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CO_2 Injectivity Review

by

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Gaffney Cline

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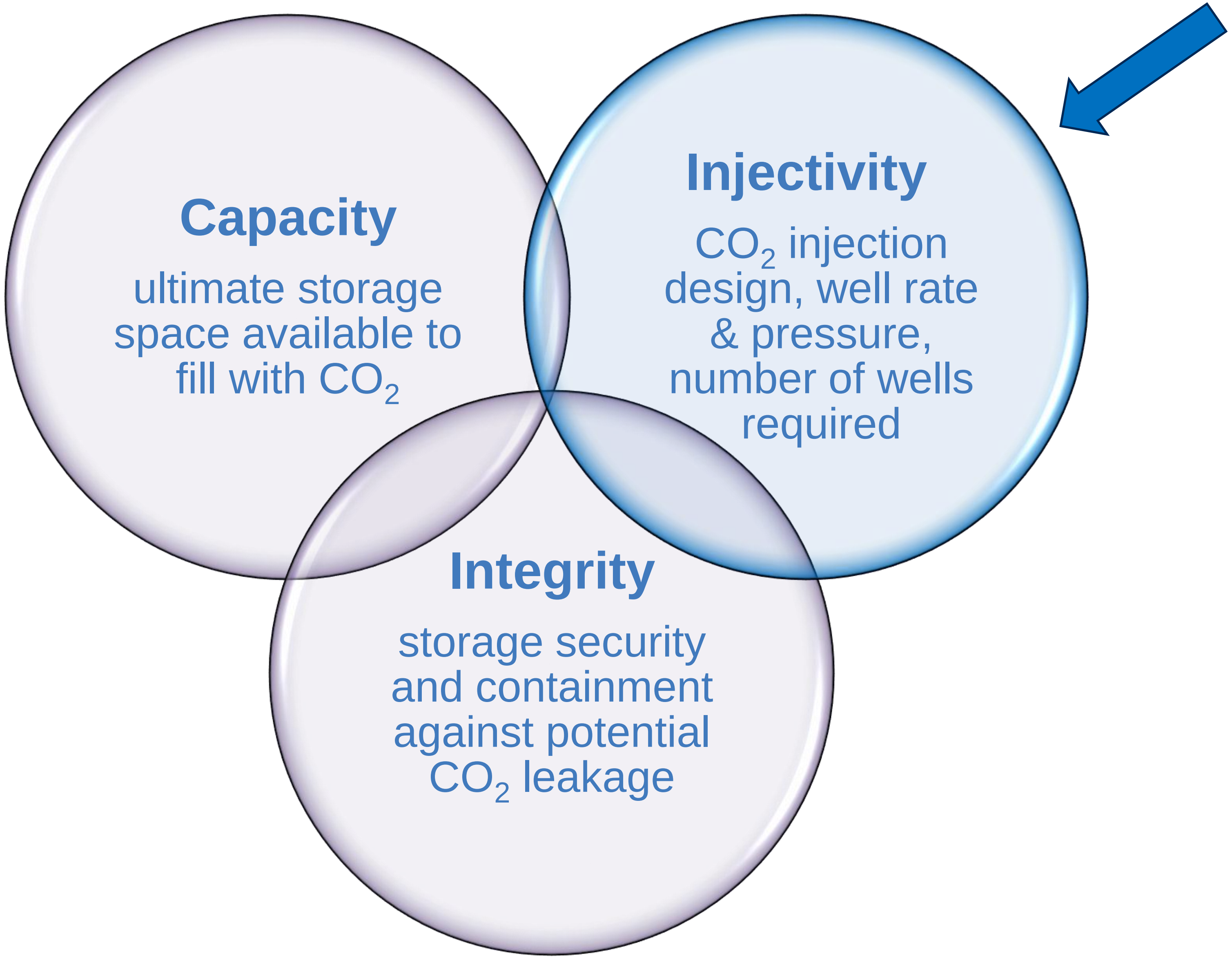
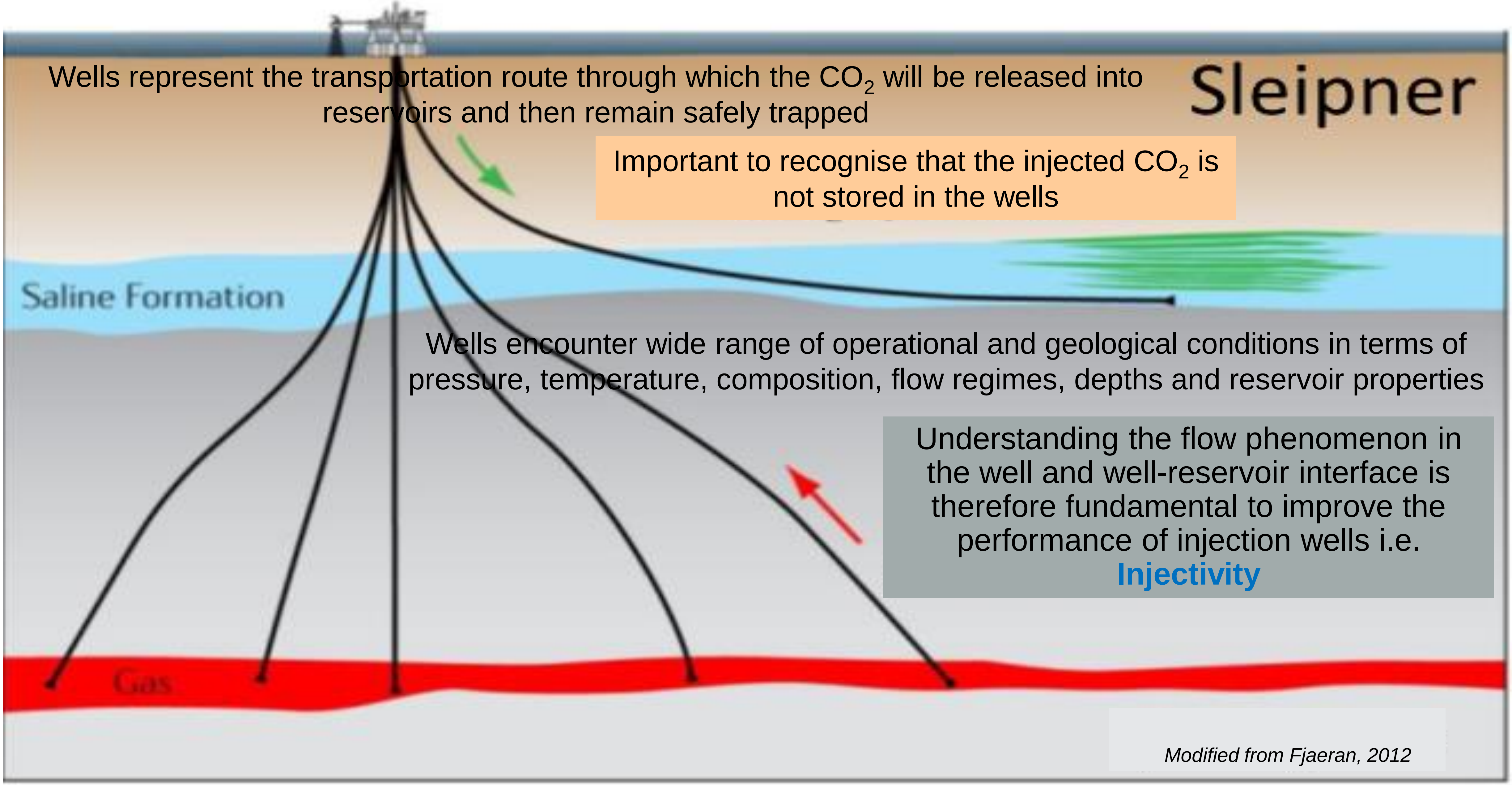
Attendees are urged to obtain independent advice on any matter relating to the interpretation of CO_2 injection operations and injectivity estimation.

