AAPG BULLETIN

Underpressure in the northern Barents shelf: Causes and implications for hydrocarbon exploration

T. Birchall, K. Senger, M. Hornum, S. Olaussen, and A. Braathen

AAPG Bulletin published online 20 July 2020
doi: 10.1306/02272019146

Cite as: Birchall, T., K. Senger, M. Hornum, S. Olaussen, and A. Braathen, **Underpressure in the northern Barents shelf: Causes and implications for hydrocarbon exploration**, *(in press; preliminary version published online Ahead of Print* 20 July 2020*):* AAPG Bulletin, doi: 10.1306/02272019146.

Underpressure in the northern Barents shelf: Causes and implications for hydrocarbon exploration

Authors: T Birchall[1,2], K Senger[1], M Hornum[1,3], S Olaussen[1], A Braathen[1,2]

Affiliations: [1]The University Centre in Svalbard, [2]University of Oslo [3]University of Copenhagen

Corresponding author: Thomas Birchall, Thomas.birchall@unis.no

Word count: 9,951

Word count (excluding refs & Abstract): 8,850 (Abstract: 230)

Number of figures:12

Number of tables: 6

Abstract

The underexplored Barents shelf petroleum province is a globally unique example where naturally occurring underpressure is observed offshore and onshore. In the offshore parts of the northern Barents shelf minor underpressure (up to 23 bar subhydrostatic) is observed in the fault-bounded Mesozoic reservoirs of the Fingerdjupet subbasin. More severe (50 bar subhydrostatic), though irregular, occurrences of underpressure are encountered in the Triassic intervals of the neighboring Greater Hoop area. The abnormal pressures extend to the onshore archipelago of Svalbard, where pressures exceeding 60 bar below hydrostatic were encountered during drilling for a carbon dioxide sequestration project. In Svalbard, reservoir pressures were constantly monitored over three years, providing an insight into the reservoir behavior at unique timescales. The low permeability (< 2 md) reservoir in Svalbard is exposed some 15 km to the north of the drill site. Quantitative analysis with the apparent lack of a regional lateral seal, suggest a geologically recent origin of underpressure. There is evidence that the underpressure extends into the top seal which provides further indication to the likely cause of underpressure. Similarly to many global occurrences of underpressure in petroleum provinces, the Barents shelf has undergone severe uplift, most recently due to deglaciation. Well data, outcrop observations and isotope data combined with the areas geological history indicate that glacial loading, unloading and erosion, potentially with the aid of natural fractures, is the likely dominant underpressure generating mechanism.

Introduction

The frontier exploration area of the northern Barents shelf, located in the Norwegian high Arctic, is the only place in the world where naturally developed underpressure has been encountered offshore in Jurassic and Triassic strata. The time-equivalent strata in Svalbard, an archipelago near to the northwestern margin of the Barents shelf, exhibit pressures as low as one third of hydrostatic (Braathen et al., 2012; UNIS CO_2 Lab AS, 2015 and references therein; Olaussen et al., 2019). The abnormally low pressures inevitably resulted in well control problems in several offshore exploration wells and boreholes drilled on Spitsbergen, the largest island of Svalbard, as part of a CO_2 storage feasibility study, the Longyearbyen CO_2 Lab (Braathen et al., 2012; Senger et al., 2015; UNIS CO_2 Lab AS, 2015; Olaussen et al., 2019). In well DH5R of the CO_2 Lab drilling fluid was lost into the formation which resulted in gas influx. Underpressure is not simply a concern for drilling processes (Mouchet and Mitchell, 1989) but can also influence elements of the petroleum system (Law et al., 1998), so understanding its distribution and causes is critical to achieve successful hydrocarbon exploration and production.

