Fluid flow test of a tight fractured and under-pressured reservoir unit, a case study from Longyearbyen CO2 drilling and test site, Adventdalen, Svalbard

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Abstract

The Longyearbyen CO2 Lab pilot project of Svalbard, Norway, has drilled 8 slim holes for testing the subsurface for possible CO_2 storage in Adventdalen near Longyearbyen. Subsurface investigations include reservoir, cap rock and overburden studies. Wireline logging, seismic, high pressured water injection and various geological studies have been used to verify injectivity and capacity of the potential storage unit, and the sealing properties of the cap rock. The targeted reservoir is an unconventional 'tight' sandstone succession of the Late Triassic to Middle Jurassic Kapp Toscana Group at 670 m to 970 m depth, below 400 m of well sealing Upper Jurassic/Lower Cretaceous shale units which are in turn overlain by 270 m of Barremian to Aptian lower Cretaceous deltaic and inner shelf deposits. (Fig.1).

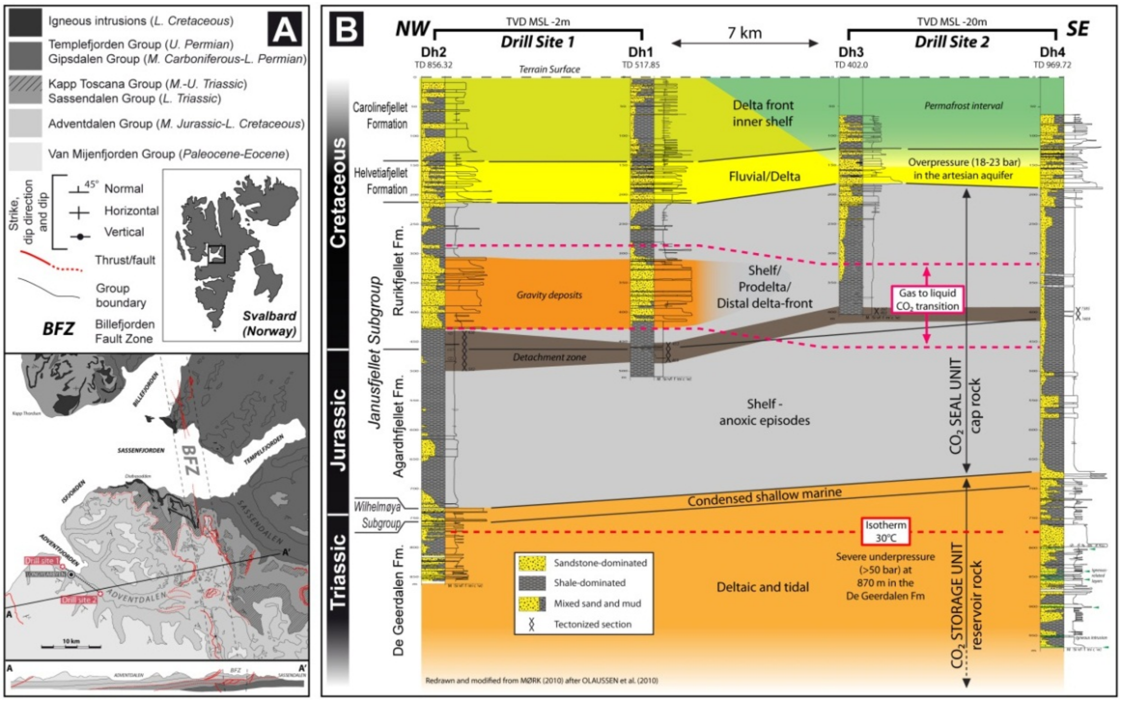

Figure 1 Simplified geologic map with explanation and cross section of western Spitsbergen (Svalbard). Main structural features and drill sites are labelled (redrawn from NPI). B: Summary of boreholes correlation with labelling of available data and location of the outcropping part of the section (From Ogata et al., 2012)

