You learn as long as you drill; research synthesis from the Longyearbyen CO₂ Laboratory, Svalbard, Norway

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From 2007 to 2015, eight wells were drilled and fully cored to test the feasibility of storing CO₂ emitted from the coal-fueled power plant in Longyearbyen, Svalbard. The drilling campaign identified three water-bearing sandstone aquifers; i) a lower aquifer in Upper Triassic strata; ii) a middle aquifer in Upper Triassic to Middle Jurassic; and iii) an upper aquifer in Lower Cretaceous strata. Only the two former are regarded as potential CO₂ storage units. Both units are unconventional reservoirs (storage units) consisting of fractured, low-porosity and low-permeability sandstones. The storage units are capped by a c. 400 m-thick Middle Jurassic to Lower Cretaceous mudstone-dominated succession, which acts as an efficient top seal. In addition, a c. 120 m-thick zone of permafrost provides an additional seal. Apart from characterising the CO₂ storage and cap-rock system, the drilling resulted in several unexpected results. These include: (a) the detection of severe underpressure of approximately 50 bar in the two storage units, (b) the discovery of gravity-flow deposits attributed to a hitherto unknown Hauterivian clastic wedge, and (c) the detection of producible thermogenic shale gas at a depth of 640 to 700 m. Moreover, core and wireline data from the wells combined with correlation to equivalent strata in nearby outcrops provide new insights into the age and depositional evolution of the succession. Thus, the data obtained from this project contributes to the regional stratigraphic understanding of the Mesozoic succession in Svalbard and the northern Barents Shelf. Until now, nearly 70 papers have been published in international peer-reviewed journals using data from or part of the Longyearbyen CO₂ Laboratory. In addition, 13 PhD candidates and 27 master students, linked to the project or using obtained data from the project, have graduated. The main achievement of our studies is that we have shown that unconventional fractured reservoirs are suitable for storing CO₂.

Keywords: Spitsbergen, CO₂ storage, fractured unconventional reservoir, shale gas, Mesozoic, underpressure, caprock, coring

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Introduction

Longyearbyen's coal-fueled power plant is a significant point-source CO₂ emitter in an environmentally sensitive Arctic terrain. To reduce the emissions from the power plant, and to characterise the CO₂ storage potential of the local subsurface, the Longyearbyen CO₂ lab project was established in 2007 (Braathen et al., 2012; Sand et

al., 2014) based in an academic consortium backed by industry and the Research Council of Norway. With time, maintenance and ownership of significant infrastructure (e.g., well park with 8 drilled wells and nearly 4.5 km of drillcore) and datasets (seismic, water-injection tests, electric and lithological logs, etc.) were transferred to the UNIS CO₂ Lab, a company fully owned by the University Centre in Svalbard (UNIS).

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One of the great challenges in carbon capture and storage (CCS) is finding suitable reservoir units, i.e., storage units, with sufficient permeability and porosity for efficient injectivity of CO₂, combined with suitable pressure and temperature for CO₂ to be stored in a critical fluid phase. Another challenge is proving storability by identifying a cap rock with sufficient seal capacity to de-risk subsurface migration of a buoyant fluid. Finally, the actual storage units should be within a convenient distance to the CO₂ point source, i.e., the Longyearbyen power plant in this case. Fortunately, Adventdalen, a major valley close to Longyearbyen, offers Mesozoic strata where both storage formations and cap rocks are present, many being analogous to reservoir and seal units in the southwestern Barents Sea oil and gas province (Fig. 1) (Nøttvedt et al., 1993; Worsley, 2008).

In regard to the favourable geological setting, Svalbard should then be suitable for storage and sealing of buoyant fluids. Longyearbyen CO₂ Lab used pressurised water with tracers to test the injectivity in three out of the total eight wells drilled, while two other wells were used for short- and long-term pressure measurements. Besides step-rate and high-pressure water injection and leak-off tests (LOT), a unique dataset of fall-off pressure measurements covering several years after the injection tests was obtained to understand fluid flow behaviour. Fig. 2 shows the design of the deepest well drilled in the Longyearbyen CO₂ Lab.

Although being an onshore analogue, Svalbard shows some important geological differences to the oil and gas fields and discoveries of the southwestern Barents Sea. These include significant structural shortening (contraction in a fold and thrust belt) along western Spitsbergen during the Paleogene. Further, there are large magnitudes of Cenozoic subsidence and uplift, causing localised exhumation of deeply buried rocks. Accordingly, formerly deeply buried successions in western and central Spitsbergen (near the study site of Longyearbyen), now at a depth of a few hundred metres, rendered the Mesozoic sandstones tightly cemented, exhibiting low matrix permeability and porosity (Farokhpour et al., 2010, 2013; Mørk, 2013; Magnabosco et al., 2014). Paleogene tectonics also resulted in extensive fracturing of the storage units and the cap rock (Ogata et al., 2014). Fluid-flow studies associated with the Longyearbyen CO₂ Lab particularly functioned as a case study of a potential storage unit qualifying as an unconventional (i.e., ‘tight’) fractured reservoir (Senger et al., 2015). This bridges across to global studies, as low-permeability and low-porosity rocks, are far more common in sedimentary basins worldwide. Although only tested by pressured water, we suggest that this pilot project provides a foundation for commercial ventures of CO₂ sequestration in unconventional storage units.