Speaker Bio

- Reservoir Engineer.
- 23+ year industry experience with leading international energy companies and consultancies working on projects related to reservoir engineering, field development planning, data-room due diligence and CO_2 storage.
- Currently with GaffneyCline as Principal Advisor – Reservoir Engineering.
- CCS projects experience:
  - Studies involving:
    - Simulation modelling studies;
    - CO_2 storage evaluation studies;
    - Peer reviews.
  - Geographical spread:
    - North Sea;
    - Eastern Mediterranean;
    - Irish Sea;
    - Middle East;
    - Sarawak basin, offshore Malaysia.
- Irfan has an M.S. in Petroleum Engineering from KFUPM in Dhahran, Saudi Arabia and a B.Eng. from NED University in Karachi, Pakistan.

CO_2 Storage – Key Links





Wells represent the transportation route through which the CO_2 will be released into reservoirs and then remain safely trapped

Important to recognise that the injected CO_2 is not stored in the wells

Wells encounter wide range of operational and geological conditions in terms of pressure, temperature, composition, flow regimes, depths and reservoir properties

Understanding the flow phenomenon in the well and well-reservoir interface is therefore fundamental to improve the performance of injection wells i.e. **Injectivity**

Modified from Fjaeran, 2012

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Injectivity – What is it & What Controls it?

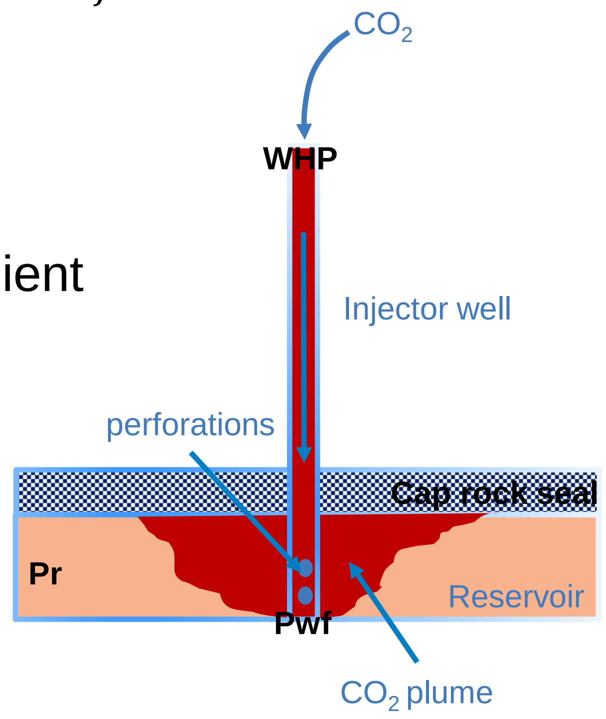
- Injectivity:
  - Ability to push the CO_2 through the matrix in the storage pore space
  - Relates injection rate to pressure difference between the injection well and the reservoir

$$q = \frac{2\pi k h T}{p \; T \ln\left(r_2 / r_1\right)} \int_{p_1}^{p_2} \frac{\tilde{p}\, d\tilde{p}}{\mu_g(\tilde{p})\, z(\tilde{p})}$$

