The development and demonstration of best-practice guidelines for the start-up injection of CO_2 into highly-depleted gas fields

UKSSCRC Call 2: 1st Sept 14 - 30th May 17
Collaborators: E.ON & Shell Global Solutions

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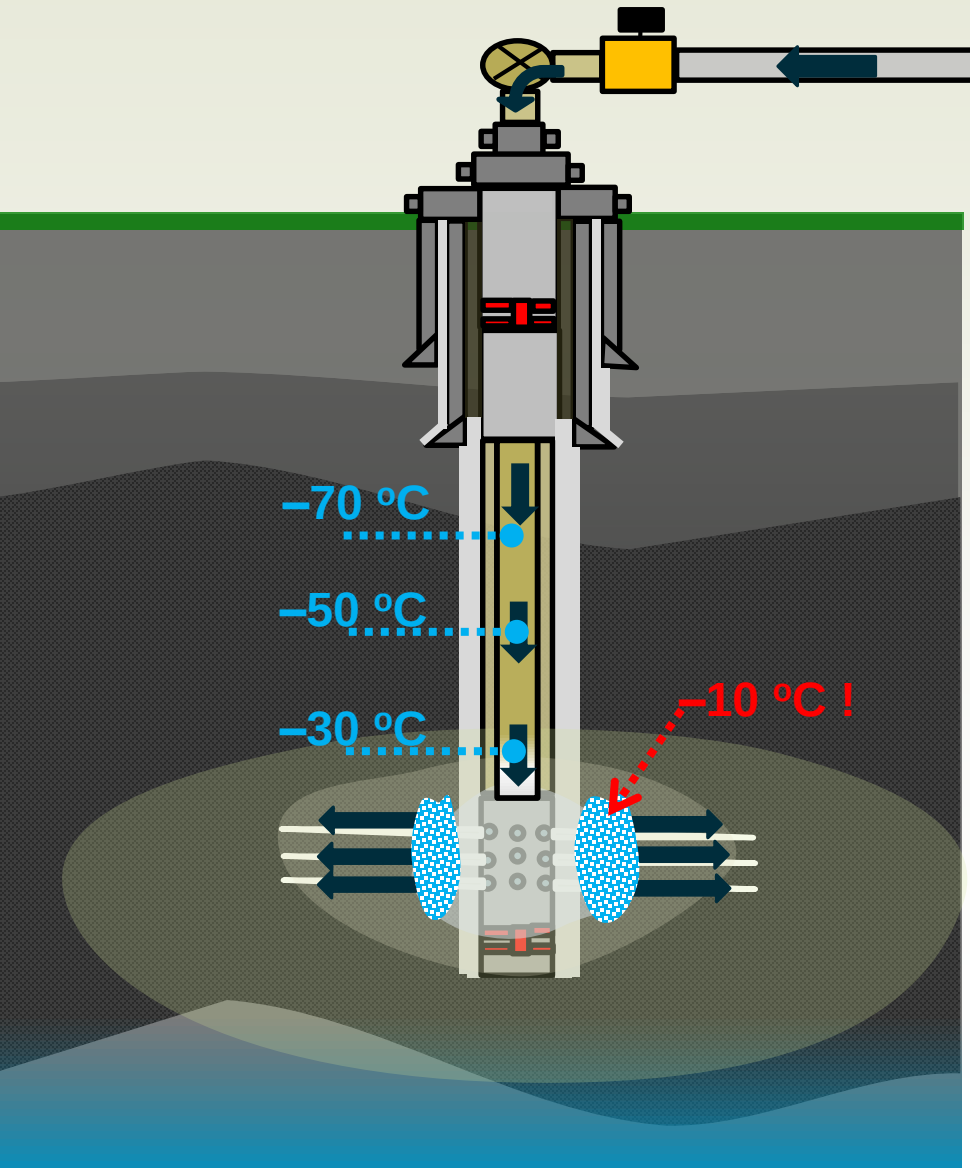
UKCCSRC AUTUMN 2017 BIANNUAL, University of Sheffield

Background

Highly-depleted gas fields such as Hamilton and Viking A represent prime potential targets for large-scale storage of CO_2. They have excellent storage efficiency (utilising between 70% to 80% of the available pore space), *but do require careful operational management because of their very low pressure and relatively shallow depth*[1].