In addition to the open-access policy of a university-driven R&D project, the Longyearbyen CO₂ Lab has been rather unique in its strategy and workflow. New knowledge has generated new questions, guiding new academic and industrial innovative and focused research. The basic motivation; “you learn as long as you drill and test”, has been realised in a vibrant knowledge pyramid following self-motivated risk management procedures.

Studies using material from the obtained data have thus far produced c. 70 peer-reviewed journal articles. Furthermore, the project facilitated the education of 13 PhD candidates and 27 masters, and established a graduate-level course in CO₂ sequestration. An overview of scientific articles and graduated students is given in Braathen et al. (2019) in this volume, and is also regularly updated on the project website at <http://co2-ccs.unis.no/Publications.html>.

The following summary is a continuation of the initial results presented by Braathen et al. (2012) who provided a brief review of the main tasks and results for the period between the project start in August 2007 and the end of Phase I in 2010. A summary volume in the Norwegian Journal of Geology (NJG), introduced by Sand et al. (2014), also summarises many of the key findings. The Phase II final report (freely available at http://co2-ccs.unis.no/Pdf/Longyearbyen%20CO2%20lab%20Phase%202%20Report_10_2015.pdf) provides important details following the active operational phase of the project. For details of all methods applied, see the Longyearbyen CO₂ Lab Phase II final report and former and enclosed publications (Braathen et al., 2019).

The aim of this paper is to present a summary of the more recent and partly surprising observations from the obtained subsurface data. This includes among others the discovery of unconventional gas and complex fluid-flow properties (PVT). Combinations of wireline logs (gamma-ray, P- and S-wave velocity and resistivity) and improved biostratigraphy and new data from chronostratigraphy, all based in fully cored sedimentary successions, have given new insights into the Mesozoic basin fill in Svalbard, and also to some extent, to nearby Arctic basins, including the northern Barents Shelf. Outcrops are commonly used to understand the subsurface geology in many buried sedimentary basins. However, the results reported in this volume also demonstrate the opposite; subsurface results have given us an improved understanding of the outcropping strata in Svalbard, which justifies the main title of this summary: “you learn as long as you drill”.

Figure 1. (A) Geological map showing the vicinity of Longyearbyen; (B) Geological cross-section and (C) Simplified stratigraphic column of Svalbard and the cored succession in the wells drilled near Longyearbyen. In the study area there are two thrust faults, seen as décollement zones that appear at two shale-dominated levels; in the Middle Triassic Botneheia Formation and the Middle Jurassic to Lower Cretaceous Agardhfjellet Formation (B). A lower regional décollement is located in evaporites of the Permian Gipsbukken Formation (e.g., Bergh et al., 1997). (D). 3D view of the Adventfjorden and Adventdalen. Lines 1, 2 and 3 are the acquired 2D regional seismic lines in Adventdalen and along the southern side of Adventfjorden. The seismic data are presented in Fig. 10.

Figure 2. Well design of the borehole DH4; the deepest well drilled in UNIS CO₂ Lab, reaching 970 m. L-M. Jur. = Lower Middle Jurassic. The figure is not in vertical scale.

Highlights of the obtained subsurface results

Nearly all disciplines within geology and geophysics have benefited from the data obtained from the Longyearbyen CO₂ Lab. A wide range of spin-off research projects complement the main objective of characterising the reservoir-caprock system for CO₂ storage. Below follows a short summary of some of the most important results obtained from the subsurface investigations of the Mesozoic succession in Adventdalen.

Sedimentological facies analysis and sequence stratigraphy

Improved facies models. Core data and wireline logs combined with investigations of nearby outcrops have improved the general depositional models for all the drilled formations (Anell et al., 2014; Rød et al., 2014; Grundvåg et al., 2017, 2019; Olaussen et al., 2018; Jelby et al., in press; Koevoets et al., 2019a; Rismyhr et al., 2019). Representative sedimentary logs of all the cored units are shown in Figs. 3, 4 and 5.

Hauterivian clastic wedge. The subsurface data have revealed the discovery of a previously unrecognised Hauterivian clastic wedge within the Rurikfjellet Formation in the two wells to the northwest of Longyearbyen (DH1 and DH2; Braathen et al., 2012; Grundvåg et al., 2017, 2019; Sliwinska et al., in press).

Late Quaternary glacial delta. One well, DH8, was specifically designed to drill and core near-surface sediments located in the permafrost zone. In this drillhole, a 60 m-deep frozen core consisting of post-glacial (i.e., early Holocene to present) sediments was successfully retrieved (Fig. 5). Detailed facies studies of the post-glacial succession in Adventdalen are given in Gilbert et al. (2018).

