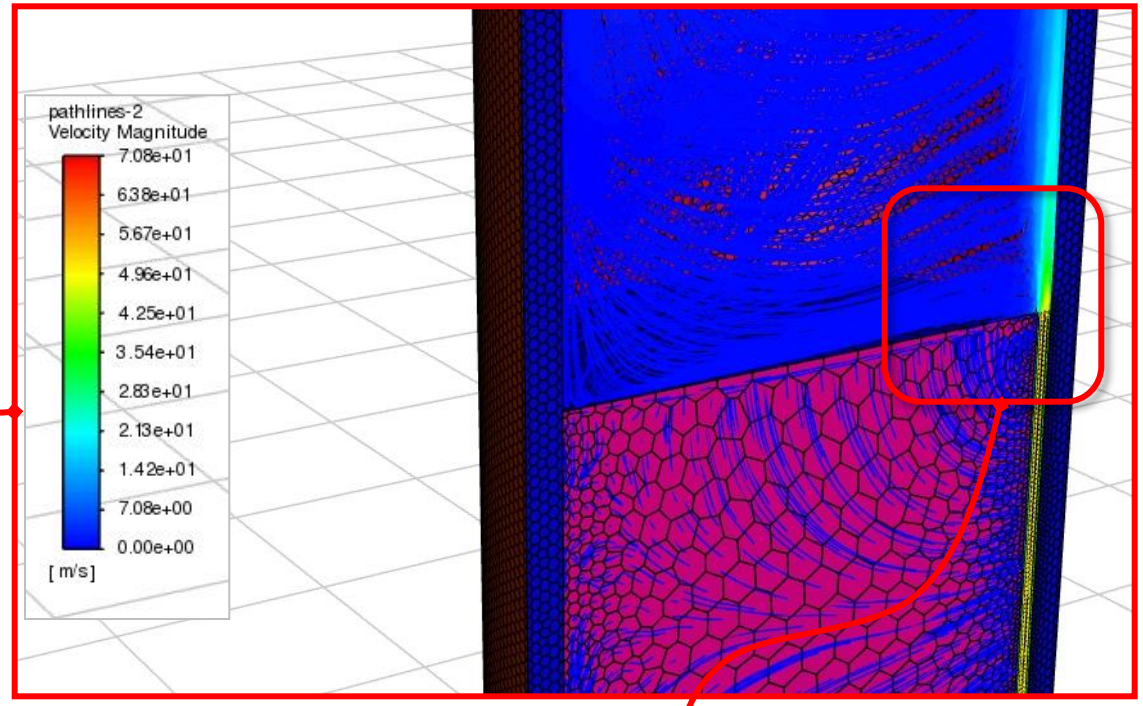
Micro annuls 75 µm
Impacting 30% of annular sealing
along the cement plug

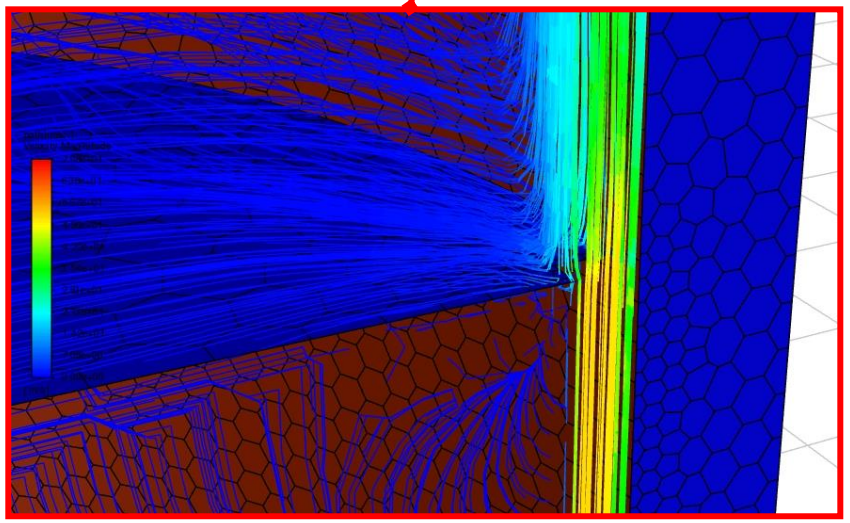
Cement: 5 m

dP = 500 psi
Pressure differential
across the plug

P2 = 2850 psi = Pressure induced by CO_2 Injection around the well water saturated zone

