Northern Lights Appraisal Well Test: How Temperature Transients Can Mislead You

Introduction

The large pore volume of saline aquifer makes them attractive candidates for CO2 geological storage. Widely used in oil & gas appraisal campaigns, well testing can help to assess their storage resource. It can provide an estimate of the formation permeability, important parameter controlling the achievable injection rate. It also gives an estimate of the reservoir connectivity and can thus demonstrate the ability of the aquifer to dissipate the pressure and sustain the injection rate over time.

Saline aquifers may appear simpler to test than oil & gas reservoirs, but their often-high permeability and large thickness can affect the reliability of pressure data. This paper presents the Northern Lights field case where temperature transients during the build-up of Eos (31/5-7) appraisal well test significantly distorted the recorded pressures due to their low variations, a result of the very high permeability of the formation.

This work shows the importance to correct pressure build-up data not only for the impact of temperature variations on the water column between the reservoir and the pressure gauges, but also for gauge movement due to the tubing shrinkage. This additional correction provides an alternative interpretation of the reservoir quality hopefully more consistent with the geology of the storage formation. Although these effects can be corrected using wellbore transient simulations and simple formula, some measures could be taken before the test to reduce their impact.

Field Example

The formations identified for the CO2 sequestration are the Johansen and Cook sandstone formations. The Eos appraisal well was drilled and tested in the Johansen to confirm the injectivity and connectivity of the formation (tested interval in purple on **Figure 1**).

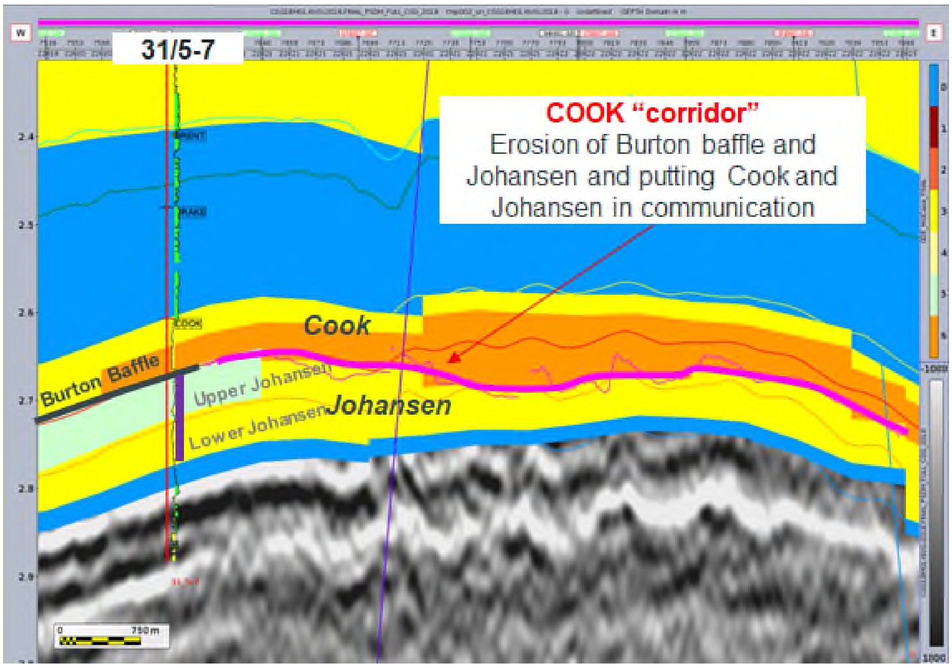


***Figure 1** East-West cross-section passing through the appraisal well with tested interval (in purple)*

The production test was performed using an electrical submersible pump (ESP) and consisted of one flow period and one build-up. The total duration of the flow period was 49 hours of which the first 20 hours was beaning up. The measured pressure, temperature and flowrates are shown in **Figure 2**. The maximum flow rate was around 1050 Sm3/d. The flowing bottom hole pressure declined rapidly during the main flow indicating a mechanical skin deterioration over time, probably due plugging of the sand screens. Last flow rate before shut-in was 948 Sm3/d. The build-up duration was 43 hours.