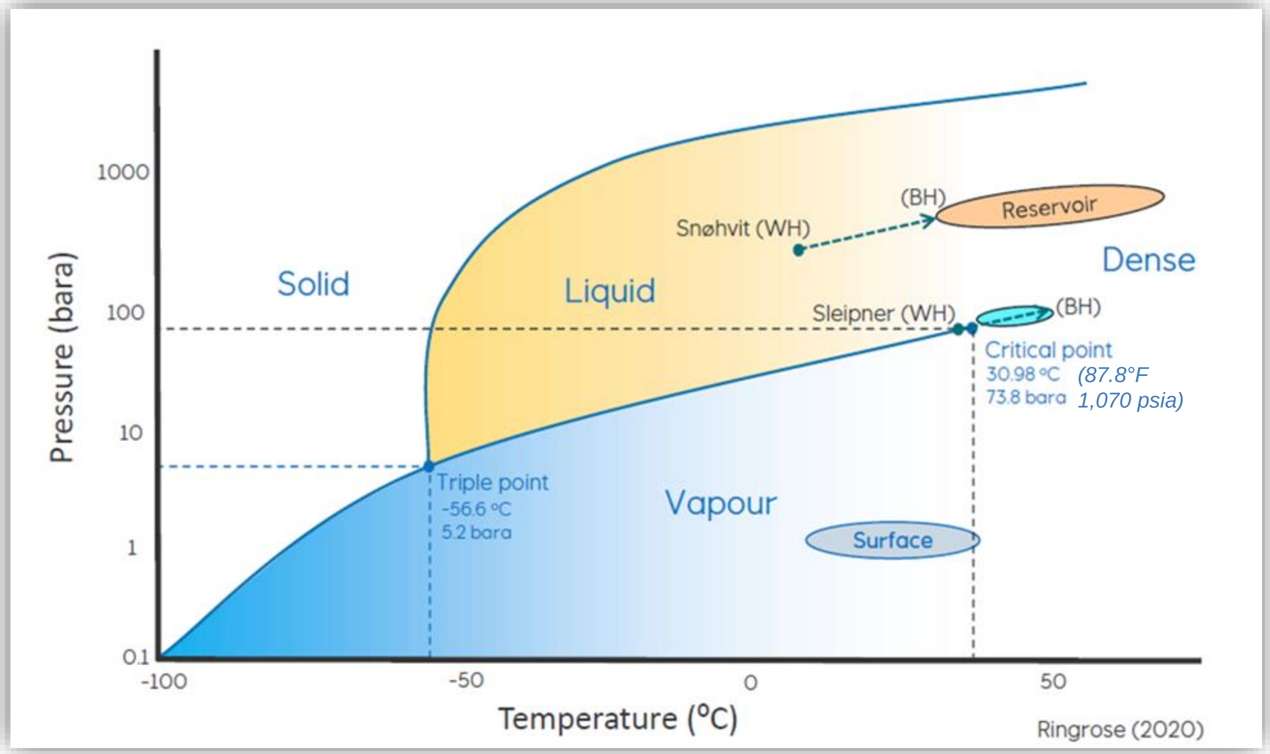
or in simple terms

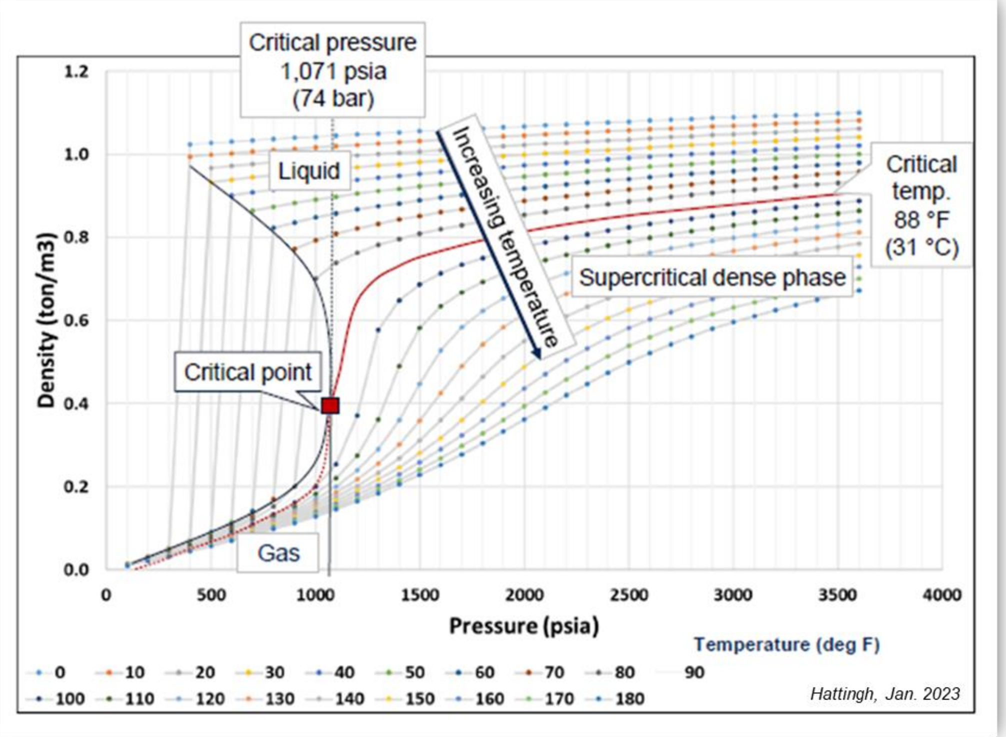
$$Injectivity = \frac{q}{\Delta p} \text{ where } \Delta p = Pwf^2 - Pr^2$$

- Controlling factors:
  - Amount and the quality of the injected CO_2
  - Reservoir conditions like pressure & temperature
  - Maximum allowable injection pressure governed by fracture pressure gradient
  - Reservoir characteristics like permeability and net pay thickness
  - Reservoir transmissibility, connectivity and relative permeability
  - Influences like heterogeneities/shale layers in the reservoir
  - Length of perforation interval and near wellbore damage (skin)
  - Near wellbore pore scale rock arrangement (matrix/natural fractures)
  - Salt precipitation/dry-out effects



CO_2 Properties





- In supercritical phase - not possible to distinguish liquid from vapor with viscosity of a gas but density of a liquid.
- Near the critical point, small changes in operating conditions lead to large changes in physical properties particularly density.
- Reservoir pressure range ~83 – 140 bar (840 – 1,400 m depth) recommended to lead to an efficient utilization of storage volume.

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Injectivity - Depleted Fields Vs Saline Aquifers

Depleted Fields

- Potentially high injectivity opportunity due to low initial pressures
- Phase change - in wellbore or near wellbore region
- Large density changes expected
- Bottomhole pressure response affected
- Possibly unstable well conditions
- Joule Thompson cooling
- Erosion risks due to increased velocity
- Risk of hydrate or ice formation

Saline Aquifers

- CO_2 injection starts in high pressure environment
- Maintaining single phase (supercritical) condition is usually not an issue
- However, injecting against a high back pressure in the reservoir requires higher bottomhole pressure
- CO_2 has to work against a higher density fluid (water) that already occupies the pore space
- Risk of near wellbore dry-out effects
- Risk of breaching allowable pressure limit

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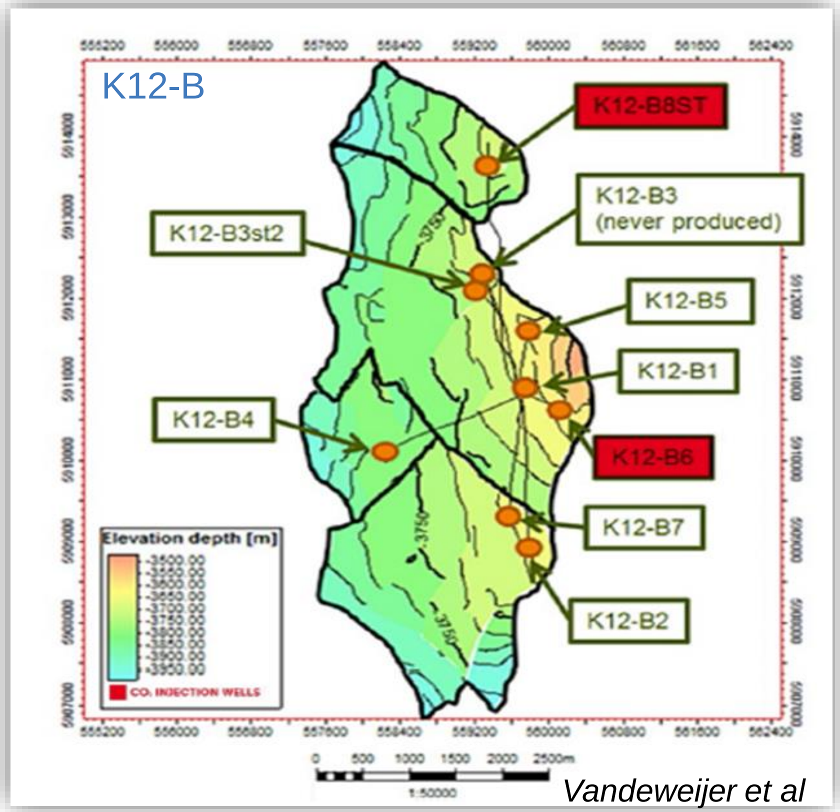
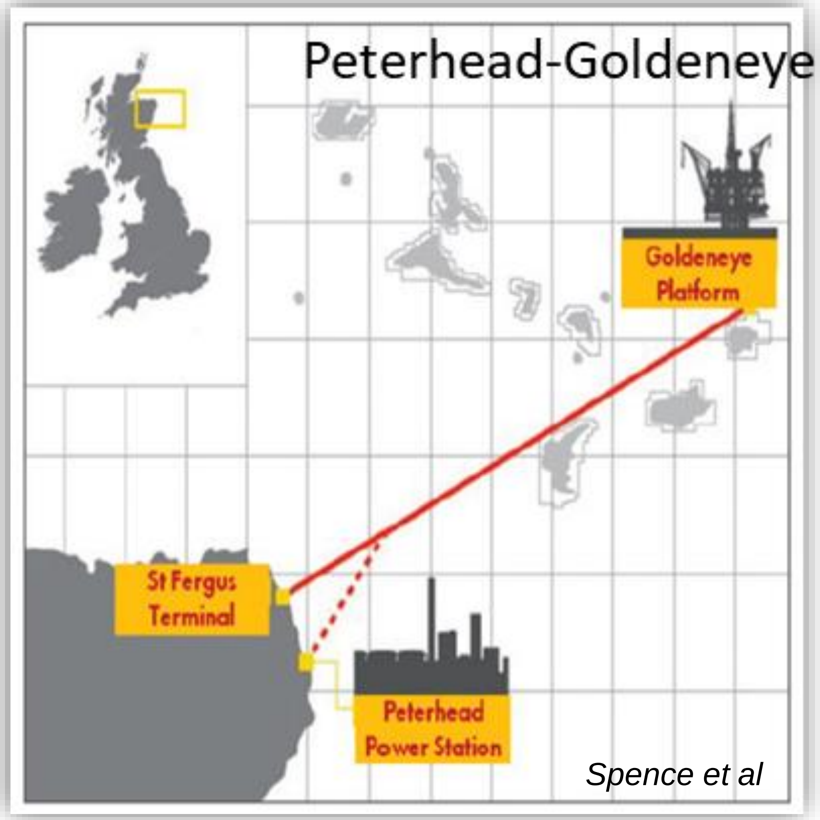
Depleted Fields – Global Experience

