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Modelling of flow, thermal and geomechanics processes in CCS projects

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Flow, Thermal and Geomechanics in CCS - Contents

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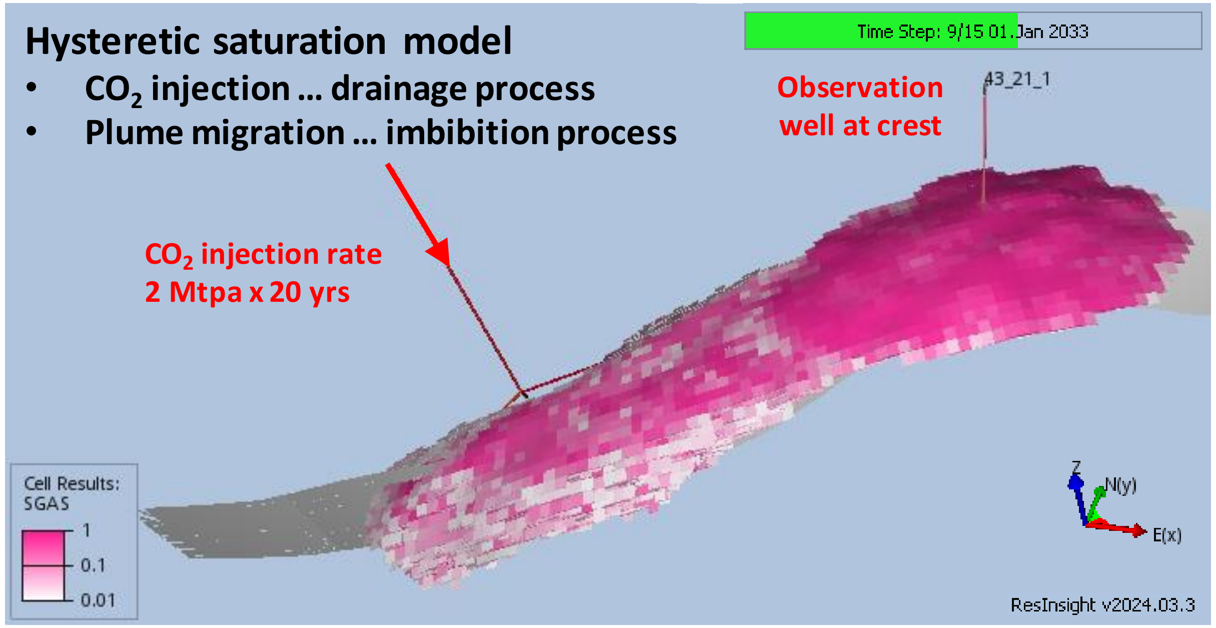
- Part II. Tian Xia – Depleted Gas - Model comparisons of Joule-Thomson cooling effect
- Part III. Tim Wynn – Geomechanics Processes in CCS Projects, Thermal Stresses & Role of Halite

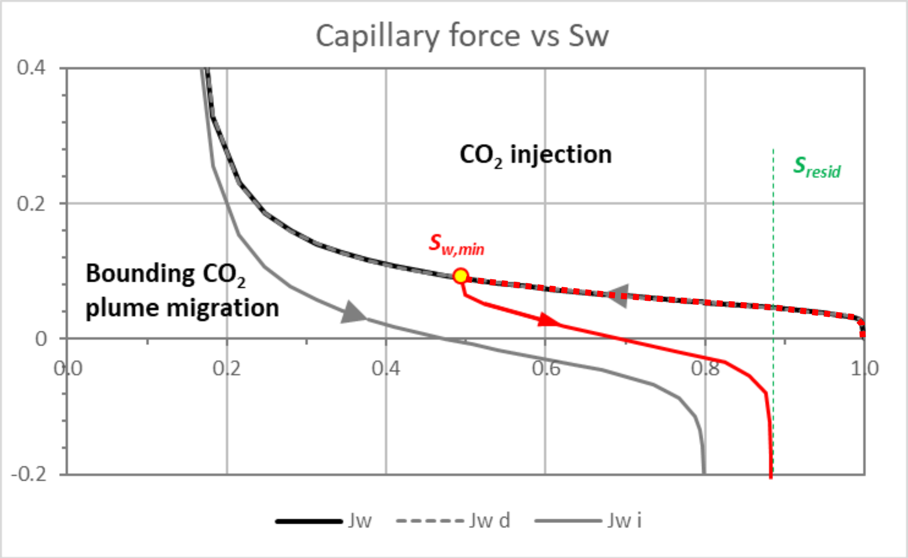
Part I: Saline Aquifers - Dynamic control of CO_2 plume migration risk

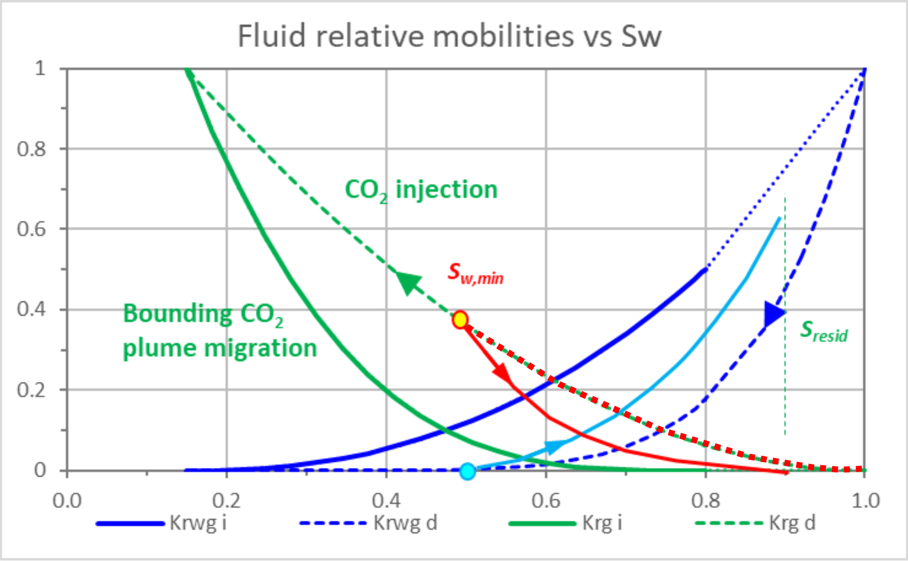
Ed Stephens

Plume modelling – trapping and mobility

- Plume scenario in White Rose (Endurance) structure
- Saturation model controls size of plume and speed of migration
- Modelling of residual trapping
  - Capillary forces responsible for trapping in early time
  - Relative permeability describes mobility of CO_2 and water
  - Hysteresis: injection (drainage), plume migration (imbibition)



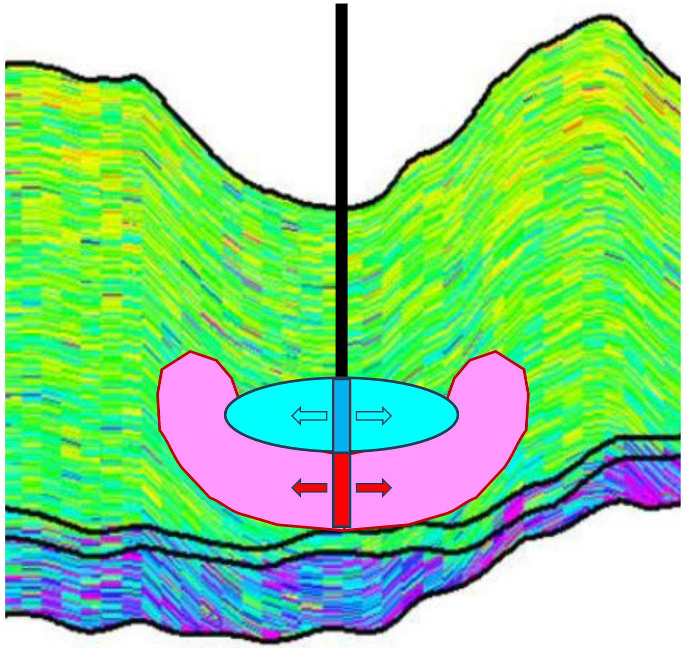




Water Cushion – controlling risk of plume migration

- Why do we need it?
  - Managing CO_2 plume migration to potential leak points (legacy wells, faults)
- Description of process
  - Injection of water cushion via the annulus, with CO_2 injected below
  - Forces the plume outwards increasing its surface area
  - Works best on thick formations - 200m plus

    → improve dissolution rate and residual trapping
- Pros
  - Primary dynamic control on the plume movement towards top reservoir
  - Could allow projects to go ahead that would otherwise be significantly curtailed / abandoned
  - Surveillance can trigger earlier control and corrective actions
- Cons
  - Water source:
    - Seawater: Additional volume added to system > pressure
    - Formation brine: May require additional brine producers
  - Additional costs: no additional injection wells needed, but additional complexity, water pumps / filtering etc.