Previous deeper burial of the strata has caused severe diagenesis (Mørk in press). The storage unit/reservoir consists of two units. The lower unit, the c. 270 m thick Upper Triassic De Geerdalen Formation comprises an overall shallowing upward unit from open marine shale successions near the base, to tidal inlet delta, to barrier spit sandstones and back barrier lagoon. This unit is capped by a 40 m thick hetereolithic coastal/delta plain with paleosoils. The net sandstone of this succession is around 25-30%The upper unit, the 20-25 m thick Upper Triassic to Middle Jurassic Knorringfjellet Formation is presented by condensed shallow fine to medium grained marine sandstones and conglomerate sections. The net sandstone and conglomerate is around 50%. A complicating factor is that the lower unit is intruded by thin dolerite sills and dikes emplaced during the Early Cretaceous. Nearby outcrops, as well as seismic data, indicate that the main storage aquifer is also affected by these intrusions some 20 km from the planned injection site.

In the summer of 2011 two shallow wells with a lateral spacing of 60 m were drilled into the Helvetiafjellet Formation to perform cross well flow. The aim was to verify pressure and test fluid flow in the deltaic and expected tight sandstone with high net sandstone content. Surprisingly high water flow was observed. Both from specific analyses of segments of the wellhead data from DH6 (Fig. 2 left) and from analyses of interference data in DH5 (Fig. 2 right) from injection and falloffs periods in DH6 the flow properties of the upper formation are found to be excellent, with an average permeability of 375 md indicated over a 20 m interval.

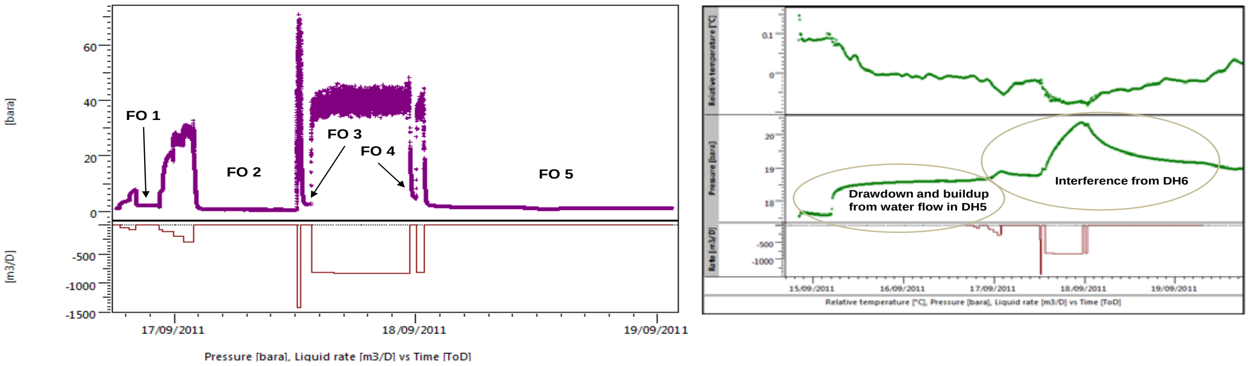

Figure 2– Left figure show wellhead data from DH6 with key falloffs. Right figure, down-hole data from DH5 showing drawdown and build-up response from natural water flow in DH5 and interference in DH5 from injection and falloffs in DH6.

Water injection studies in the drill hole Dh4 show significant injectivity (Fig. 3) in the lower part of this unit (870-970 m TD). This part, together with the hetereolithic upper part, has the lowest net/gross, permeability and porosity values, suggesting injectivity due to fractures