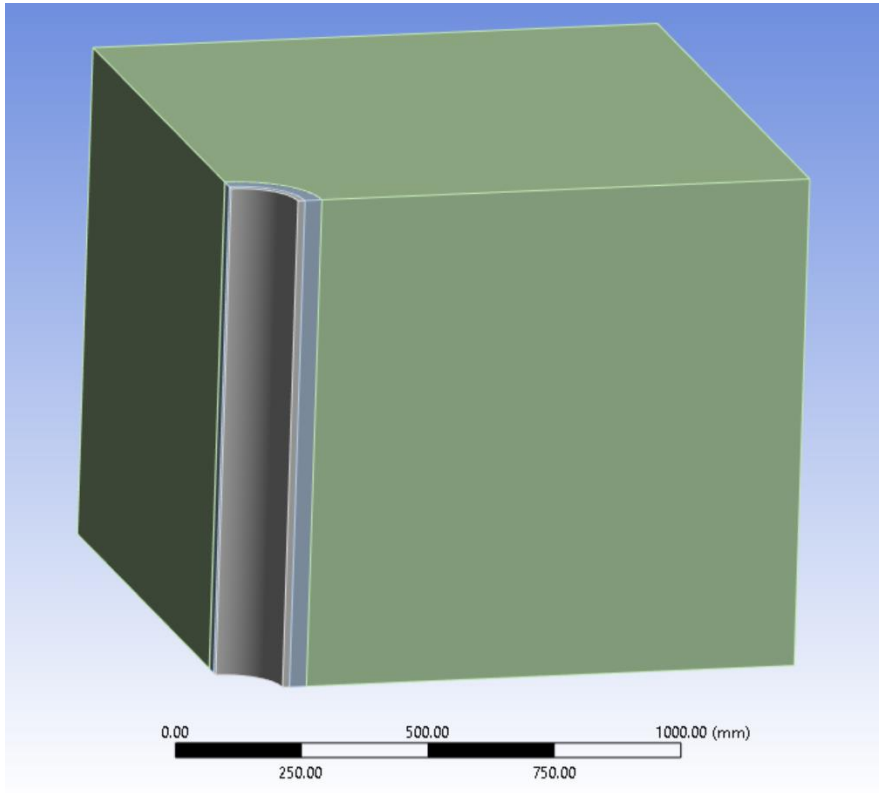
CO_2 under supercritical conditions

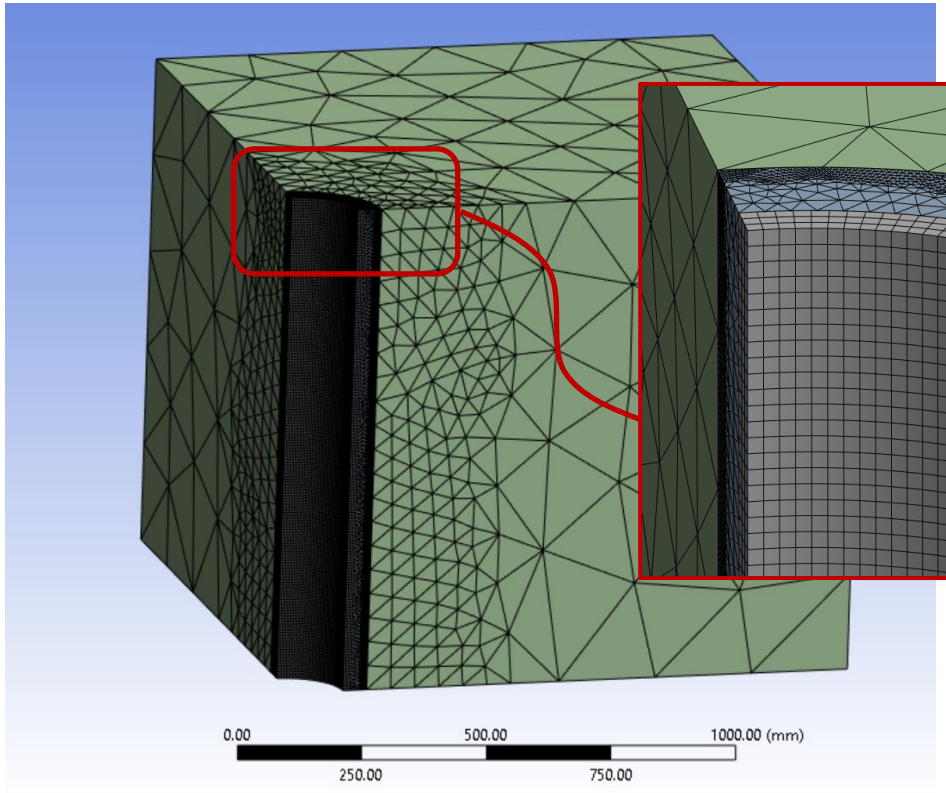


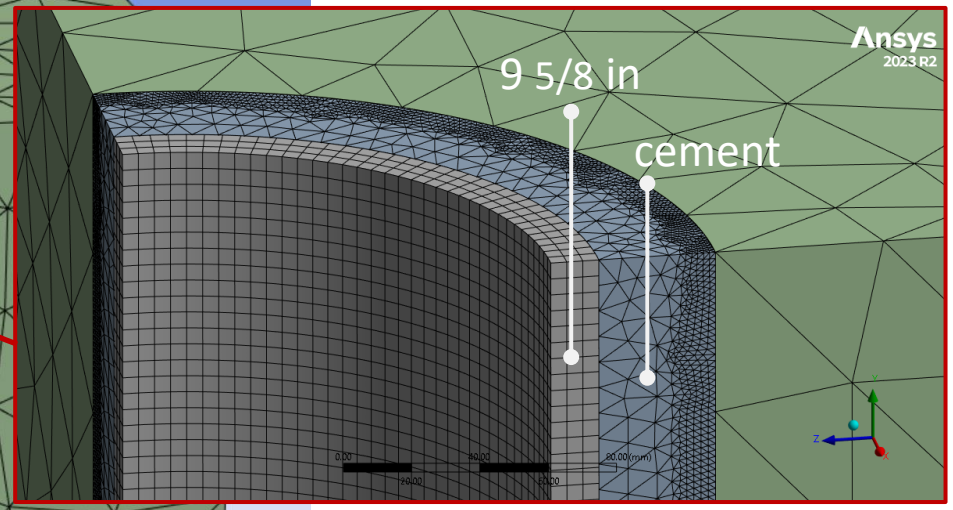


Well Integrity/thermal effects

Casing, cement and formation configuration

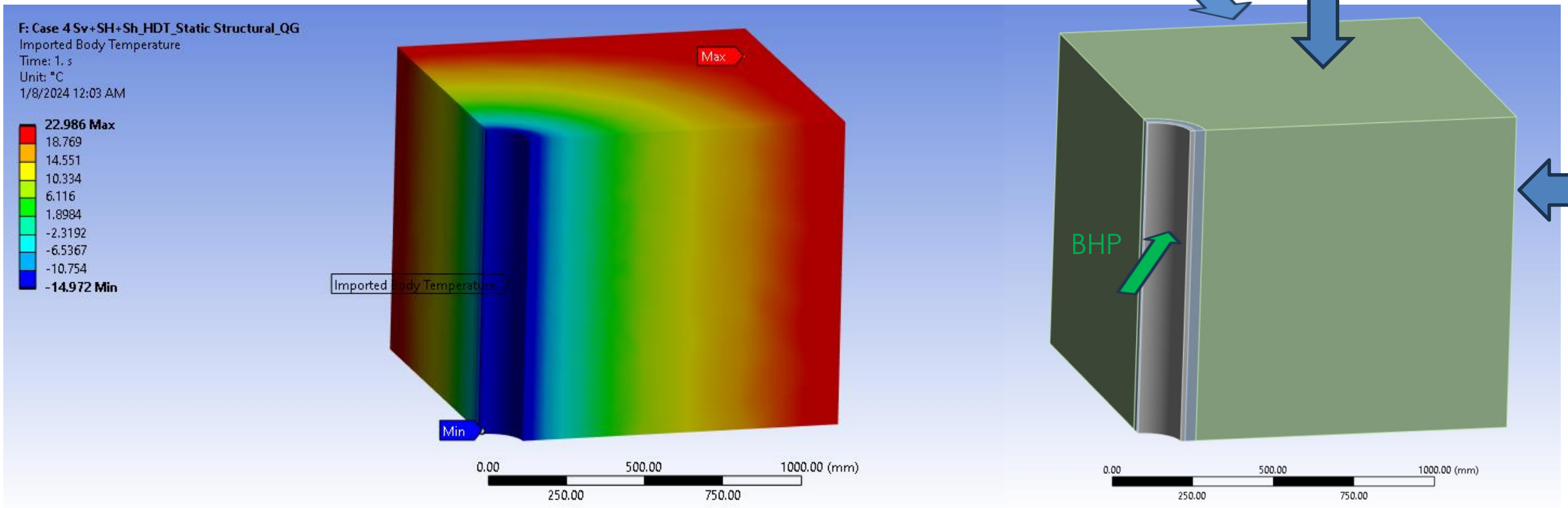






Casing, cement and formation configuration

- BHT = -15degC & Temperature Map
- Formation - Dolomitic Shale
- Cement –Lab data @ -10degC
- 9 5/8in Csg - S13Cr110 – mechanical and thermal properties