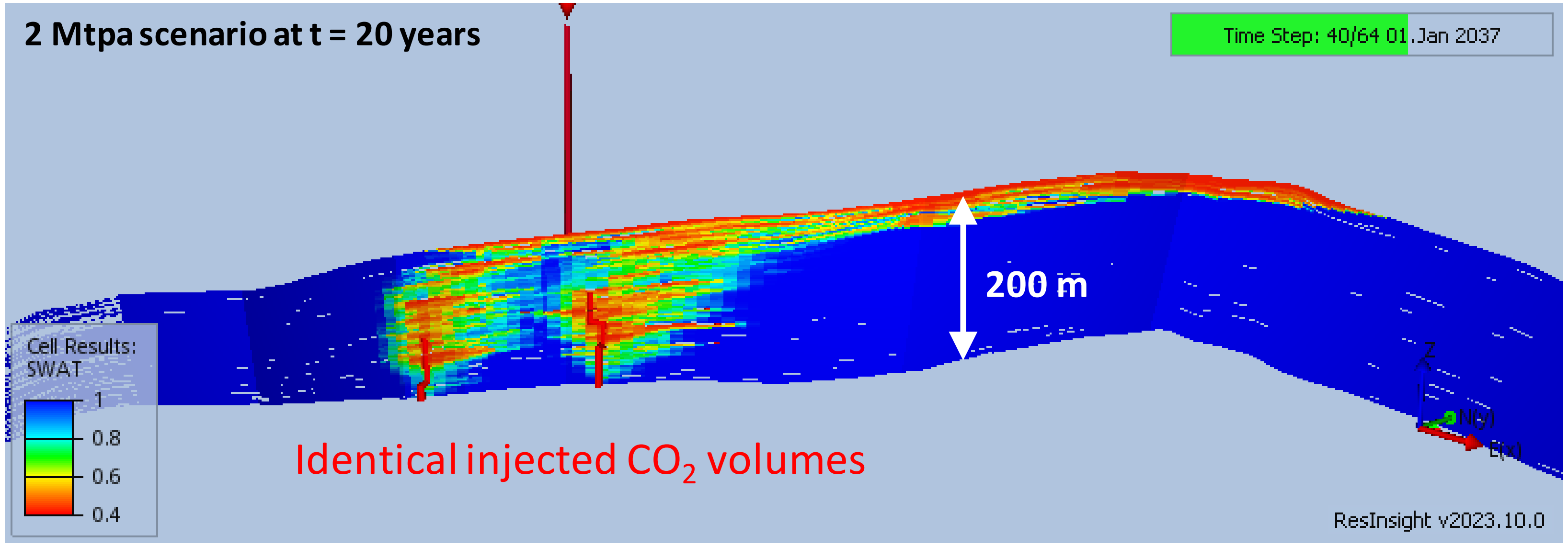
See also Ngheim et. al. 2009, Energy Procedia “Risk Mitigation Through the Optimization of Residual Gas and Solubility Trapping for CO2 Storage in Saline Aquifers”

Trial in White Rose Structure (Now Endurance)

White Rose model
Heterogeneous properties
Thickness ~ 200 m, K av. 150 md
Kv/Kh 0.1 – 0.0001

Injection 2 Mtpa, 3 wells (phased)

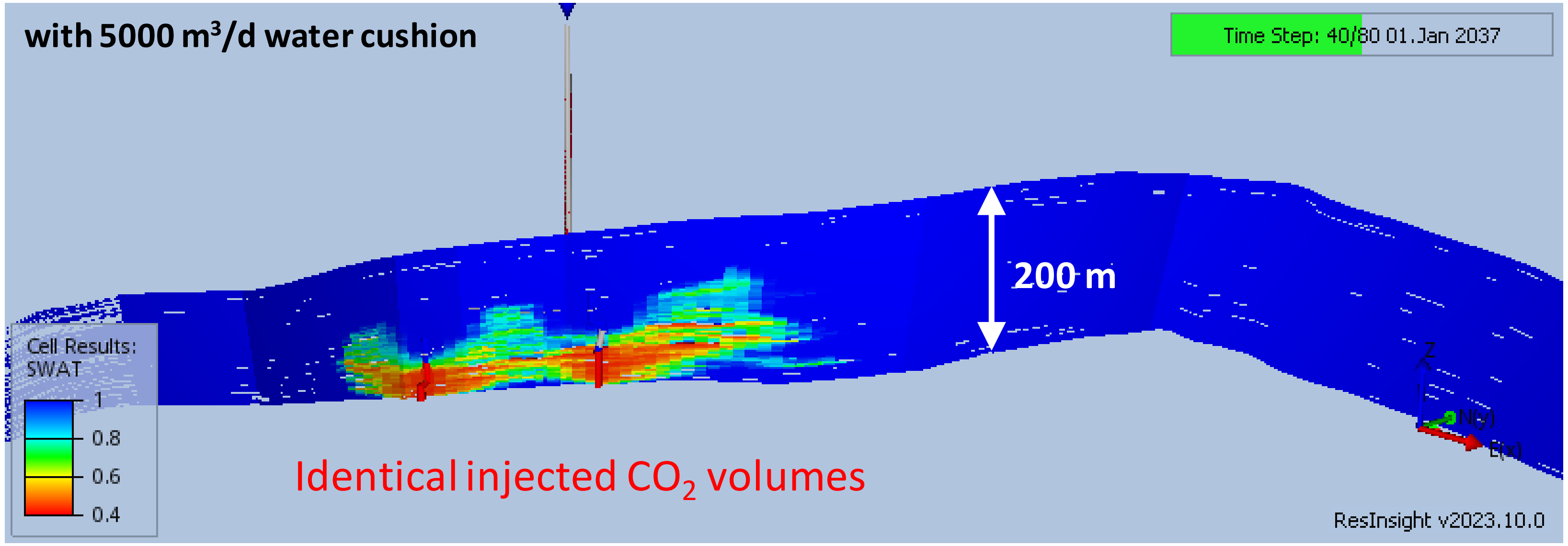
Plume migrates to crest



Scenario with seawater cushion
Annulus 5000 m^3/d x 2 flowing

Same CO_2 injection volume, rate & phasing

Plume controlled



Part II: Depleted Gas Reservoirs – Model comparisons of the Joule-Thomson cooling effect

Tian Xia

Depleted Gas Reservoirs – Joule-Thomson Effect

- Key Challenge of Reservoir Simulation Modelling
  - Lack of real reliable data of CCS in depleted gas reservoirs to validate simulation models
    - Several reservoir simulators claim to have the ability to capture Joule-Thomson Cooling Effect
    - CO_2 injection tests at a commercial rate (~1Mt/y/well): yet to start or just started
- Preliminary Testing of Reservoir Simulators for J-T Cooling Effect
  - Reference: Mathias (2014)
    - One dimensional radial mathematical model
    - Main inputs and outputs provided
  - Three simulation models constructed with three simulators to mimic Mathias' model
    - One dimensional irregular grid: 45° → 1/8th of a rectangle – Simulator A and B
    - One dimensional radial grid – Simulator C

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Heat transport and pressure buildup during carbon dioxide injection into depleted gas reservoirs