The United States Geological Survey suggests that 30% of the world's undiscovered gas and 13% of undiscovered oil are located in the Arctic (Gautier et al., 2009). The Norwegian Petroleum Directorate (NPD) recently estimated that undiscovered resources of 15.9 billion barrels of oil equivalent remain under the Norwegian Barents Sea, including areas presently not opened for exploration (Stordal, 2018). The Barents shelf has seen significant exploration activity with recent interest moving to northern parts following several promising discoveries (e.g. Wisting) and the opening of new exploration acreage in recent years (Nyland, 2018; Berthelsen, 2019). Formation pressure data is vital to hydrocarbon exploration, because of the influence it has on the different elements of the petroleum system and in ascertaining pressure communication or compartmentalization.

In exploration, the effects of depth are removed by analyzing the pressure relative to hydrostatic pressure, i.e. the pressure exerted by a column of water at any given depth. The hydrostatic pressure exerted is dependent on the density of the pore water. Pore water density is predominantly influenced by its salinity (Swarbrick and Osborne, 1998). Pressures lower than the hydrostatic are underpressured and those exceeding it are defined as overpressured (Law et al., 1998). Underpressure is a common condition in regional groundwater flow systems of the world (Tóth, 2009), including the western Great Artesian Basin of Australia (Love et al., 2013), the Llanos Basin in Colombia (Person et al., 2012), the Pannonian Basin in Hungary (Mádl-Szőnyi et al., 2015) and large areas of the Texas-Oklahoma panhandle (Sorenson, 2005). However, it is relatively rare in more deeply buried prolific petroleum basins (Dickey and Cox, 1977; Belitz and Bredehoeft, 1988; Scott et al., 1994; Puckette and Al-Shaieb, 2003; Lazear, 2009).

The majority of documented cases of underpressure in petroleum producing basins have undergone recent uplift either due to tectonic forces or deglaciation. These include the petroleum provinces of the Western Canadian Sedimentary Basin (Davis, 1984; Gies, 1984), several basins of the central United States (Dickey and Cox, 1977; Belitz and Bredehoeft, 1988; Scott et al., 1994; Puckette and Al-Shaieb, 2003; Lazear, 2009) and onshore basins in China (Xie et al., 2003; Hao et al., 2012). Onshore basins make pressure analysis more challenging because there are uncertainties with the hydrostatic gradient in addition to the effects of topographic driven flow (Nelson et al., 2013).

Because underpressure in the Barents shelf is subsea (including the reservoir interval in Svalbard) the hydrostatic gradient is calibrated to the mean sea level. The presence of underpressure in the area is not a new concept, as since Mobil and Norsk Hydro both encountered underpressure in the Fingerdjupet subbasin in the 1980s (Nyland et al., 1992; Hinna et al., 2016; Serck et al., 2017). Underpressure has subsequently been encountered within the past ten years in the Greater Hoop area, the northern Loppa high and in Svalbard (Table 1). Importantly, there is evidence of underpressure in the claystone dominated top seal in the study area in Svalbard which has implications to the potential driving mechanisms controlling the underpressure. Underpressure in Svalbard was first documented during analysis of the carbon dioxide storage potential (Braathen et al., 2012; Senger et al., 2015). Wangen et al. (2016) attempted to identify the cause of underpressure through numerical modelling. They suggest that decompaction resulting in an increase in pore volume caused the underpressure locally, but the model also relies on compartmentalization. Decompaction, however, is a poorly understood mechanism (Liu and Roaldset, 1994; Baig et al., 2016) and the complex, laterally heterogeneous burial and uplift history of the Barents shelf (Ohm et al., 2008; Henriksen et al., 2011) is difficult to quantify.

In this article we document the distribution and magnitude, and investigate the likely causal mechanisms of underpressure in the northern Barents shelf. In addition, we discuss the implications behind our findings and the applications to hydrocarbon exploration of the northern Barents shelf.

