Will Two-phase CO2 Tubing Flow be Stable – or Should it be Avoided?

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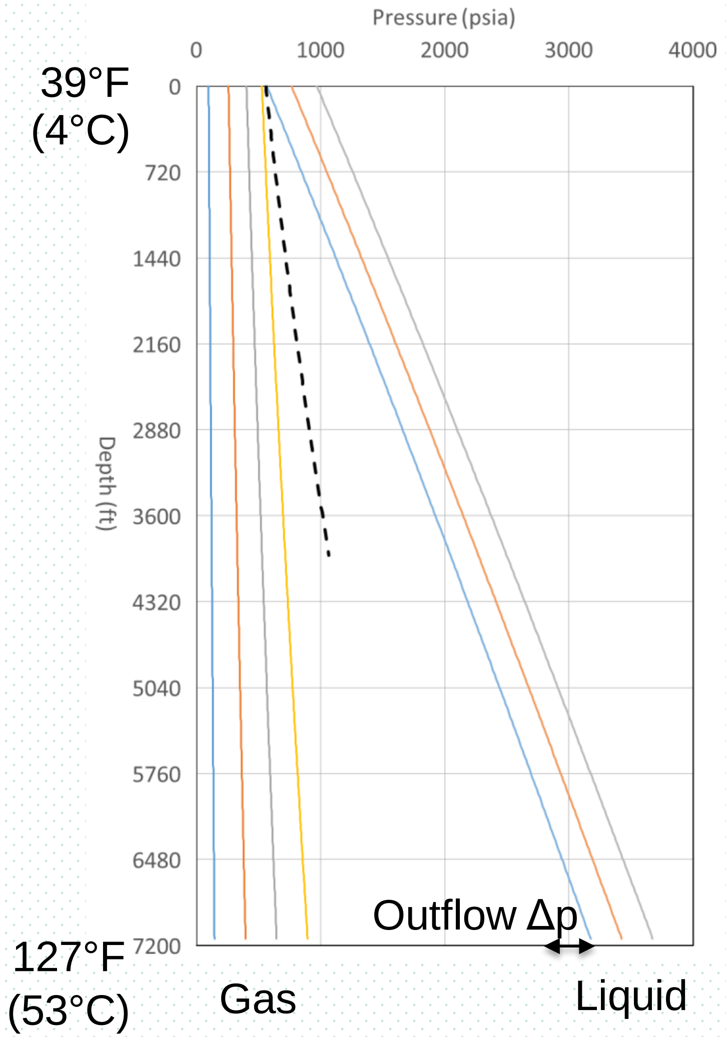
Introduction

- Highly pressure depleted gas fields are prime targets for CO_2 storage especially in the UK
- Injecting into such a low pressure environment will likely involve initially injecting the CO_2 as a gas
- But when the weight of the gas column minus the pressure loss from friction becomes insufficient to achieve the bottom hole pressure (BHP) required for a given injection rate
- Then, if the tubing head temperature (THT) of the CO_2 is below critical (31.0°C, 87.8°F), the fluid in the tubing will turn two phase (liquid/dense phase below with vapour/liquid equilibrium fluid above)
- This will persist for intermediate BHPs until the reservoir pressure has increased such that an all liquid/dense phase CO_2 column is necessary to achieve the required BHP
- However, if the THT of the CO_2 is heated to significantly above the critical temperature throughout, then two phase flow in the tubing can be avoided
- It is clear that CO_2 flowing in the tubing in a single phase (gas or liquid) is stable
- But would this also be true under conditions where there is a phase transition in the tubing?
- This talk reviews practical experience

Depleted gas field disposal – demo of tubing flow issues



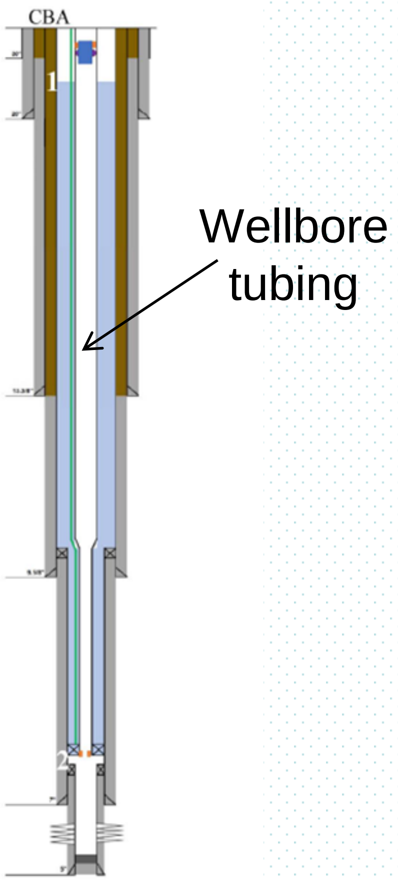
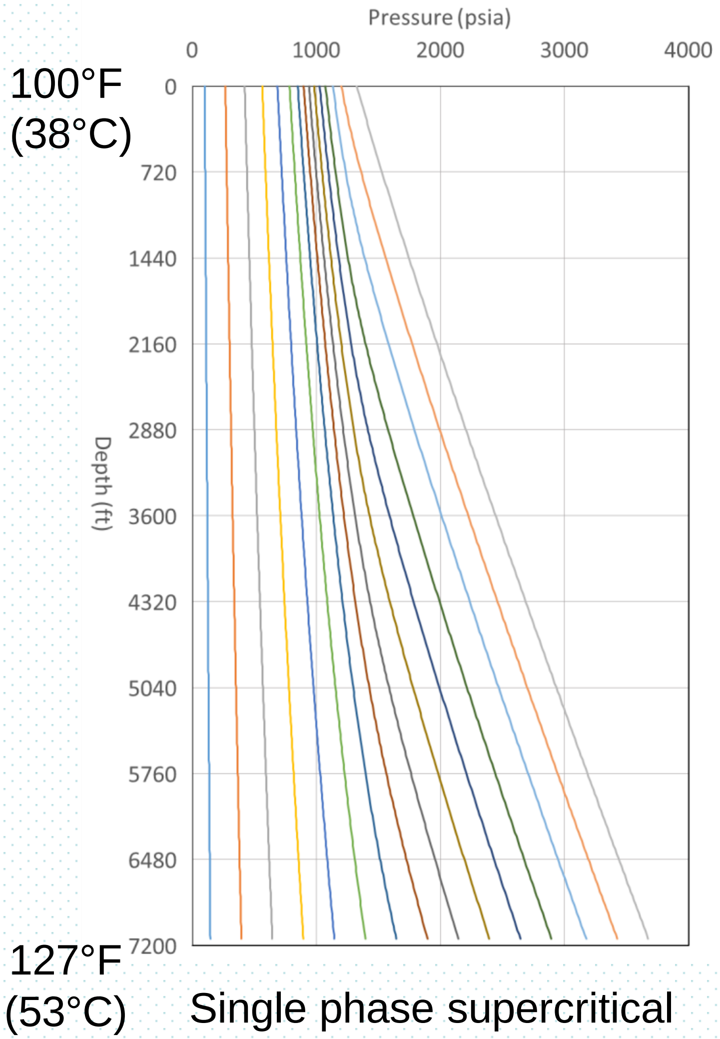


Figure 15—Example Porthos well completion



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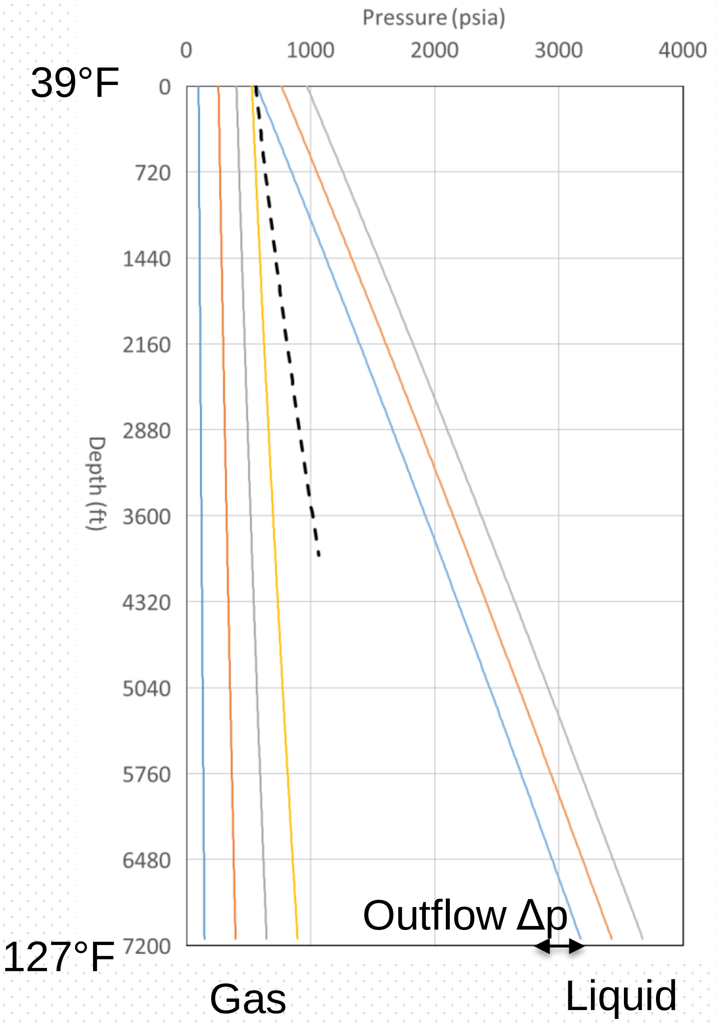