In the case of the Hamilton gas field for instance, its shallow depth and low pressure means that the injected liquid or dense phase CO_2 during start up injection will be expand into the vapour phase.

1. Progressing Development of the UK's Strategic Carbon Dioxide Storage Resource https://s3-eu-west-1.amazonaws.com/assets.eti.co.uk/legacyUploads/2016/04/D16-10113ETIS-WP6-Report-Publishable-Summary.pdf



This results in a reduction in the storage capacity. Also the accompanying expansion induced cooling of the CO_2 poses significant safety and operational risks :

- Thermal stress shocking of the well bore casing steel leading to its fracture and escape of CO_2

- Blockage due to hydrate and/or ice formation;

- Over-pressurisation accompanied by CO_2 backflow into the injection system due to the violent evaporation of the superheated liquid CO_2 upon entry into the well bore

- Reduction in reservoir storage capacity due to interstitial freezing and CO_2 hydrate formation leading to near-field immobilisation of CO_2 within the porous rock structure

One potential solution is to pre-heat the CO_2 on the platform until the liquid CO_2 can be injected without crossing the liquid to vapour transition at any time during the injection process.

However this is expensive and hit and miss.

Aims and objectives

Aim

- to develop a rigorous CO_2 Injection Model, accounting for all the important processes governing the fate of CO_2 in terms of its variation in pressure, temperature and hence the fluid phase along the well during the injection process;

Objective

- demonstrate the efficacy of the model as a powerful optimal injection process control tool by simulating a real case study involving various ramp-up CO_2 injection rates and starting temperatures and pressures.

Injection flow model

$$\frac{\partial}{\partial t}\begin{pmatrix}\rho A\\ \rho uA\\ \rho EA\\ A\\ \rho Ax\end{pmatrix}+\frac{\partial}{\partial z}\begin{pmatrix}\rho uA\\ \rho u^2A+AP\\ \rho uHA\\ 0\\ \rho uAx\end{pmatrix}=\begin{pmatrix}0\\ P\frac{\partial A}{\partial z}\\ 0\\ 0\\ 0\end{pmatrix}+\begin{pmatrix}0\\ A(F+\rho\beta g)\\ A(Fu+\rho u\beta g+Q)\\ 0\\ \rho A\frac{x-\bar{x}}{\theta}\end{pmatrix}$$

x is the vapour quality,
u is the mixture velocity,
ρ is the mixture density,
E is the mixture total energy,
H is the mixture total enthalpy,
P is the mixture pressure,
A is the cross-sectional area,
t is the time,
z is the space coordinate,
F is the viscous friction force,
Q is the heat flux,
g is the standard gravity,
$\bar{x}$ is the equilibrium vapour quality,
θ is the relaxation time.

The frictional loss can be expressed as $= -f_w\frac{\rho u^2}{D_p}$, where f_w is the Fanning friction factor, calculated using Chen's correlation, and D_p is the internal diameter of the pipe. The gravitational term includes $\beta = \beta(z)$, which accounts for the possible well deviation.

Q accounts for the heat exchange between the fluid and the well wall. The corresponding heat transfer coefficient, η is calculated using the well-known Dittus-Boelter correlation:

$$\eta = 0.023\, Re^{0.8} Pr^{0.4} \frac{k}{D_p}$$

where k, Re and Pr are the thermal conductivity, Reynold's number and Prandtl's number for the fluid. The heat exchanged between the fluid and the wall is calculated from:

$$Q = \eta(T_w - T)$$

where T_w and T are the temperatures of the fluid and of the wall, respectively which can change with time and space obtained from transient heat conduction equation in the coordinate$r$,

$$\rho(r) c_p(r) \frac{\partial}{\partial t} T(r,t) = \frac{1}{r} \frac{\partial}{\partial r} \left(r\kappa(r) \frac{\partial}{\partial r} T(r,t) \right)$$