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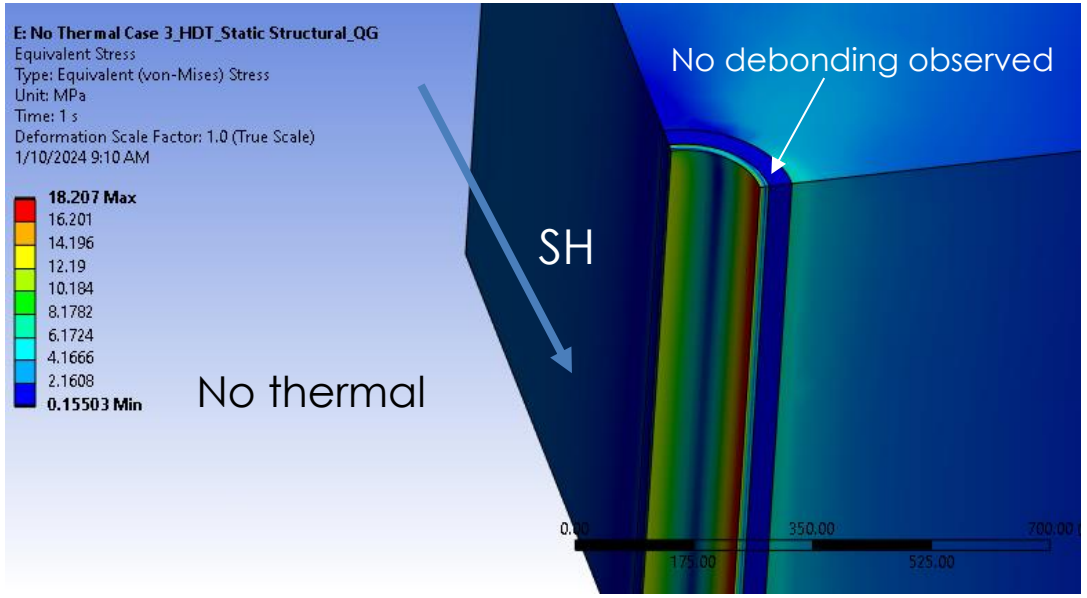
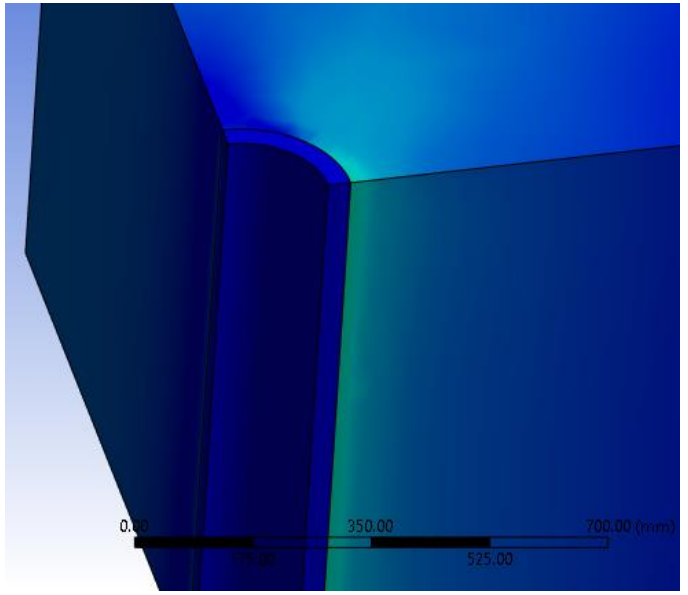
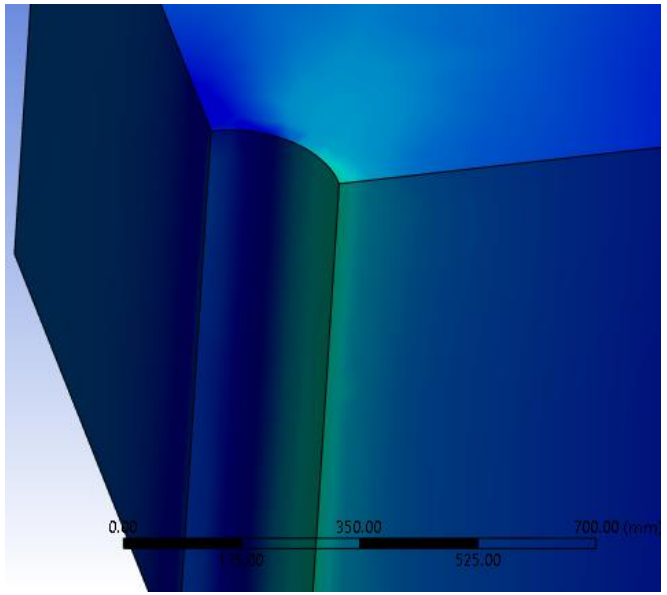
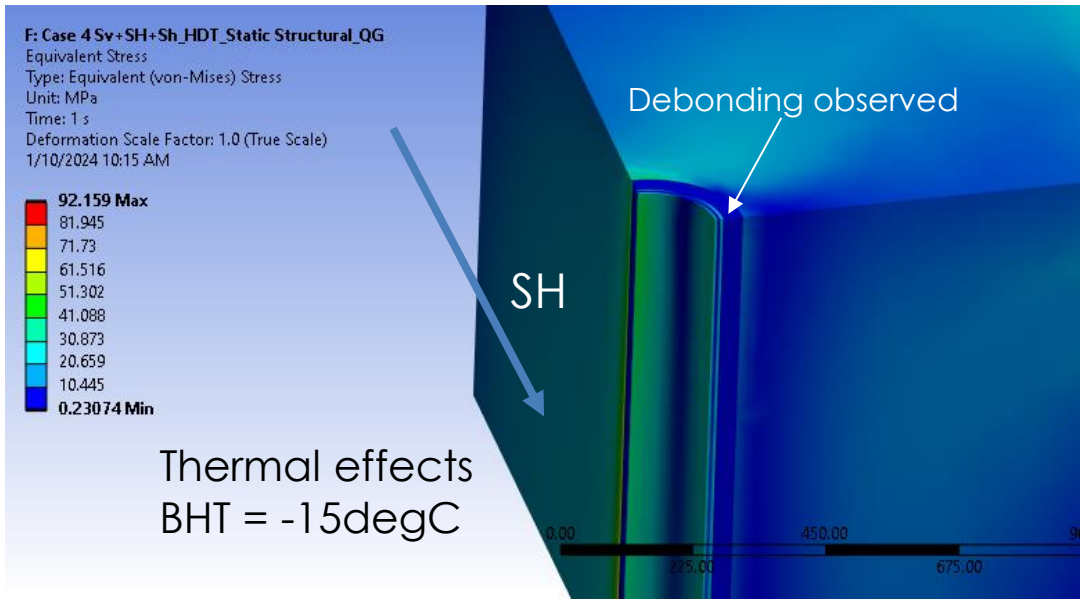
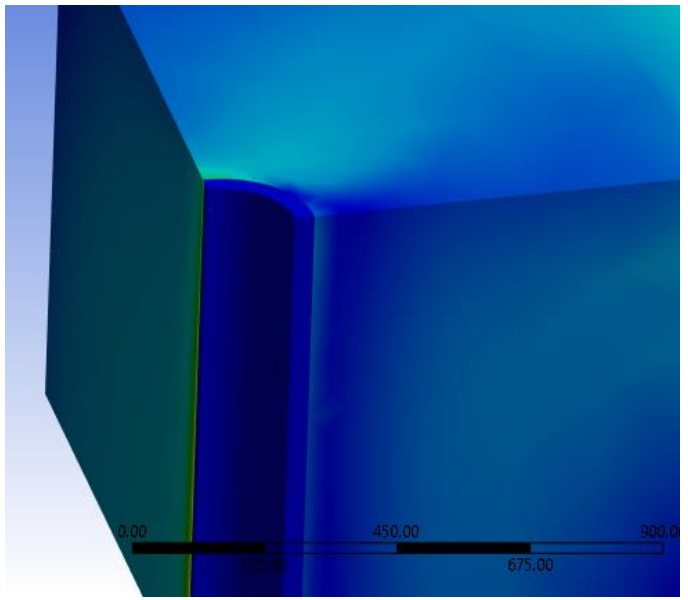
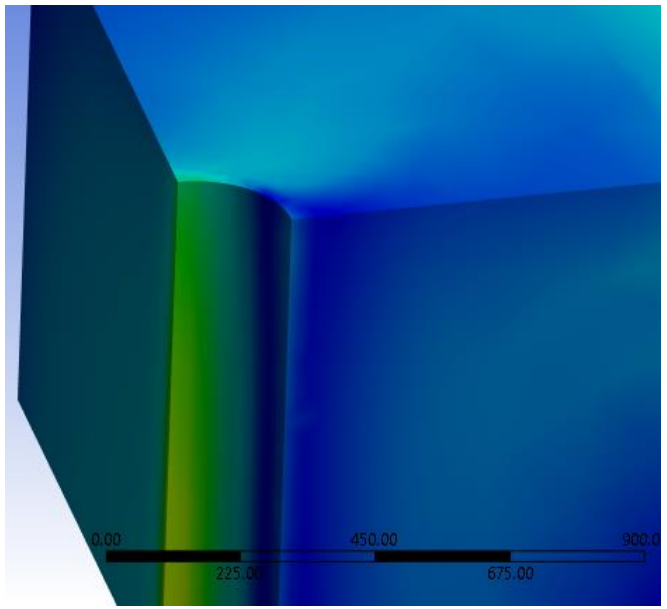