Key sequence-stratigraphic surfaces. Sedimentological core descriptions combined with wireline logs of the drilled succession enabled the recognition and definition of genetically linked stratigraphic units and their bounding surfaces (Fig. 6). Thus, we propose a subdivision of the various formations into non-hierarchical transgressive-regressive (TR) sequences that can be linked to the tectonic development of Svalbard and the northwestern Barents Shelf margin. Some of the bounding surfaces are key regional sequence-stratigraphic surfaces with a clear correlative link to nearby Arctic basins (Midtkandal et al., 2016; Grundvåg et al., 2017, 2019; Olaussen et al., 2018; Jelby et al., 2019; Koevoets et al., 2019a; Rismyhr et al., 2019). The following recognised surfaces are of regional importance and have been better age-constrained by our associated

studies (Figs. 3, 4, 5, 6); i) the Norian flooding surface; ii) the lower Jurassic unconformity (down-cutting the Rhaetian unconformity on Spitsbergen); iii) the Bajocian unconformity; iv) the lower Bathonian flooding surface; v) the basal surface of the condensed Valanginian Myklegardfjellet Bed, which is closely associated with the Base Cretaceous Unconformity offshore; vi) the lower Barremian subaerial unconformity, and vii) the lower Aptian flooding surface associated with the early Aptian Oceanic Anoxic event; OAE1a (Midtkandal et al., 2016). OAE1, which also has a source-rock potential, has now been recognised in all the wells and in outcrops across the entire Lower Cretaceous outcrop belt on Spitsbergen (Grundvåg et al., 2019).

Unconventional storage (reservoir) units. Petrographic and diagenetic studies have confirmed a prognosis of previous deeply buried sandstones with low matrix permeability and low to moderate porosity, in line with the maturation of the succession (Abay et al., 2017; Ohm et al., 2019). The low porosity of the sandstones is due to quartz and carbonate cementation. The higher porosity of 18 to 20% in sandstones of the Wilhelmøya Subgroup is a result of feldspar dissolution and offers non-effective porosity. i.e., dead-end pore space conforming to very low permeability in the range of 1–2 mD (Mørk, 2013). In contrast, the quartz-cemented quartz arenites of the Festningen Member of the Helvetiafjellet Formation have a porosity of 10% or less but record up to 100 mD in permeability.

Bio-, chrono-, chemo- and magnetostratigraphy

New absolute age of the deltaic coastal plain segment of the Helvetiafjellet Formation. Absolute age dating of a 10 cm-thick bentonite in the middle part of the Helvetiafjellet Formation, i.e. the Glitrefjellet Member has yielded an age of 123.3 ± 0.2 Ma (Corfu et al., 2013). The indicated age better constrains the timing of volcanism related to the High Arctic Large Igneous Province (HALIP; Senger et al., 2014b; Polteau et al., 2016). In addition, a carbon-isotope signal attributed to the early OAE1a was identified in a lower Aptian mudstone at the base of the overlying Carolinefjellet Formation. Collectively, this suggests that the Barremian-Aptian boundary should be revised in the international geological time scale (Midtkandal et al., 2016). Recent magnetostratigraphic studies of Svalbard boreholes combined with the reported results given above, thus propose that the Barremian-Aptian boundary should be placed at 121.2 ± 0.4 Ma (Zang et al., 2018).

High-resolution biostratigraphy. Biostratigraphic studies of the Upper Triassic to Lower Cretaceous succession have improved our tectonostratigraphic understanding of the Mesozoic succession in Svalbard and its link to the Barents Shelf and other adjacent Arctic basins (Smelror et al., 2018; Rismyhr et al., 2019). Detailed facies analysis

(A) continued.

Figure 3. Logs of the Upper Triassic to Middle Jurassic succession, i.e., the main storage units, covering the Tschermakfjellet Formation, De Geerdalen Formation and Wilhelmøya Subgroup, modified from (A) Husteli (unpublished) and (B) Rismyhr et al. (2019), respectively.

Figure 4. Logs of the Middle Jurassic to Lower Cretaceous succession and Rurikfjellet Formation. (A) The Agardhfjellet Formation is from DH2, modified from Koevoets et al. (2019a). (B) The Rurikfjellet Formation in well DH5R; modified from Jelby (2015). (C) The Adventpynten Member of the Rurikfjellet Formation in well DH1; modified from Grundvåg et al. (2017, 2019).

Figure 5. (A) Logs of the Lower Cretaceous Helvetiafjellet Formation; well DH5R, (B) Carolinefjellet Formation, well DH1, both modified from Grundvåg et al. (2017, 2019). (C) represents the Quaternary near-surface succession drilled in the permafrost zone (well DH8), modified from Gilbert et al. (2018).

combined with new palynology analysis of the thin (<20 m thick) and very condensed Norian to Bathonian succession, the Wilhelmøya Subgroup, have resulted in a revision of some of the key regional sequence-stratigraphic surfaces.

Revised biostratigraphy of Bathonian to Aptian. The biostratigraphy of the Adventdalen Group has been considerably improved thanks to high-quality material from the full coring and wireline logging (Fig. 7) (Grundvåg et al., 2017, 2019; Koevoets et al., 2018, 2019a, b; Hammer et al., 2019; Sliwinska et al., 2019). However, some challenges remain, especially around the Jurassic–Cretaceous boundary.

$\delta^{13}\text{C}$ excursion for regional correlation. The updated biostratigraphic framework combined with the $\delta^{13}\text{C}$ excursion of the Bathonian to Volgian and Barremian to Aptian of the cored successions gives an additional tool for regional correlation (Koevoets et al., 2016; Midtkandal et al., 2016). Ongoing studies will include the Volgian to Hauterivian succession.