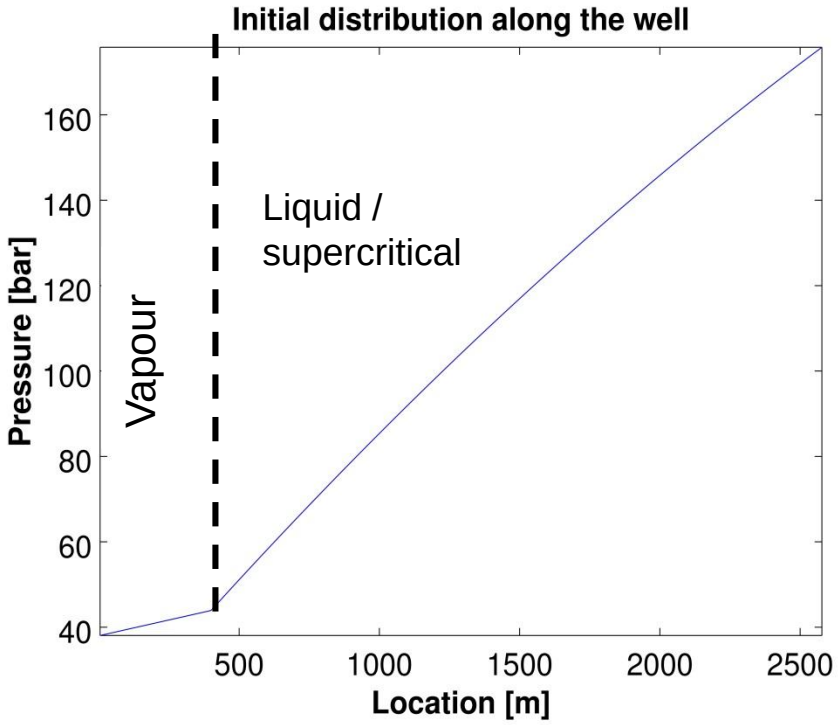
where T, ρ, c_p and κ represent temperature, density, heat capacity and heat conductivity calculated at the radial coordinate r.

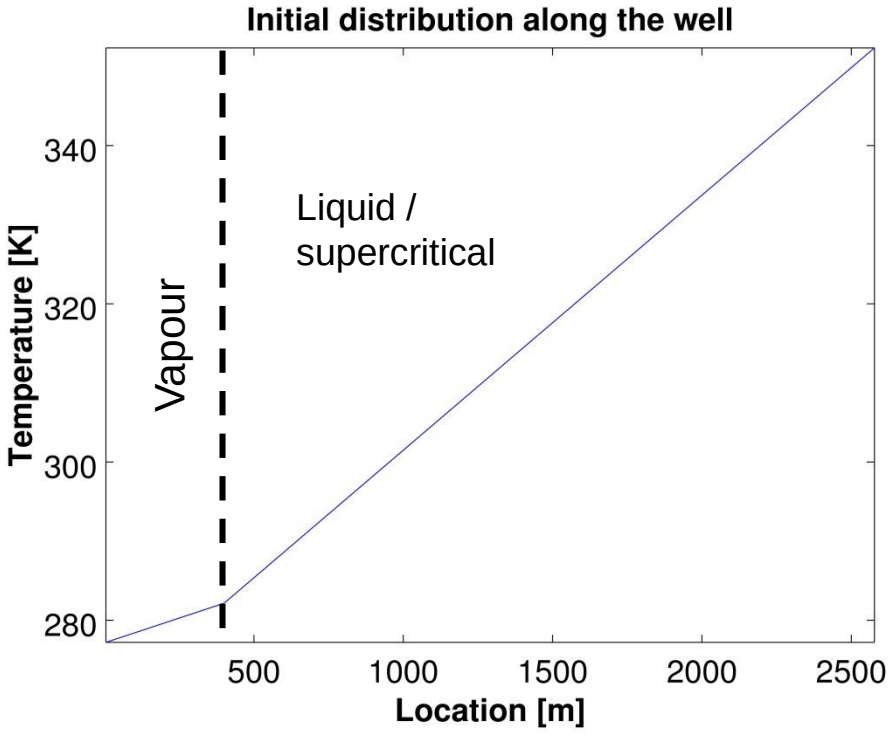
Peterhead CCS Project: Goldeneye gas field

Located 100 km offshore in geological strata at a depth of around 2600 m beneath the outer Moray Firth. The plan was to store 10 to 15 m tonnes of CO2 over a 10 -15 yr period commencing 2020.