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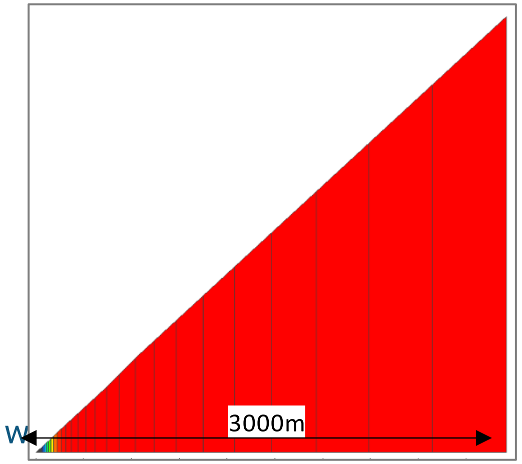
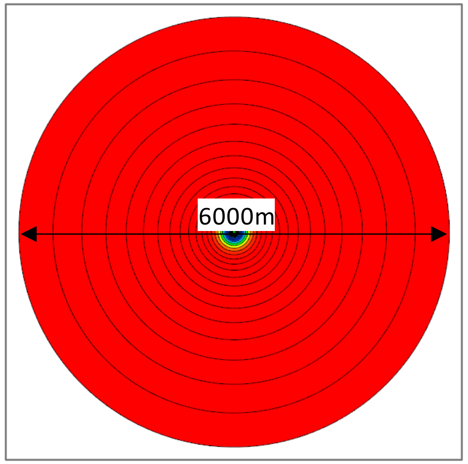




Carbon dioxide injection into depleted gas reservoirs

Formation thickness	$H = 150$ m
Permeability	$k = 100$ mD
Relative permeability	$k_{rg} = 0.6$
CO_2 injection rate	$M_0 = 0.3$ Mt year^{-1}
Initial pressure	$P_0 = 0.7$ MPa
Radial extent of reservoir	$r_e = 3000$ m
Well radius	$r_w = 0.1$ m
Residual water content	$\theta_w = 0.05$
Initial temperature	$T_0 = 35\,^\circ$C
Injection temperature	$T_w = 35\,^\circ$C
Volume fraction of rock	$\theta_r = 0.8$

TABLE 1. Parameter values assumed for base case.

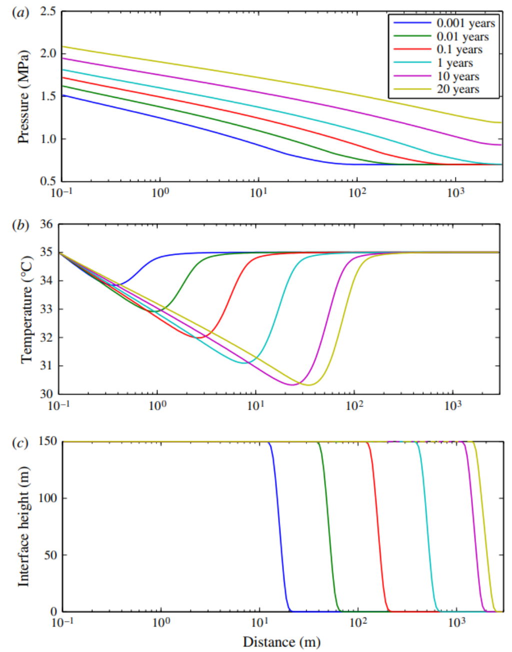
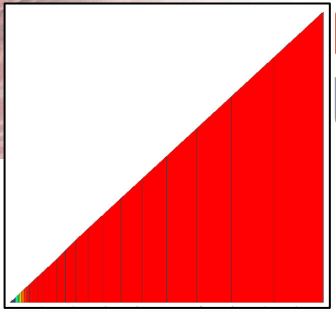
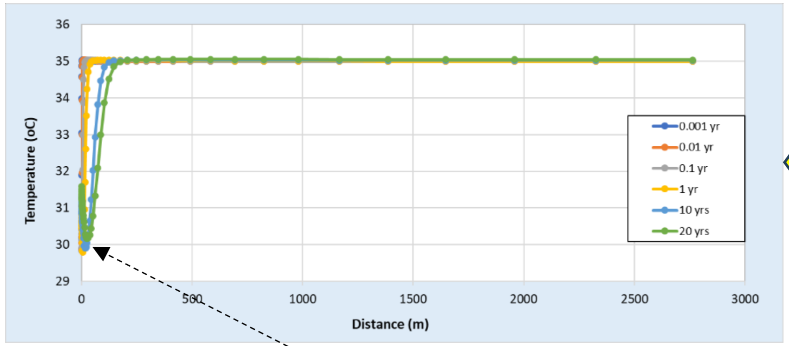


FIGURE 2. Results from the base case simulation (see table 1) including plots of: (a) pressure at the base of the reservoir, (b) temperature and (c) the CO_2–CH_4 interface height against radial distance for various times, as indicated in the legend.

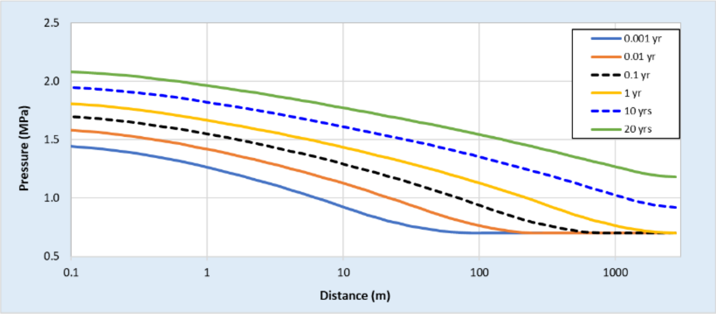
Depleted Gas Reservoirs – Joule-Thomson Effect

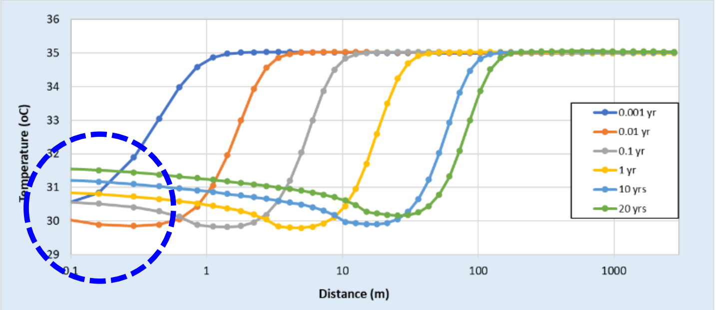


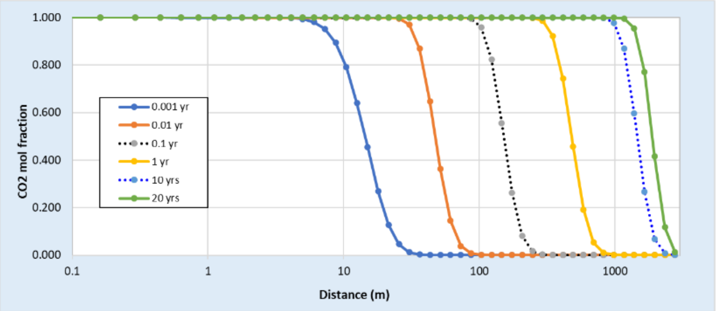
- Simulation Model A -- One dimensional irregular grid model
  - Modifications required to match Mathias' output profiles
    - Pressure, CO_2 interface: matched
    - Temperature profile: not matched
      - max. temperature drop at wellbore