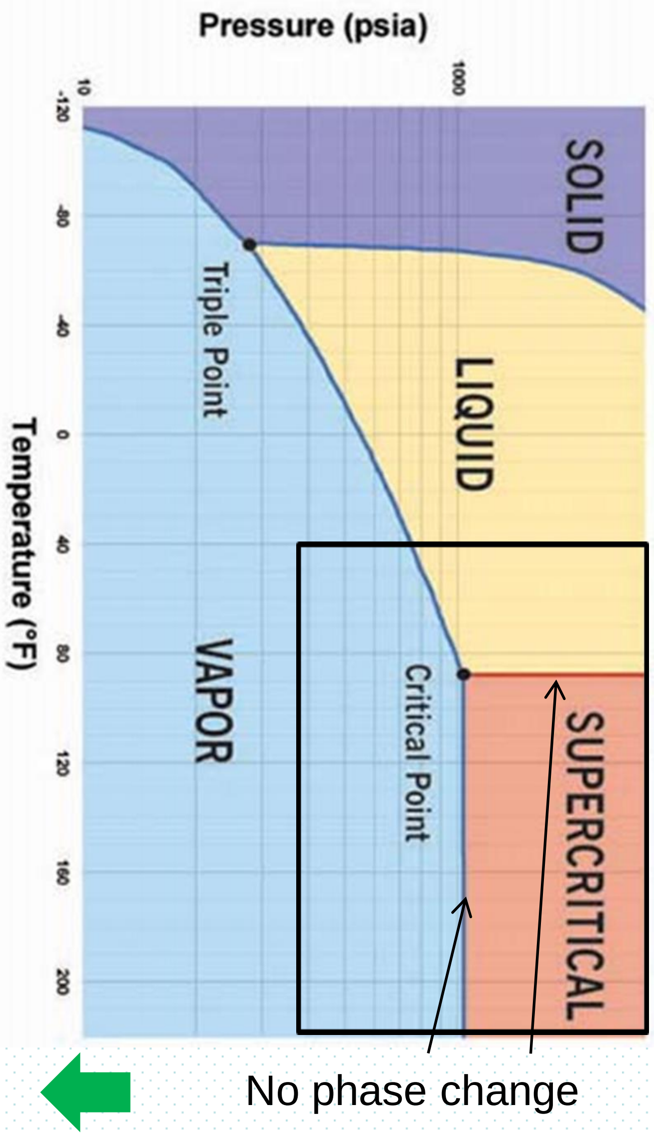

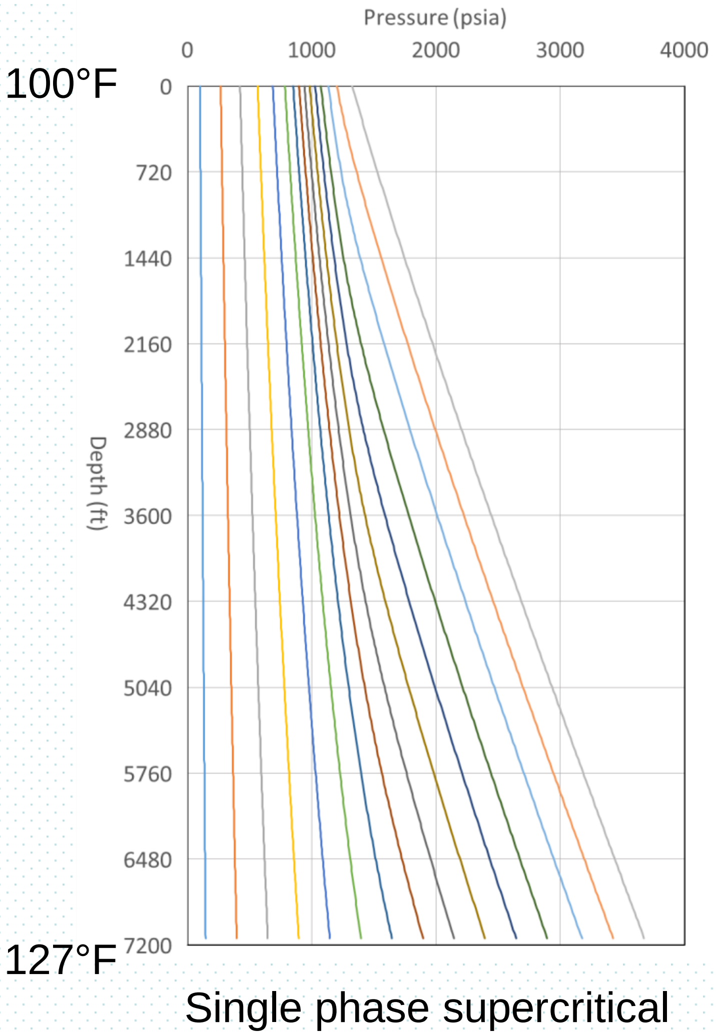

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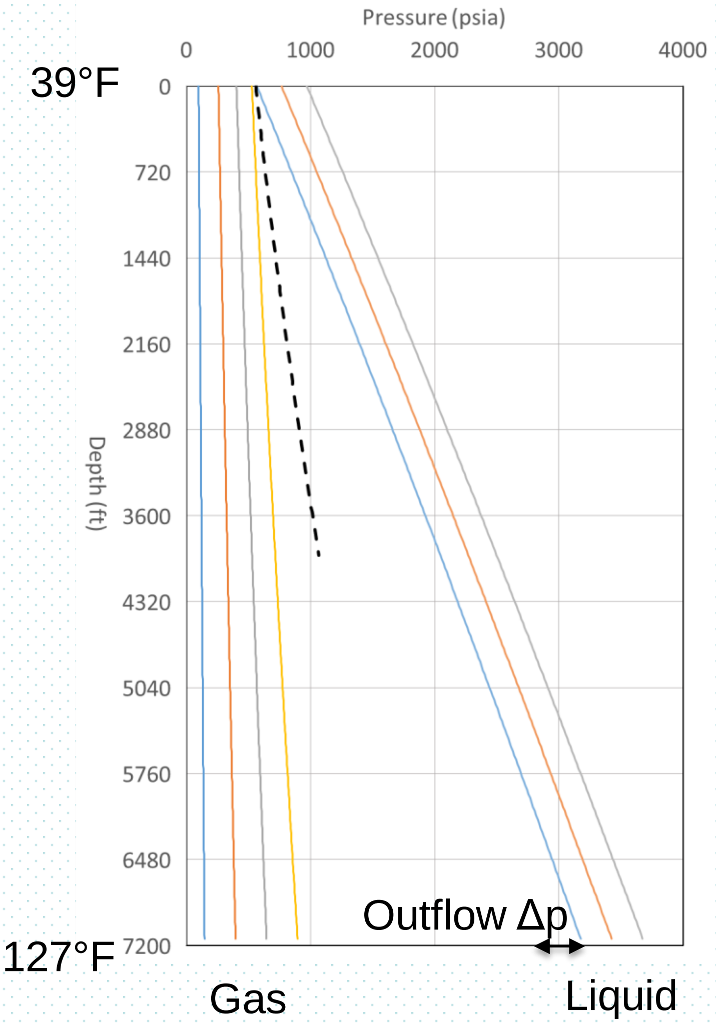