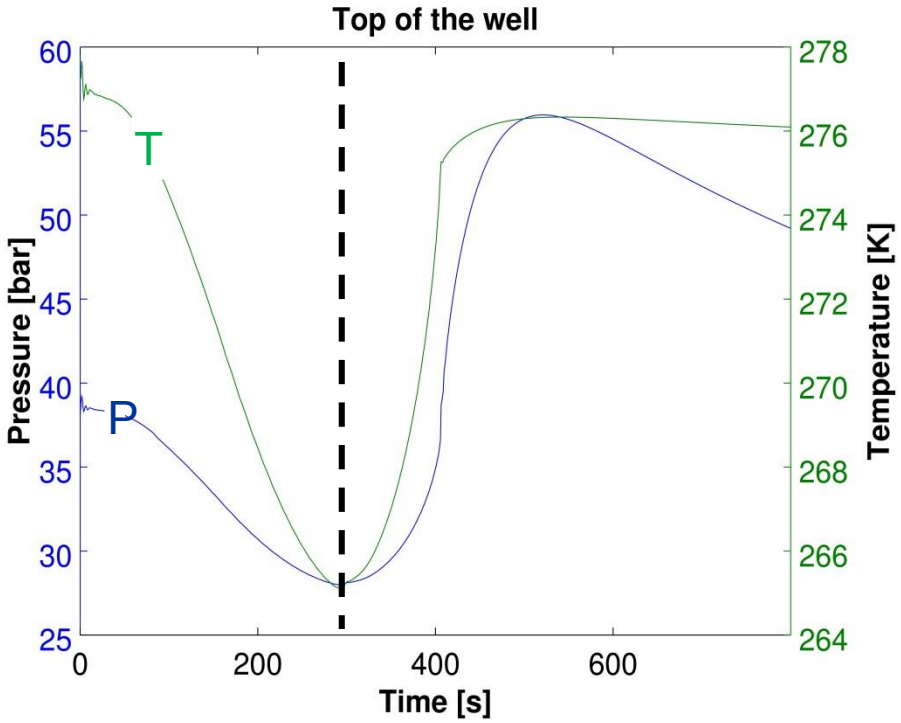
Parameter	Value
Length of the well	2581.9m
Internal diameter	0.125m (0 – 800m depth)
	0.076m (800 – 2581.9m depth)
Fluid composition	Pure CO_2
Upstream pressure	115 bar
Upstream temperature	278.15 K
Inlet mass flow rate	Case 1: linearly ramped-up from 0 to 33.5 kg/s in 5 mins Case 2: linearly ramped-up from 0 to 33.5 kg/s in 30 mins
Outflow	Site-specific pressure-flow relation*: $A + B \times M + C \times M^2 = P_{BHF}^2 - P_{res}^2$, where M is the mass flow rate at the bottomhole, P_{BHF}^2 is the bottomhole flowing pressure, and P_{res}^2 is the reservoir static pressure
Formation temperature	Varying linearly with depth, from 277.15 to 353.15 K