Organic geochemistry and hydrocarbons

Originally oil-prone source rocks. Oil-prone source rocks are proven in the late Oxfordian to early Kimmeridgian succession and in the late Kimmeridgian Volgian/early Ryazanian successions in the CO₂ Lab wells. These will probably be in the gas window down dip of the well sites (Koevoets et al., 2016; Abay et al., 2017, 2018; Ohm et al., 2019).

Late-oil to gas window organic-rich shales. Based on vitrinite and T-max values (Fig. 8), the maturity of the Middle Jurassic to Lower Cretaceous, Agardhfjellet Formation, organic-rich mudstones has been better constrained. These mudstones are in the late-oil maturation to gas window. Furthermore, the oil and gas isotope composition of a Lower Cretaceous coal bed suggests that most of the succession is in the late-middle oil window generation, i.e., the formation has experienced maximum burial temperatures of 150–180°C (Koevoets et al., 2016; Abay et al., 2017, 2018; Grundvåg et al., 2019; Ohm et al., 2019).

High paleo-temperature gradient. The drill core data combined with published vitrinite reflectance and T-max data indicate that approximate 2.5 km of overburden is missing above the valley bottom in Adventdalen (Fig. 8). A high paleo-temperature gradient of 50 to 54 °C/km for the Cenozoic (Eocene) is suggested in this area (Marshall et al., 2015; T. Throndsen, pers. comm. 2019).

Lower Aptian potential gas condensate source rocks. At the base of the Carolinefjellet Formation, the lower Aptian mudstone unit which is associated with a regional flooding event i.e., the Aptian oceanic anoxic event; the

Figure 6. Proposed sequence stratigraphy for the drilled succession based on the wells drilled in the Longyearbyen CO₂ lab. Acronyms for wireline log tools: CALP – Caliper, NGAM – Gamma-ray, SHN/

Figure 7. Revised biostratigraphy and improved age resolution of the Lower Cretaceous succession on Spitsbergen. The age model is based on core material from the UNIS CO₂ Well Park in Adventdalen combined with data from outcrops across the northern part of the outcrop window. (A) and (B). Spatial distribution of the age-diagnostic dinocysts events (colour coded) in the Helvetiafjellet and Rurikfjellet formations, here dated to be of Barremian to early Aptian age and early Valanginian to late Hauterivian/early Barremian age, respectively. Both correlation panels are modified from Sliwinski et al. (in press). (C) Map showing the investigated sections and the distribution of Lower Cretaceous strata in Svalbard. The map is compiled by Winfried Dallmann.

Figure 8. T-max values for vitrinite (A) and T-max (B) values from the cored succession. For details see Koevoets et al. (2016) and Ohm et al. (2019). Vitrinite and T-max are from a coal seam in the overlying coal in the Paleocene Firkanten Formation and the late Eocene Aspelintoppen Formation; see Marshall et al. (2015) for details. Although only a few points, a simplified trend can be established based on: i) a coal sample from the Lower Cretaceous Helvetiafjellet Formation (T. Throndsen, pers. comm. 2016) (green framed with a black pyramid in A); vitrinite value together with a coal sample from the Firkanten Formation in Mine 7 (Green framed 7 in A) (Marshall et al., 2015) and Aspelintoppen Formation on Nordenskjöldtoppen (Fig. 1) (Green framed N in A) (Throndsen, 1982). Using this vitrinite trend, more than 2 km of overburden is missing in the Adventdalen region. In a regional context this is consistent with a raised paleo-temperature gradient of 50 to 54 °C/km during the Cenozoic, cf. Marshall (2015) and T. Throndsen (pers. comm. 2019) respectively. The figure is modified from Ohm et al. (2019). 0 m in depth is 6 m above Mean Sea Level (MSL). L. Pal = Lower Paleogene; L. Cr. = Lower Cretaceous; (1) T. Throndsen, pers. comm. 2015; (2) Grundvåg et al. (2019); (3) Marshall et al. (2015). (4) Throndsen (1982).

OAE1a is proven as a gas condensate-prone organic-rich mudstone. This mudstone unit is now recognised throughout Svalbard (Midtkandal et al., 2016; Grundvåg et al., 2017, 2019).

Middle Triassic migrated oil. Oil (bitumen)-stained sandstones in the De Geerdalen Formation are linked to migrated oil from the Middle Triassic Botneheia Formation. In addition, gas shows in this formation suggest migration from a deeper source (Abay et al., 2017; Ohm et al., 2019).

Discovery of shale gas. Dry to semi-dry thermogenic gas was discovered during water injection testing of the Wilhelmøya Subgroup and the lowermost part of the Agardhfjellet Formation in wells DH7A and DH5R. A 59

Figure 9. Flared thermogenic gas from open hole at 648–701 m depth, well DH5R. Stable semi-dry gas, i.e., 95% methane was produced at a stable rate of 1500 Sm³/day, see Ohm et al. (2019) for details.

m open-hole interval of the Wilhelmøya Subgroup and lowermost part of the Agardhfjellet Formation in DH5R was production tested (Fig. 9) and shows potential for unconventional production (Ohm et al., 2019).