Hydrogeological setting

The Barents shelf exhibits three geological areas (Figure 1) with underpressured Mesozoic intervals (Figure 2): i) The Fingerdjupet subbasin is situated on a terrace between the deep rifted basins to the west and the more stable Bjarmeland platform to the east (Serck et al., 2017). The Fingerdjupet subbasin has the deepest underpressure bearing reservoirs in our study area at approximately 2300 m. ii) The Greater Hoop area to the east is shallower with underpressure confined to the Triassic reservoirs with normal pressure prevailing in the very shallow Jurassic intervals. iii): In Svalbard – the exhumed portion of the Barents shelf. A CO_2 sequestration feasibility study was carried out near the town of Longyearbyen in Svalbard. The site is situated on the eastern limb of the Central Tertiary Basin (Braathen et al, 2012) and severe underpressures of up to 60 bar (1 bar ~ 14.5 psi) were encountered at depths between 600 and 950 m below sea level.

The underpressure was encountered in tight heterolithic sandstones of the Triassic and Jurassic Wilhelmøya Subgroup and the Triassic De Geerdalen Formation (Figures 1 and 2).. The Wilhelmøya Subgroup is capped by a 400 m thick shale aquitard of the Agardhfjellet and Rurikfjellet Formations. The aquitard is overlain by a slightly overpressured Cretaceous aquifer of the Helvetiafjellet Formation.

Overpressures in the Helvetiafjellet Formation were identified during drilling when water unexpectedly flowed from the wellbore to the surface at 125 liters per minute (Olaussen et al., 2019). This interval appears to be sealed by the base of permafrost at approximately 120 m depth (Braathen et al., 2012; Betlem et al., 2019). Water being expelled at pingos in the area is from this subpermafrost groundwater system (Hodson et al., 2019). Recent work suggests millennium-scale adjustment times in the subpermafrost groundwater system. Overpressures are thought to be generated by freezing at the permafrost base associated with thermal equilibration to Holocene climate cooling and land emergence rather than relict (glacial) artesian pressures or present day flow and recharge (Hornum, 2018; Hodson, A., personal communication,). Such natural fluid migration pathways through the permafrost are common throughout Svalbard (Humlum et al., 2003; Haldorsen et al., 2012; Hodson et al., 2019). At the wellsite the underpressured interval is isolated from the overpressured aquifer by several hundred meters of organic-rich shales of the Agardhfjellet and Rurikfjellet Formations.

The deeper, and severely underpressured, Triassic-Jurassic system dips to the southwest and has permeabilities an order of magnitude lower than the Helvetiafjellet Formation (Mørk, 2013; Magnabosco et al., 2014; Senger et al., 2015). Updip the reservoir crops out along the coastline and beneath the fjord 15 km to the northeast (Braathen et al., 2012; Ogata et al., 2014; Olaussen et al., 2018). Subsea permafrost does not exist in the outcrop area (Christiansen et al., 2010) so it is unlikely a geologically long-lived lateral seal exists in the underpressured interval. In a regional context the interval is exposed to the west-southwest some 50 km away in the West Spitsbergen fold-thrust belt (Braathen et al., 1995) and to the east beneath Storfjorden and on Edgeøya approximately 100 km away. At all outcrop locations, the hydrostatic pressure is defined by present-day sea level or higher so it is not feasible that a downdip outflow can reduce hydraulic pressures below this level.

Geological Setting

Depositional history

Figure 2 shows a stratigraphic correlation of the Mesozoic intervals of Svalbard and the offshore Barents shelf. The intervals of interest in this study are: (1) the Middle to Upper Triassic Snadd (offshore) and De Geerdalen (Svalbard) Formations. (2) The Upper Triassic to Middle Jurassic Realgrunnen Subgroup. (3) Middle Jurassic to Lower Cretaceous shales.