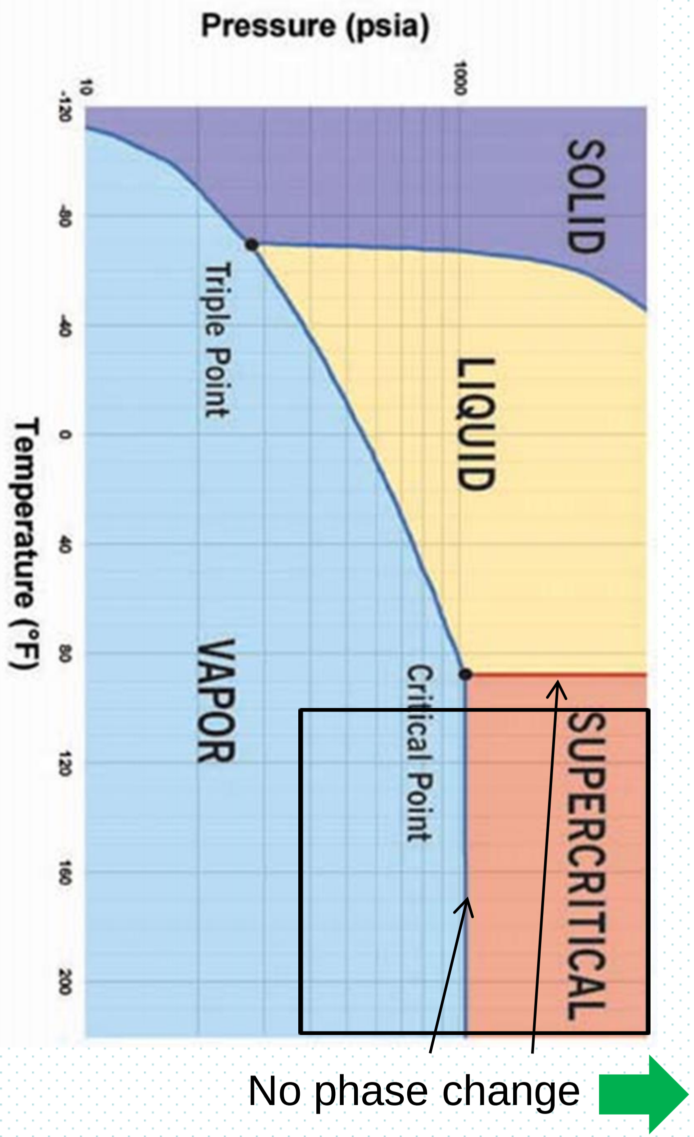

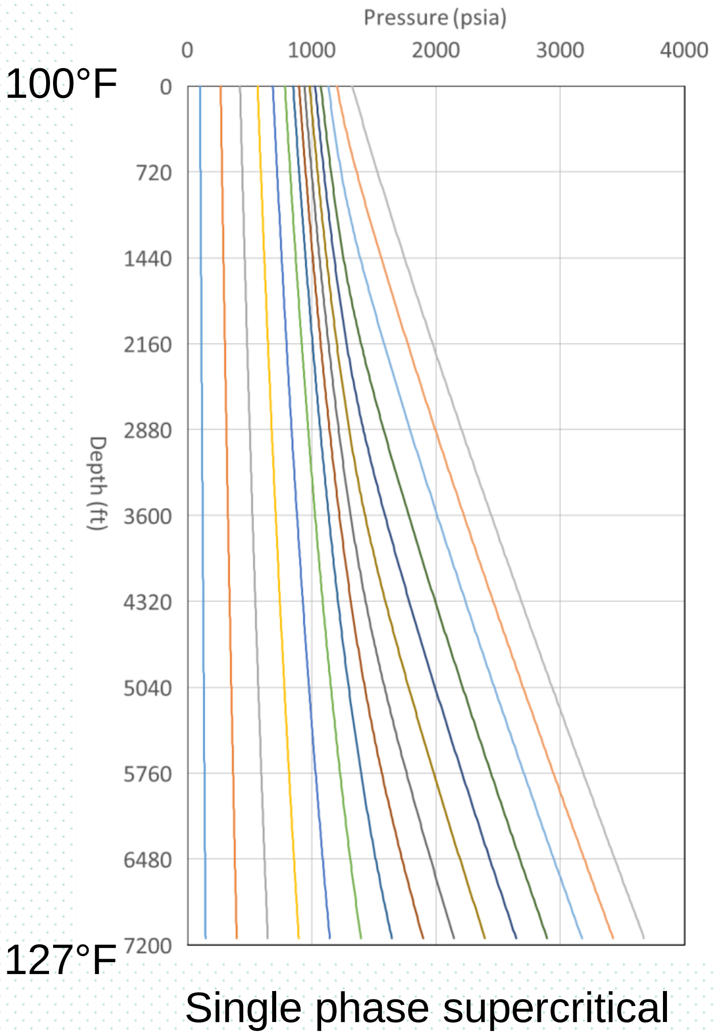

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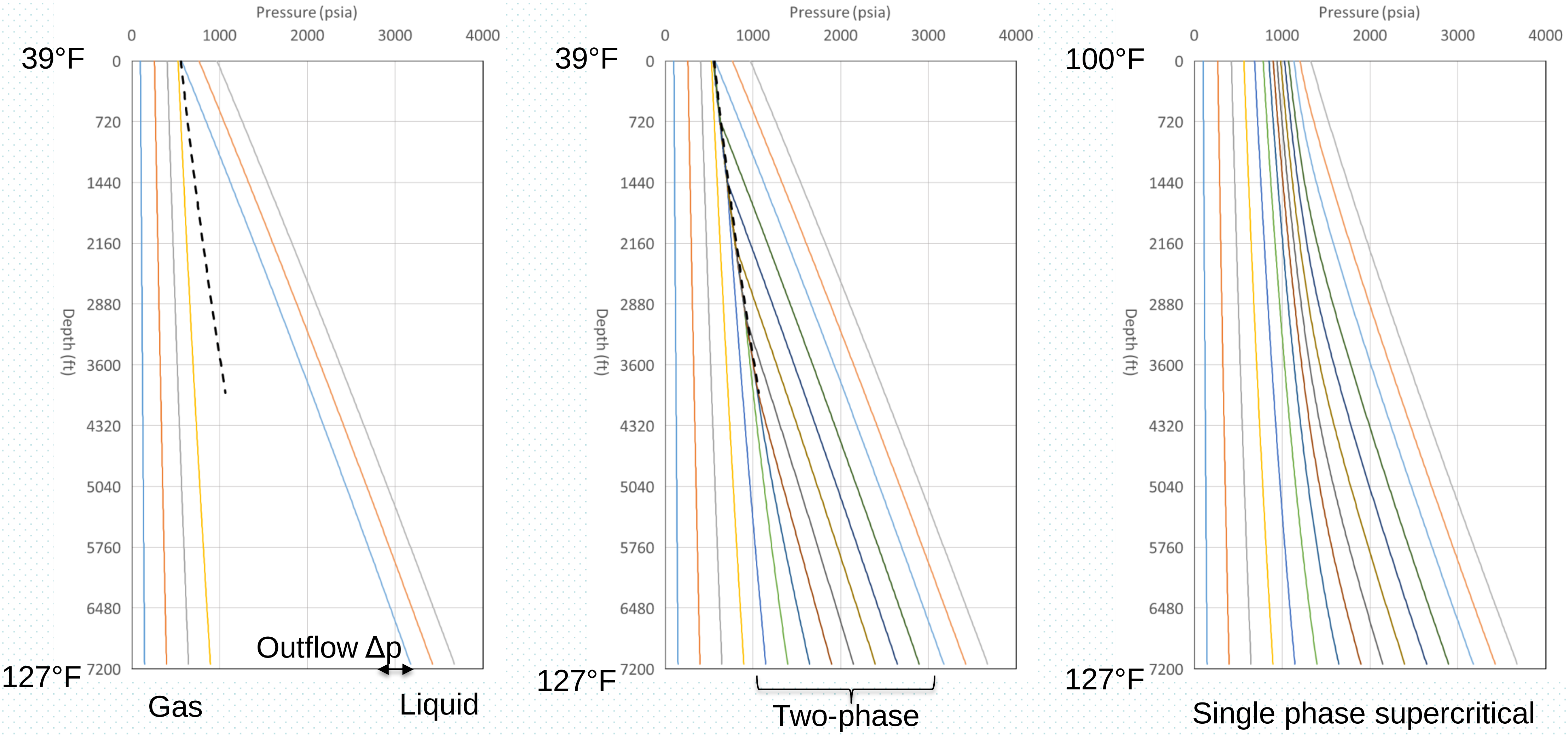
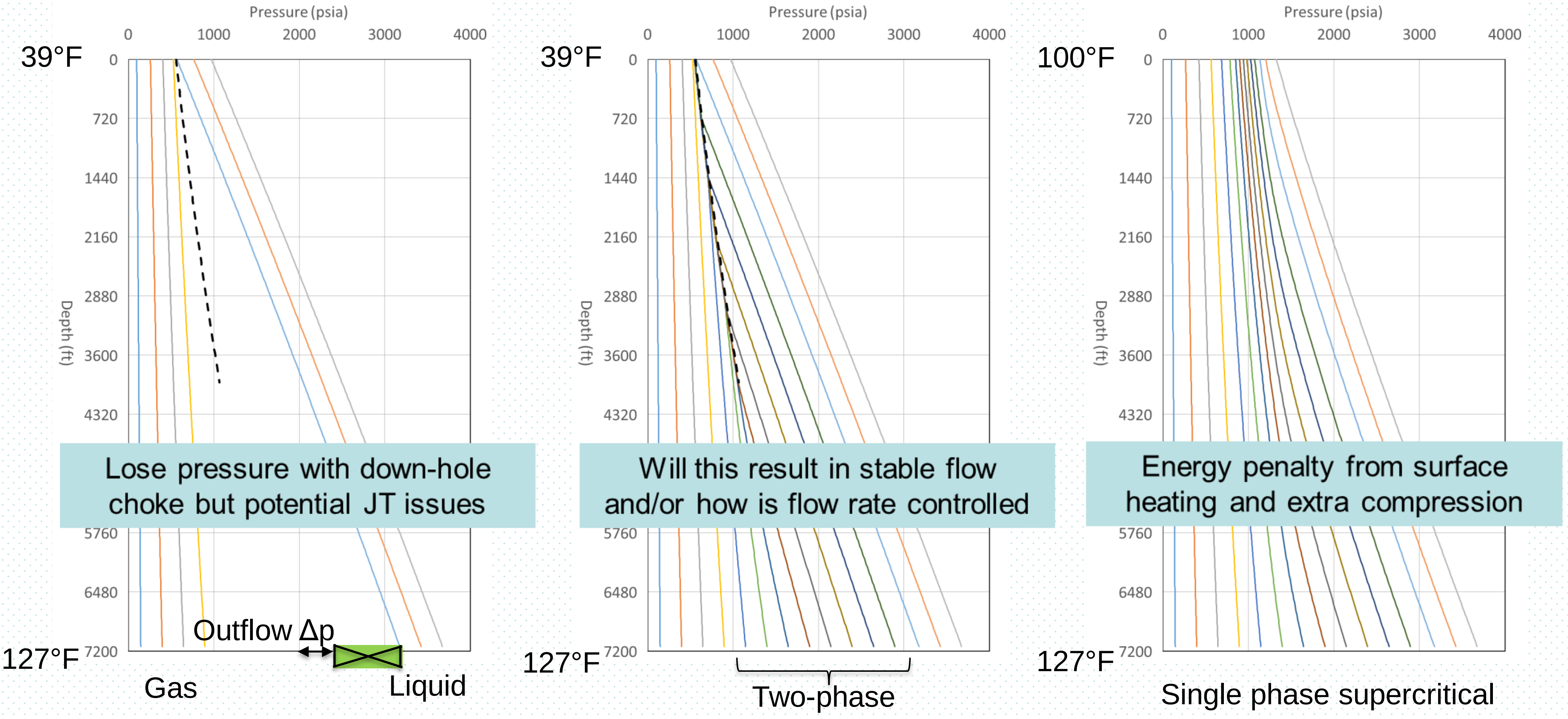
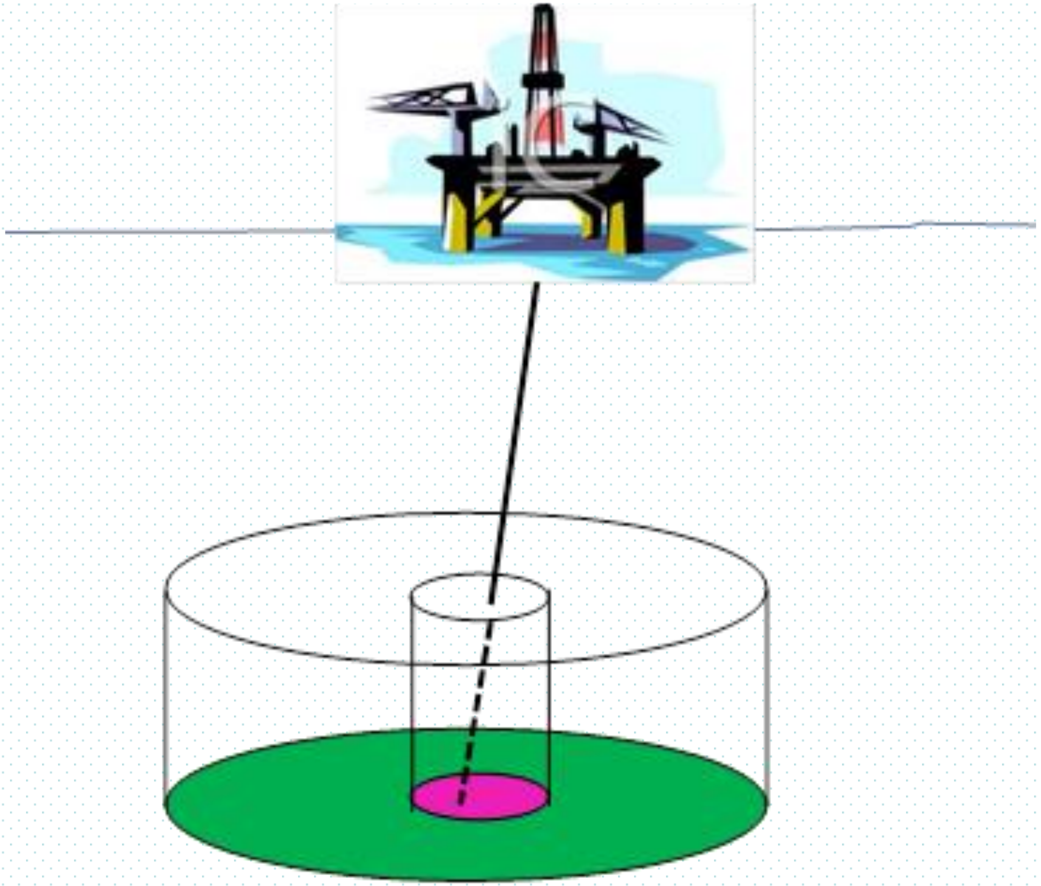


Depleted gas field disposal – demo of tubing flow issues



Issues initially investigated using simplified analytical model

- Reservoir tank
- Gas outflow equation (Δp injector to reservoir)
- Volume balance
- Tubing pressure equation (including friction and compression/expansion heating and cooling terms)
- Correlation for hydrocarbon gas properties
- Equation of state for CO_2 properties
- Initial conditions:
  - Hydrocarbon gas composition
  - Size and properties of gas reservoir
  - Initial depleted conditions
  - CO_2 injection rate



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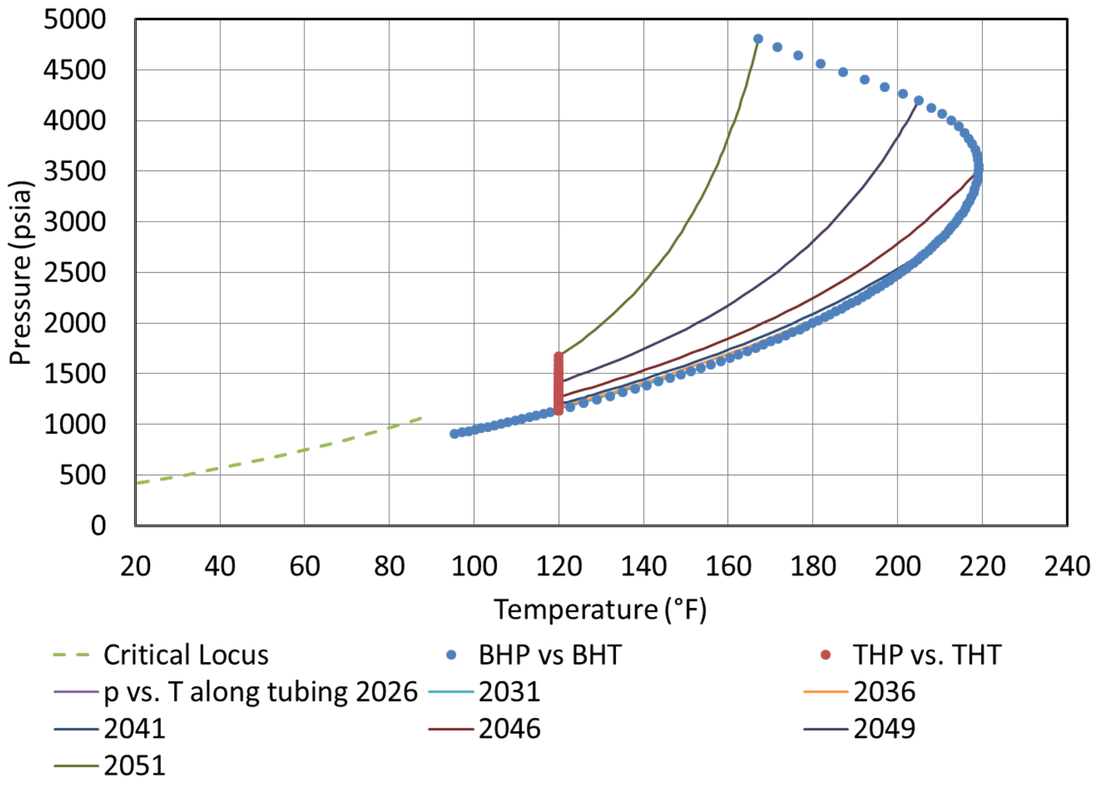
Single well model input data:

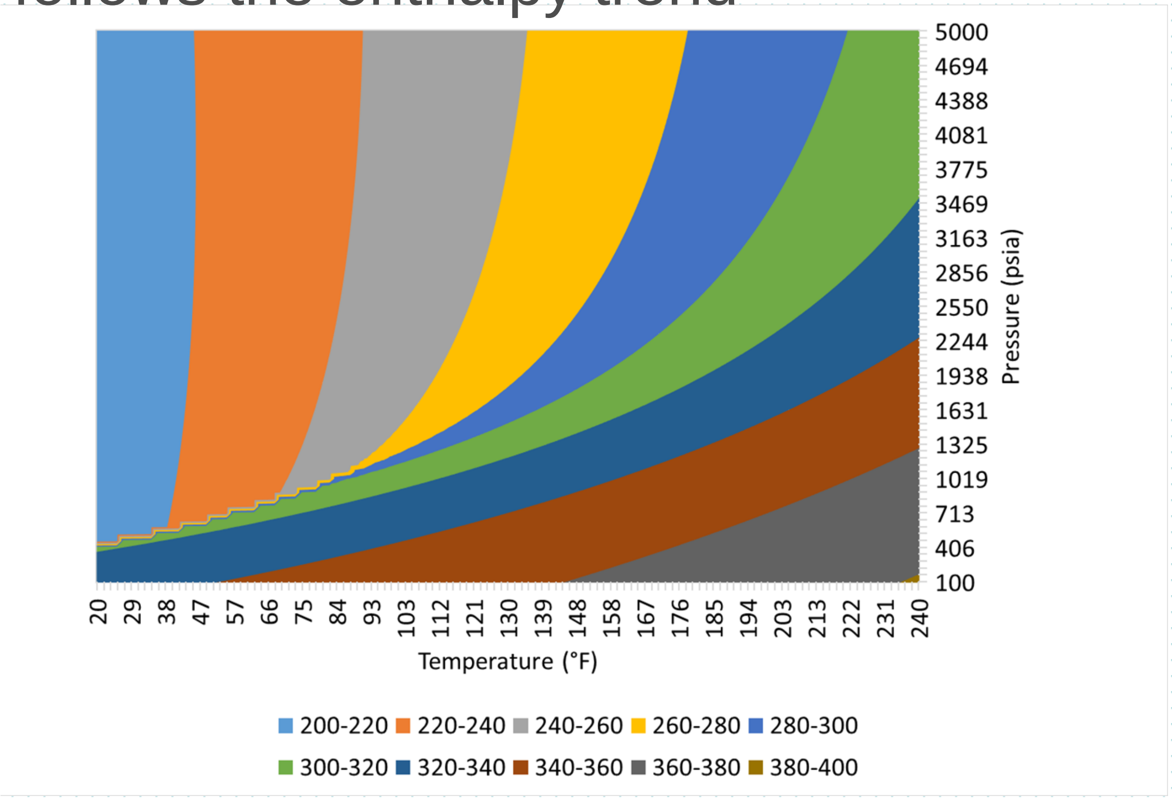
- Depth **10,000 ft** TVDss
- Average thickness 500 ft
- Reservoir temperature 200°F (93°C)
- Original GIP **640 Bscf**
- Original pressure **4650 psia**
- GIP at start of CO_2 injection **49 Bscf**
- Pressure at start of CO_2 injection **350 psia**
- Swi 0.2, porosity 0.15, permeability 50 mD
- 6″ ID tubing
- Injection rate **100 MMscf/d (1.9 mtpa)**
- 1/1/2026 – 1/1/2051 **(25 years)**

Result if CO_2 is heated at the surface to 120°F (49°C) - (p vs. T)

- BHP in range 909 to 4809 psia
- THP in range 1136 to 1674 psia



- CO2 enthalpy in BTU/lb
- Unsurprisingly the tubing calculation follows the enthalpy trend



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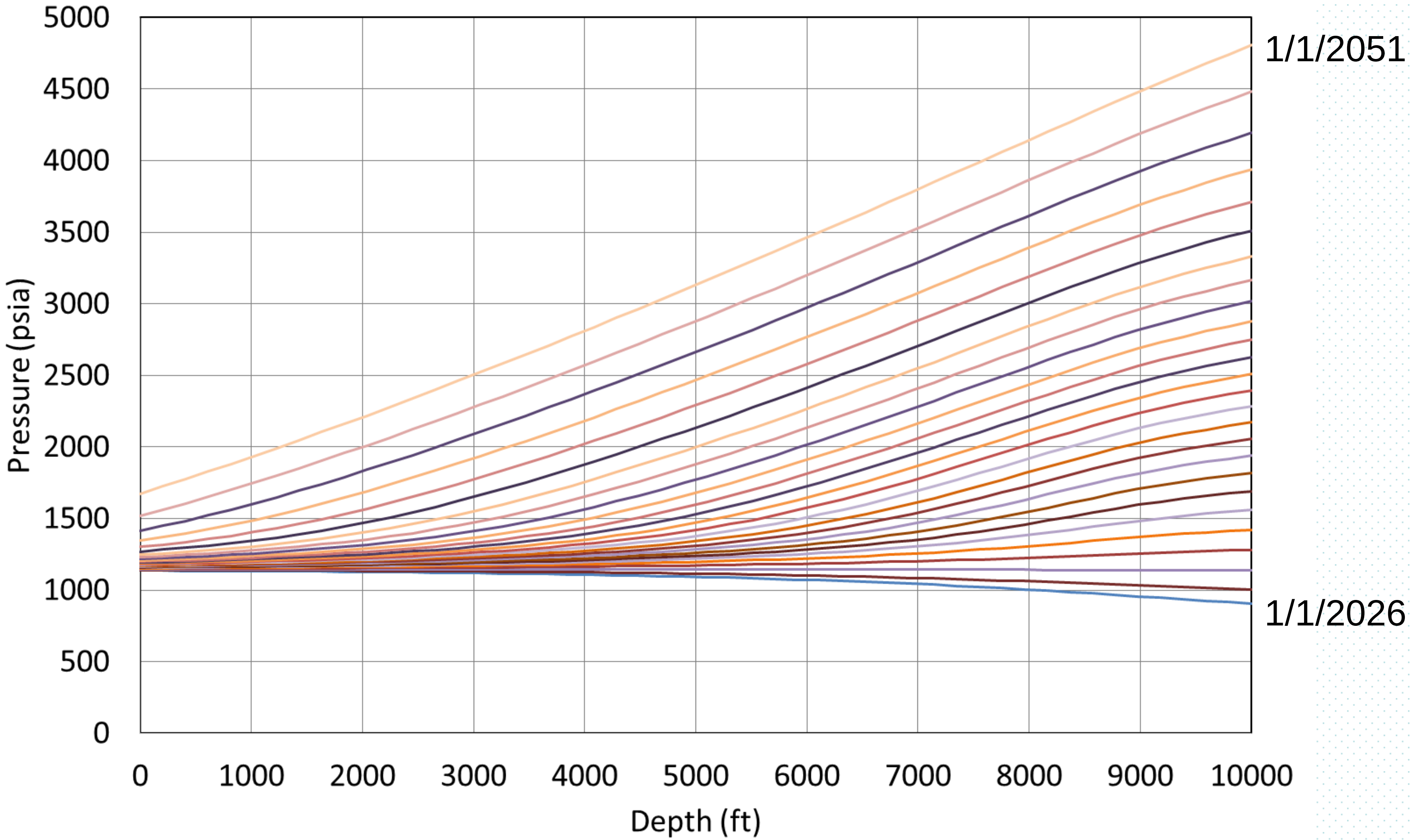
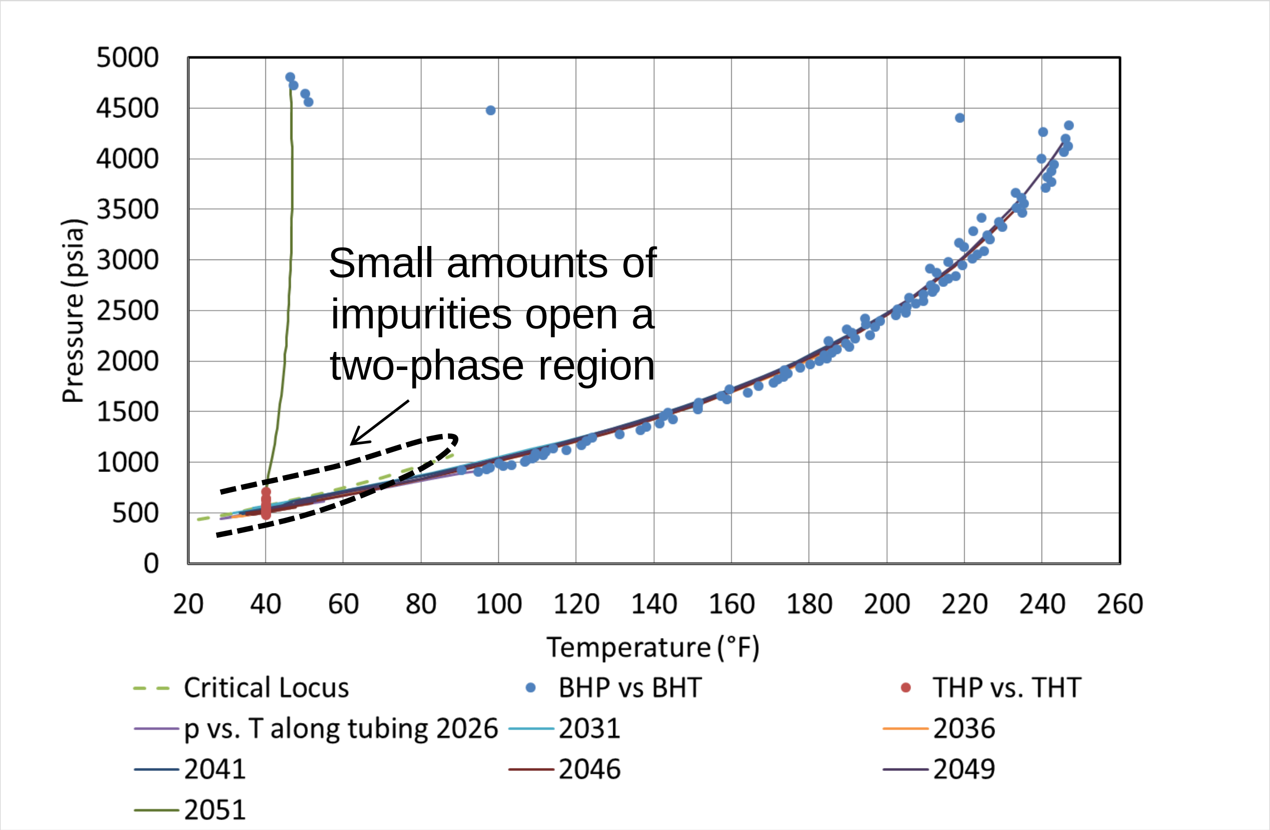
Result if CO_2 is heated at the surface to 120°F - (p vs. depth)