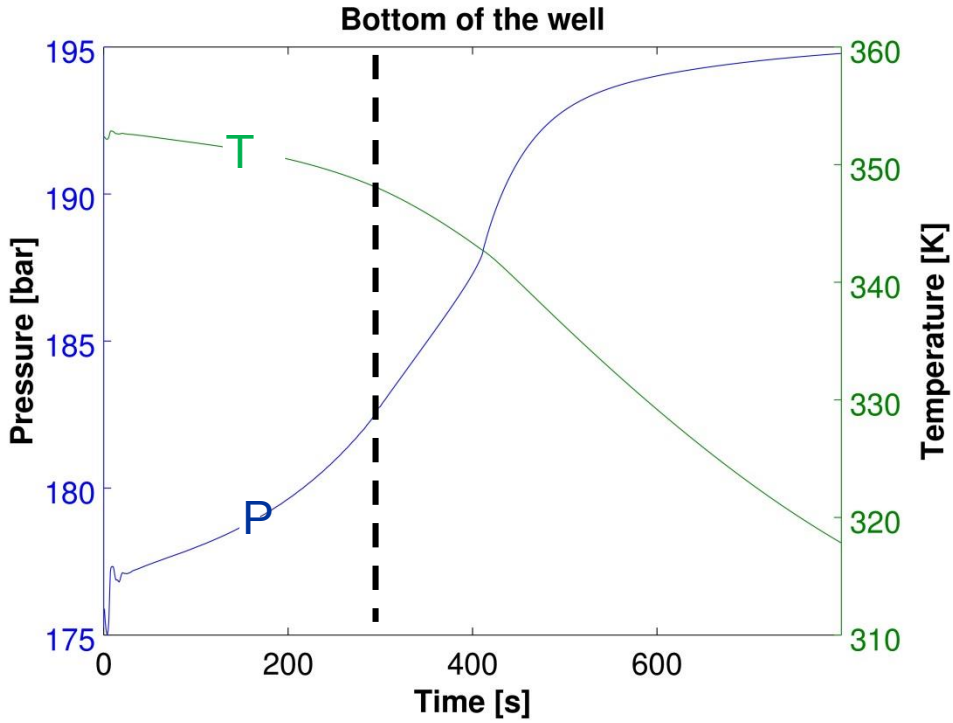
Initial conditions:
vapour (0 – 400m depth), liquid/supercritical (400 – 2581.9 m depth)