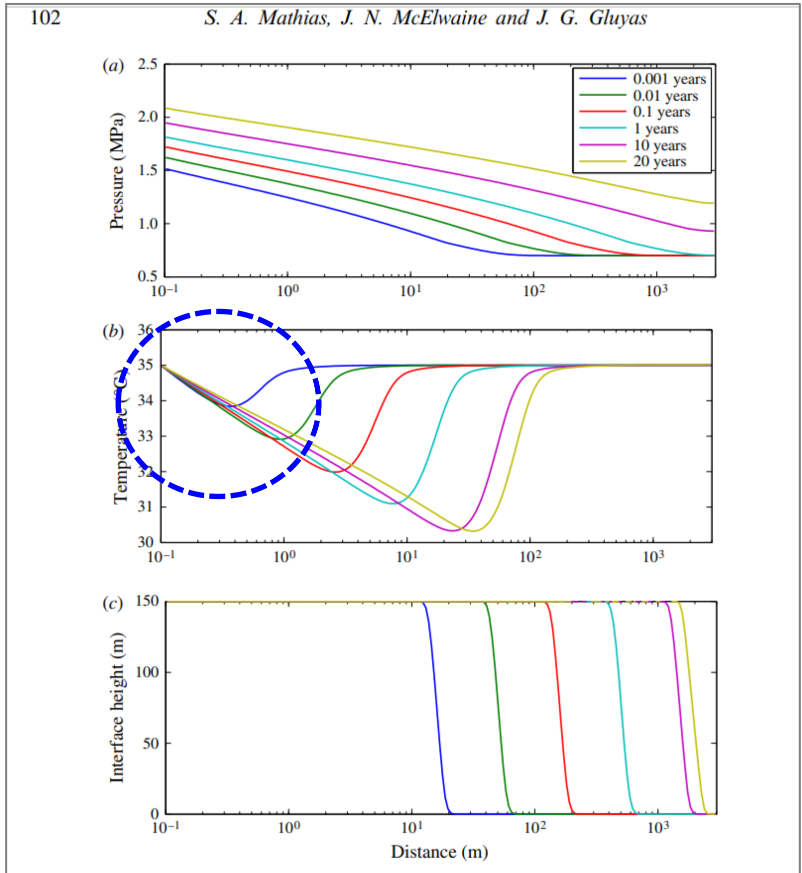


J-T cooling zoom: ~50m from the injection well









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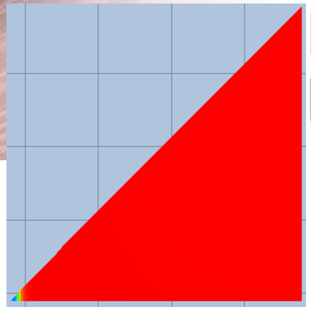
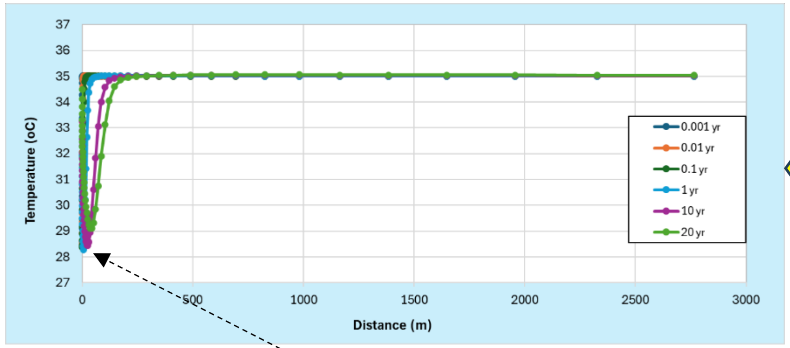
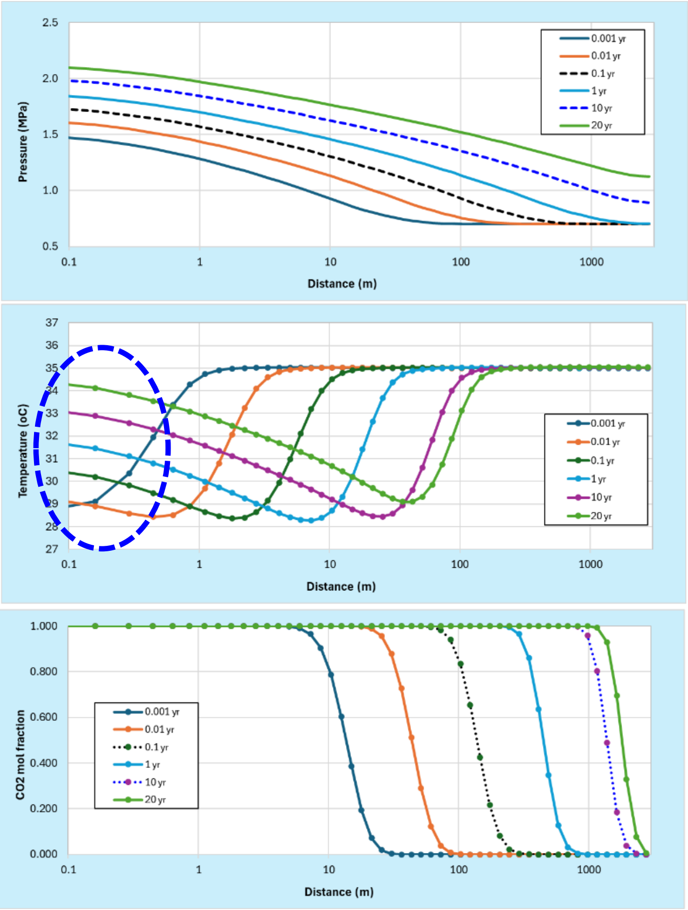
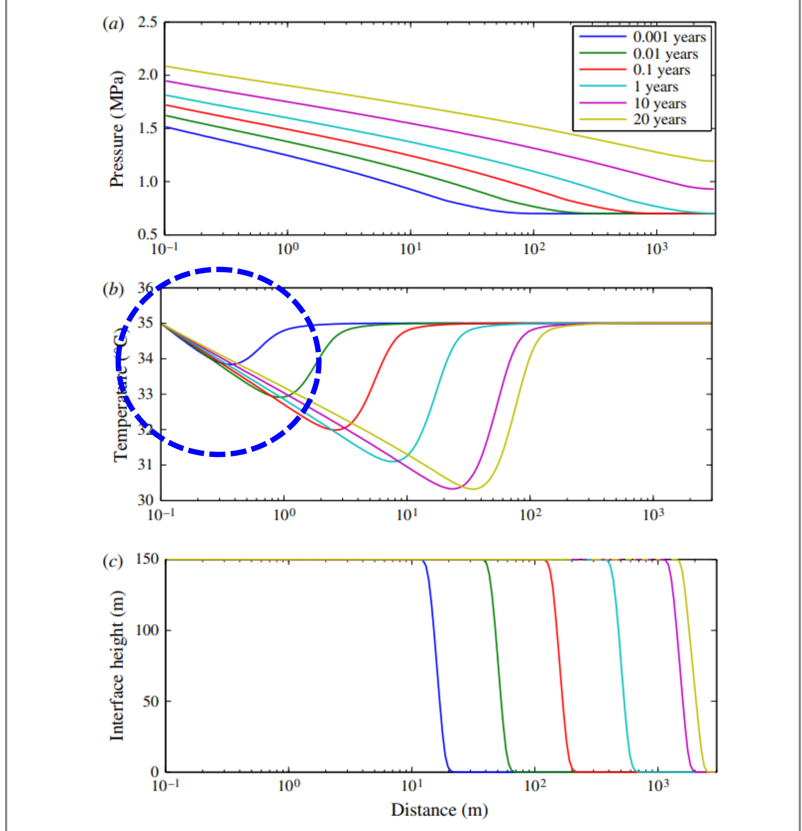
Depleted Gas Reservoirs – Joule-Thomson Effect



- Simulation Model B -- One dimensional irregular grid model
  - Modifications required to match Mathias' output profiles
    - Pressure, CO_2 interface: matched
    - Temperature profile: not matched
      - Max. temperature drop at wellbore



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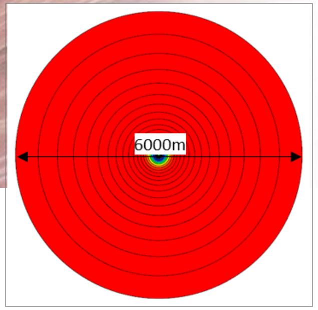
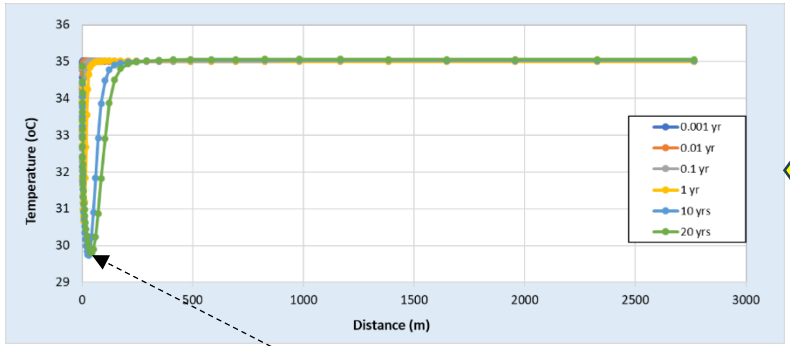
J-T cooling zoom: ~50m from the injection well