Gas hydrates. Natural gas hydrates are likely to be present onshore Svalbard, as suggested by regional thermo-baric modelling (Betlem et al., 2019). In Adventdalen, the presence of higher-order hydrocarbons suggests that some of the gas trapped beneath the permafrost could well be in gas hydrate form. Experimental modelling of CO₂-hydrate formation in cores from the Helvetiafjellet Formation suggests that CO₂ hydrate may form an additional self-sealing unit at the pressure-temperature conditions in the upper aquifer (Almenningen et al., 2019).

Thermogenic gas leakage in nearby fjords. Past gas leakage indicated by pockmarks throughout Isfjorden has been relatively common (Roy et al., 2015) and a baseline study was conducted for Adventfjorden (Roy et al., 2014). Recently, thermogenic gas seepage was documented in Isfjorden and Storfjorden (Liira et al., 2019), and active gas seepage through the water column in Nordfjorden (Roy et al., 2019).

Geophysical studies

Poor geophysical images. Conventional 2D reflection seismic studies have suffered from weak imaging due to both high-velocity rocks and permafrost within the upper 120 m of heterolithic Holocene deposits. Accordingly, there is significant uncertainty on more detailed scales (Bælum et al., 2012). Strong reflectors below the deepest borehole are likely imaging Early Cretaceous igneous intrusions as also observed in nearby outcrops) and are penetrated in the DH4 borehole (Fig. 10) (Senger et al., 2013, 2014a,b). However, a well tie suggests good imaging of the base Helvetiafjellet Formation and near-top Kapp Toscana Formation reflectors, both known to represent key sequence-stratigraphic surfaces and regional reflectors. Further, the top of the Kapp Starostin Formation (Fig. 10) is identifiable, albeit at times distorted by possible intrusive sills. Overall, the mappable reflectors of the strata follow the general trend of the geological maps in the area (cf., Dallmann, 2015). Furthermore, the regional ties to commercial seismic profiles allow regional correlation of the drilled succession towards eastern Svalbard (Anell et al., 2014).

Microseismic water injection and flow detection. In addition to conventional seismic reflection data, a microseismic array was established using five, near-surface, 3C geophones (depth of 12 m) and two geophone strings. Strings were deployed in the DH3

Figure 10. First-order seismic to well correlation, using project-acquired 2D seismic data linking the two drill sites near Longyearbyen. For details on the seismic acquisition, see Bælum et al. (2012).

(5-level 3C geophone string at 100–300 m depth) and DH4 (8-level 3C geophone string to 590 m depth, i.e., beneath the décollement zone) wells during the water-injection tests (Oye et al., 2013; Kühn et al., 2014). The most comprehensive water-injection test in 2010 resulted in a single ~M1 event, with seven aftershocks identified through normalised cross-correlation (Kühn et al., 2014). Subsequent water-injection tests did not result in detectable events. This result suggests that aseismic fracture propagation is necessary to obtain satisfactory history matching of water-injection tests.

Complex velocity structure. Part of the challenge with precisely locating micro-earthquakes relates to the complex velocity structure of the area, and especially the permafrost which is not characterised by the velocity logs at the UNIS CO₂ lab well park. Shear-wave seismic measurements were conducted to contribute to an improved velocity model (Lecomte et al., 2014).

Seismic interferometry. Seismic interferometry using seismic noise was also considered as a possible monitoring method, particularly attractive in the long-term (Tsuji et al., 2016).

Passive seismic. The micro-seismic monitoring during the injection phase facilitated attempts to improve the signal-to-noise ratio in passive seismic data, for instance by adaptive cancellation (Harris et al., 2017)

Magnetotelluric studies. The deep and well characterised boreholes in Adventdalen were also used to calibrate

various non-seismic acquisition campaigns, including regional magnetotelluric studies targeting geothermal potential (Beka et al., 2016), joint MT–TEM profiling to characterise the resistivity structure of the uppermost 1 km (Beka et al., 2017) or combined nuclear magnetic resonance with audio-magnetotelluric data to characterise the water content in and around the permafrost in Adventdalen (Keating et al., 2018).

Wireline logging. Wireline logging (Fig. 11) including caliper, gamma-ray, resistivity, velocities (P and S waves) and acoustic televiewer have been important tools for improvement of facies associations, sequence studies and subdivision of reservoir (storage) units (Grundvåg et al., 2017, 2019; Koevoets et al., 2019a; Mulrooney et al., 2019; Rismyhr et al., 2019).

PVT, Fluid-flow studies

Storage capacity. First-order static storage capacity estimates suggest that adequate capacity is present for the modest volumes required by the local coal-fueled power plant (Senger et al., 2015). There is, however, uncertainty around the fluid injectivity of the different storage units and the dimensions of the pressure compartments in Adventdalen. While the two lower aquifers are underpressured, the upper aquifer has a slight overpressure (Fig. 12, 13).

Natural fractures. The low to moderate matrix porosity is partly offset by an extensive network of natural fractures that contribute both to fluid injectivity and to storage capacity. Detailed field studies (Ogata et al., 2012, 2014) provide comprehensive input on fracture orientations within the main reservoir units. Conversely, metre-scale normal faults offsetting the Wilhelmøya Subgroup likely baffle fluid flow along the formation within the spatial extent of the CO₂ lab well park (Mulrooney et al., 2019).