During the Early Triassic the Uralide orogeny formed a foreland basin in the eastern Barents shelf area (O'leary et al., 2004; Eide et al., 2017). Extremely high subsidence rates and denudation of the Uralian Mountains and Fennoscandia resulted in vast prograding delta systems from the southeast characterized by highly heterolithic sandstones and shales (Faleide et al., 1984; Faleide et al., 1993; Worsley, 2008; Glørstad-Clark et al., 2010; Henriksen et al., 2011; Klausen et al., 2014). Offshore this succession is known as the Snadd Formation and is well in excess of 1 km thick in all wells of the study area

(Norwegian Petroleum Directorate Factpages, 2019). Onshore Svalbard it is known as the De Geerdalen Formation which represents the distalmost part of the largest recorded delta plain in Earth's history (Klausen et al., 2017; Klausen et al., 2019b). It is at least 250 m thick in the DH4 well in central Spitsbergen and up to 400 m thick on Edgeøya in eastern Svalbard (Gradstein et al., 2010; Braathen et al., 2012; Mørk, 2013; Mulrooney et al., 2019).

The subsidence rate decreased and orogenic front shifted in the Late Triassic leading to more complex depositional trends (Ryseth, 2014; Klausen et al., 2017; Klausen et al., 2018). This marks the depositional change to the Realgrunnen Subgroup in the Barents Sea and the onshore equivalent Wilhelmøya Subgroup in Svalbard. Offshore, the heterolithic sandstone and shales of the Fruholmen Formation marks the base of the Realgrunnen Subgroup. It is between 150 to 200 m (492 to 656 ft.) thick in the Fingerdjupet subbasin and 30 to 100 m thick in the Greater Hoop area (Klausen et al., 2019a and references therein; Norwegian Petroleum Directorate Factpages, 2019).

The Lower to Middle Jurassic Stø Formation is the most prolific reservoir in the Barents Sea petroleum province and marks a significant improvement in reservoir quality (Henriksen et al., 2011). Numerous hiatuses and substantially slower subsidence than during the Triassic resulted in extensive reworking resulting in clean sandstone deposits (Klausen et al., 2018). The onset of deposition marks a change from easterly derived sediments to quartz rich sources from the southwest and southeast (Klausen et al, 2018). The Stø Formation is relatively thin in the study area with thicknesses ranging from 8 to 38 m but has significantly better reservoir properties than the underlying formations (Klausen et al., 2019a).

In Svalbard, the Upper Triassic to Lower Jurassic Wilhelmøya Subgroup is a condensed sandstone dominated succession broadly time-correlative to the offshore Fruholmen, Nordmela and Stø Formations (Nøttvedt et al., 1993; Mørk, 1999; Olaussen et al., 2018;

Rismyhr et al., 2019). The Wilhelmøya Subgroup thickness varies laterally: in the wells of the Longyearbyen CO_2 Lab in central Spitsbergen it is only 23 m (75 ft.) thick whereas a 250 m thick succession is exposed in Kong Karls Land to the east (Gradstein et al., 2010; Mulrooney et al., 2019; Rismyhr et al., 2019). It is compositionally similar to the offshore Stø Formation. However, in Svalbard, deep burial prior to uplift has resulted in severe chemical diagenesis, the most predominant being quartz cementation and clay diagenesis (Mørk, 2013).

The onshore mudstone-dominated Agardhfjellet Formation, containing thick organic-rich units, is up to 350 m (1150 ft.) thick (Dypvik and Zakharov, 2012; Koevoets et al., 2016). The offshore counterparts, the Fuglen and Hekkingen Formations, reach a similar thickness in the Barents Sea with the Hekkingen Formation providing a major source rock for the oil and gas fields and many recent discoveries on the Barents shelf (Langrock et al., 2003; Ohm et al., 2008; Koevoets et al., 2019; Ohm et al., 2019).

In Svalbard the sediment source moved to the northwest and north through the Late Jurassic and Early Cretaceous (Gjelberg and Steel, 1995; Koevoets et al., 2016).

Uplift commenced on the Barents margins in the Early Cretaceous due to the formation of the High Arctic large igneous province (HALIP) and the opening of the Amerasian Basin (Grantz et al., 2011; Senger et al., 2014; Polteau et al., 2016). The lack of Upper Cretaceous strata in Svalbard is suggested to be the continued basement uplift of the northern Barents margin (Maher, 2001; Smelror and Larssen, 2016).