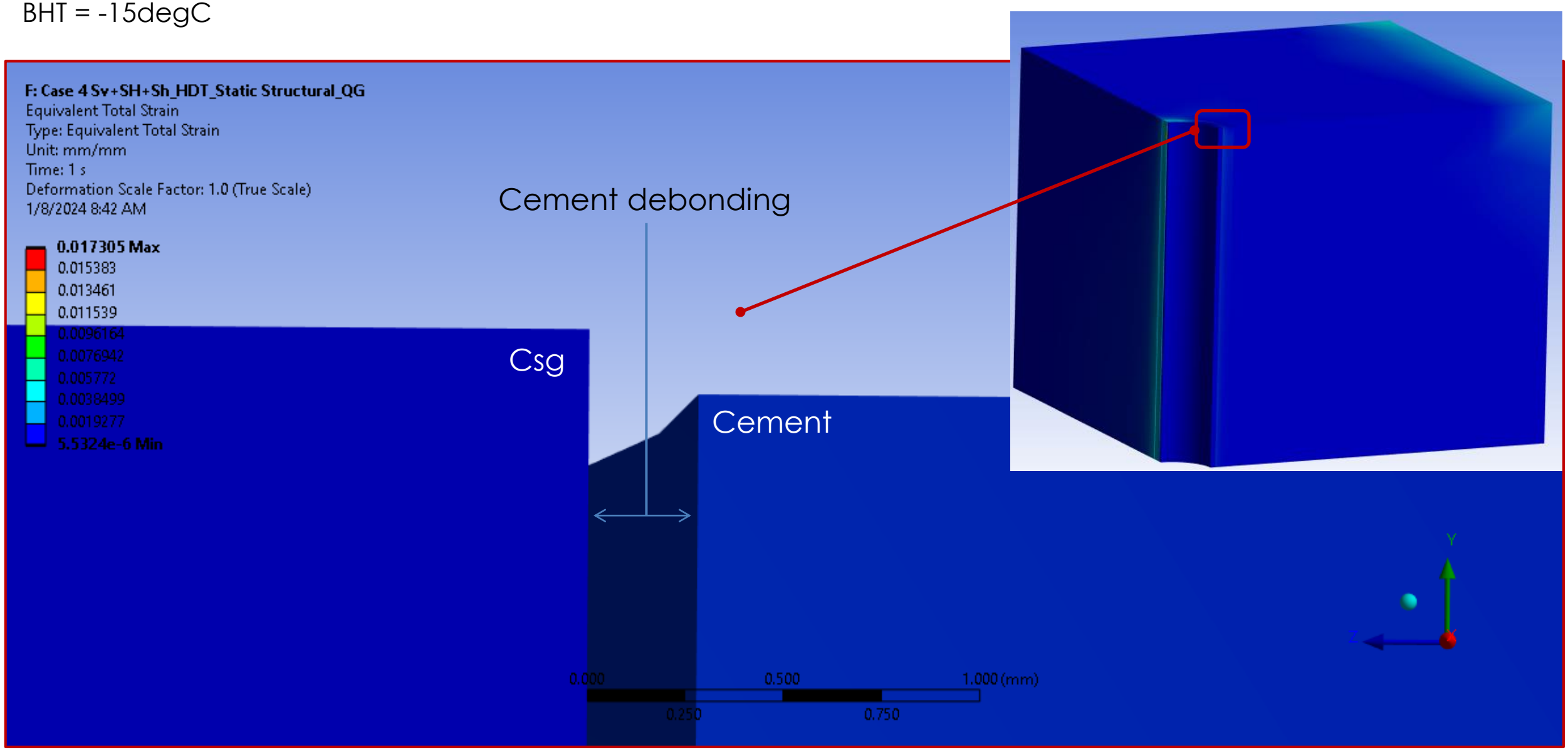






Casing, cement and formation configuration

BHT = -15degC



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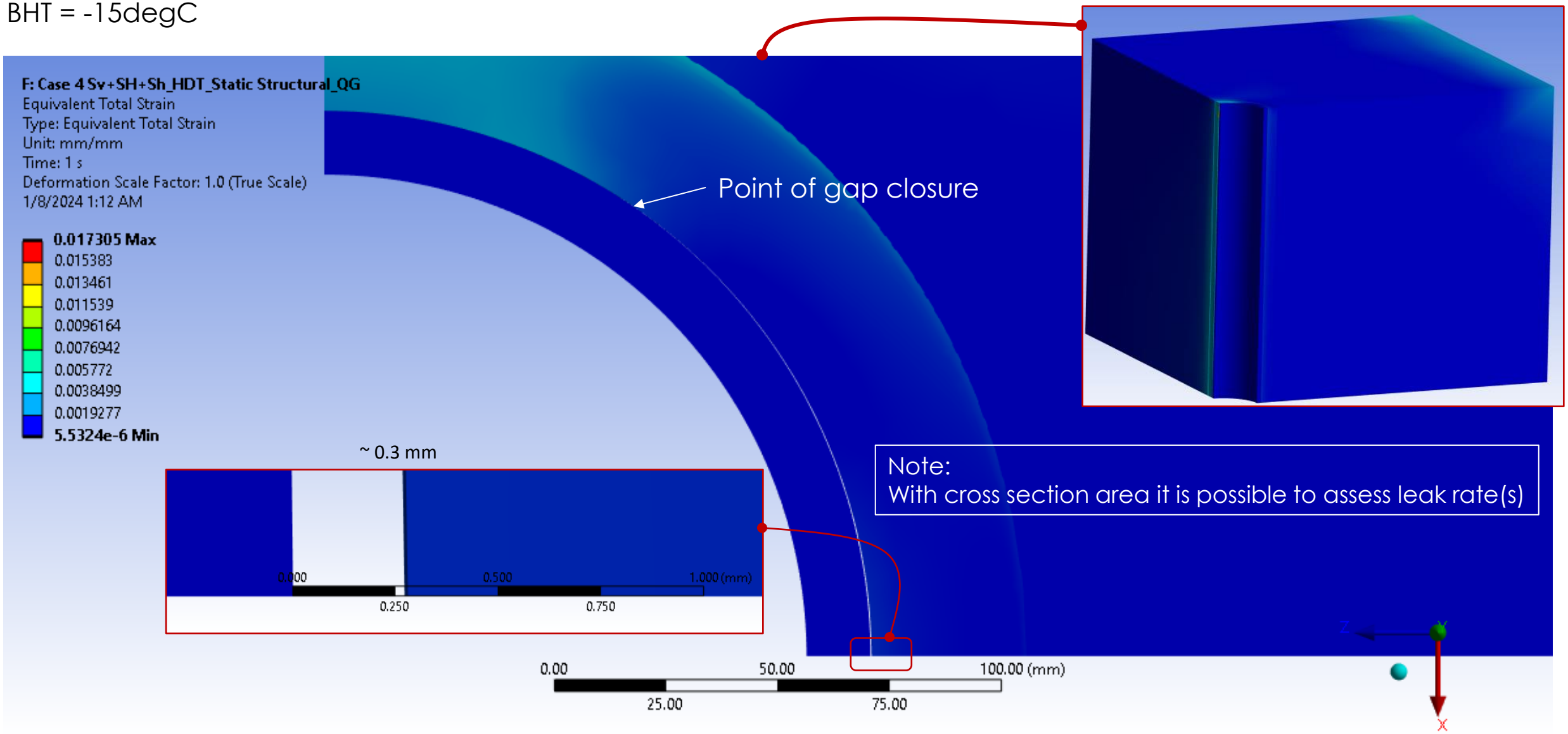
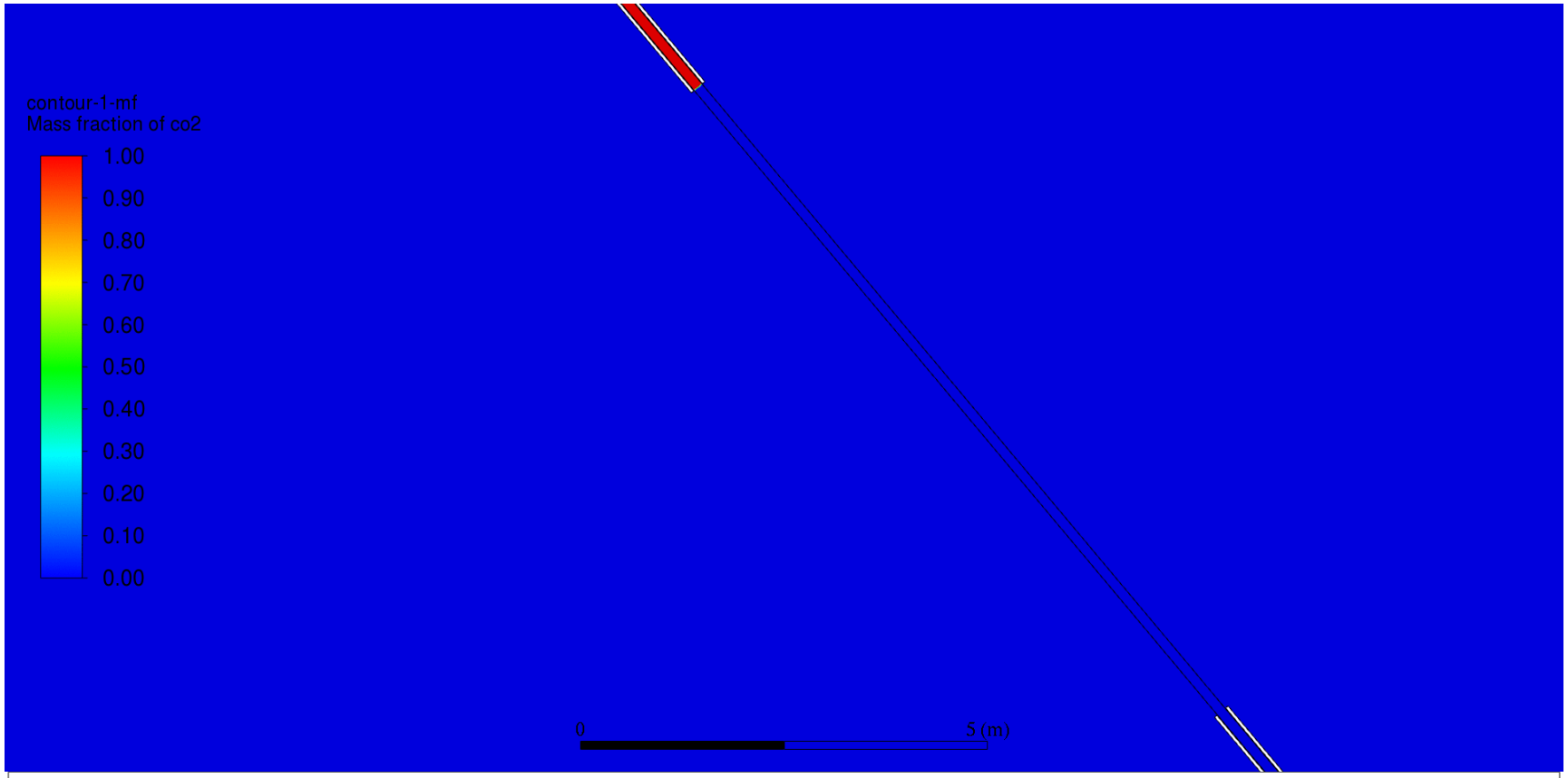


Note:
With cross section area it is possible to assess leak rate(s)

Convection/diffusion
Well shut-in

Water – CO2 Movement due to Diffusion & Convection

- Animation showing Water-CO2 movement



Contour of CO2 (Red) and Water (Blue) (Time=0.0000e+00 s)
CO2-Water Diffusion & Convection Simulation; Time: 0.00 min / 0.00 hrs / 0.00 days