Result if CO2 injected at the surface at 40°F (4°C) - (p vs. T)

- BHP in range 909 to 4809 psia
- THP in range 522 to 712 psia



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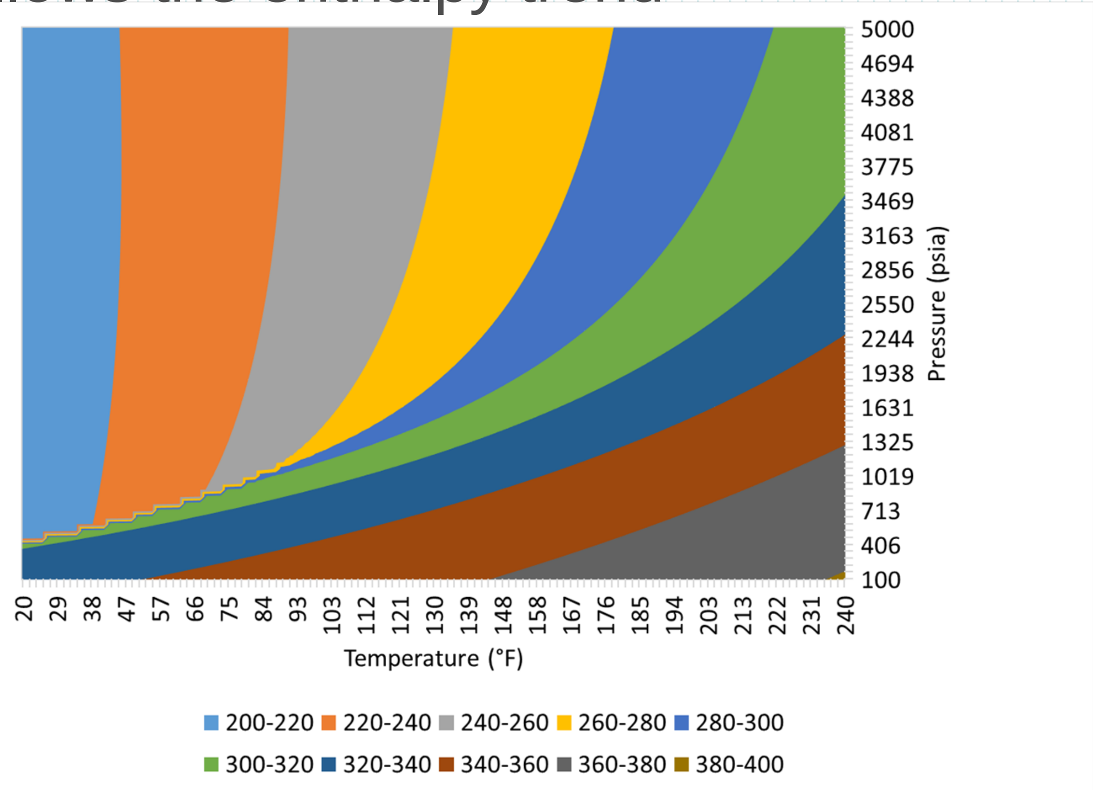

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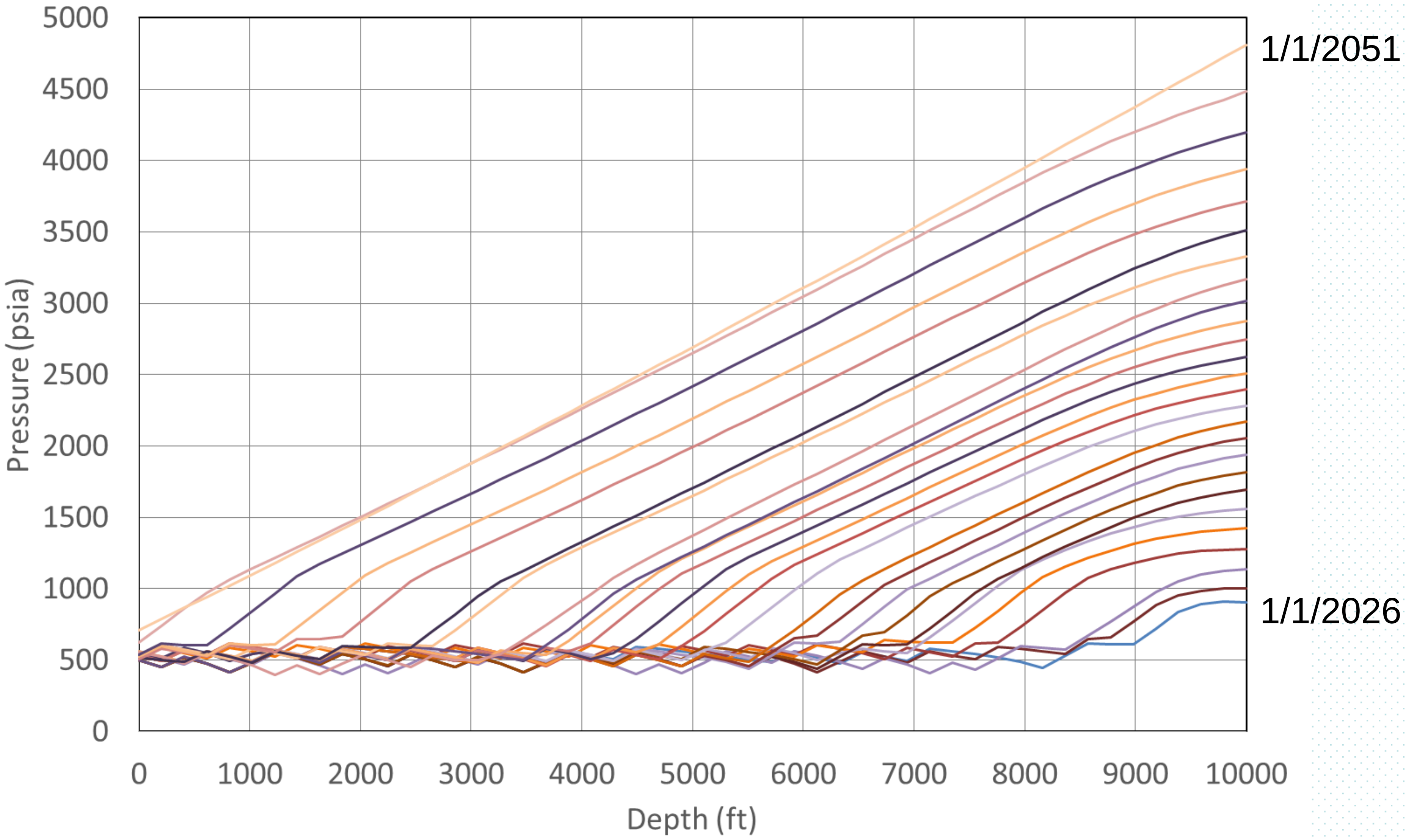
Result if CO_2 injected at the surface at 40°F - (p vs. depth)



Real life examples of two-phase tubing flow in CO2 injection

- Numerous papers report that CO_2 injection into a low pressure environment may result in two-phase tubing flow
- However, a study of the literature has shown very little practical experience
- Two examples that have been identified are:
  - In the upper part of the tubing during regular operations at the Sleipner (offshore, Norway) CO_2 injection project, and
  - A 2013 planned experiment at the Ketzin (Brandenburg, Germany) CO_2 injection pilot where the conditions were deliberately adjusted to induce two-phase tubing flow
- In addition a two-phase downwards flow experiment undertaken at the vapour/liquid conditions found at the tubing head of the injector at Sleipner has been reported
- A similar process to CO_2 injection is the re-injection of acid gas (a mixture of H_2S and CO_2) captured at gas sweetening plants
- This has been undertaken in Canada since 1989
- Four projects have been identified where two-phase conditions may have been encountered although no stability issues are reported

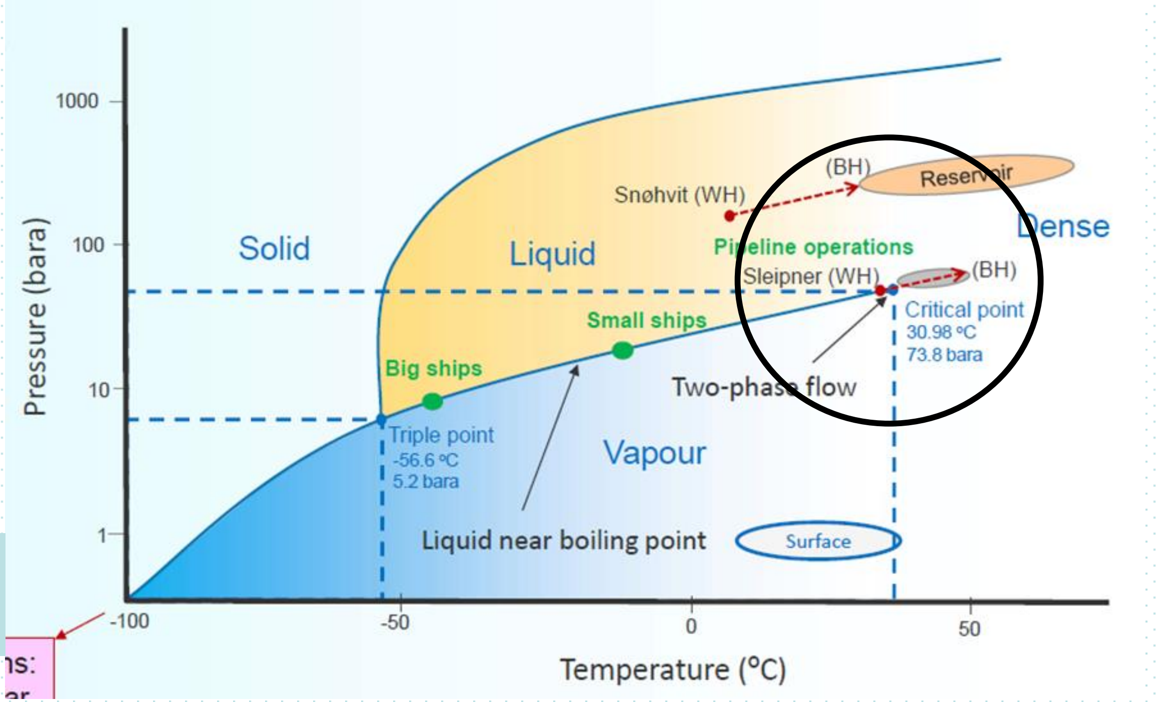
Sleipner injection conditions

- As shown in the figure opposite, the CO_2 is injected at vapour/liquid equilibrium conditions (so two-phase) at the wellhead (25°C, 62-65 bara) and this condition persists for some distance along the tubing
- The CO_2 becomes supercritical (so single-phase) further down the tubing and heats to 48°C prior to being discharged into the reservoir
- The initial reservoir pressure and temperature were 96 bara and 35°C; so the CO_2 cools as it enters the reservoir
- Because of the large volume and high permeability of the Utsira formation, the discharge pressure has only increased by around 1 bar

Liquid and gas have similar properties at tubing head conditions
The density and viscosity ratios are both around 3