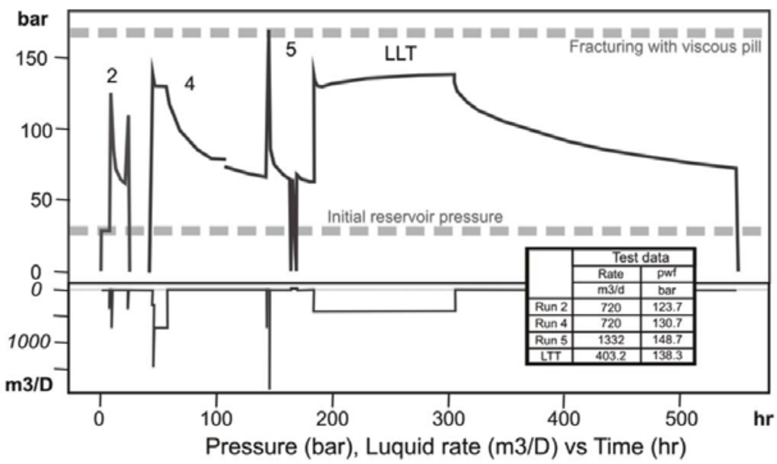

Figure 3. The figure shows observed initial pressure, pressure development during injection, and shut-in trends in Dh4 after injection tests of August 2010, as well as injection rates with time. The pressures are calculated based in recordings at the annulus; the open well is at 870-970 m TD. The peak during run 5 indicates the fracture pressure for viscous fluid (brine mixed with polymer). LLT is long-time test. From Braathen et al. in press.

The believed better part of the lower reservoir unit (760 -870 m) is not tested. The Upper 20-25 m thick unit has provided the best porosity and permeability numbers with beds offering up to 20% porosity but no more than up to 4-6 mD permeability (Fig 3). Analysis of drill core suggest that some of the permeable layers are through going between the three 90-m spaced wells penetrating this level. To further constrain injectivity at this upper reservoir level, two wells were drilled to 700m in the summer of 2012 with a distance of 90 m. The aim was to test injectivity and cross well flow in the upper reservoir unit. Undesirably, this unit had a high gas content of hitherto unknown gas saturation and the successful water injection test analysis could therefore be complicated to interpret.

Lower Cretaceous sandstone units in the overburden part of the drilled section show a slight overpressure while the reservoir section has a considerable under-pressure, varying between 30% and 60% of hydrostatic pressure. This is consistent with two overall different pressure systems that confirm an efficient seal under initial conditions. To verify the sealing cap rock, three leak off tests (LOT) have been performed in the upper, middle and lower part of the cap rock succession; all confirming sealing capacity. In a broader context, under pressured sandstones below good seals are also known from the Barents Sea (Olaussen et al. 2011) and are related to recent uplift.

Injection tests with good injectivity in tight sandstones points to fractures as a key to flow. This led to detailed fracture mapping of the well exposed outcropping reservoir units 15 km northeast of the planned injection site. Fracture studies led to the identification of a predominant WSW-ENE regional trend which is inferred to be associated with Tertiary compression. This orientation seems to be parallel to the maximum horizontal stress as encountered in coal mines (Jochmann pers. com.), suggesting preferred fluid flow along this trend. Subordinate fracture sets related to local tectonism in the Triassic, emplacement of igneous intrusions and decompaction during recent uplift are also identified. Fractures are represented on the basis of litho-structural units (Fig. 4), and implemented in a near-well reservoir model.