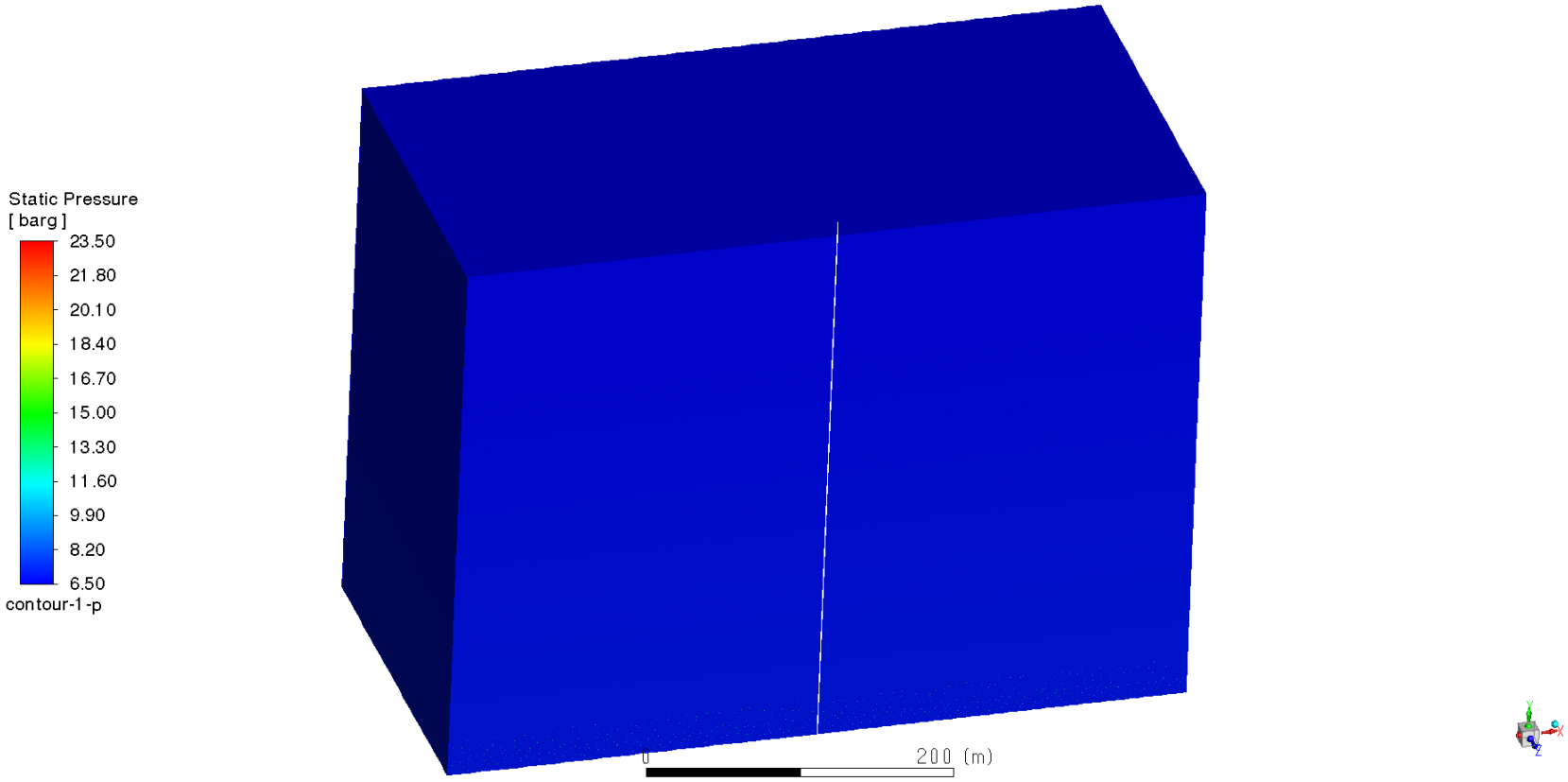
Convection Current – Top of the Well

- After a while a steady convection current is established

Injectivity

Reservoir Pressure v Time

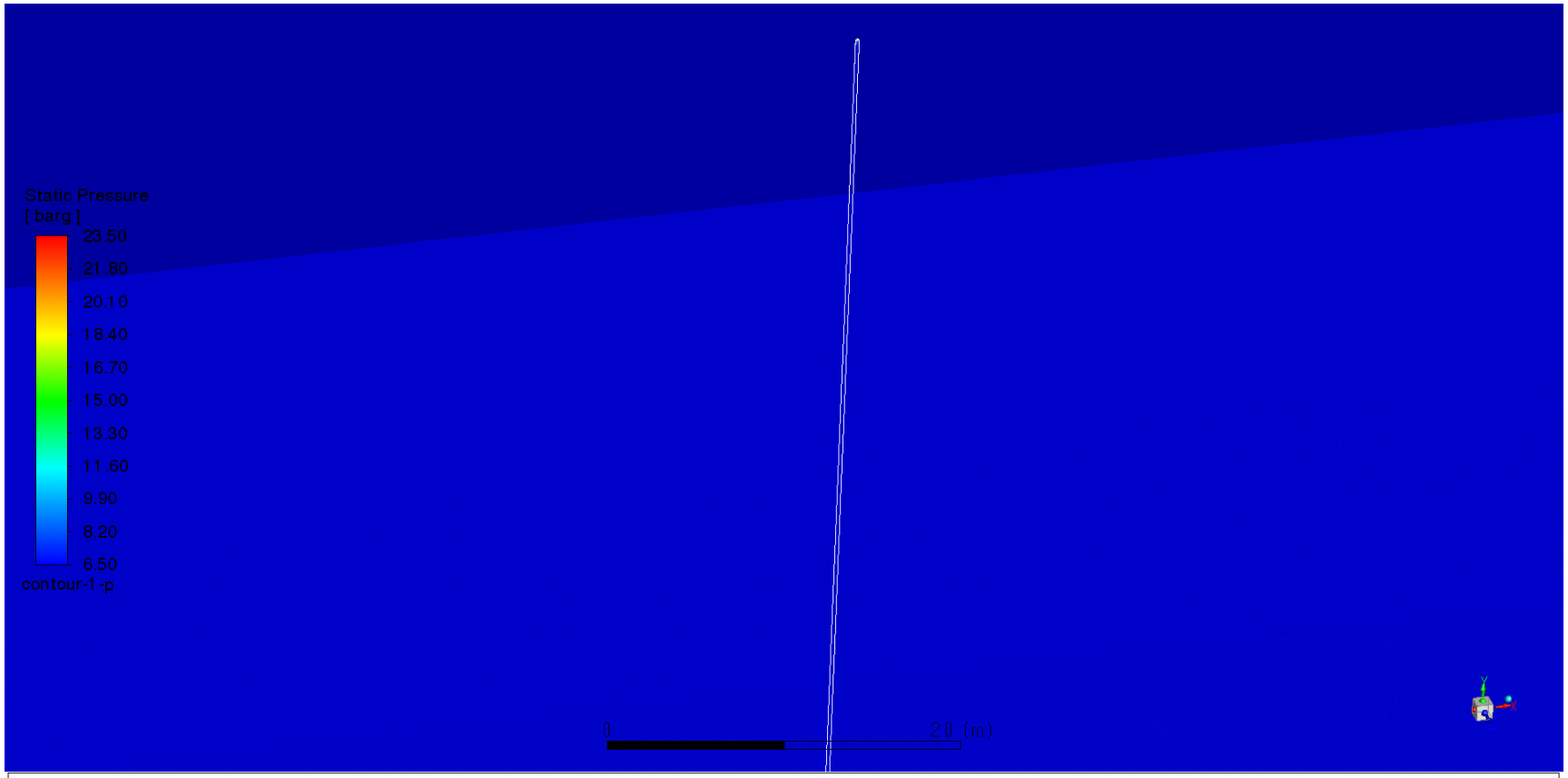
- Reservoir pressure increases from ~ 7 bar to ~ 24 bar due to CO2 injection in ~ 1 year



CO2 Injectioin - Reservoir Pressure Profile (Time=1.0000e-03 s)
Injection Time: 0.00 hrs / 0.00 days

Reservoir Pressure (Zoom in Near Wellbore) v Time

- Reservoir pressure increases from ~ 7 bar to ~ 24 bar due to CO_2 injection in ~ 1 year