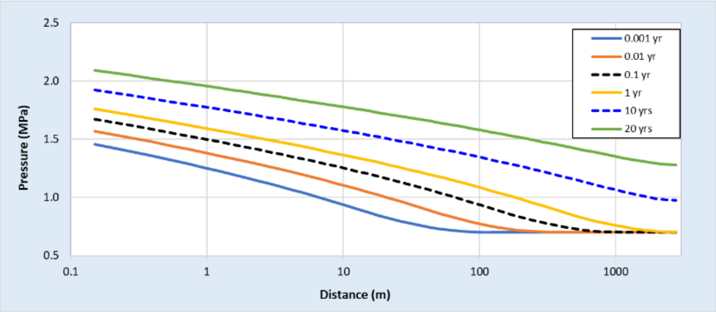
Depleted Gas Reservoirs – Joule-Thomson Effect

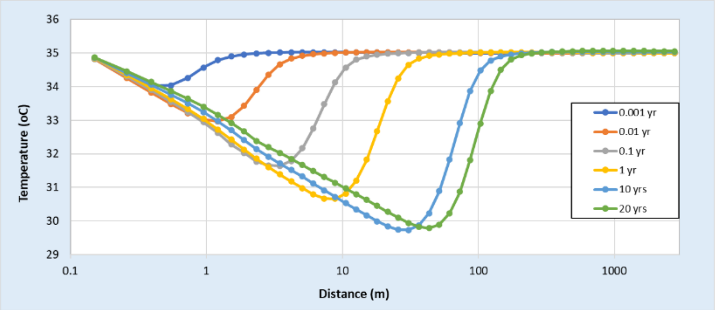


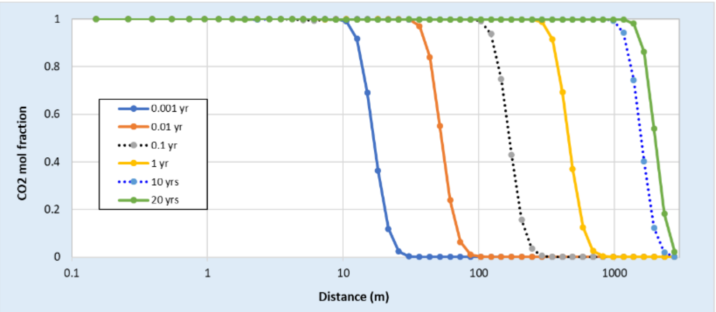
- Simulation Model C -- One dimensional radial grid model
  - Modifications required to match Mathias's output profiles
  - Close match to all profiles
    - CO_2 interface
      - Mathias's model: interface height
      - Model C: CO_2 gas mol fraction

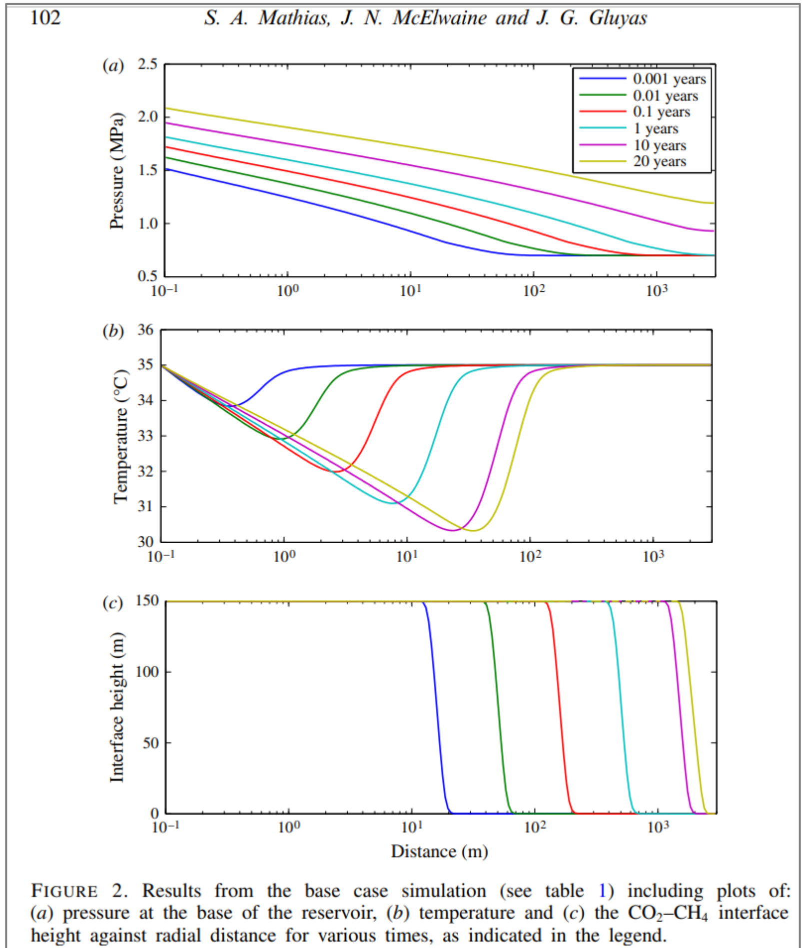


J-T cooling zoom: ~50m from the injection well





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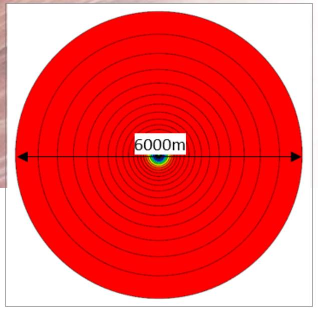
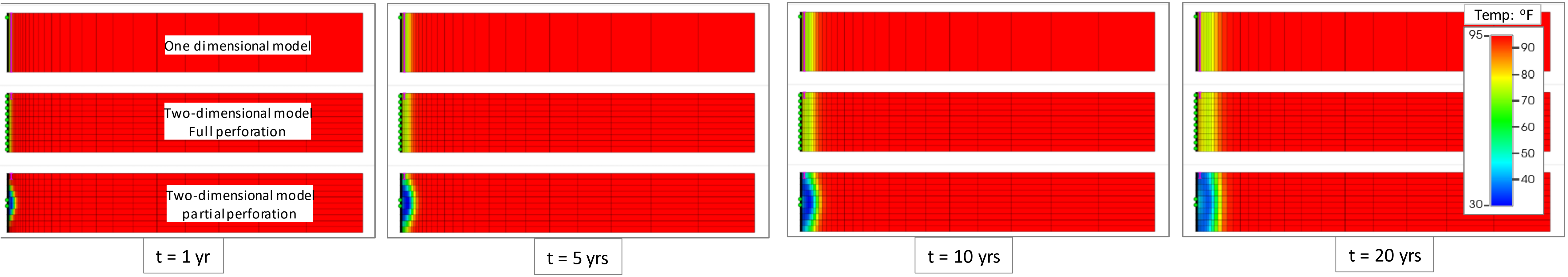
Depleted Gas Reservoirs – Joule-Thomson Effect



- Simulation Model C – Two-dimensional radial grid models
  - Sensitivity study
    - CO_2 injection rate; Permeability; CO_2 injection temperature and etc.
    - 2D radial cases: full perf., partial perf.
      - 2D full perforation, temperature profiles: same as 1D radial model
      - 2D partial perforation: high J-T cooling effect → subzero temperature (30°F → -1.1°C)