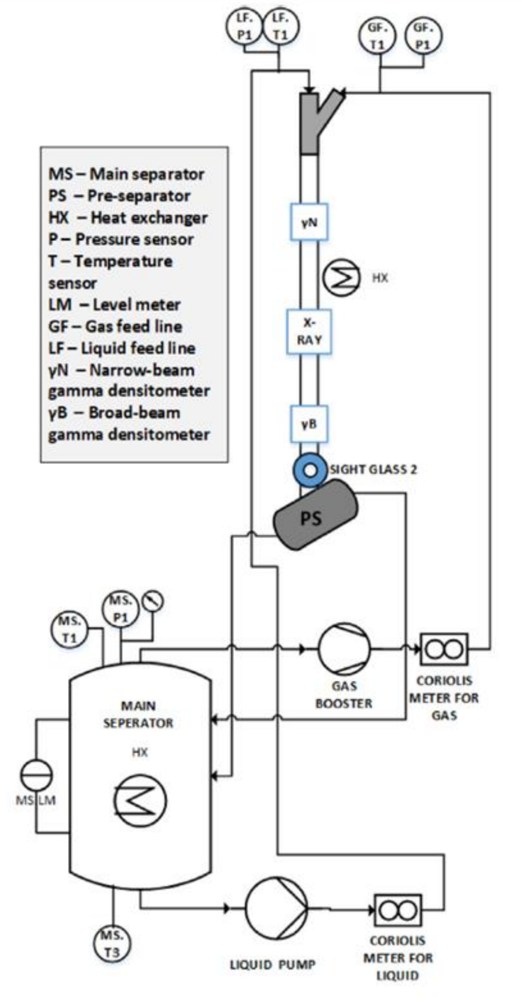
From : Philip Ringrose private communication, April 2025

- Sleipner is an example of where two-phase tubing flow has occurred without any reported issues or problems indicating that certainly under some circumstances two-phase flow can be allowed without fluctuations or stability issues



Two-phase downwards flow experiment at Sleipner TH conditions

- The experimental arrangement and instrumentation is as shown
- The pipe is 44 mm inside diameter and 13.7 m tall, and the experiments are conduced at a saturation pressure of 65 bara corresponding to a saturation temperature of 24.4°C
- The CO2 is conditioned in a separator (p and T as noted above) and individual single phase feed lines of gas (from the top) and liquid (from the bottom) convey the CO2 to the “inlet merger” or manifold at the head of the test section
- The gas and liquid were injected in various proportions
- The objective of the experiments was to measure the pressure drop, the liquid holdup and the flow regime for the different proportions of gas and liquid



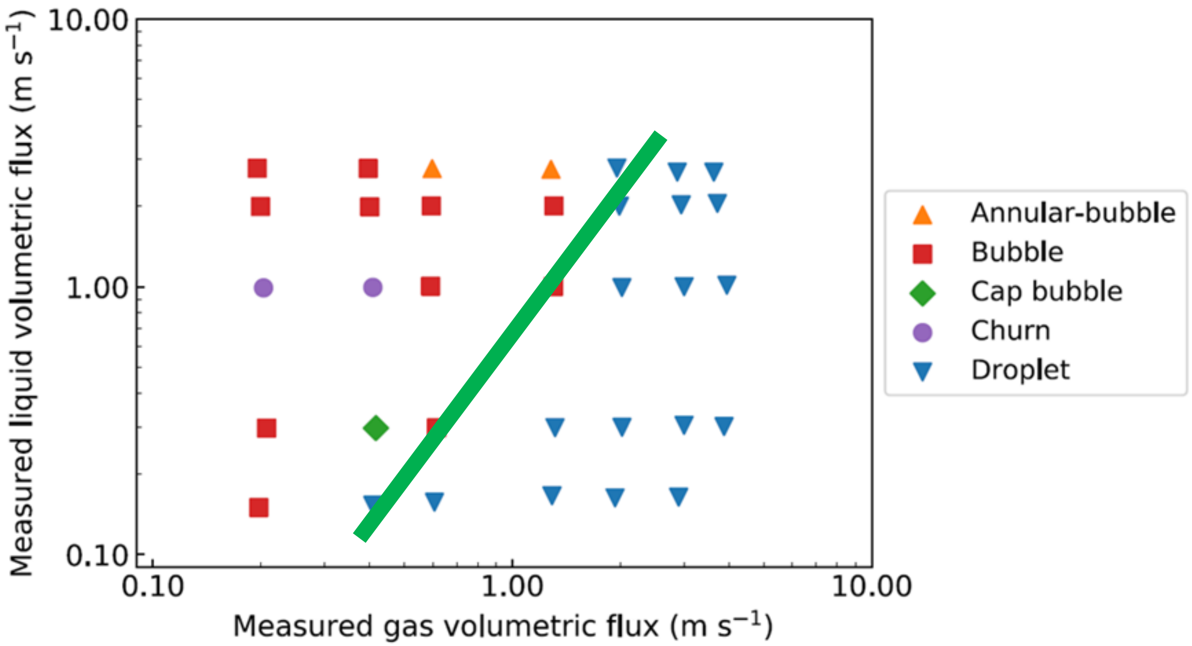
(a) Process design layout for vertical downward flow with indication of the gamma densitometers and X-ray locations,

“*Upward and downward two-phase flow of CO2 in a pipe: Comparison between experimental data and model predictions*” by Morten Hammer et al, International Journal of Multiphase Flow, 2021

Experiment conducted in FALCON flow assurance loop, Institute for Energy Technology, Norway

Results of two-phase downwards flow experiment

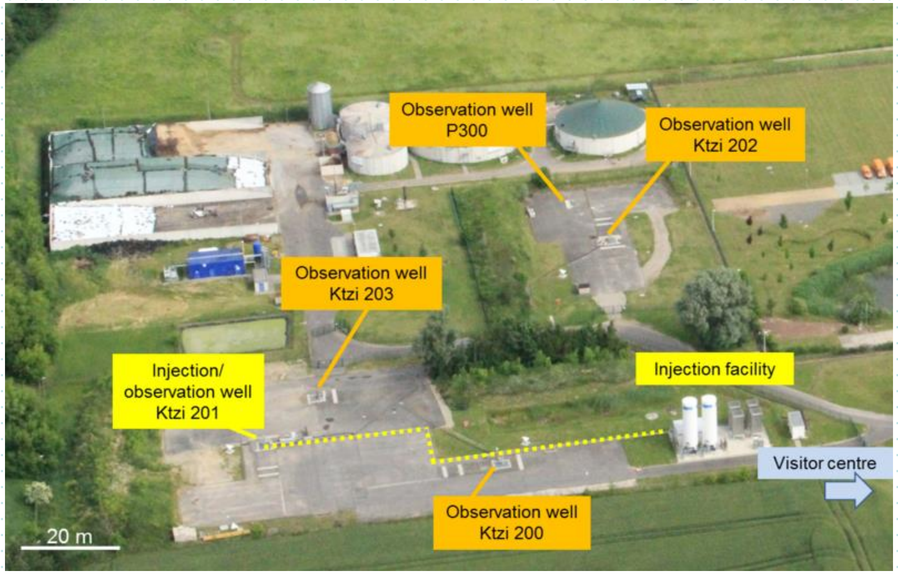
- The results in terms of the manually observed flow regimes are as shown
- With a small proportion of gas there is a continuous liquid phase with gas bubbles
- Whereas with a high proportion of gas there is a continuous gas phase with liquid droplets
- There are some slight variations in these regimes at intermediate proportions
- Various models were considered for phase slip and friction pressure drop but given the near critical conditions there are only small differences between the thermophysical properties of the two phases (factor of ~3 in density and viscosity)
- Consequently the flow is close to “no slip” and homogeneous models which assume a proportional average of gas and liquid properties perform well

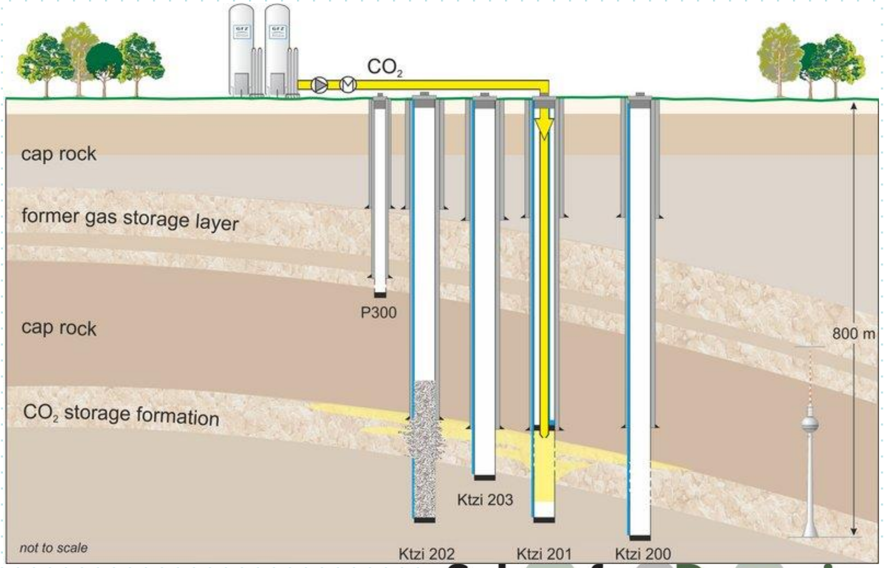


- More variability is observed in the friction element of the pressure drop for downwards flow compared to upwards flow
- Possibly due to flow regime variations or increased experimental uncertainty as friction and gravity are acting to oppose each other

Ketzin

- A European pilot CO2 injection project coordinated by the German Research Centre for Geosciences (GFZ) was undertaken at a site in Ketzin, 40 km west of Berlin, Germany
- From June 2008 to August 2013 67,000 tonnes of CO2 were injected into a saline aquifer at a depth of 630-650 m through 3½″ tubing
- CO2 was delivered in road tankers and stored on site in storage tanks at minus 18°C, 21 barg
- The initial temperature and pressure of the aquifer at 33°C, 62 barg are very near to the CO2 critical point of 31°C, 73.8 bara
- To avoid the possibility of any phase transitions within the surface facilities and injection well the CO2 was heated and vaporised at the surface to 35 to 45°C (but recognising that this may not be economically viable for full scale projects)





Ketzin two-phase “cold” experiment

- However, to see what the effect might be if phase transitions were allowed in the tubing an experiment was undertaken during March to July 2013 reducing the injection temperature to significantly below critical
- The injection rate was maintained at 1.5 tonnes per hour as the temperature was reduced in steps from 40 to 35, to 25, to 15 and finally to 10°C

Ketzin Injection Well (Ktzi 201)

- The following were monitored:
  - Mass flow rate with a Coriolis flowmeter installed about 8 m upstream of the wellhead
  - “Wellhead” temperature about 3 m upstream of the wellhead
  - Wellhead pressure directly at the wellhead
  - Distributed temperature sensing (DTS) with a fibre-optical cable running on the outside of the tubing
  - “Bottom hole” pressure (BHP) and temperature (BHT) with a fibre-optic sensor at 550 m depth (80m above top reservoir)

Figures from : *“Injection of CO2 at ambient temperature conditions – Pressure and temperature results of the “cold injection” experiment at the Ketzin pilot site”,* Fabian Möller et al, GHGT-12, 2014

Ketzin two-phase "cold" experiment - results

- The results of the experiment are shown opposite
- There were two interruptions to flow; one due to a workover at a nearby observation well and one for technical reasons
- It is reported that the injection process *"ran smoothly although measured wellhead and bottom hole pressure and temperature fluctuations became more pronounced with decreasing well head injection temperature"*
- Also, although the CO_2 was being delivered at a constant rate of 1.5 tonnes per hour, there were significant variations in the measured flow rate because the CO_2 became two-phase in the surface flow line whereas the meter is only able to measure liquid rates