CO2 Injectioin - Reservoir Pressure Profile (Time=1.0000e-03 s)
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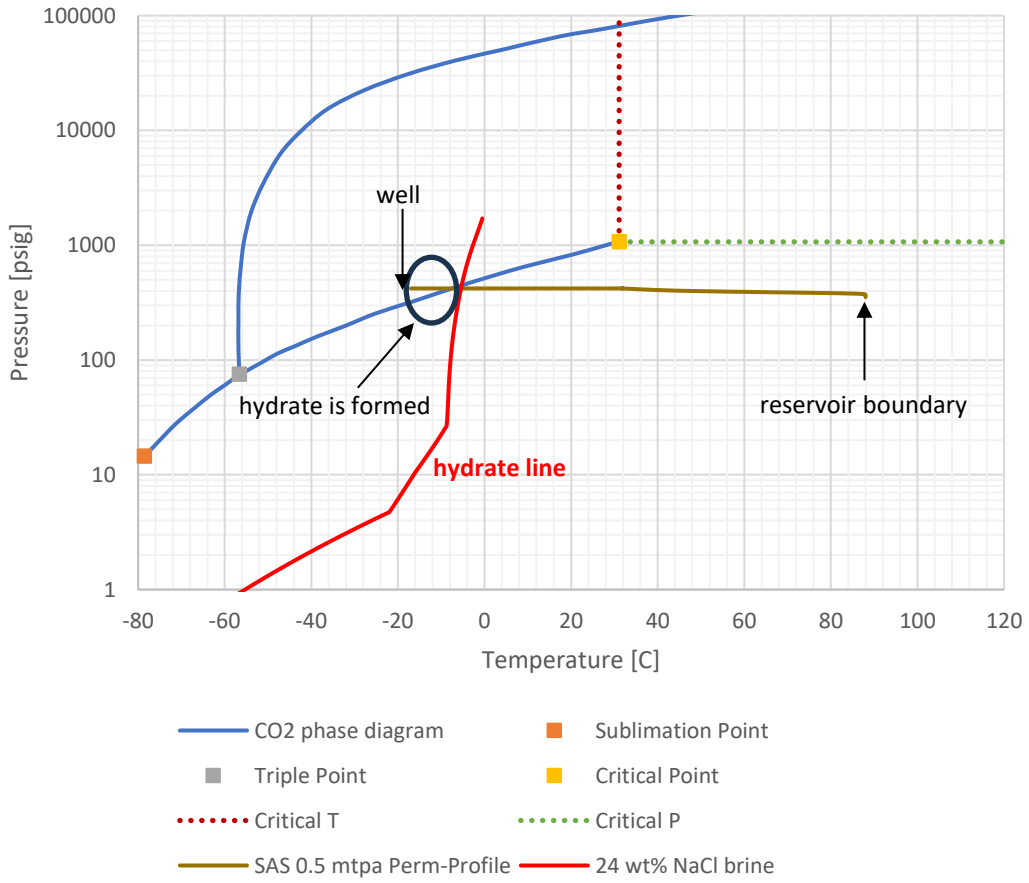
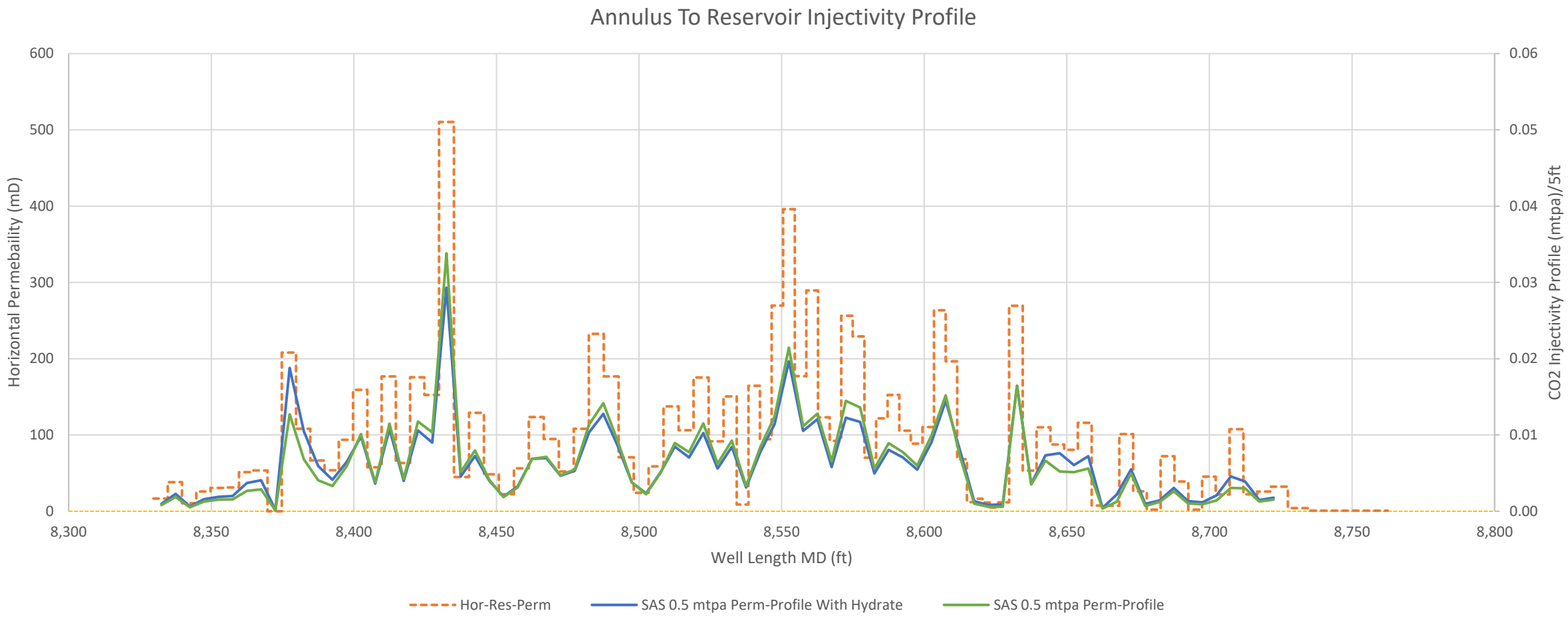
CO2 P&T Phase Diagram; 0.5 mtpa, -17 BHIT, SAS, Perm Profile



- The phase diagram on the left shows that hydrate is likely to be formed near wellbore, where the temperature is below the hydrate-saturation temperature for a given pressure
  - No hydrate is formed to the right of the hydrate line
- A function is written to implement the impact of hydrate formation on injectivity index
- This function makes use of the 24 wt% NaCl brine hydrate line

The Impact of Hydrate Formation on Injectivity Index

Case	Remarks	BHIT [C]	T-Res [C]	Q-inj [mtpa]	P-res [psig]	BHIP [psig]	DP [psig]	II [tpa/psi]	II Diff [%]
7	SAS Profiled Perm Phase Change	-17	88	0.5	340.00	421.62	81.62	6,126	-
9	SAS Profiled Perm Phase Change With Hydrate	-17	88	0.5	340.00	432.64	92.64	5,398	-12%