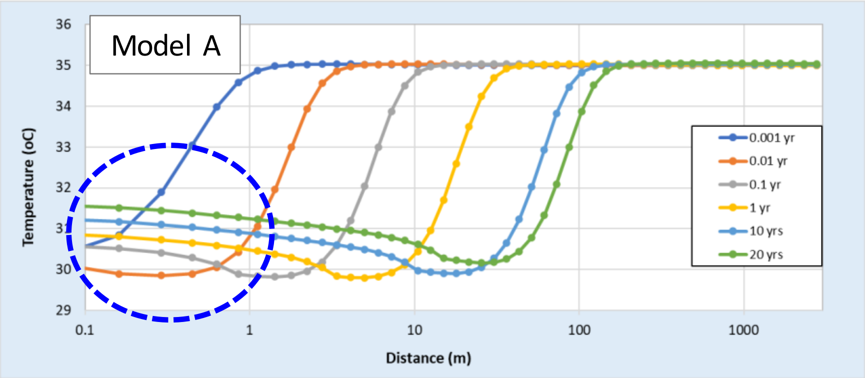
Temperature profiles

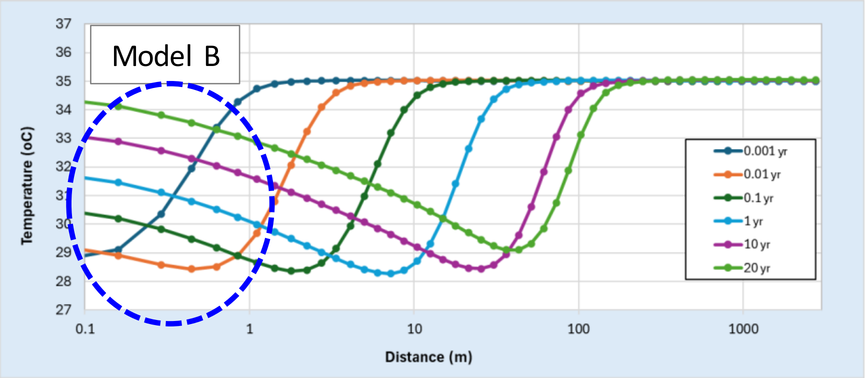


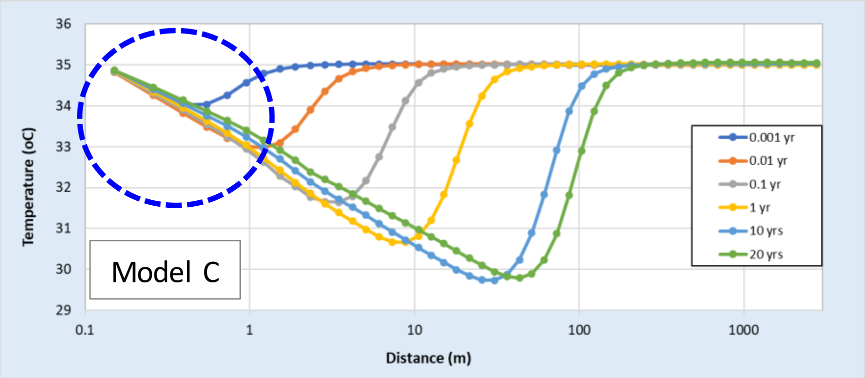
Depleted Gas Reservoirs – Joule-Thomson Effect

- Observations
  - J-T cooling zone: within 50m ~ 100m to the injection well
  - Three simulators: different temperature at or near the well
  - Possible subzero temperature, if there is a combination of adverse reservoir properties and well completions

- Recommendation
  - The simulation model for large-scale CCS in a depleted gas reservoir needs to be validated against reliable measured data
    - Laboratory test: porous medium J-T effect (microscopic level)
    - CO_2 injection well pilot (or test): near wellbore J-T cooling (macroscopic level)







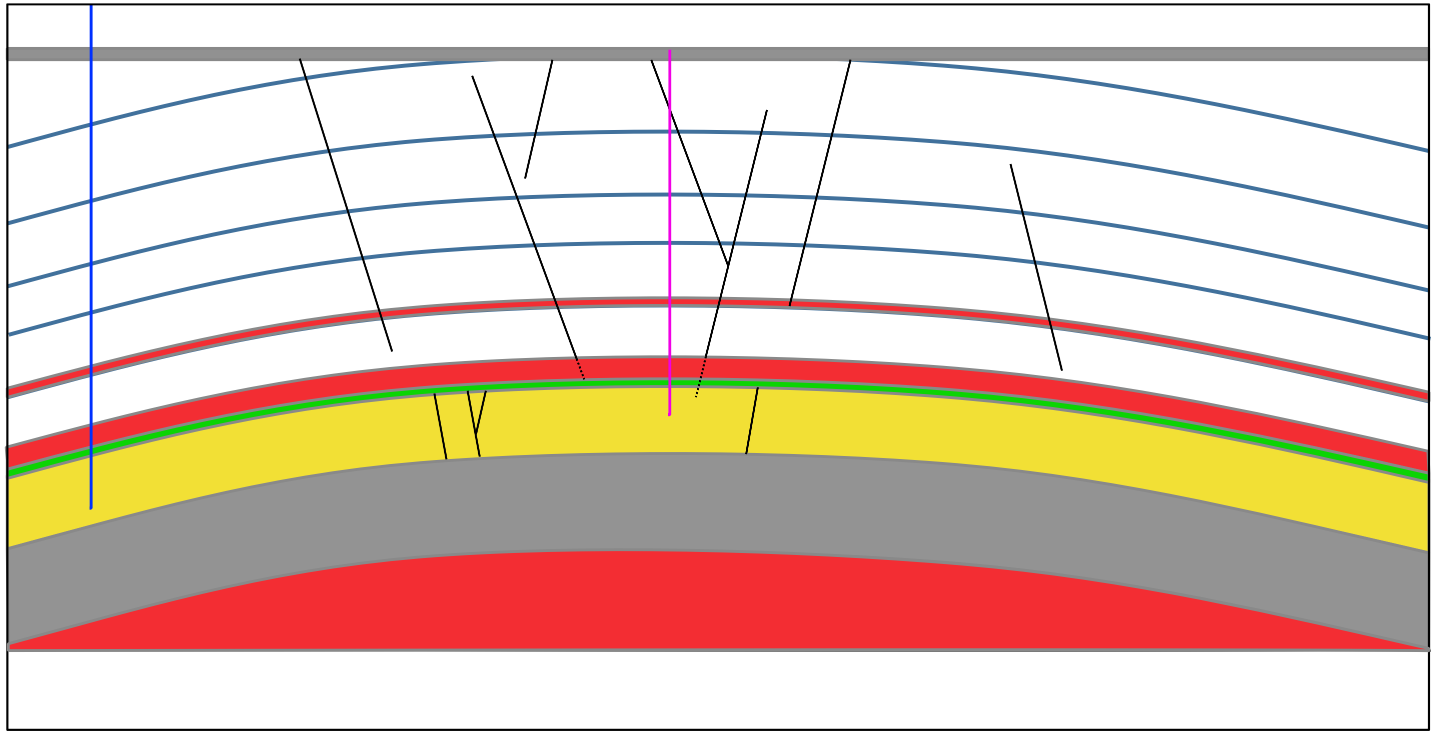
Part III: Geomechanics Processes in CCS Projects, Thermal Stresses & Role of Halite

Tim Wynn

Saline Aquifers E.g. Southern North Sea Triassic

- Upsides: Large potential capacities. Fewer legacy wells less leakage risk?
- Downsides: Maybe under appraised. Can seal and overburden cope with the extra pressure?
- Conceptualise the processes to be modelled and define the volume within which they may occur. This volume will often be larger than the storage complex