- CO_2 EOR targeting tertiary oil recovery from depleted oil fields has long been established
- However, projects exclusively aiming for CO_2 storage in depleted oil and gas fields are still few
- Pilot projects like Otway (Australia), Rousse (France) and K12-B (Netherlands) present some first-hand experiences
- Others in planning/feasibility stages provide useful public domain information (Peterhead/Goldeneye, ROAD, etc.)



Vandeweijer et al

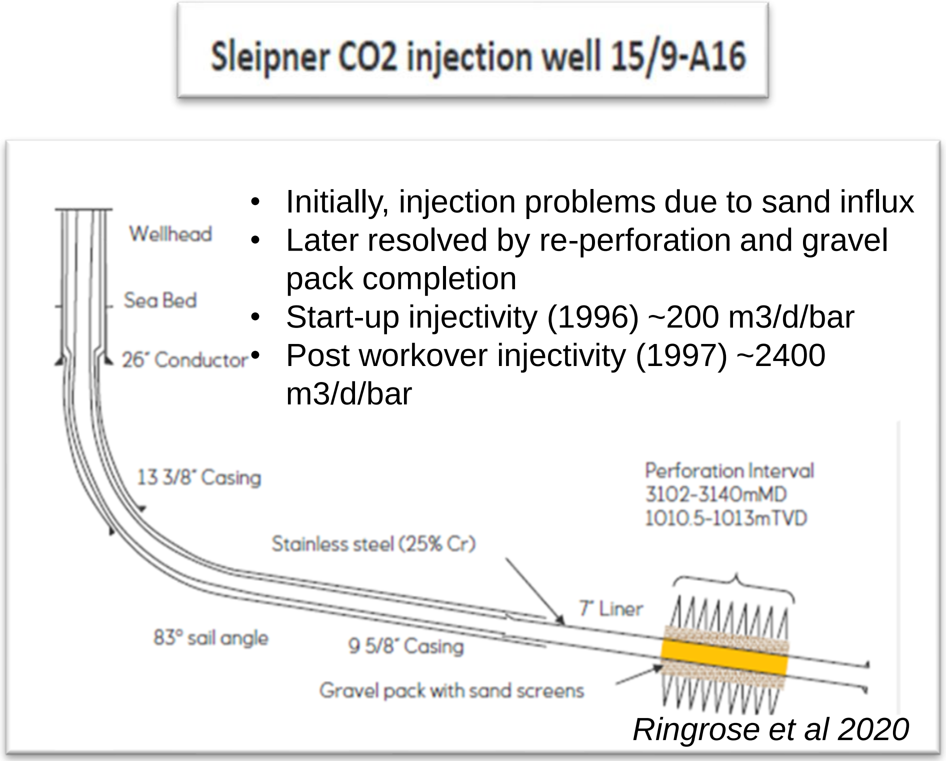
- **At K12-B**, CO_2 stripped from produced gas (13% CO_2) and re-injected into depleted gas reservoir between 2004-2017 (total 0.1 Mt CO_2 injected)
- Injection operations involved phase changes in the wellbore and in the reservoir
- However, K12-B field CO_2 injection continued without any major complications
- Depleted gas field **'Goldeneye'** (offshore UK) was selected for the Peterhead CCS project aiming to inject 1 MTPA for 15 years
- Four Goldeneye legacy wells were planned to be re-fitted for CO_2 service
- Strong aquifer drive during production phase meant that water was expected at the sand face initially



Spence et al

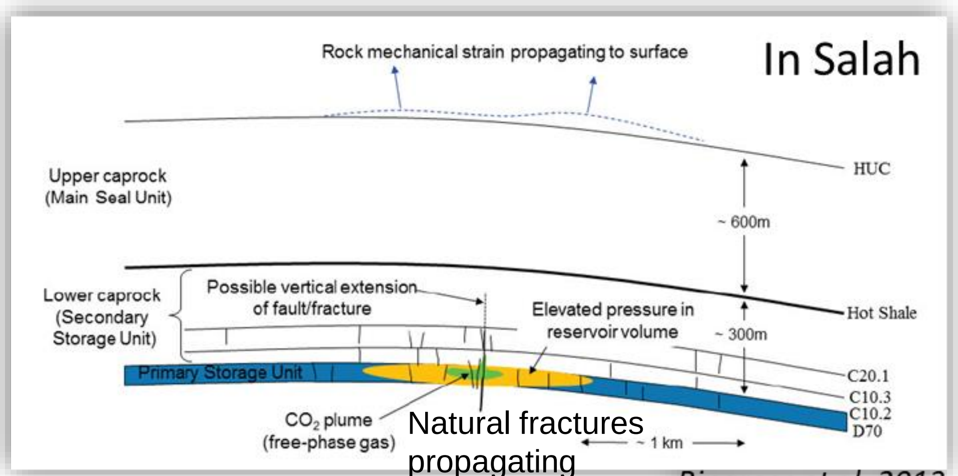
Saline Aquifers – Global Experience

- Most large-scale operational CCS projects have used saline aquifers as storage formations
- Sleipner (offshore Norway) - operational since 1996, annual CO_2 injection rate 1 Mt
- In Salah (onshore Algeria) – CO_2 injection into the down-dip aquifer of the Krechba SS
- Snøhvit LNG project in the Barents Sea (Norway) – Saline aquifer