Micro CT proves connectivity. Detailed characterisation of fractures using micro CT-scanning provides constraints on the fracture aperture (Van Stappen et al., 2014), including the effects of varying pressure on the aperture (Van Stappen et al., 2018). Flow properties from injection tests and advanced porosity and permeability studies using CT scanning have proven connectivity between fractures and matrix in the lower aquifers.

Seismic velocity vs CO₂ saturation. Numerous laboratory experiments have been conducted on samples from the CO₂ lab boreholes. Moghadam et al. (2016a), for instance, investigated the seismic velocity of CO₂-saturated sandstones as a function of pressure and temperature. This is expanded by Moghadam et al. (2016b) who investigated how permeability changes as a function of confining stress and pore pressure. All these experiments are crucial to correctly predicting the relative permeability of CO₂ within the reservoir intervals, and particularly for constraining modelling parameters with site-specific data (Moghadam et al., 2019). Nooraiepour et al. (2018) utilise both electric and elastic parameters to characterise how CO₂ flow within a fracture will change the overall parameters, providing important constraints for designing multi-physical monitoring systems.

Fracture-dominated linear flow. Injection tests, some with a Strontium tracer, show that fractures were the main fluid-flow parameters in the identified aquifers. Step-wise increase in flow rates and thereafter shut in, followed by fall-off curves of reservoir pressure, record transitions from matrix (or radial) flow to fracture-dominated, more linear flow in rocks with some permeability such as reservoirs (Senger et al., 2015).

Three aquifers. Based on gas composition and isotopes, ⁸⁷Sr/⁸⁶Sr data and pressure gradients, the succession can be subdivided into three aquifers, as outlined in Table 1. Only the lower and middle aquifers are planned as CO₂ storage units. In contrast to the two lower aquifers with underpressure, the upper aquifer is slightly overpressured (Braathen et al., 2012; Betlem et al., 2019). In the middle aquifer, i.e., the upper part of the De Geerdalen Formation and Wilhelmøya Subgroup, Sr data indicate good lateral connectivity between the UNIS CO₂ Lab Well Park and the well DH2 well, approximately 7 km to the west (Fig. 1, 12). In contrast, injection tests within the UNIS CO₂ Lab Well Park suggest baffling and barriers

between adjacent wells within the hours-days time-frame of the injection tests (Mulrooney et al., 2019).

Compartmentalisation of the aquifers. Sr isotope data (⁸⁷Sr/⁸⁶Sr) from residual salts in wells DH2, DH4, DH6, DH7A combined with gas composition and isotopes for fluid communications define the vertical compartmentalisation of the three aquifers (Fig. 12) (Huq et al., 2017; Ohm et al., 2019). These data combined with measured reservoir pressure from the aquifers show the sealing capacity of a buoyant fluid within a threshold of pore pressure, albeit with a degree of flow from the underlying reservoir partially into the overlying shale (Birchall et al., in review).

Severe underpressure. Pressure conditions define the expected phase of CO₂ at reservoir conditions, with direct implications on storage capacity (Senger et al., 2015). The severe underpressure encountered in the lower and middle storage units (Braathen et al., 2012; Birchall et al., in review) would lead to gas-phase CO₂ in the initial phase, though this may change to a denser liquid phase as reservoir pressure increases during injection. Clearly, the shallow reservoir depth and the severe underpressure are potential operational challenges, with similarities to sequestering CO₂ in depleted (i.e., anthropogenic underpressure) hydrocarbon fields (Hoteit et al., 2019), and careful site-specific evaluation is required to maintain adequate injection rates. The water-injection tests, however, clearly confirm better than expected fluid injectivity, even given the low-moderate permeability.

Mixture of water-carbon dioxide-methane. Miri et al. (2014) used experimental data and statistical analyses to predict how CO₂ interacting with saline water and light hydrocarbons encountered in the boreholes will affect the fluid mobility in the subsurface. Hydrocarbon impurities are, for instance, shown to increase plume migration rates.

Underpressure due to decompaction, unloading and possible fracturing of shales. Birchall et al. (in review) characterise the underpressure in Svalbard and exploration boreholes in the northern Barents Sea, concluding that it is a recent phenomenon associated with the ongoing uplift. The main mechanism is due to decompaction, unloading and possible fracturing of shales. Underpressure is transferred to reservoir intervals through the migration of fluid into the decompacted caprock, in line with isotope data in Huq et al. (2017) and global analogues (Birchall et al., in review). Repeated glacial loading and unloading cycles as modelled by Wangen et al. (2016) are a likely candidate for its cause.

Strontium isotope studies show barriers. Strontium isotopes (Fig. 12) (Huq et al., 2017) suggest the presence of an effective barrier or seal between the lower and the middle aquifer at approximately 800 m (Fig. 12). Pressures also indicate a barrier here with

Table 1. Summary of the properties of the three aquifers studied in the Longyearbyen CO₂ Lab.