Initial conditions

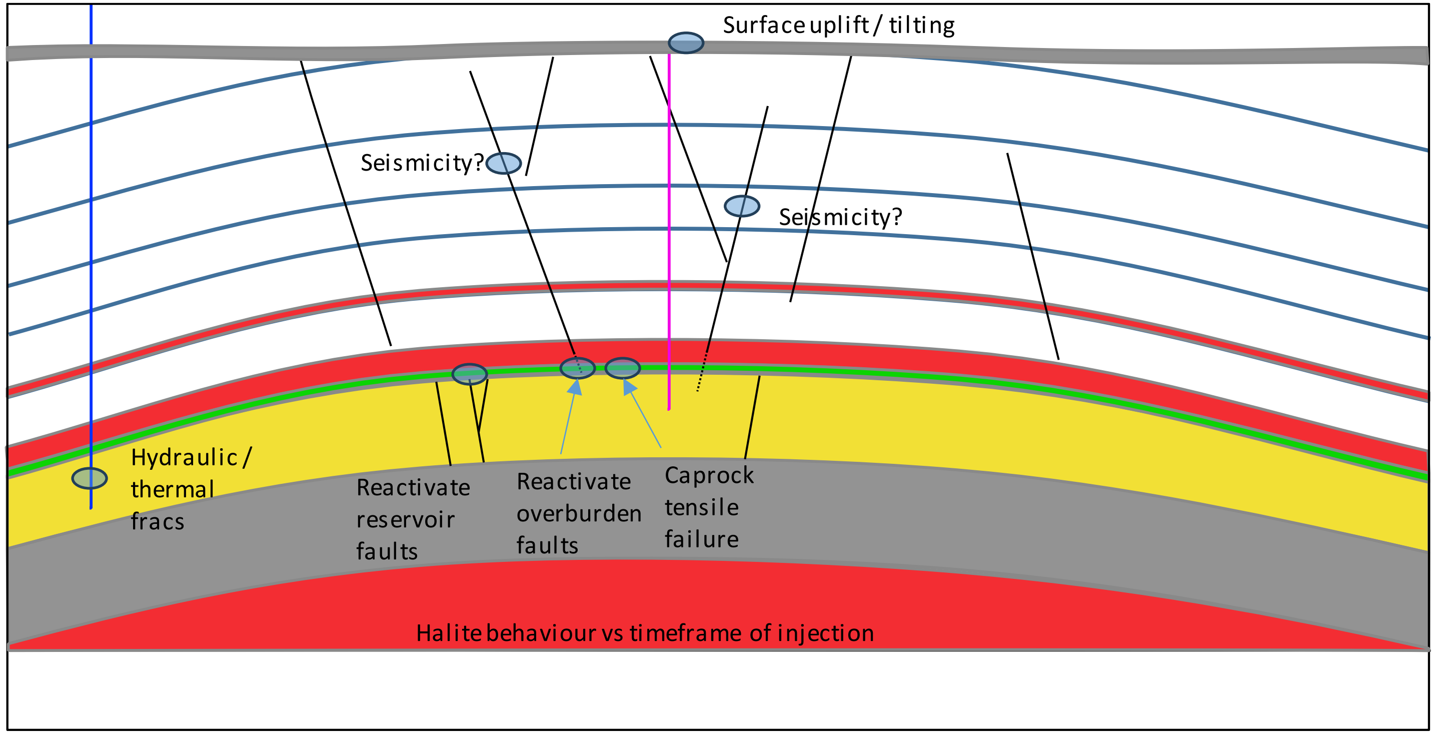


- White Rose / Endurance store
  - Yellow = Bunter Sandstone
  - Grey = Bunter Shale
  - Red = Halites
  - White = Triassic and Jurassic Mudstones and younger sediments
  - Grey at seabed = Quaternary
  - Blue well = CO_2 injector
  - Pink well = legacy well

Saline Aquifers E.g. Southern North Sea Triassic

- Injection: Inflate reservoir, compress and uplift overburden
- Can aquifer absorb pressure increase? If not, may need to reduce injected volumes and/or produce brine
- Two-way coupled modelling can explore the feedback mechanism of plastic failure and potential for poroperm changes in the reservoir and/or caprock. This includes poroperms associated with the fault and fracture system.

End Injection

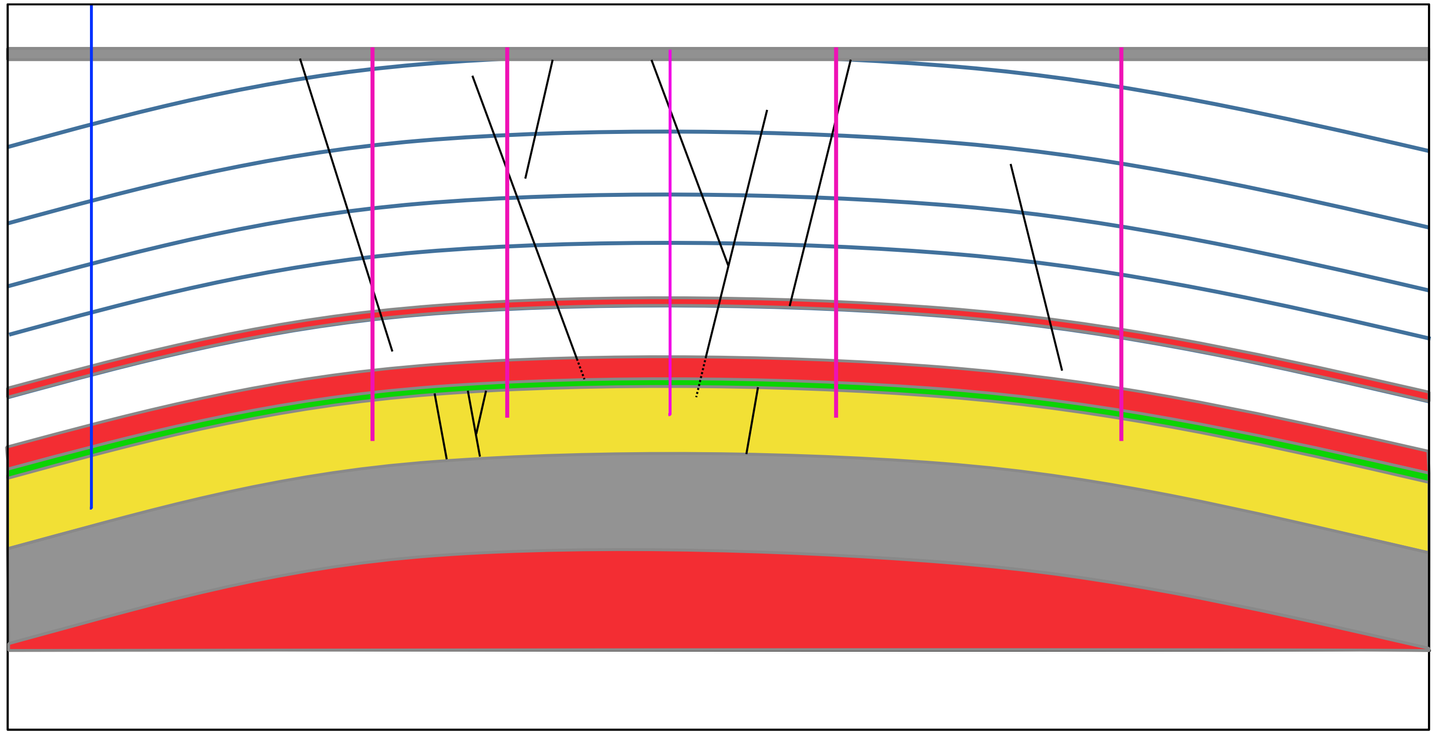


- Thermal fracs:
- $\sigma_{\Delta T} = \frac{\alpha_T \Delta T E}{1-\nu}$
- Where
  - $\sigma_{\Delta T}$ is thermal stress Pa
  - α_T is linear thermal expansion coefficient (LTEC) $°C^{-1}$
  - ΔT is temperature change °C
  - E is Young's Modulus Pa
  - ν is Poisson's Ratio
- Most sensitive to ΔT and E. Stiffer rocks more susceptible to thermal fracturing
- Thermal fracturing of the reservoir may not be a problem if contained - could help injectivity

Depleted Gas e.g. East Irish Sea Basin Triassic

- Upsides: Lot of data for calibration, proven long term seal, lot of pressure capacity
- Downsides: Any permanent deformation during depletion > weakening of overburden faults? Hysteresis of reservoir stress path > reduced capacity? Often many legacy wells higher leak risk?