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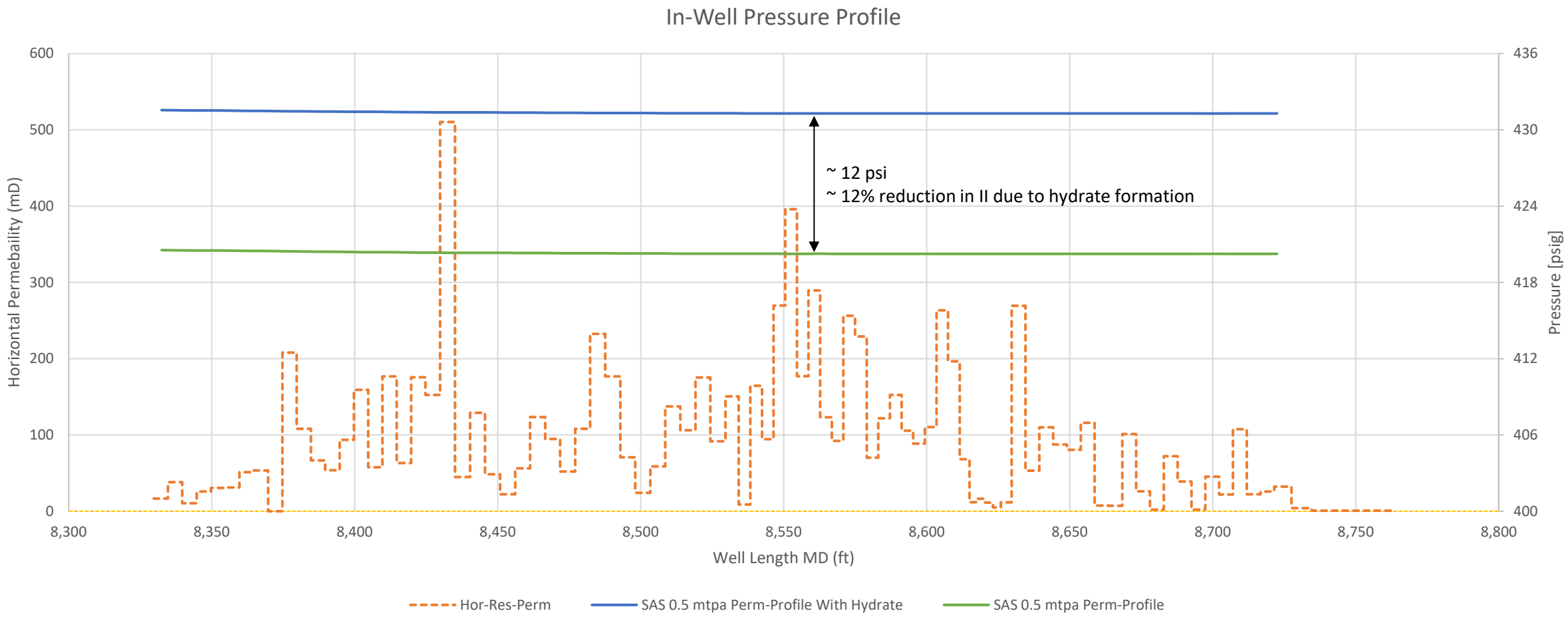
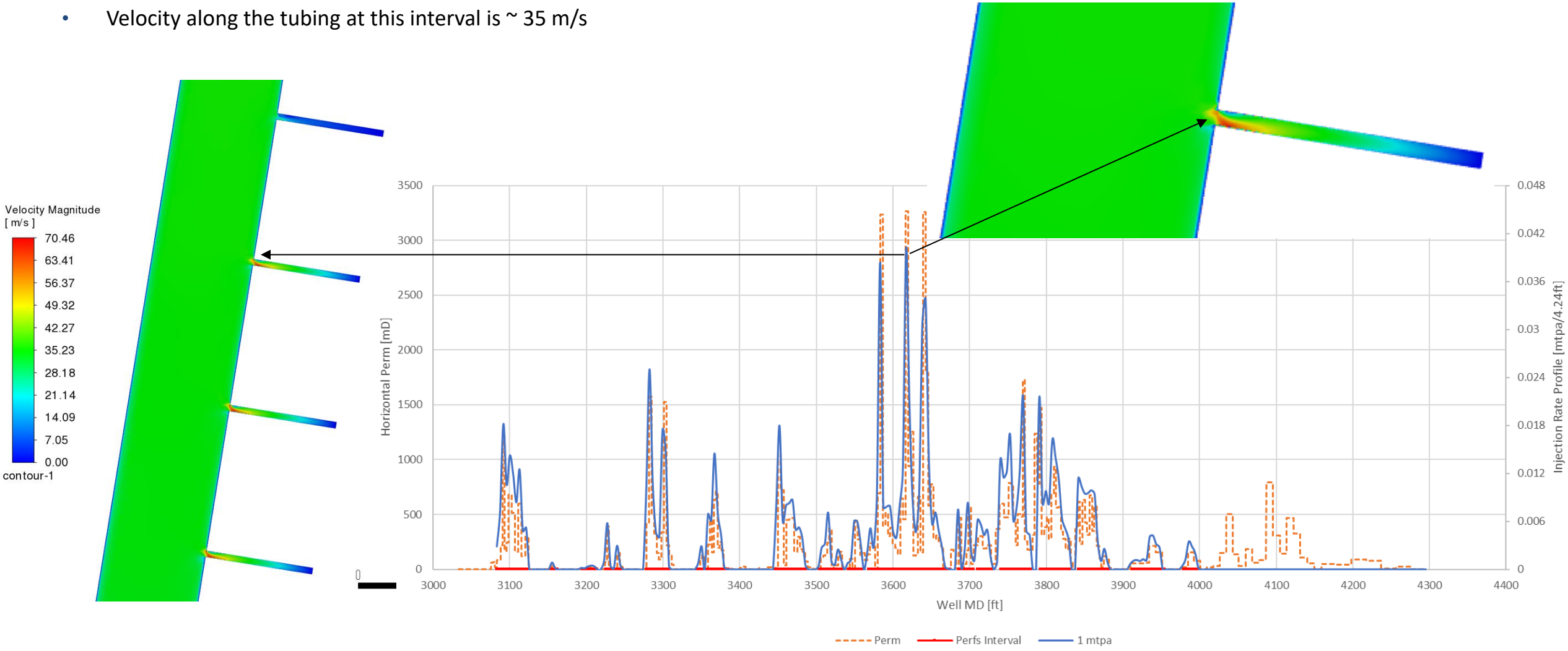


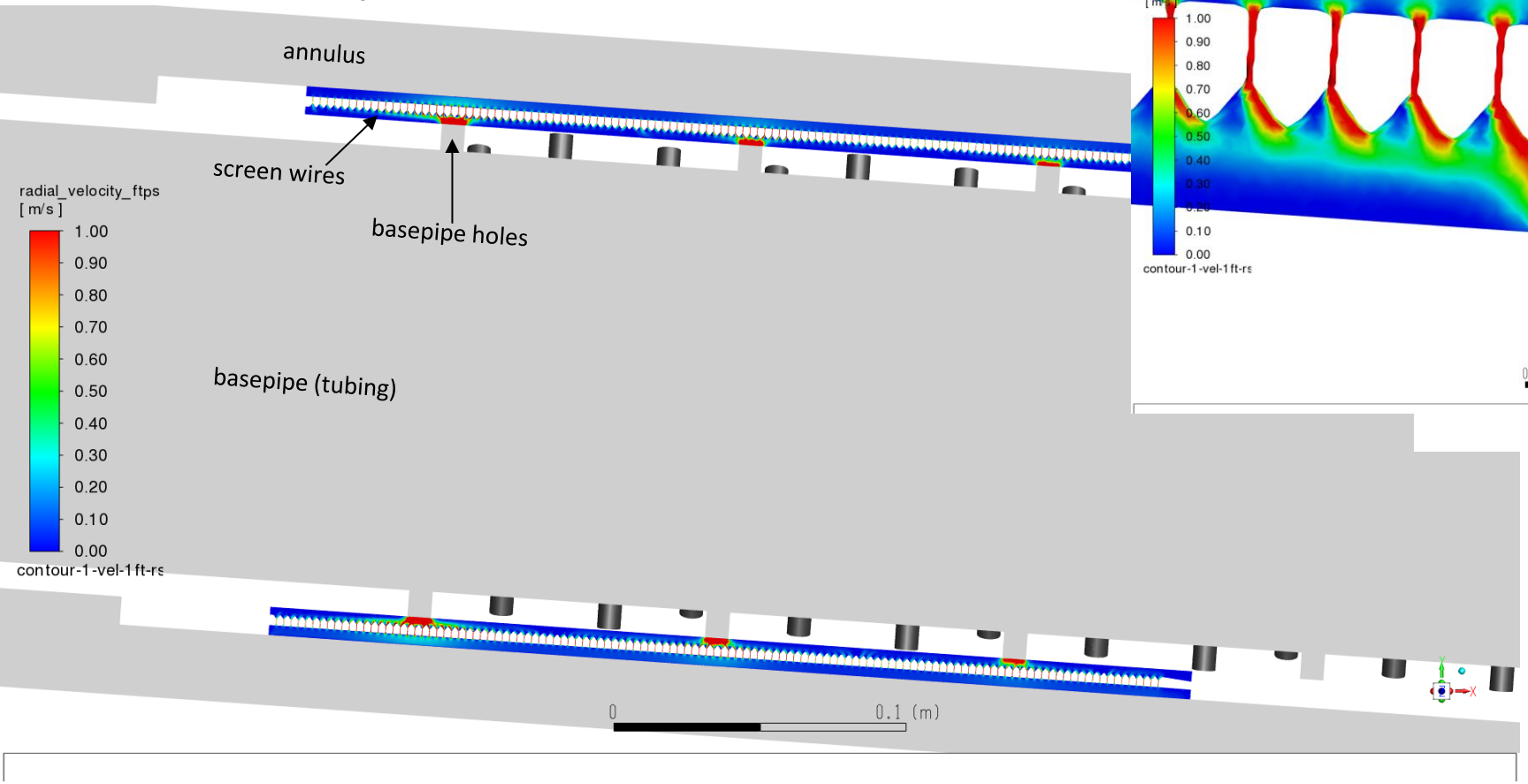
Velocity Entering Perforations

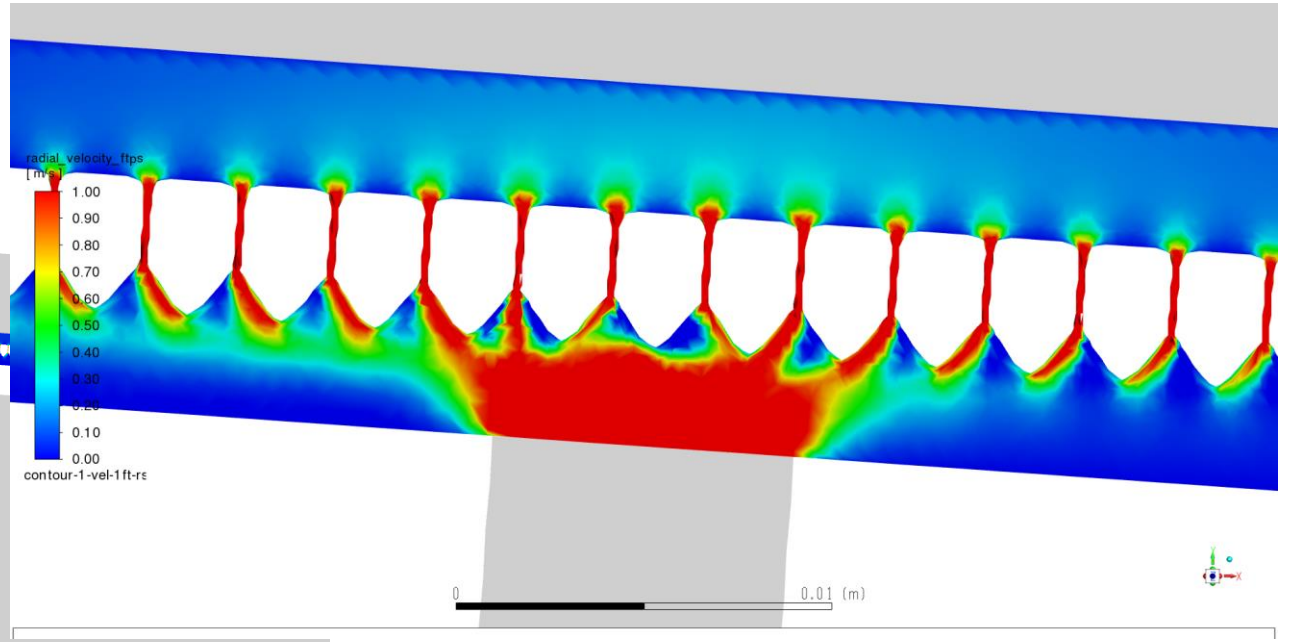
- The CO2-gas velocity entering the perforation reaches ~ 70 m/s, which then reduces as CO2-gas invades the formation
- Velocity along the tubing at this interval is ~ 35 m/s