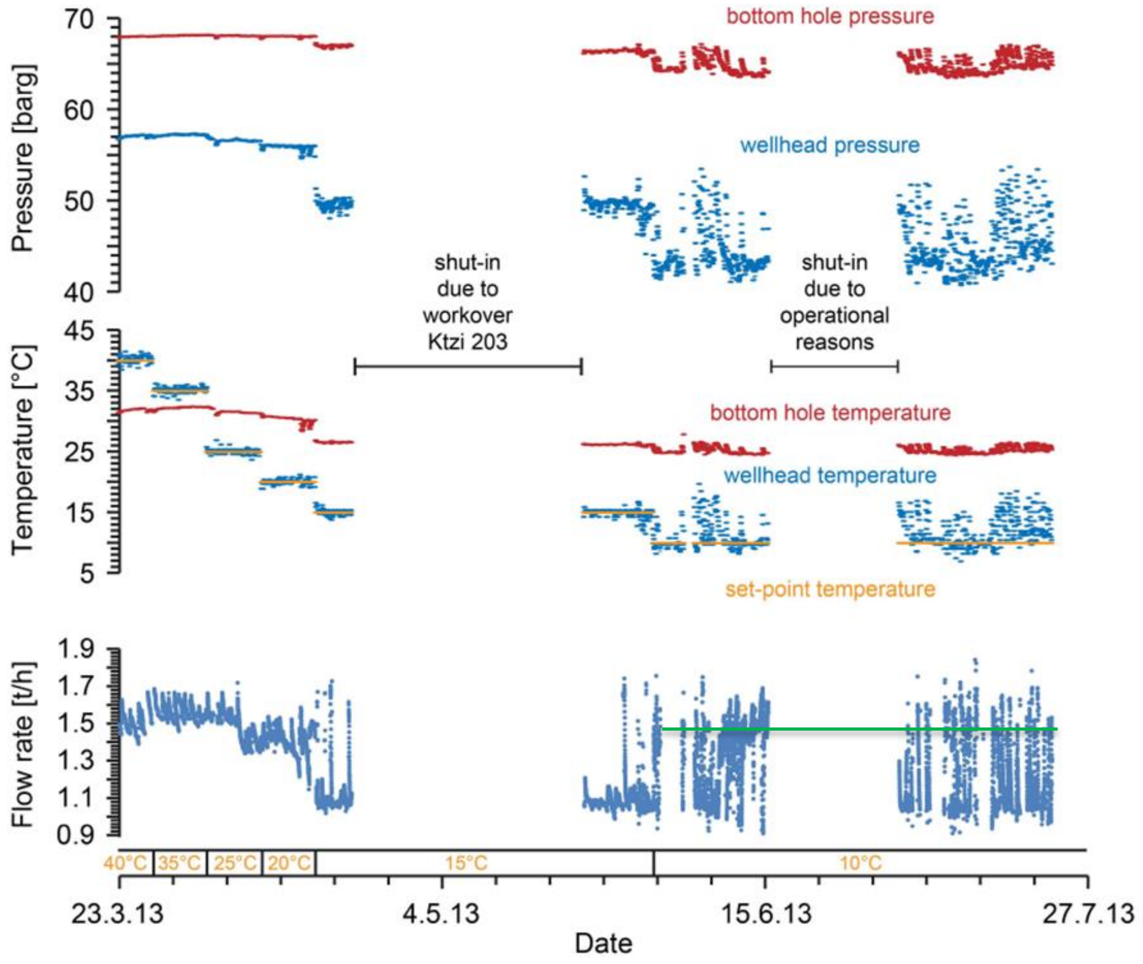


Fig. 2. Overview on all measured parameters during the cold injection experiment

Ketzin two-phase "cold" experiment - results

- Compared to original 40°C injection temperature, during the nominal 10°C injection step:
  - Because the CO_2 is colder and more dense the BHP is lower as the injection Δp is smaller for the same mass rate of injection
  - The wellhead pressure is also lower because the higher CO_2 density provides a heavier net CO_2 "head"
  - The fluctuations in both the BHP (64-67 barg) and BHT (~26°C) are relatively modest
  - Whereas the fluctuations in wellhead pressure (41-54 barg) and temperature (9-18°C) are significant
  - These fluctuations point to the CO_2 hugging the vapour/liquid equilibrium p-T locus within the tubing with instability as the CO_2 "hunts" between gas and liquid phases

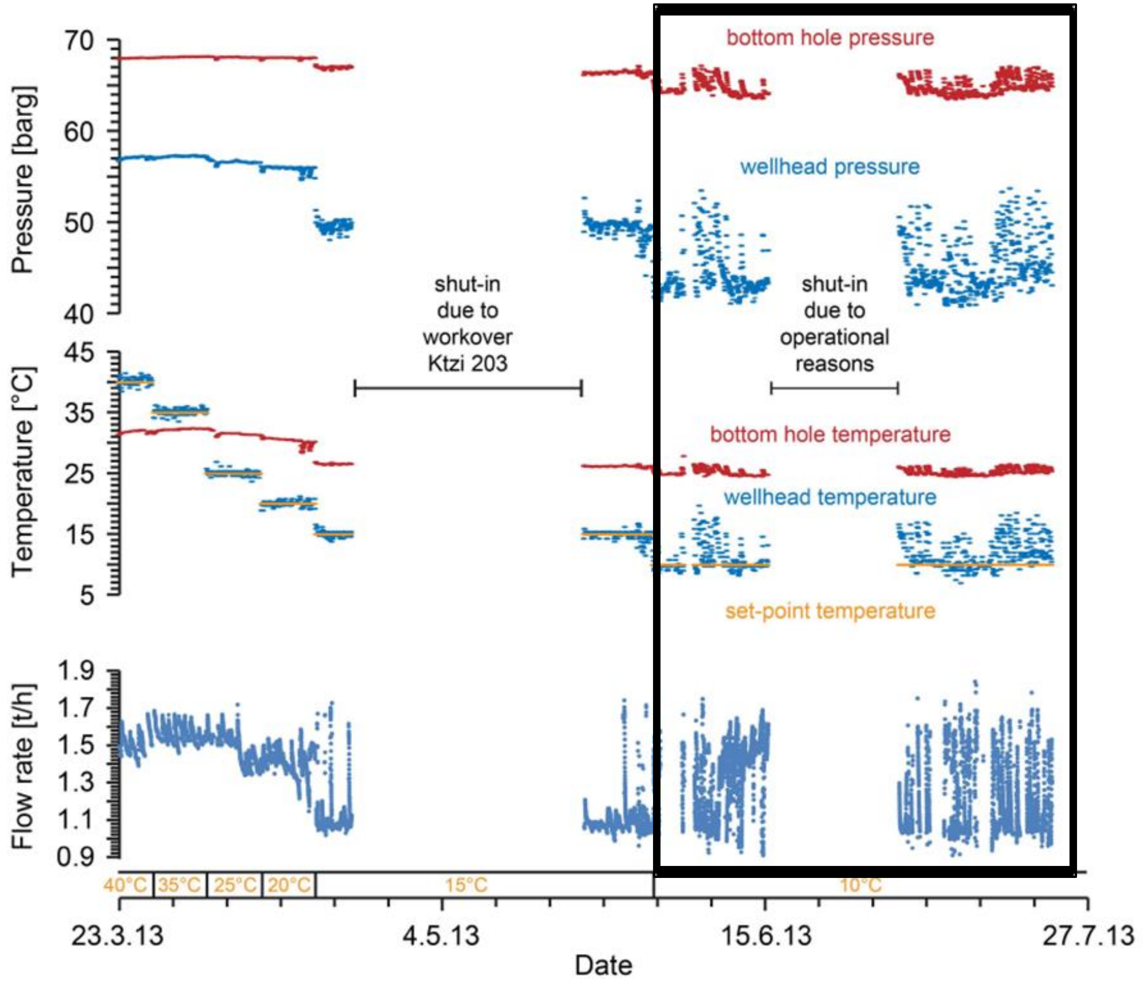


Fig. 2. Overview on all measured parameters during the cold injection experiment

Ketzin two-phase “cold” experiment - results

- This is illustrated in the figure opposite which is a plot of wellhead pressure vs. temperature and similarly for the in-well sensor
- Note again the significant fluctuation in the wellhead measurements
- All measurements lie on or near the line of vapour/liquid equilibrium confirming that the CO2 is hovering between gas and liquid or in some instances, as the CO2 also contains up to one mol% impurities, as two simultaneous phases
- Summing up: the Ketzin experiment shows that allowing for the possibility of two-phase flow in the tubing can result in fluctuations and instabilities, particularly in the ability to control wellhead injection pressure and temperature