- Initially, injection problems due to sand influx
- Later resolved by re-perforation and gravel pack completion
- Start-up injectivity (1996) ~200 m3/d/bar
- Post workover injectivity (1997) ~2400 m3/d/bar

Ringrose et al 2020



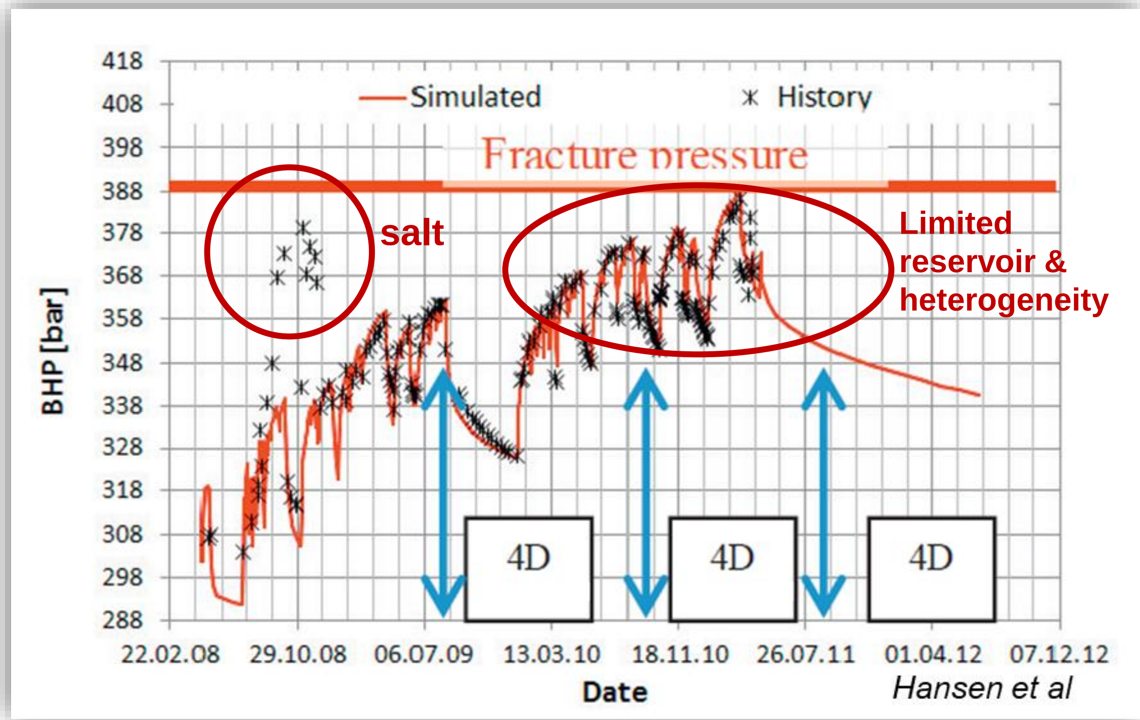
Natural fractures propagating upwards

Ringrose et al, 2013

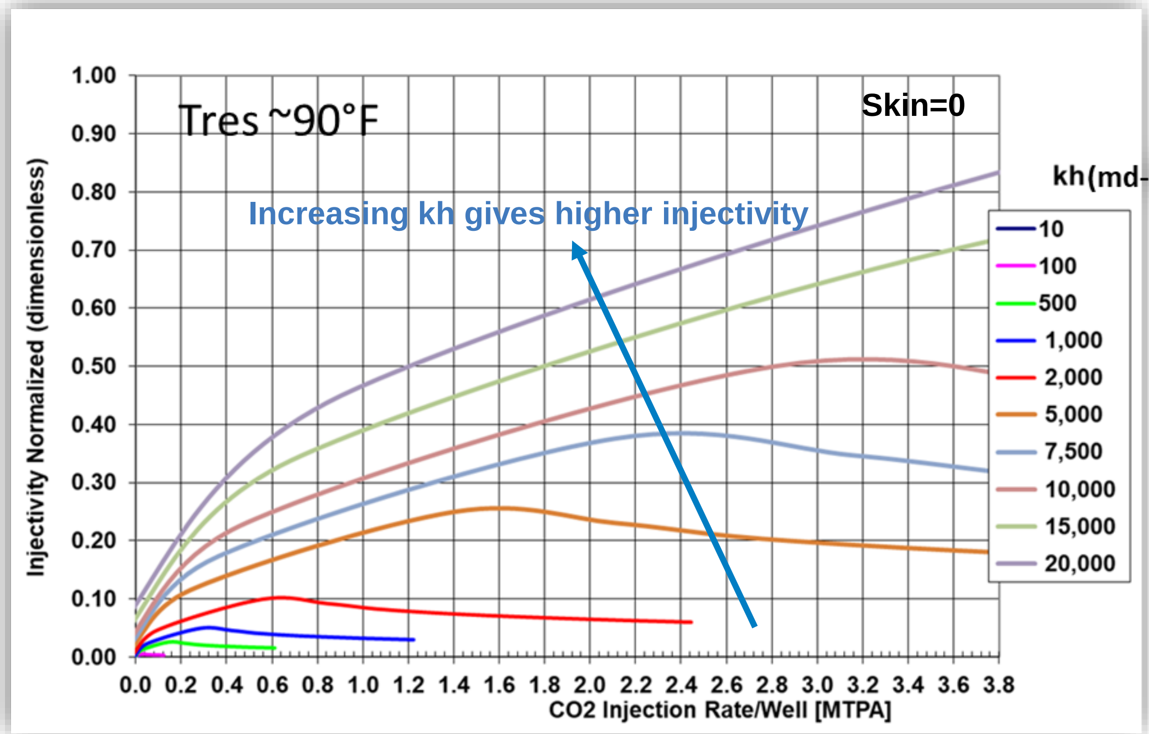
Saline Aquifers – Snohvit Experience

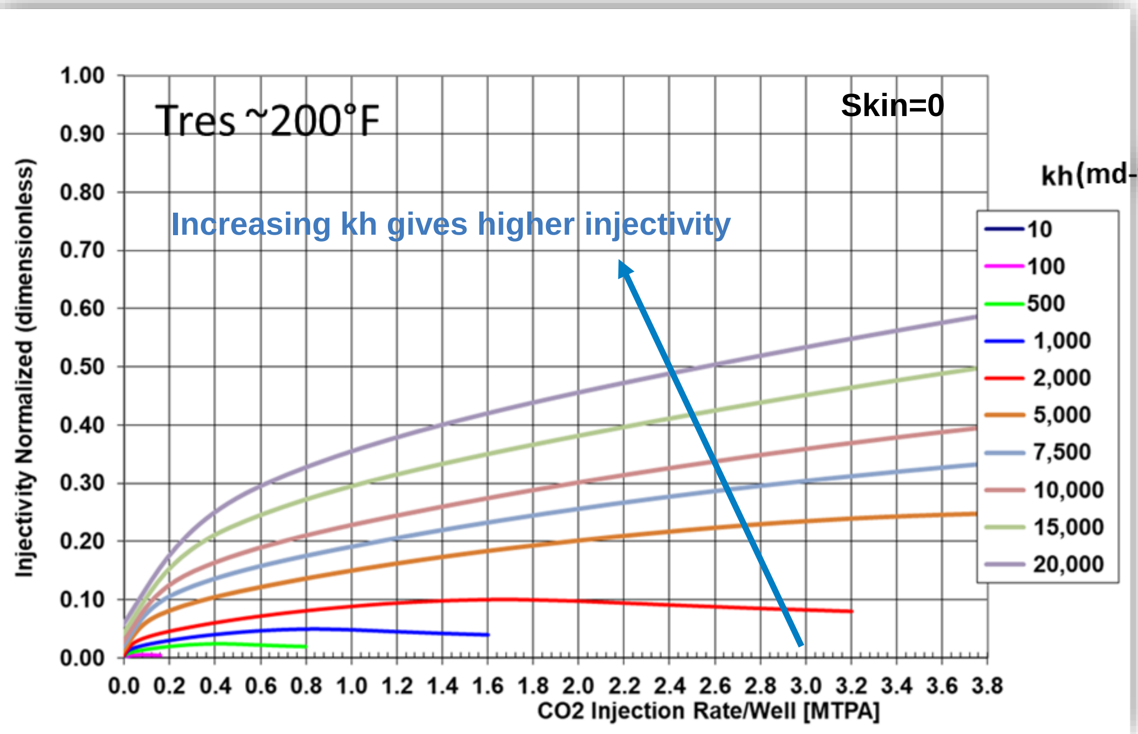
- Snohvit project injected 1.6 Mt of CO_2 between 2008 – 2012 in the Tubåen formation
- 110 m thick formation, depth 2.7-2.8 km, initial conditions of Pres 285 bar, Tres 98°C
- Pressure build-up observed and injection stopped
- Initially salt precipitation in the near wellbore formation was suspected and treated by MEG injection
- Followed up with PLTs and reperforations; subsequent injection again led to continued pressure rise
- Studies/investigations showed that this pressure build-up was mainly caused by limited reservoir volume and formation heterogeneity
- Reservoir heterogeneities and connectivity across faults mean the effective permeability of the Tubåen formation units around the injector well was much lower