Aquifer	Boundary	Lithology	Thickness (m)	Facies	Net sandstone-sandstone ratio	Average matrix porosity	Sandstone body architectures, fluid flow	
							permeability	
Lower Includes the lower part of the De Geerdalen Formation (DGF)	Gradual transition from the lower shale part of a coarsening-upward (CU) unit.	Immature sandstone and shale. Scattered thin coal beds.	175 m	Pro-delta to delta front in the lower part passing upwards into mouth-bar deposits.	0.4	12%–0.5 mD For details of DGF see Mørk (2013).	Tabular sandstone bodies. Distributary channels might intersect the delta front and delta plain giving additional shoe-string reservoir architectures. A potential good reservoir body for fluid flow. Deep burial has resulted in severe chemical compaction and formed a low porosity and permeability reservoir. Main fluid flow via fractures.	
Middle Includes the upper part of the De Geerdalen Formation and the Wilhelmøya Subgroup (WØSG)	Sharp, erosive boundary. Probably local undulation due to incision.	Sandstone and shale. Heterolithic sandstone. Shale with scattered carbonates and thin coal beds in the middle part of the aquifer. Mature (quartz-rich), coarser grained sandstone in deposits of the WØSG	125 m	The lower 50 m represent estuarine deposits followed by tidal flat and coastal/delta plain deposits intersected by a thin marine incursion. The lowermost part possibly represents an incised valley fill. The WØSG consists of interbedded sandstones and mudstones of shallow-marine and offshore origin, respectively.	0.5	14%–1 mD For details of WØSG see Mulrooney et al. (2019).	The thick fining-upwards unit in the lower part has similarities to equivalent strata described from Hopen (Klausen & Mørk, 2014) and probably has more limited lateral continuity with a more shoe-string reservoir architecture. The heterolithic part has a more tabular architecture, but is characterised by more mud-rich sandstones. In addition, lateral continuation of paleosols with calcrete profiles will be efficient vertical barriers for fluid flow. Deep burial and chemical compaction have resulted in a low-porosity and permeability reservoir. The coarser grained sandstones in the WØSG have somewhat higher permeability and porosity up to 18%. However, the porosity is of a non-effective type (dead-end porosity). Main fluid flow via fractures, including micro fractures, which give additional flow from matrix in WØSG.	
Upper Includes the Helvetiafjellet Formation (HF) and the Carlinefjellet Formation (CF)	Sharp erosive boundary. Undulating at longer distances due to fluvial incision.	HF: Massive quartz sandstone, partly conglomeratic passing upward to interbedded sandstone and shale with some thin (cm- to dm-scale) coal beds. CF: Immature sandstone, commonly carbonated cemented (i.e. siderite), and interbedded shale.	70 to 200 m	Lower part (HF) represents fluvial braid plain deposits succeeded by coastal / delta plain with scattered distributary channels. Upper part (CF) consists of offshore mudstones and heterolithic sandstone units of offshore transition to lower shoreface origin.	0.6 (Only HF)		The lower part of the HF has a tabular architecture and occurs as lateral continuous bodies in the central and western parts of Spitsbergen. The coastal (or delta) plain deposits consist mostly of tabular beds, but lenticular-shaped distributary channels might give additional shoe-string architectures. In outcrops, CU units are seen connected with the channelised sandstone units. The upper part (CF) is characterised by lenticular sandstone bodies partly embedded in shale. Carbonate cementation has led to low porosities. The sandstone in HF is intensely quartz cemented. Chemical compaction has led to a low-porosity permeability reservoir. However, 10–20 cm-thick beds of loosely consolidated sandstones are commonly seen at the base of the HF at the boundary to the Rurikfjellet Formation. Preliminary analysis suggests that clay-coated grains have impeded quartz cementation. Good permeability measurements (c. 100 mD) and near-instantaneous pressure response following cross-well water-injection tests between DH5R and DH6 testify good injectivity, despite a low matrix porosity. We attribute this to a combination of clean and well-sorted sandstone beds and micro-fracturing.

Figure 11. Summary of the wireline and core analysis data available in the wellbores drilled by the Longyearbyen CO₂ Lab. The inset map illustrates the location of the two main drill sites on opposite sides of Longyearbyen. Wireline logging was conducted by NGU (Elvebak, 2008; Elvebak, 2010; Braathen et al., 2012), TOC data (red) from Koevoets et al. (2016) and Senger et al. (2014) and porosity plug data (blue) from unpublished data and Mørk (2013).

Figure 12. Strontium Isotopes, pressures and gas analyses from the Longyearbyen CO₂ Lab. See text for discussion.

the lower aquifer demonstrating greater magnitudes of underpressure than the middle aquifer. However, it should be noted that the pressures in the middle aquifer were slightly elevated due to drilling operations, giving rise to some uncertainty at the time of testing. The fact that the elevated pressure could be identified at all is testament to the long-term, high-quality testing carried out. The same subtle changes in pressure would not be identifiable in shorter-term pressure measurements in offshore tests (Birchall et al., in review).

Spitsbergen shows a variable geothermal gradient. The deep boreholes constrain the geothermal gradient in Longyearbyen, and are thus critical for considering the geothermal potential of Svalbard (Midttømme et al., 2015). By combining the CO₂ lab data with exploration boreholes onshore Svalbard (Senger et al., 2019), a high temperature anomaly is identified in eastern Spitsbergen. The Adventdalen wells record an average gradient of nearly 40 °C/km (Braathen et al., 2012; Betlem et al., 2018).

Caprock integrity

Pressure differences show efficient seal. The top seal of the two potential storage units is the Janusfjellet Subgroup. This is evidenced by the large pressure difference from the underlying under-pressured middle and lower aquifers, to the slightly overpressured upper aquifer. In addition, the same unit represents a major regional caprock across the Barents Shelf, sealing many of the hydrocarbon discoveries and producing fields.