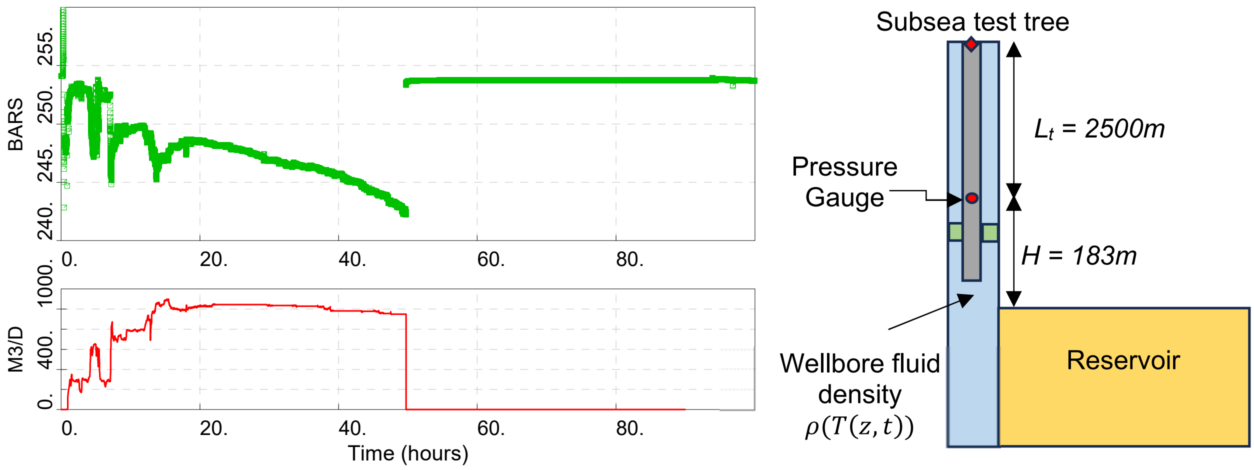
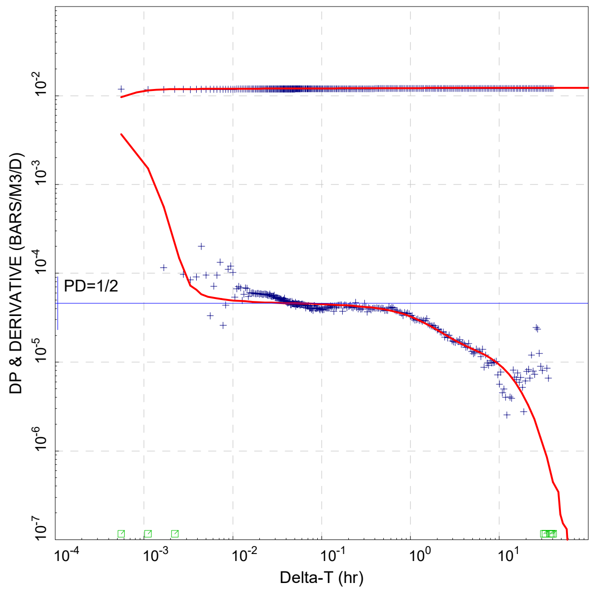


***Figure 2** Well test rate and pressure data (left) and wellbore schematic (right).*

After applying tide correction to the pressure data, the log-log derivative plot indicated a high transmissibility k.H of 72 D.m (see **Figure 3**). This demonstrated the good injectivity of the Johansen formation. The late-time behaviour, however, revealed a closed reservoir signature, indication of a poorly connected reservoir: a very negative outcome for the CO2 storage project.