- Eventually, injection was diverted to another target formation, as the required injection rate could not be accommodated by the near well reservoir in the Tubåen

Reservoir Unit	Core porosity average (%)	Core permeability average (mD)	Approximate k.H in perforated interval [mD.m]
Tubåen 3	12.32	114	2400
Tubåen 2	7.44	362	550
Tubåen 1	19.75	7650	40000



Injectivity – Strongly Depleted Reservoir Conditions (Pres ~15bar)





Injectivity estimate (Y-axis) has been standardized by normalizing with the maximum injectivity obtained

- Better reservoir quality (higher kh) results in improved injectivity at all reservoir PT conditions
- Injectivity increases when bottomhole injection pressure is below critical pressure
- While it decreases and then stabilizes as BH pressure rises above critical pressure
- At higher temperature, injectivity shows a smooth increasing trend but is smaller than that at lower temperature
- Changing density and viscosity behaviour of CO_2 below and above critical point causes the above phenomenon

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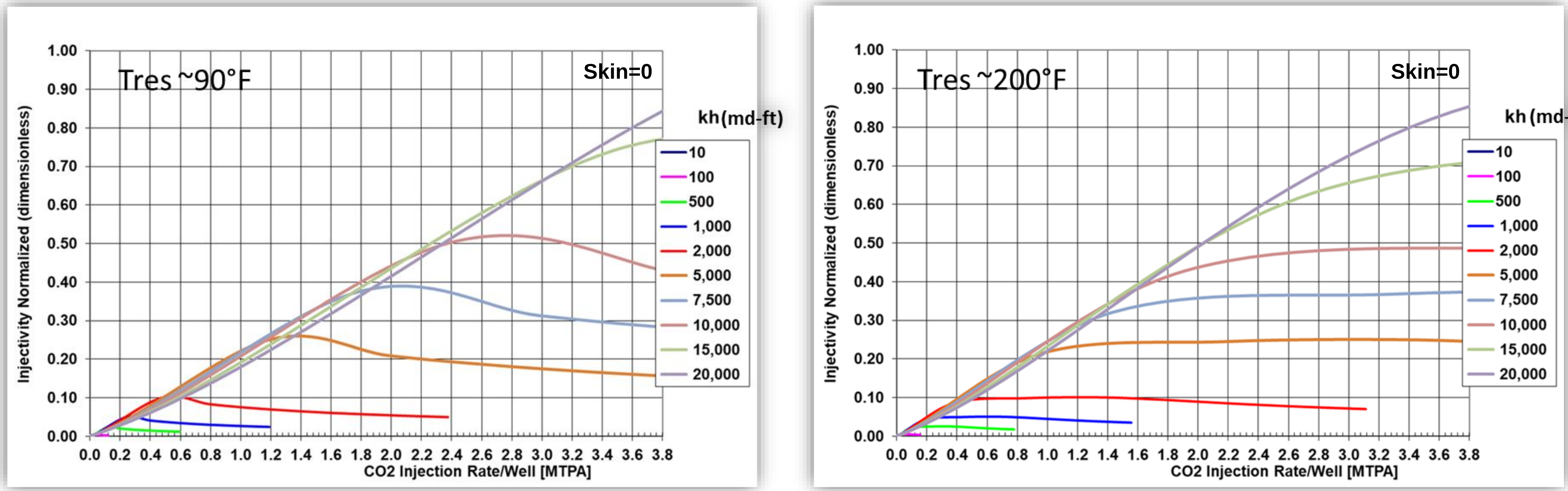
Injectivity – Near Critical Reservoir Conditions (Pres ~70 bar)



Injectivity estimate (Y-axis) has been standardized by normalizing with the maximum injectivity obtained