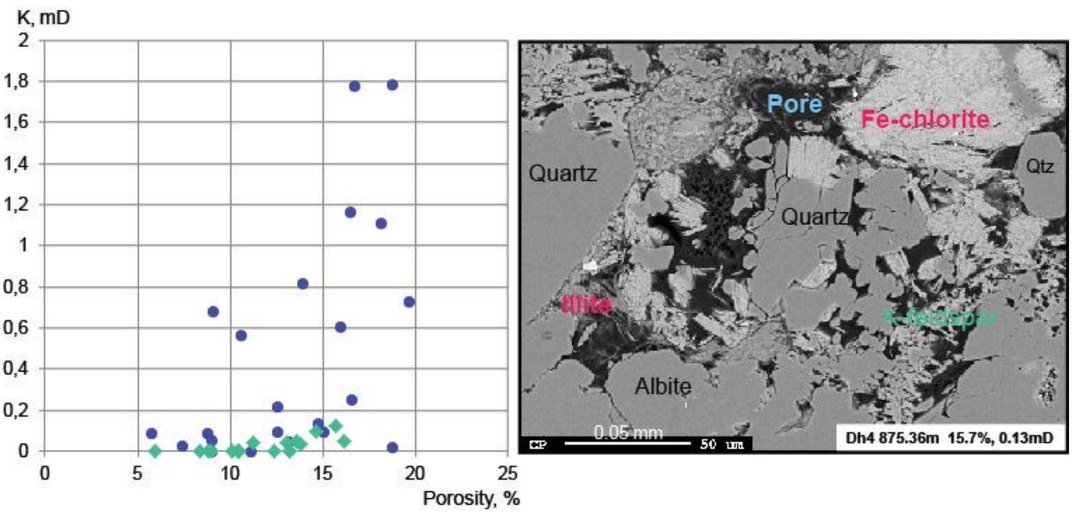

Fig. 3 Left part of the figure shows sandstone porosity and permeability (K) from laboratory measurements (Farokhpoor et al. 2010). Blue dots show values from the Norian to Bajocian Knorringfjellet Formation while green diamonds represent the De Geerdalen Formation. Note several high porous sandstones in the Knorringfjellet Formation, but still low permeability. Figure to the right is an electron microscope image of sandstone rich in secondary dissolution porosity (black colour) Clay minerals, such as fibrous illite and Fe-chlorite, have severely reduced the permeability. (All samples are from well Dh4). Modified from Mørk in press.

In summary the good water injectivity observed at 870-970m in Dh4 suggests flow on fractures. Further, there seems to be directional flow barriers, with injectivity vs. pressure increasing during injection tests through fracture opening and growth. Storability remains questionable, since fluid interaction between fractures and the rock porosity remains enigmatic. The encountered gas adds further uncertainty.

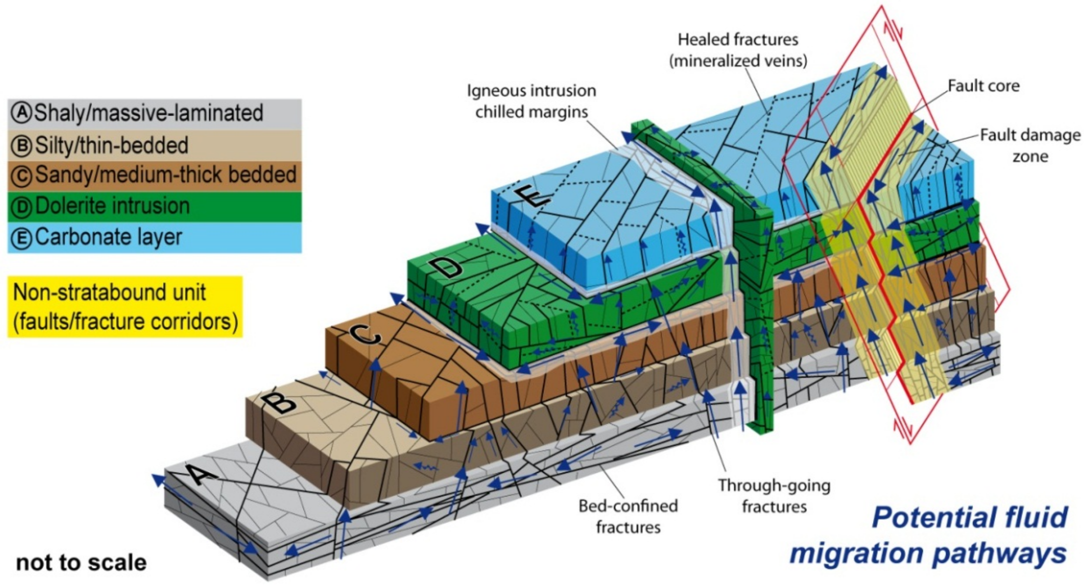

Figure 4 Schematic diagram of the interconnectivity and intensity of fractures within the five lithostructural units: A, B, C, D and E (see the text for details). The finer-grained lithostructural domain A is typically characterized by conjugate, lower-angle shear fractures, leading to enhanced lateral connectivity. The coarser-grained units, however, are typically dominated by steep fractures, and may thus enhance vertical connectivity. Note also the mixture of steep and lower-angle fractures within the silty interval of lithostructural domain B. The lithostructural units D and E represent a small portion if the investigated lithilogies (less than 5% so they are marginally discussed. From A Ogata et al. in prep.

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