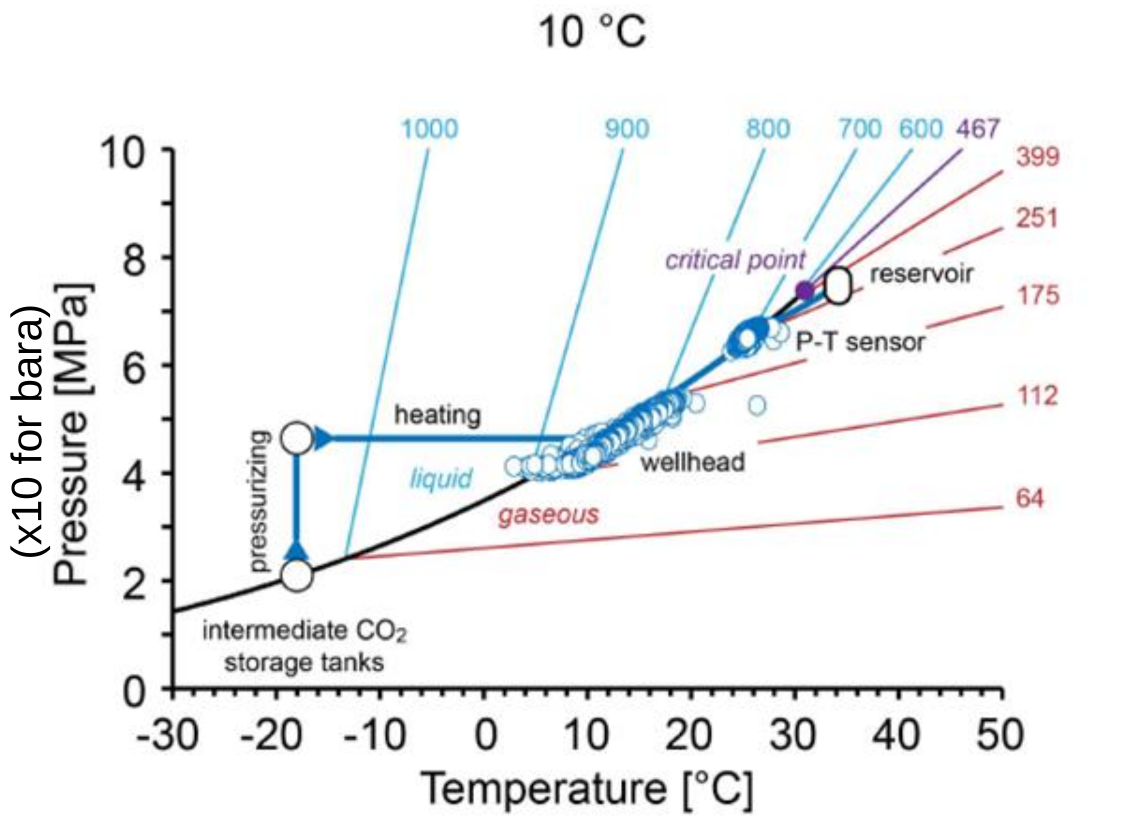


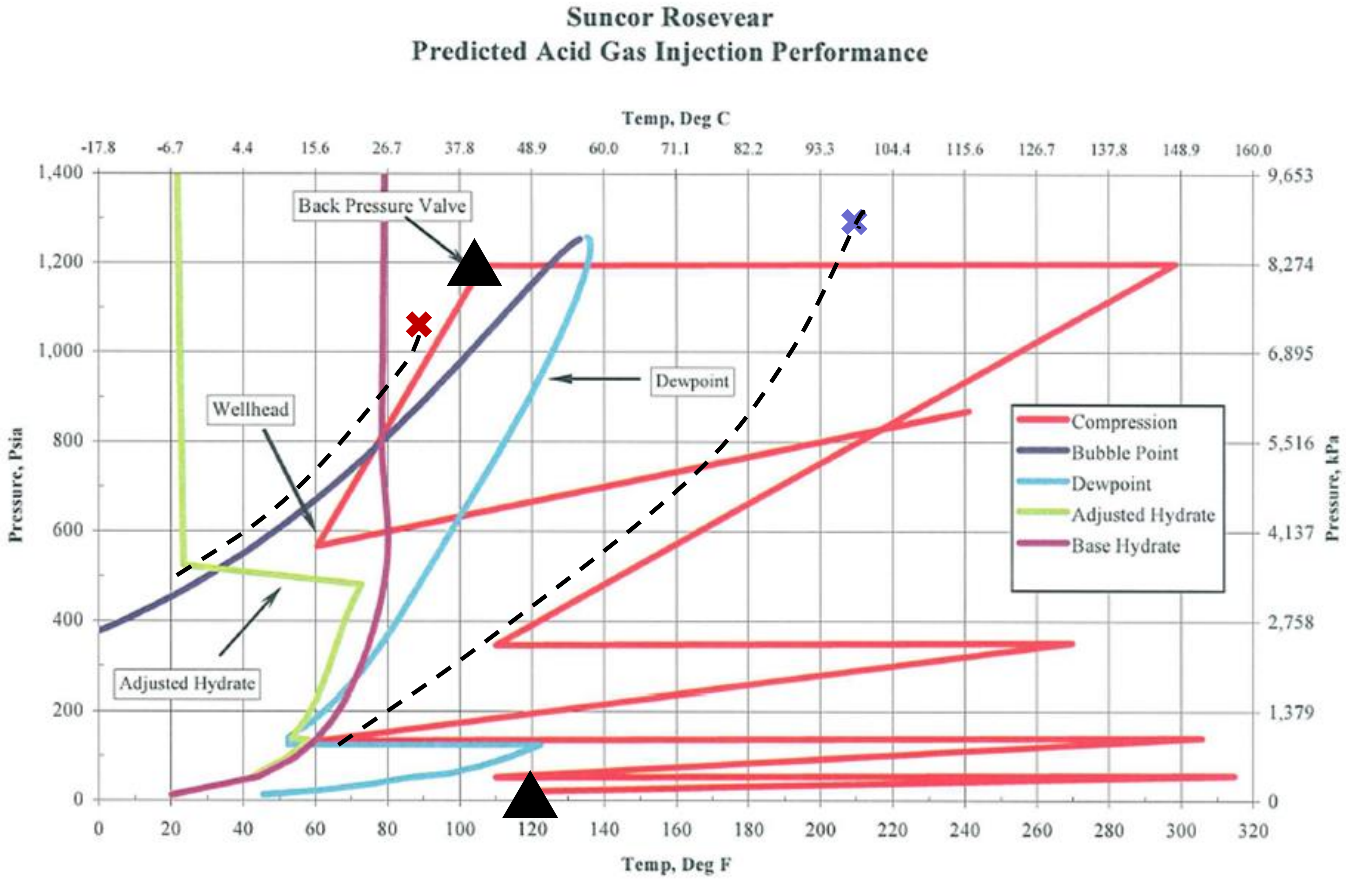
Figure 4: Measured pressure and temperature data at the injection well and the in-well pressure-temperature-guage for 10C

Acid gas injection

- The geological storage of acid gas as practiced in Alberta and elsewhere is analogous to the geological storage of CO_2 and has been in operation since 1989
- Many of the fields in the Rocky Mountain Thrust and Fold Belt in Alberta and British Columbia contain “sour” gas (i.e. gas that contains varying amounts of H_2S and CO_2)
- To meet pipeline and sales gas specifications the gas is “sweetened” by separating out the acid gas components
- Prior to the late 1980s the usual practice was either to recover sulfur from the acid gas or incinerate the acid gas
- Sulfur recovery became uneconomic because of a world over supply, and flaring became publicly unacceptable on environmental grounds
- From 1989, reinjection of the separated acid gas into depleted hydrocarbon reservoirs or into saline aquifers was introduced
- There is an extensive literature on Canadian acid gas injection experience but very little actual data to allow analysis of tubing flow conditions
- It appears that injection mostly occurs with the acid gas at liquid or dense phase (supercritical) conditions and remains single phase in the tubing
- However, four projects have been identified where two-phase conditions may have been encountered in the wellbore tubing during steady operations although no stability issues are reported
  - Suncor: South Rosevear
  - Keyera Corp: Bigoray
  - Chevron: Acheson
  - ATCO: Golden Spike (no AGI details found)

Acid gas injection – Injection well conditions – South Rosevear

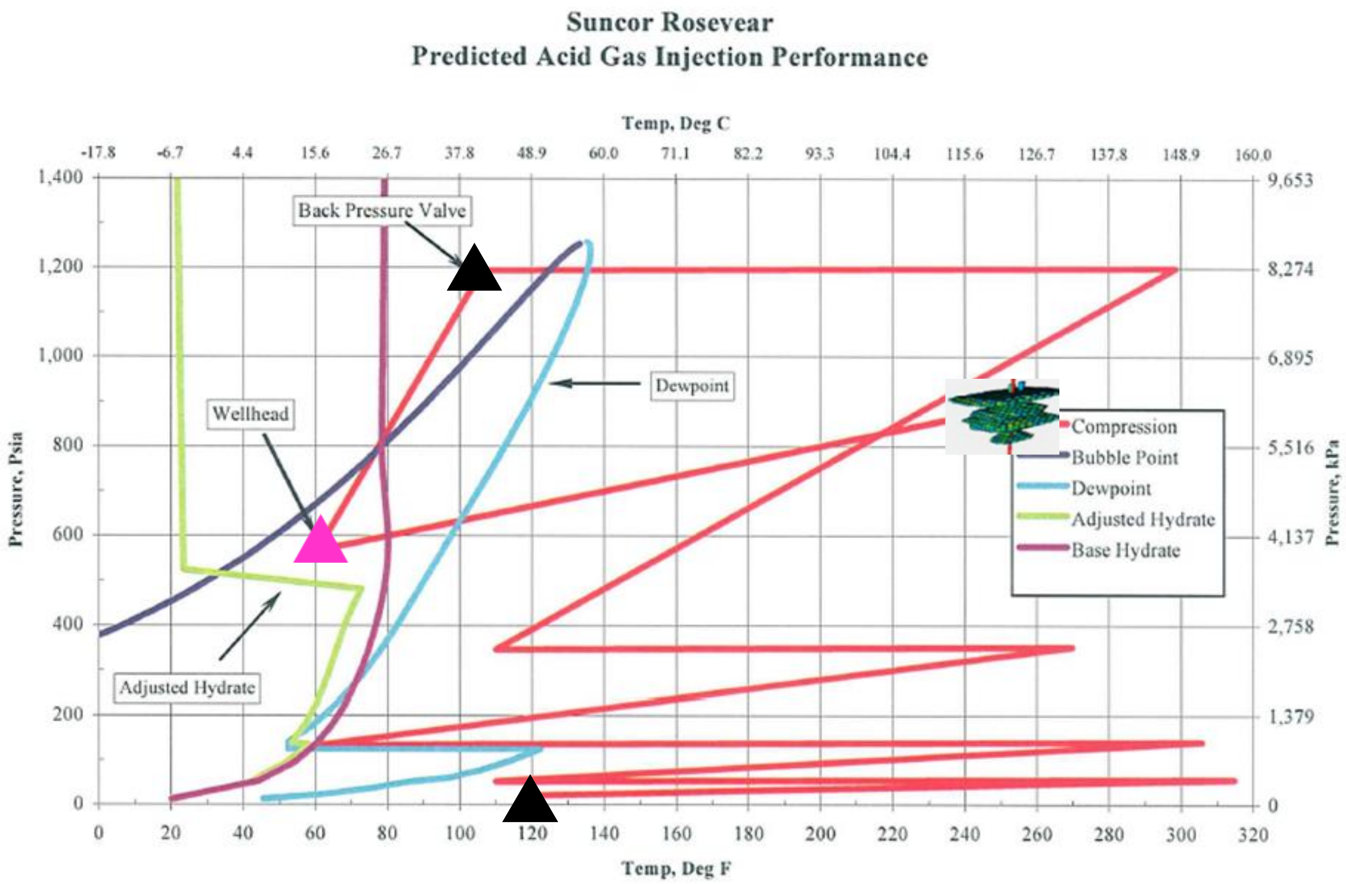
- Out of the four projects South Rosevear is the only one where the operator (Suncor) has published a paper including details of the injection system
- Project was designed for a 48 mol% H_2S, 48 mol% CO_2 and 4 mol% light hydrocarbons mix
- Field production had declined to 40 MMscf/d of which 0.85 MMscf/d (35 t/d) was H_2S with a similar amount of CO_2
- Two four-stage compressors compress the separated gas to 80 barg (1160 psig) to ensure adequate injection under all conditions
- Injection is into nearby depleted gas reservoir
- Well 8-11, 620 m south of the plant completed in the Beaverhill Lake horizon
- Injection depth 3280 m (10,760 ft)



From : *"Conversion of Suncor's South Rosevear facility to acid gas injection"*, James R Maddocks (Gas Liquids Engineering Ltd). Mark Conacher and Leroy Dixon (Suncor Energy, Canada), GPAC, Calgary, May 2007

Acid gas injection – Injection well conditions – South Rosevear

- BHP and BHT 60 barg (870 psig), 116°C (241°F)
- Conditions and volumes are such that no discernible increase in BHP would be expected
- Back pressure control valve on wellhead reduces pressure to 41-42 barg (595-609 psig) with slight later increase up to 43 barg (624 psig)
- This means that the acid gas becomes two phase at the well head as shown opposite
- Surprising that the increase in pressure vs. temperature is linear as the fluid passes from two phase to single phase gas (would expect change in gradient)
- It is reported that operating response has been very positive and the system has shown remarkable resilience to inlet slugging



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Summary and conclusions

- It is likely that CO_2 injection into highly pressure depleted gas fields will begin in the gas phase and then transition to the liquid phase as the reservoir pressure increases (for injection below the critical temperature)
- Many published studies show there is a period between gas and liquid injection where two phases are present simultaneously in the tubing
- However, there is little reported industry experience of two-phase tubing flow, although where it is reported no particular issues have been noted
- As there is so little experience the question remains whether two-phase tubing flow should be allowed during steady flow conditions (unless the temperature is maintained above critical, it is virtually inevitable during start-up or shut-down)
- Two examples of two-phase tubing flow during CO_2 injection have been identified and a handful of examples from acid gas disposal operations
- This research has been hampered by a lack of detailed reporting and I have been unable to track down a number of references
- Nevertheless, no particular issues have been reported during operations involving two-phase tubing flow
- Although the “cold injection” experiment at Ketzin did show more pronounced pressure and temperature fluctuations at colder injection temperatures and the presence of two phases made flowrate measurement more problematic
- Hopefully the Perenco/Carbon Catalyst Leman CO_2 injection tests when fully analysed and reported will help in the understanding of the two-phase tubing flow issue

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