- As reservoir pressure increases and nears the critical pressure, injectivity aligns to a linear positive trend
- At higher temperature, injectivity again shows a smooth rising trend that later stabilizes
- As reservoir pressure increases further (to typical un-depleted level), injectivity changes are small; main limiting factor being the maximum allowable injection pressure constraint at the bottomhole

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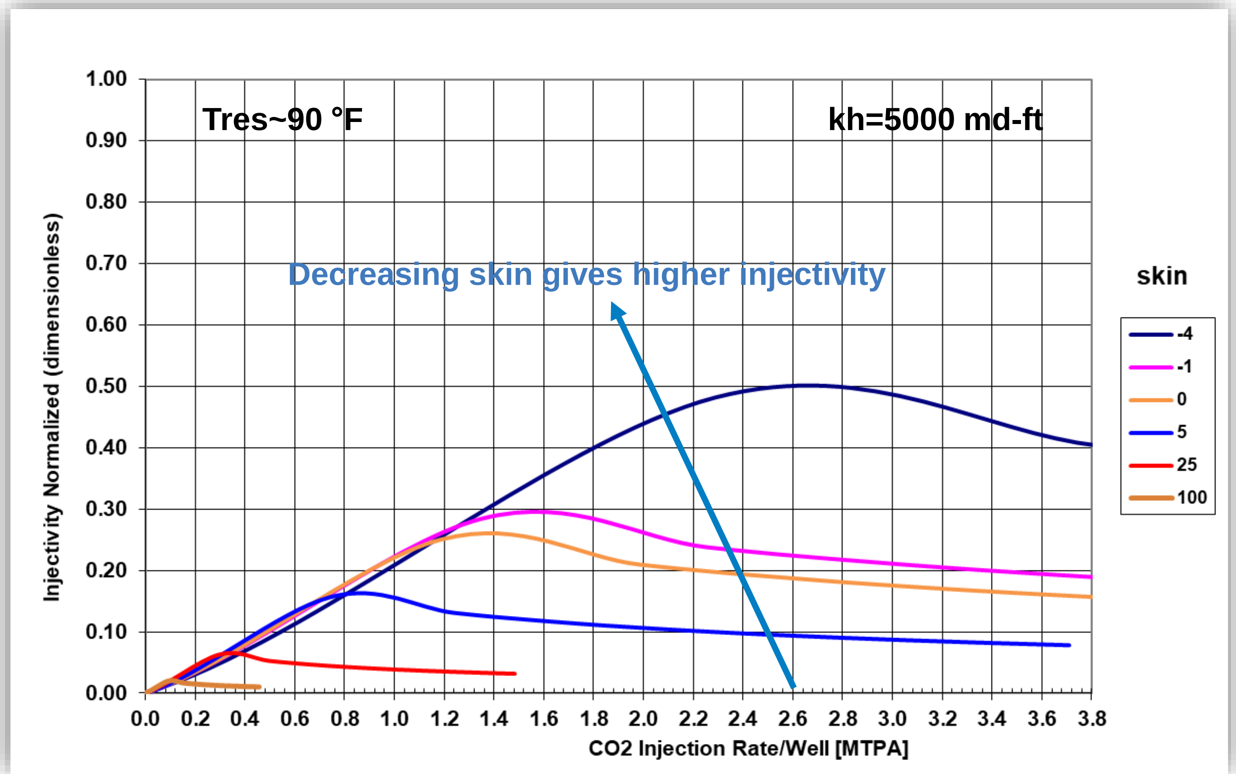
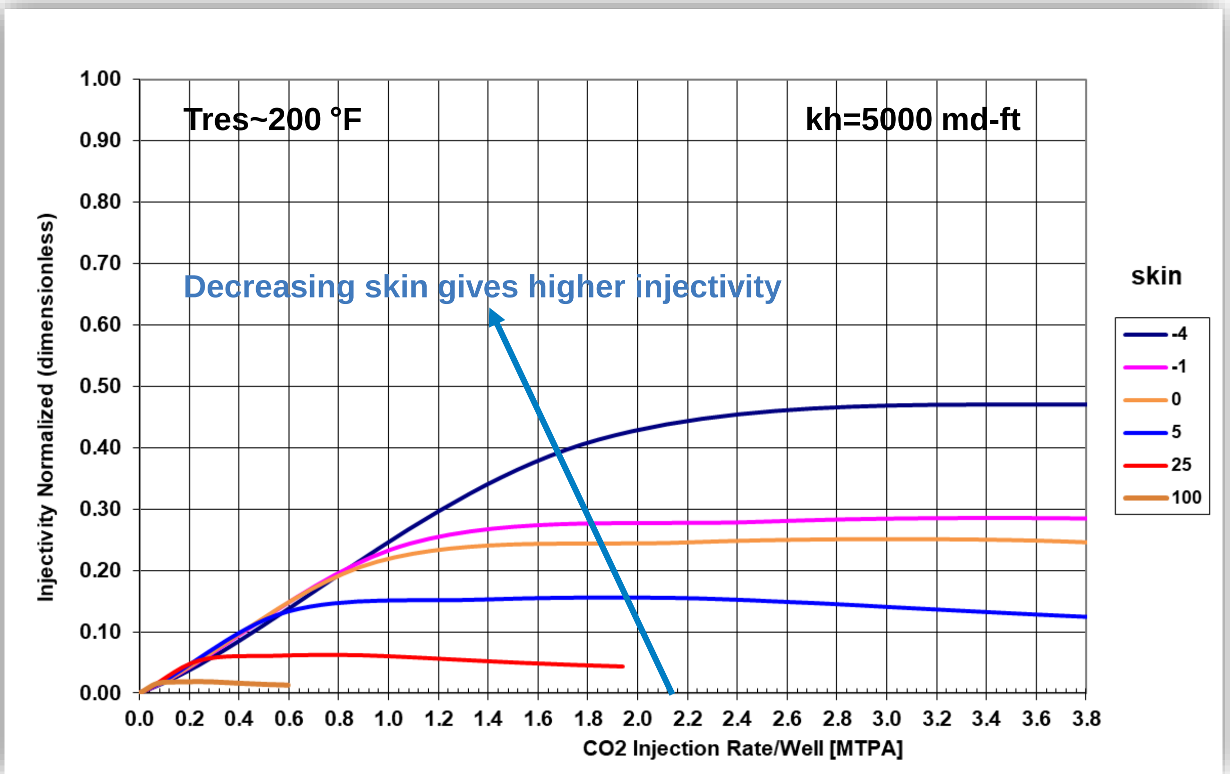
Injectivity – Skin Sensitivity (Pres ~70 bar)