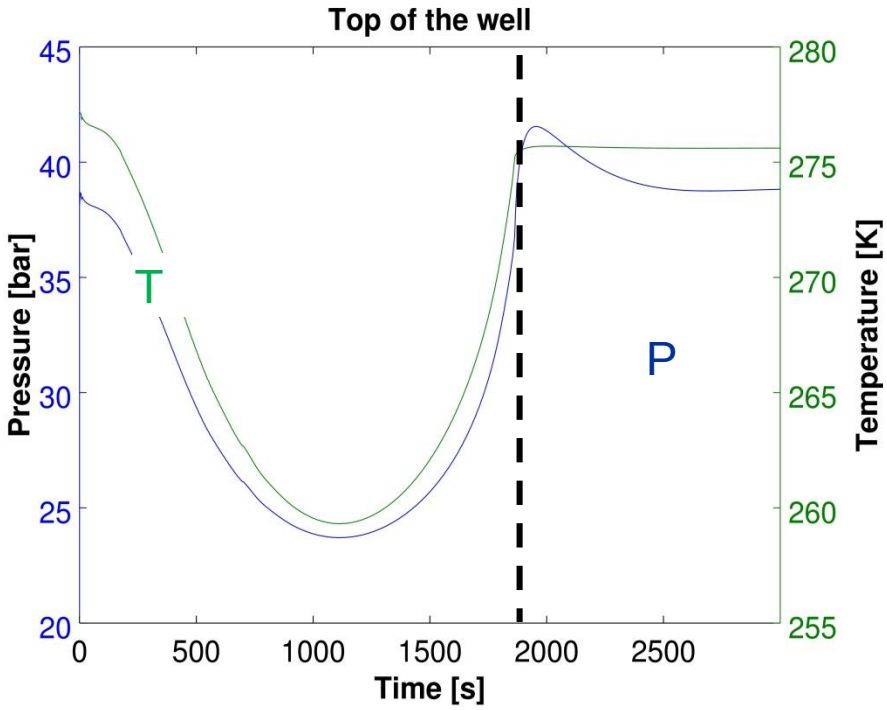


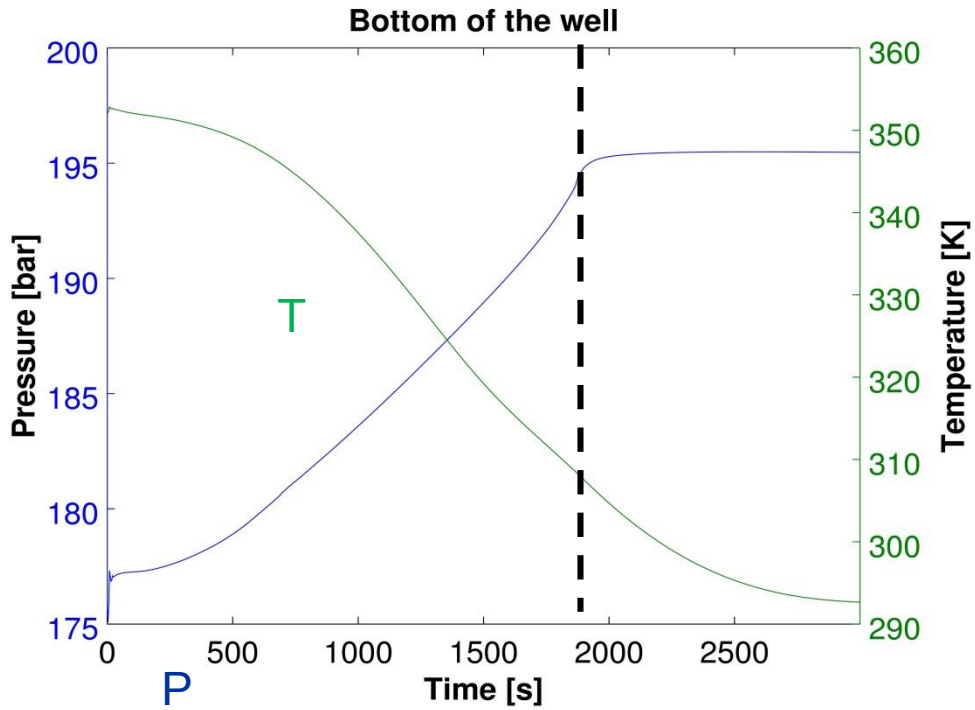
Case 1: Feed injection rate linearly ramped-up to 33.5 kg/s in 5 mins.





Case 2: flow rate linearly ramped-up to 33.5 kg/s in 30 mins.



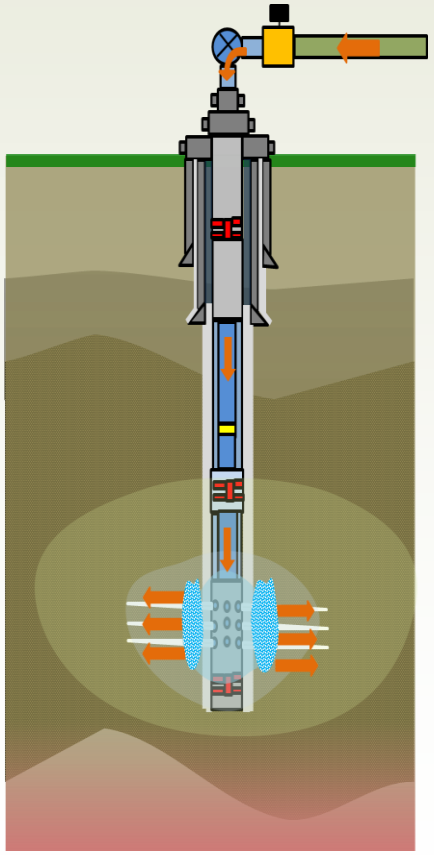


Conclusions

- initial rapid and significant cooling (- 13 ^{o}C) at the wellhead prior to a recovery leading to the risk of ice/hydrate formation and thermal shocking of well. No such risk at the bottom of the well
- the slower the ramp up duration, the lower minimum temperature at the wellhead (ca -7 ^{o}C for ramp up in 5 min ;– 13 ^{o}C for ramp up in 30 min)
- the simulated temperature and pressure profiles at any time and location along the may be used to determine optimum injection conditions for CO_2 including the maximum allowable injection rate, ramping up duration, feed temperature and pressure, and if required, any preheating. *The injection simulation model developed in this work provides such capability.*

Conclusions (continued)

- The results presented are site specific with and must not be generalised. Shallower reservoirs might exhibit lower pressure, exaggerating the above risks

Future work

- Coupling the flow model with site specific boundary conditions accounting for pressure, porosity, permeability, infectivity
- Accounting for CO_2 impurities
- Modelling CO_2 BELEVE leading to well blowout
- Modelling thermally induced near-field immobilisation of CO_2 during its injection