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Homogeneous Reservoir
** Simulation Data **
 well. storage  = 0.0012039 M3/BAR
 skin           =     124.13
 permeability   =     716.14 MD
 Areal Ky/Kx    =     1.0000
 Perm-Thickness =     67317. MD-METRE
 +x boundary    =       592. METRE (1.00)
 -x boundary    =       794. METRE (1.00)
 +y boundary    =      1160. METRE (1.00)
 -y boundary    =       681. METRE (1.00)
 Initial Press. =    272.129 BARS
 Average Press. =    271.514 BARS
 Pore-Volume    = 55173000. METRE^3
Smoothing Coef = 0.050,0.
```

***Figure 3** Log-log plot with build-up data (blue) and closed reservoir model (red).*

Effects of Temperature Transients on Well Test Data

Well test interpretation implicitly assumes that the pressure gauges are recording the reservoir response. In practice, however, pressure gauges are never located at the sandface but somewhere in the wellbore, 183m above the reservoir in the present case. During build-up, the pressure difference between the reservoir and the gauges corresponds to the hydrostatic gradient. Therefore, the pressure variations measured at the gauge location can be written:

$$\Delta p_{gauge}(t) = \Delta p_{reservoir}(t) - \Delta p_{hydrostatic}(t)$$

Where $\Delta p_{hydrostatic} = \rho . g . H$ with ρ the fluid density, H the distance between the gauge and the reservoir and g the standard acceleration of gravity (see **Figure 2**).

During shut-in, the wellbore temperature decreases to the formation temperature. This causes the hydrostatic gradient to increase as the fluid between the gauges and the reservoir becomes denser and the tubing contracts moving the gauges upward. These variations are usually negligible compared to the reservoir signal. However, this may not be the case in thick and highly permeable formation where the reservoir pressure increases rapidly back to the original pressure.

As demonstrated by Sidorova et al. (2014) or Maizeret et al. (2018), the increase of wellbore fluid density between gauge and reservoir is function of the water volumetric coefficient α_f (around 6.6e^{-4} K^{-1}) and the average temperature change below the gauge since the beginning of the build-up, $\overline{\Delta T}_{below}$:

$$\Delta\rho(t) = -\rho_0.\alpha_f.\overline{\Delta T}_{below}(t) \quad (1)$$

The tubing contraction ΔL and the corresponding change of gauge position, may be estimated from the tubing linear coefficient of thermal expansion, α_t, and the average temperature variation between the subsea test tree (fixed point) and the gauge, $\overline{\Delta T}_{above}$:

$$\Delta L(t) = L_t.\alpha_t.\overline{\Delta T}_{above}(t) \qquad (2)$$

With L_t the tubing length between the subsea test tree and the gauge at the beginning of the build-up.

Temperature Correction

To correct the non-isothermal effects, a model was built by the Northern Lights team to simulate the temperature variations along the wellbore (see Kindt 2022). This model was calibrated to match the pressure and temperature data recorded during the test (see **Figure 4**).

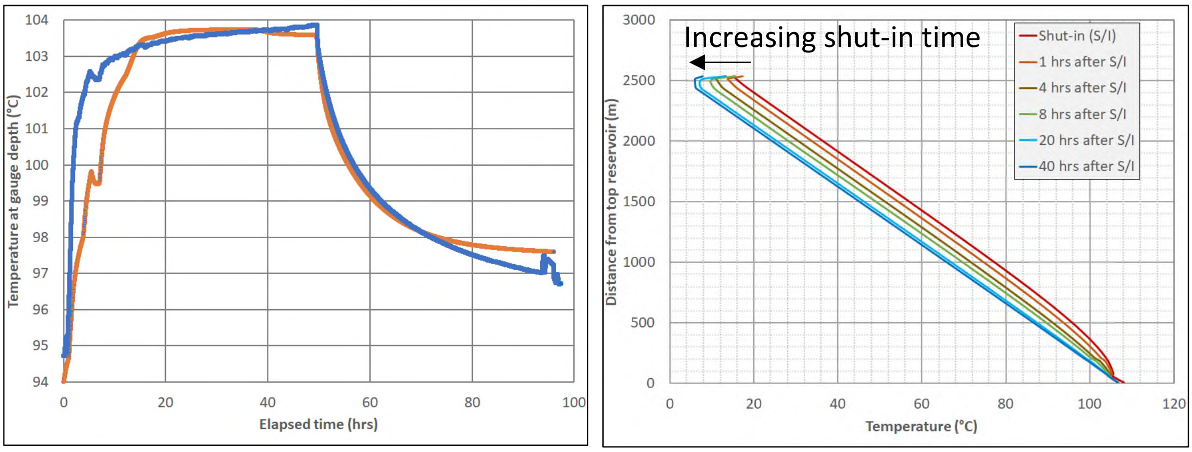
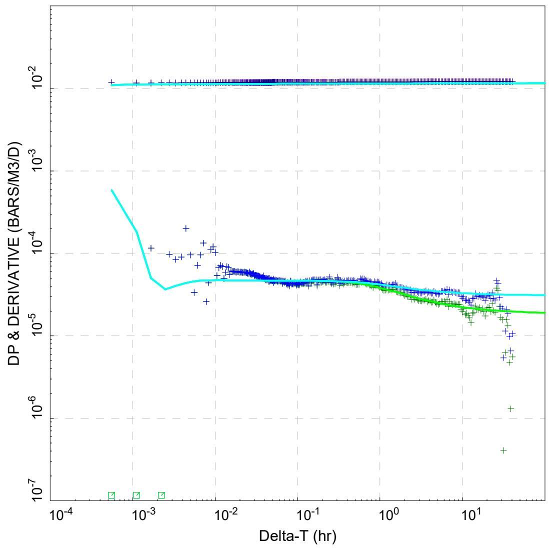