Initial conditions

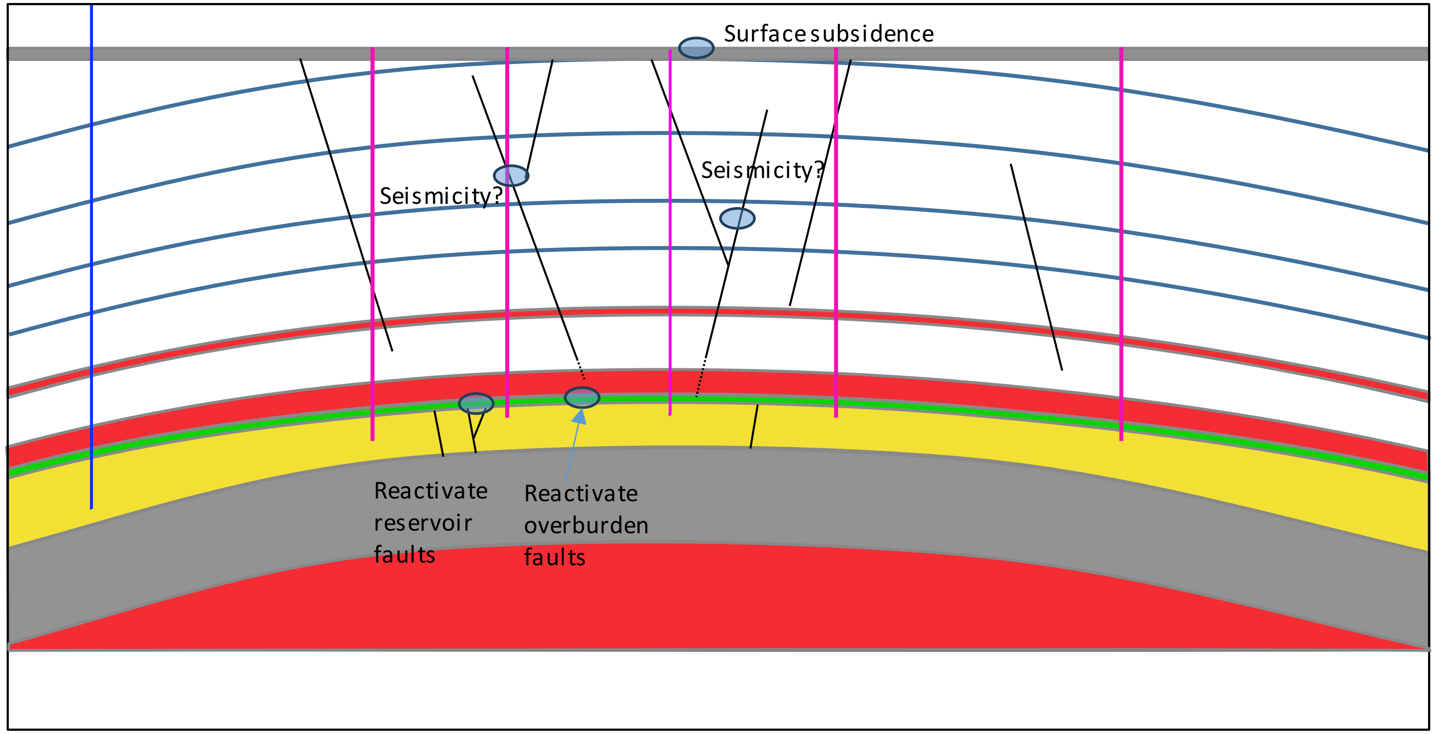


- Similar to EISB sequence
  - Yellow = Sherwood Ormskirk Sandstone
  - Grey = Rottington
  - Red = Halites
  - White = Triassic Mudstones
  - Grey at seabed = Quaternary
  - Blue well = CO_2 injector
  - Pink wells = legacy gas producers

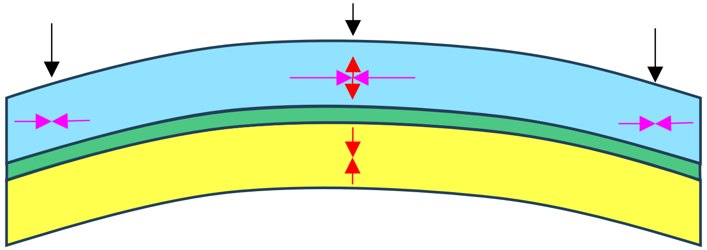
Depleted Gas e.g. East Irish Sea Basin Triassic

- Depletion: Reservoir compaction, subsidence and stretching of overburden. Stress arch may form, reduces surface subsidence
- Weakening of overburden faults possible > has that created a leak pathway or induced seismicity? Models can assess where and how much failure could occur

Depletion



Stress Arch

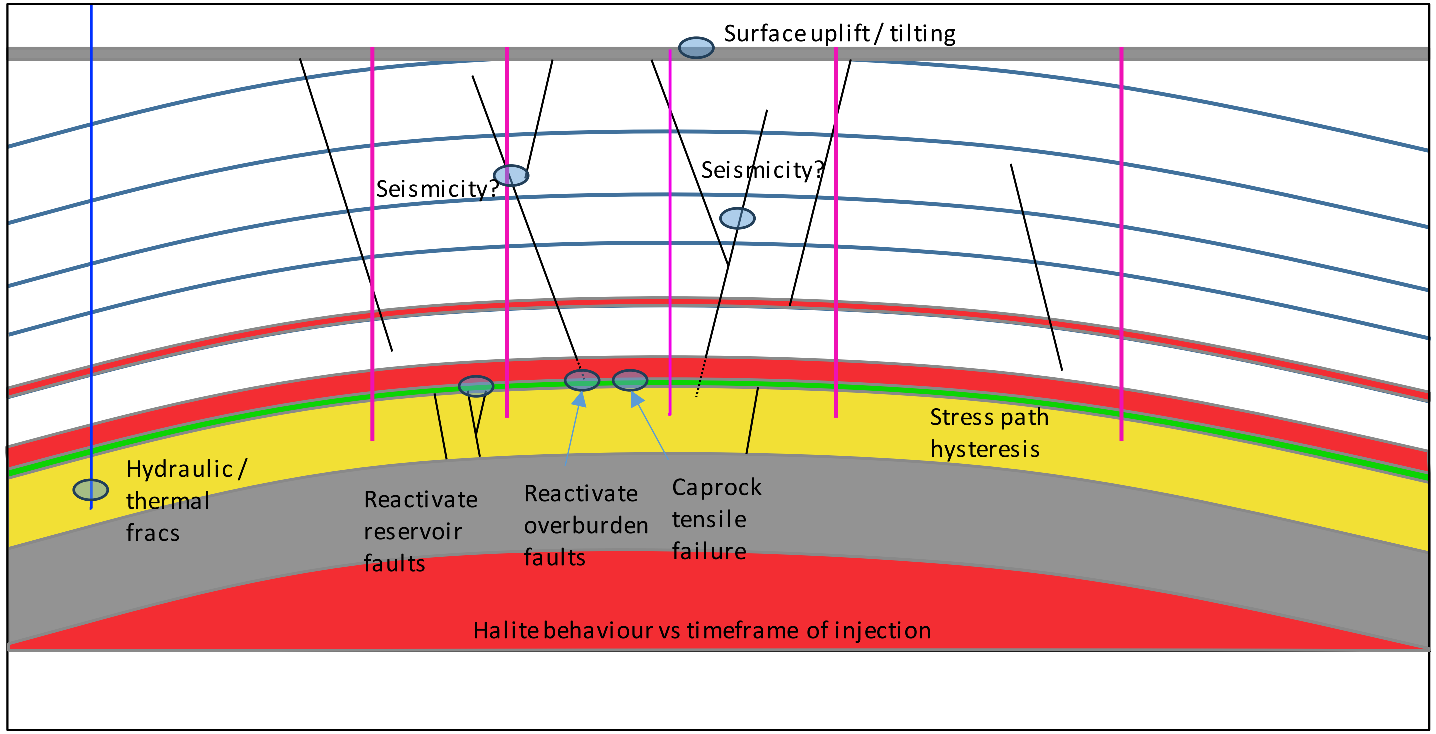


- Can form during depletion when reservoir narrow and more compliant than overlying rocks
- Crest: Overburden stretched, vertical stress reduced, horizontal stress increased, subsidence reduced
- Flanks: Vertical stress increased, horizontal stress decreased

Depleted Gas e.g. East Irish Sea Basin Triassic

- Injection: Reinflation of reservoir, uplift of overburden
- Stress path hysteresis: Reservoir depletion may also reduce the reservoir horizontal stresses due to poroelastic coupling. In some cases, if permanent compaction has occurred, that stress may not recover during injection leading to more hydraulic fracturing than anticipated.
- Injection Seismicity: May occur over a large interval and depth range due to stress strain transfer to critically stressed faults

Injection



- Halites
  - Very low porosities and permeabilities > Effective seal
  - Acts as a stiff material on short timeframes, creep on long timeframes. What is the stress-strain impact of different material responses?
  - Creep leads to lithostatic stresses > High stress suppresses fracture opening or propagation
  - Creep can help seal discontinuities and legacy wells
  - More thermally conductive and higher LTEC than most other rocks > More susceptible to thermal fracturing