Cenozoic Tectonic History

It is generally accepted that the Cenozoic burial and uplift history of the Barents shelf is the dominant process which has affected fluid migration and trap breaching in the prospective strata of the Barents shelf (Ohm et al., 2008; Henriksen et al., 2011; Abay et al., 2017). In Svalbard Paleogene transpression created the West Spitsbergen fold-thrust belt (WSFTB) and uplift to the west, but led to the development of a small foreland basin in central Spitsbergen (Bergh et al., 1997; Braathen et al., 1999). Similarly, in the Barents Sea, uplift related to complex tectonic movements around the Atlantic margin is observed by the lack of Paleogene and Neogene successions in most wells in the platform areas in contrast to the thick sedimentary wedges of the same age on the western margin (Doré and Lundin, 1996; Faleide et al., 1996; Brekke et al., 2001; Ohm et al., 2008; Henriksen et al., 2011; Lasabuda et al., 2018).

The most recent regionally extensive uplift and erosion event that occurred was during the past few million years due to repeated glaciations (Dimakis et al., 1998; Landvik et al., 1998; Lasabuda et al., 2018). These are arguably the most important geological events in respect of the preservation, migration and leakage of hydrocarbon accumulations of the Barents shelf (Riis and Fjeldskaar, 1992; Cavanagh et al., 2006; Ohm et al., 2008; Henriksen et al., 2011).

Attempts to reconcile Cenozoic net erosion are based on shale compaction, vitrinite reflectance, apatite fission track analysis and diagenesis (Henriksen et al., 2011). However it is almost impossible to individually quantify the magnitude of uplift and erosion of each event (Faleide et al., 1993; Gabrielsen et al., 1997; Henriksen et al., 2011; Lasabuda et al., 2018). The total magnitude of Cenozoic uplift is different throughout the Barents shelf. In the context of our study area up to 3 km of uplift has occurred in Svalbard (Marshall et al., 2015; Ohm et al., 2019) and approximately 1.5 km in the Fingerdjupet subbasin and Greater Hoop area (Dimakis et al., 1998; Henriksen et al., 2011). The contours in Figure 1 (From Henriksen et al, 2011) indicate the variation in the magnitude of Cenozoic uplift throughout the Barents shelf.

Faults and fractures

Meter-scale faults are observed in the reservoir and top seal intervals in outcrops and wells (Mulrooney et al., 2019). While these faults may form baffles to fluid flow, it is extremely unlikely they provide a regional lateral seal. Ogata et al (2014) carried out detailed analyses of fractures in the reservoir and cap rock intervals in both drill cores and outcrops (Figure 3) (Ogata et al., 2014). Both through-going and bed-confined fractures were observed in the reservoir and cap rock interval. Through-going fractures cut across stratigraphic boundaries whereas bed-confined fractures either terminate at such boundaries or run concordantly with bedding. Through-going fractures likely enhance vertical flow whereas bed-confined fractures may enhance lateral flow properties and, to a much lesser extent, porosity (Ogata et al., 2014). Their formation is associated with the numerous and complex events of the Barents shelf's tectonic history, with the Paleogene formation of the WSFTB a likely major contributor. The most recent episode of uplift and erosion has resulted in many of the observed fractures being presently open (Ogata et al., 2014).

Data and methods

We compiled reservoir properties for each location in the study area based on well data (Anadrill-Schlumberger, 1988; Norsk-Hydro, 1988, 1989; Elvebakk, 2010; Titlestad, 2012; Schlumberger, 2013, 2014c, d, e, f, a, b; Tveranger et al., 2014; Schlumberger, 2015; UNIS CO_2 Lab AS, 2015 and references therein; Schlumberger, 2016b, a; Weatherford, 2017; Norwegian Petroleum Directorate Factpages, 2019), core analysis and outcrop data. On the Norwegian shelf raw well data is released to the public domain two years after well completion while interpreted data and reports are released twenty years after completion. We accessed available well data through the Norwegian Petroleum Directorate DISKOS database. In Svalbard, well data from the Longyearbyen CO_2 Lab is freely available for academic purposes through the University Centre in Svalbard (UNIS).