***Figure 4** Measured (blue) and simulated (orange) temperature at gauge depth during shut-in (left) and simulated temperature profile along the wellbore (right).*

A first correction of the build-up pressure was done to account for fluid density change between gauges and reservoir using formula (1). This removed a large part of the apparent flattening trend recorded at the gauge depth: the closed reservoir signature changed to a transmissibility increase at 275 meters from the well (see **Figure 5**). This increase was attributed to vertical communication between the Johansen and the Cook formations due to the erosion of the Burton shale (see **Figure 1**). However, a thickness increase of a factor 4 was required to match the data while the Cook was at best multiplying by two the contributing thickness. Even though the permeability was already quite high, an alternative interpretation might be that both thickness and permeability go up. The summary of findings is available in Kindt 2022.

With a tubing length L_t of 2500m between the subsea wellhead and the pressure gauge and taking a standard value of 12e^{-6} K^{-1} for α_t, the tubing contraction was estimated around 30cm using formula (2). The resulting gauge movement generated a maximum pressure variation of 0.03 bars. This could be considered as low but in this high k.H formation, the pressure variations during the build-up were almost similar, around 0.07 bars. A second correction was therefore performed resulting in the blue derivative on the log-log plot of **Figure 5** which was matched with a thickness increase of a factor 2.

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Linear-Composite 2-Zone
** Simulation Data **
 well. storage  = .5000E-03        M3/BAR
 skin           =    116.62        ()
 permeability   =    712.28        MD
 Areal Ky/Kx    =    1.0000        ()
 X-Interface(1) =    275.00        METRE
 Mob.ratio(1)   =    4.0000 2.0000 ()
 Stor.ratio(1)  =    4.0000 2.0000 ()
 Perm-Thickness =    66954.        MD-METRE
 Initial Press. =   272.129        BARS
Smoothing Coef = 0.050,0.
```

Figure 5 *Log-log plot with build-up data after correction for density change (green cross), build-up data after correction for density change and tubing contraction (blue cross), model with a thickness increase of a factor 4 in one direction (green line) and model with a thickness increase of a factor 2 in one direction (blue line)*

Conclusions

In thick and highly permeable aquifers, typical good candidates for CO2 sequestration, temperature variations during build-up or fall-off tests may significantly affect the recorded pressure. These effects happen because of the change in the fluid density in the wellbore and the movement of the gauges due to tubing expansion/contraction. This paper highlights the importance to correct the pressure data for both effect and not only for change in the water density column (as performed in Kindt 2022). However, the uncertainty on the corrected data may still be high. Therefore, to minimise these temperature effects, it is strongly advised to locate the pressure gauges below packer (the packer acting as a fixed point) and as close as possible to the top of the reservoir. Moreover, to avoid losing data if the test packer gets stuck in the hole, the use of wireless telemetry is strongly advised.

Acknowledgements

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References

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Kindt, R, "Pressure Transient Analysis (PTA) of well test in the Eos CCS well – 31/5-7" presented at the Well Testing Network in Hamburg, 9 – 10 November 2022.