Lower part of caprock in fluid communication with the middle aquifer. The caprock integrity is, amongst others, proven by gas analyses which show some step-change between the Wilhelmøya Subgroup and the overlying Agardhfjellet Formation that may reflect its barrier-like nature (Fig. 12). Pressure data in the lower parts of the caprock also show that severe underpressure is extending into the caprock itself. The isotope gradient through the shale-dominated Agardhfjellet and Rurikfjellet

formations also suggests that fluid mixing has occurred from the reservoir into the caprock. Whilst fluid mixing has occurred in the caprock, its gradational nature through the caprock shows that the entire interval is still acting as a barrier. The upper part of the caprock shows a reversal of the gradient, again indicating some mixing from the above-lying upper aquifer, the Helvetiafjellet and Carolinefjellet formations. A décollement zone, a severely fractured damage zone with swelling clays, near the Agardhfjellet–Rurikfjellet formation boundary presented significant drilling problems at the DH1/DH2 drill site and gas analyses suggest that this interval may act as an even more effective seal within the caprock succession.

Permafrost as secondary seal. $\delta^{13}\text{C}$ isotope data are also consistent with the notion that the base of the permafrost acts as an effective barrier near the base of the Carolinefjellet Formation. We conclude that the 120 m-thick permafrost in Adventdalen, which includes bedrock and the unconsolidated Quaternary deposits in the upper 70 m towards the present-day valley floor (Gilbert et al., 2018) provides an additional seal. The sealing properties of the permafrost are manifested by the gas accumulation at its base (Betlem et al., 2019).

Geomechanics of a fully cored caprock. The full coring of the shale-dominated caprock succession in four boreholes allows for detailed studies on geomechanics (Bohloli et al., 2014, 2015, 2016), analysis of permeability within subunits of the obtained cores (van Noort & Yarushina, 2016) and an integrated characterisation using wireline logs, drillcores and outcrop data (Senger et al., 2016).

Fault identification after CO₂ injection. Field and outcrop studies have documented extensive natural fracturing, as well as some faults. Lubrano-Lavadera et al. (2018, 2019) builds on these field observations and considers, through

seismic modelling, whether the identified faults should be visible on seismic data under a variety of scenarios during and after CO₂ injection (e.g., brine-filled vs CO₂-filled, increasing complexity of background).

Limited CO₂-brine-rock interaction. Alemu et al. (2011) conducted experiments to quantify the reaction rates of CO₂-rich brine on two samples of potential intra-formational barriers within the De Geerdalen Formation, and concluded that the low permeability allows only limited CO₂-brine-rock interaction.

Epilogue

Carbon capture and storage (CCS) is part of the solution required globally to reach the Paris agreement goals of keeping the global temperature increase well below 2°C above pre-industrial levels. Few studies on storage units have been carried out in Europe. Lack of test sites in suitable basins, and more so, the public oppositions to store CO₂ in the subsurface near communities have been major impediments to operations. The Longyearbyen CO₂ Lab offers a suitable locality for a test site that could explore challenges and outcomes of injection and storage of CO₂ in the subsurface. Furthermore, Longyearbyen offers a site with a supporting public opinion and limited political challenges, which typically relate to contamination of groundwater, anthropogenic earthquake activity (generated micro-earthquakes during water injection are well below the magnitude of natural earthquakes) or the not-in-my-backyard (NIMBY) syndrome. On the contrary, Longyearbyen's direct reliance on a coal-fueled power plant with the highest per capita CO₂ emissions in the world provides incentives to investigate the potential of CCS for reducing local emissions.

An important aspect of the Longyearbyen CO₂ Lab is the possibility to test and evaluate an unconventional reservoir (storage). The UNIS CO₂ Lab has operationally tested the subsurface by drilling, injection testing, geological reservoir studies and geophysical acquisition. This is a workflow common for exploration in the initial phase of a prospect discovery and evaluation in the gas and oil industry. The results are promising, suggesting that injection and storage of a small amount of CO₂ emitted from the coal power plant in Longyearbyen is feasible. Furthermore, it will be safe, as pressure differences prove that the main Upper Jurassic to Lower Cretaceous mudstone-dominated succession is an efficient seal (up to a pressure threshold for at least several tens of thousands of years). In addition, the approximate 120 m-thick permafrost will act as a secondary seal. Unfortunately, the project was not supported for injection testing with CO₂ that would have fully validated the storage formations and potentially

Figure 13. Artesian water from wellhead, producing 125 litres brackish water per minute from the Helvetiafjellet Formation, i.e., the upper aquifer.

contributed to significantly lowering Longyearbyen's CO₂ emissions.

On the other hand, if CCS does develop as a global climate mitigation method, numerous early career geologists and geophysicists have gained expertise in CCS technology in Longyearbyen by conducting their theses as part of the project, attending CO₂-related graduate courses at UNIS, or attending some of the international CCS summer schools or workshops held in Longyearbyen. Hence, our future CCS experts have greatly benefitted from the large-scale laboratory experiments conducted at the Longyearbyen CO₂ Lab. For the future, UNIS has placed itself on the map as a well-poised research institution that conducts innovative, need-driven research combining the best from industry and academia.

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