Direct pressure data

Table 2 shows a summary of underpressures in the study area. For the wells drilled in the 1980s in the Fingerdjupet subbasin area, original pressure buildup plots were not available, so we obtained pressures stated in drilling and end of well reports. Nevertheless, we have good confidence in these data points because the Jurassic Stø reservoir in this area is of reasonably good reservoir quality (Table 3). Well 7321/9-1 also displays a clear water gradient with very little spread in data which is indicative of good tests.

In the Greater Hoop and Loppa high areas we analyzed original pressure buildup plots to ascertain the quality of each pressure point (Schlumberger, 2013, 2014c, e, b, 2015). The main risks are either the lack of pressure buildup in the tool, resulting in pressures lower than the true pore pressure and supercharging or tool seal failure. Seal failure and incomplete pressure buildup in the tool is easily identified by the contractor (seal failure will draw in drilling mud fluid and thus pressures equal to the mud weight). Supercharging is common in low-permeability reservoirs. Reservoirs in the study area are typically very low permeability due to their previously deep burial causing mechanical compaction and quartz diagenesis (Olaussen et al., 1984; Mørk, 2013). Supercharging occurs when drilling fluid enters the reservoir and the resulting measured pressure can be anywhere between the true reservoir pressure and the pressure exerted by the drilling mud. Supercharging is identified in the pressure tests where the repeated cycles of pressure drawdown show progressively decreasing pressures as the drilling fluid slowly dissipates from the near-wellbore environment (e.g. Figure 4A). Underpressures also likely enhance supercharging as drilling is almost certainly overbalanced. In Svalbard, continuous pressure measurements record this pressure decrease on a more detailed level but Figure 4C and 4D show the very long timescales it takes for near-wellbore reservoir conditions to return to normal. Because of this it is unreasonable to attempt to correct for such supercharging but, nevertheless, it is clear that these recorded pressures represent a maximum possible reservoir pressure. Therefore the identification of underpressure from supercharged intervals is valid.

Slight apparent overpressures exist in some wells of the Greater Hoop area. Although salinity data is not available, the fluid gradients in 7220/2-1 indicate water densities of between 1.049 to 1.102 g/cc (Schlumberger, 2014d). These are in-line with the slight apparent overpressures and probably reflect higher salinities of the area. The higher salinities here may reflect the closer proximity to the salt influenced areas to the southeast (Jensen and Sørensen, 1992; Smelror et al., 2009). The 7324/8-1, 7324/7-2, 7324/9-1 wells also exhibit some hydrocarbon buoyancy overpressure.

The study area has seen no hydrocarbon production in the region and, because it is largely underexplored, data is sparse. Spatially, we identified areas of underpressure, its general geological setting, as previously discussed, the underpressured reservoir characteristics (Table 2), the fluid types encountered and uplift history (Henriksen et al., 2011).

Indirect data

We have compiled the qualitative evidence of underpressure (Table 2) from drilling reports. These include drilling fluid losses to formation, stuck drill pipe and wellsite observations. In the Greater Hoop area no porosity-permeability analysis is publicly available. The targeted reservoir here is regionally poor (Mørk, 2013), so we have used pressure build-up plots (e.g. slow build-up or supercharging) to confirm the reservoirs here are also of low permeability. Supercharging typically occurs in reservoirs with permeability of a few millidarcys or less (Ceyhan et al., 2016).