Velocity map in SAS

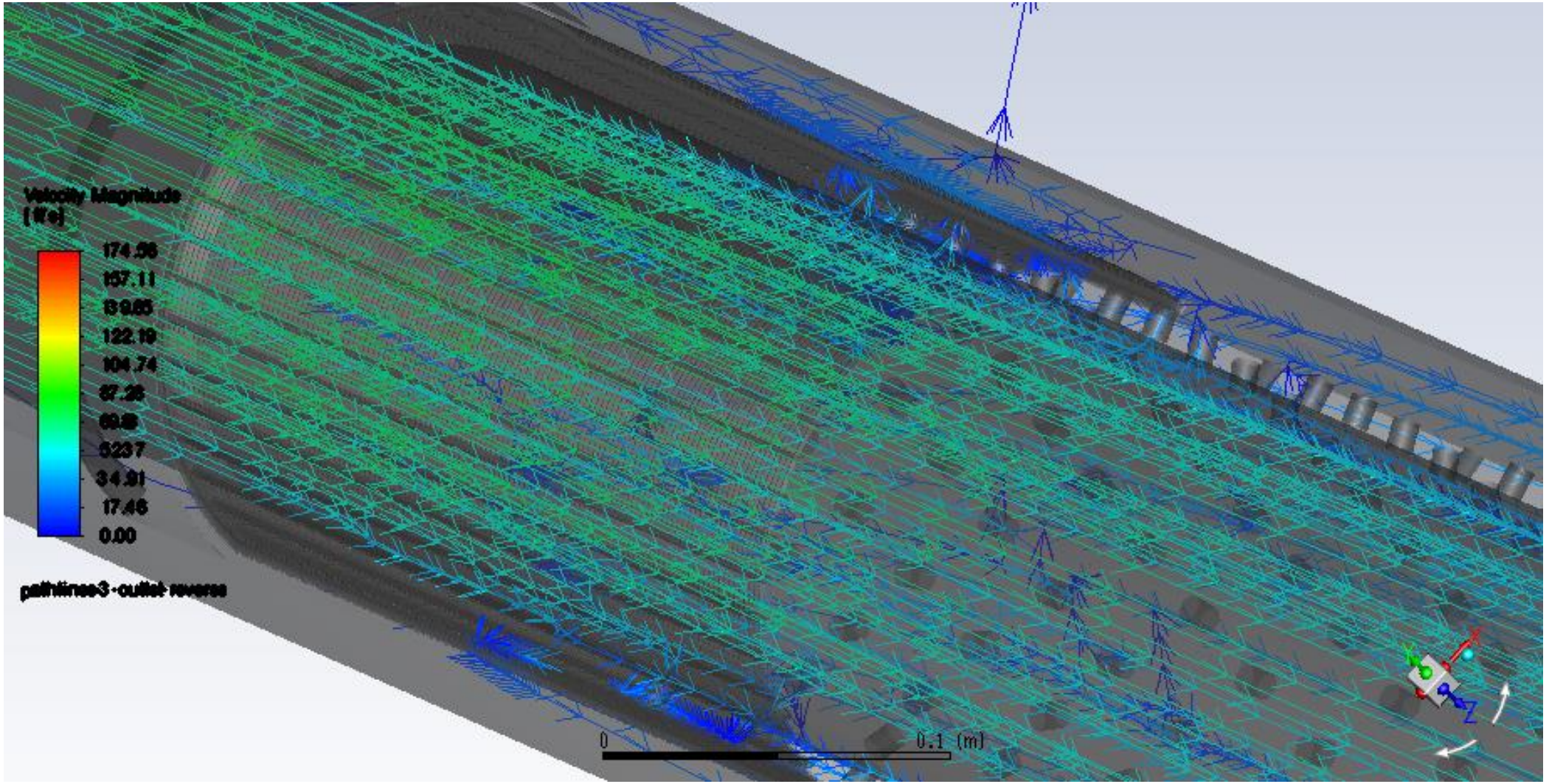
- Max velocity through the screen wires ~ 4.87 ft/s
- At the first joint from the heel





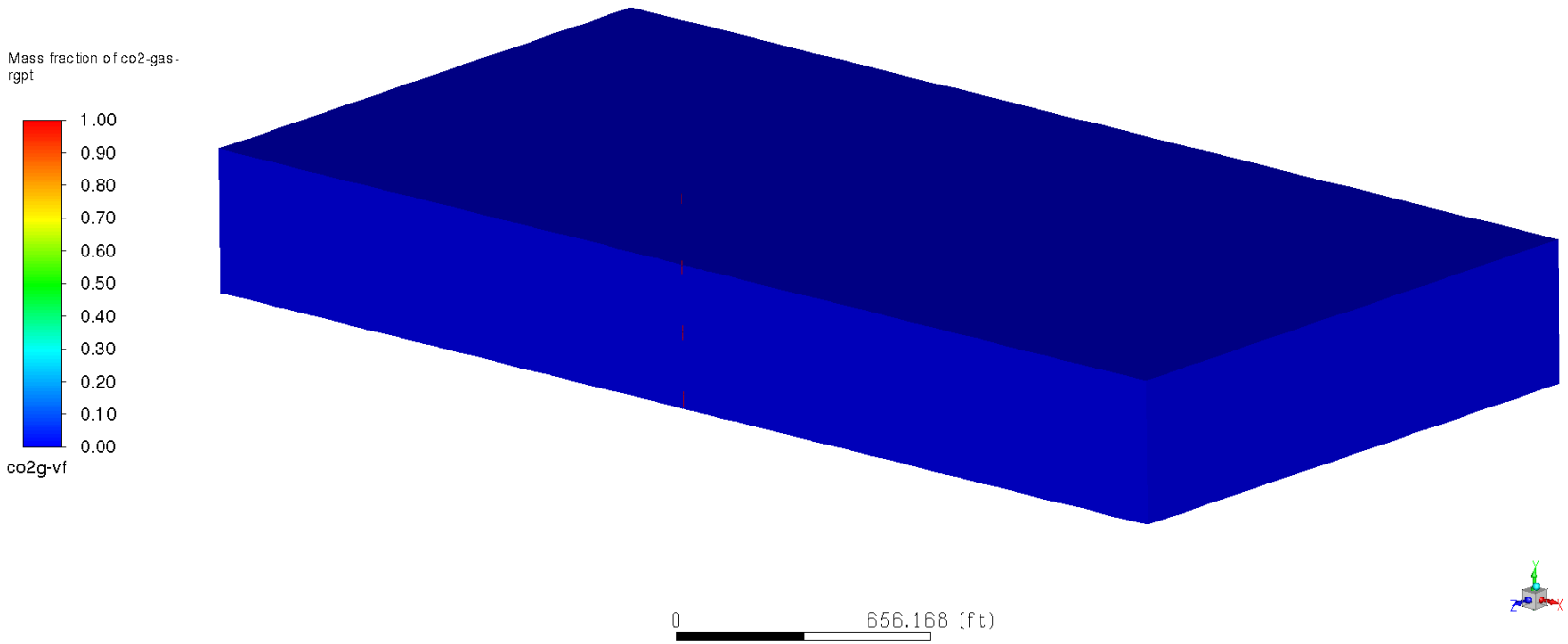
Red colour → 1 ft/s or higher (max ~ 4.9 ft/s)

Erosion/Velocity Prediction for CCS well



CO2-gas (Red) and Methane (Blue) Movement v Time

- Inject CO2-gas @ 0.5 mtpa, -17 C BHIT



Thank you

WRS Rock Properties

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