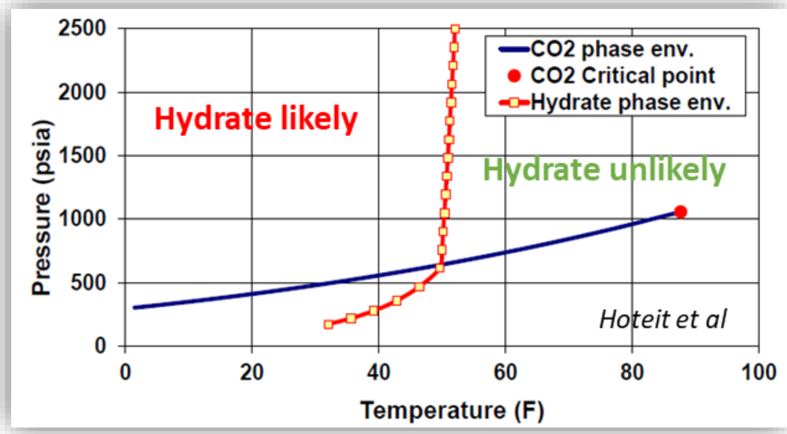


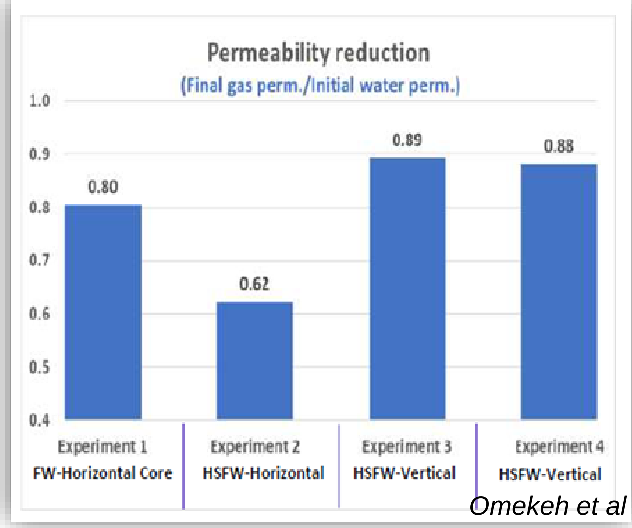
Injectivity estimate (Y-axis) has been standardized by normalizing with the maximum injectivity obtained

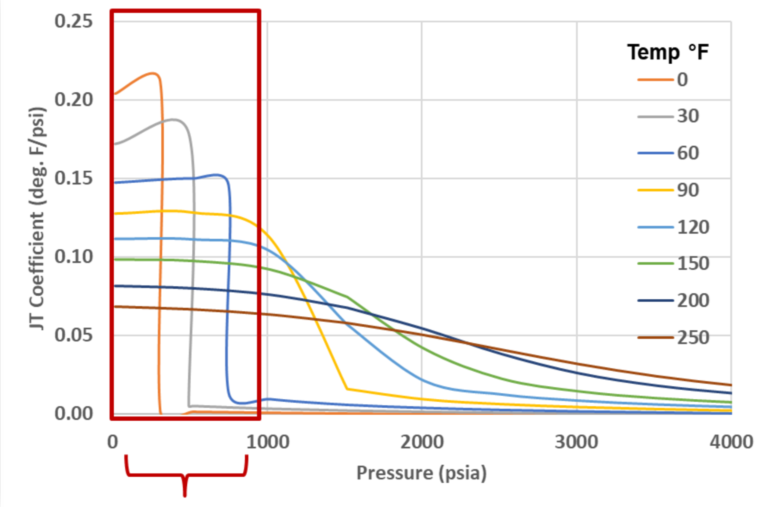
- Decreasing skin implies lower damage around wellbore and leads to lower pressure differential between the bottomhole and the reservoir for the same injection rate resulting in higher injectivity

Flow Assurance Issues Impacting Injectivity

- Joule Thomson Cooling – cooling effect as the fluid expands up the well or into the reservoir
- Hydrates - Loss of flow due to hydrate formation at the wellhead or across perforations
- Dry supercritical carbon dioxide can evaporate saline water in rock pores and precipitate salt leading to impairment of injection rates
- Pore space blockage due to hydrate/ice formation, salt precipitation – acts like a positive skin effect and reduces injectivity







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Thermally Induced Fractures During CO_2 Injection

- Thermal fracturing in the near wellbore area due to sharp temperature reduction
- Temperature effects reduce the fracture critical pressure and induce near wellbore fractures
- Slow growth fracture can increase injectivity without changing flood region shape
- Fast propagation fractures increase injectivity but stretch flood region very flat
- Optimum fracture growth enhances permeability around the wellbore and increases injectivity

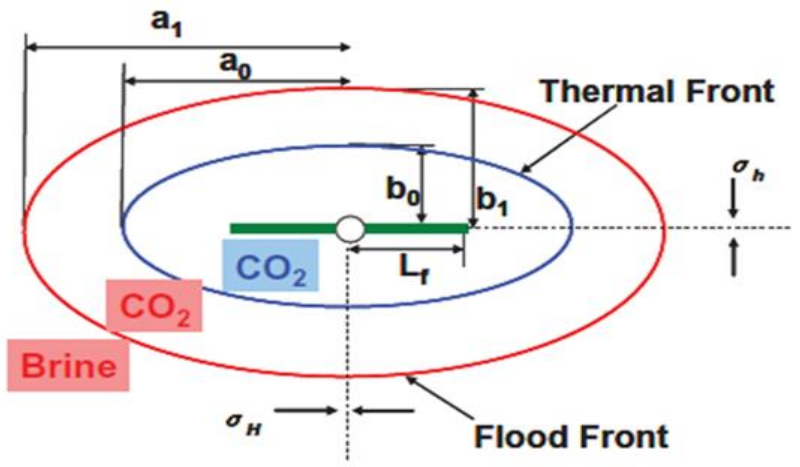

Figure 3. Map view showing a two-winged infinite conductivity vertical fracture (dark green line) of half length L_f oriented perpendicular to the plane of minimum horizontal stress (σ_h). The two ellipses stand for thermal front (blue) and flood front (red) during CO_2 injection process, respectively. Fluids in CO_2 storage aquifer occupy three regions divided by the two fronts: a cool CO_2 zone between the fracture and the thermal front, warm CO_2 zone between thermal front and flood front, and warm brine zone beyond flood front.

Lou and Bryant

GaffneyCline

Summary

Injectivity

- Ability to push the CO_2 through the rock matrix
- Controlled by various reservoir, fluid and operating parameters
- Determines number of injection wells required; big impact on any CCS project economics and feasibility

Depleted Fields

- High injectivity potential due to large available pressure differential
- Suffer from phase change related challenges which can reduce injectivity

Saline Aquifers

- Dense phase injection and therefore abrupt phase change issues are avoided
- High back pressures in the reservoir from the beginning leading to decreased injectivity

Impact Factors

- Permeability-thickness (kh) and formation damage (skin)
- Others include heterogeneity, limited drainage area and connectivity

Ways to Improve

- Optimized utilization of high perm reservoir zones and perforation intervals
- Matrix stimulation, rock fracture growth optimization, etc.
- Pressure management

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Thank You

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Event Audience
References
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