Distribution of underpressure

The offshore Barents shelf comprises domains exhibiting hydrostatic to near hydrostatic, underpressured, and near high-pressure high-temperature (HPHT) conditions (Figure 5). Basins in the southwest are at near maximum burial (Henriksen et al., 2011) and exhibit near HPHT conditions. The central and southern parts exhibit hydrostatic to slight overpressures. Underpressures are observed in all wells of the Fingerdjupet subbasin and in two wells (that are publically available) of the Greater Hoop area. Underpressure occurs in the northern part of the Norwegian Barents shelf and in Svalbard in severely uplifted areas in typically low-quality reservoirs and is our area of interest for this study. Figure 6 is a pressure-depth plot of the wells in our study area.

Svalbard

Eighteen hydrocarbon exploration wells have been drilled in Svalbard in the period from 1961 to 1994 (Senger et al., 2019). No commercial discoveries were made in these wells with various intervals being targeted. No pressure tests were carried out the Jurassic-Triassic sandstones. No evidence of underpressure exists in these wells, though the data availability from these wells is very fragmentary.

The Longyearbyen CO_2 Lab drilling programme comprises eight wellbores and the project's scientific results are summarized by Olaussen et al. (2019). The first two wells, DH1 and DH2, were drilled near Longyearbyen Airport. Both wells experienced significant technical difficulties related to wellbore stability in the Jurassic-Cretaceous shale-dominated top seal affected by a regional decollement zone. Subsequent wells were relocated to Adventdalen to the east of Longyearbyen, some 7 km to the southeast of drill site 1, where six further wells (DH3 to DH8) were drilled. With basis in learnings from wells at the initial drill site and input from industry experts, both the drilling and well-test programs were improved for the subsequent wells (DH4 and onwards). We have analysed data from the latter wells that penetrated the study interval. Underpressure is observed in the Triassic and Jurassic intervals, whereas slight overpressure occurs in the Cretaceous Helvetiafjellet Formation that is separated by at least 400 m of shale from the underpressured units below (UNIS CO_2 Lab AS, 2015 and references therein).

Strontium isotope data (Huq et al., 2017) shows long-term lateral communication between the two drill sites. It also shows fluid migration into the Agardhfjellet-Rurikfjellet cap rock from the underlying and overlying intervals (Figure 7). The rate of fluid mixing into the cap rock cannot be explained by only diffusion since depositional times (Huq et al., 2017).

Drillhole-5R (DH5R) and Drillhole-7A (DH7A)

Two wells, DH7A and DH5R, were drilled, 94 m apart, to test fluid communication in the Wilhelmøya Subgroup reservoir. The tests were carried out in open-hole conditions including both the Wilhelmøya Subgroup and the lowermost 30 m of the Agardhfjellet Formation cap rock. A leak-off test was carried out in the lowermost part of the Agardhfjellet Formation in well DH5R. Following the injection tests, during which no communication was identified (Mulrooney et al., 2019), drilling fluid (water) was sucked into the formation and methane gas entered the wellbore of DH5R. The gas was bled of multiple times but the same occurred several times with gas pressures stabilizing after approximately 24 hours each time (Figure 8). No gas was encountered in the Wilhelmøya Subgroup in any wells of the study which is in agreement with petrophysical data. Detailed analysis of the gas by Ohm et al. (2019) indicates it entered the wellbore from the shales of the Agardhfjellet Formation rather than the Wilhelmøya Subgroup sandstone. Flow from the Agardhfjellet Formation likely occurred through fractures opened during the leak off test of the top seal. Gas from the Agardhfjellet Formation also entered the DH7A, the injector well for the interference tests (Ohm et al., 2019) which also probably opened fractures to allow the gas to flow.

We hypothesize that drilling fluid lost into the Wilhelmøya Subgroup reduced the confining pressure in the wellbore allowing gas to enter the DH5R wellbore from the Agardhfjellet Formation. The well was shut-in during monitoring, so gas ultimately filled the wellbore and pressures stabilized to reservoir conditions. The pressure sensor was located in the wellbore at a depth of 645 m near the base of the Agardhfjellet Formation. Figure 8 shows the series of events recorded by the sensor. Pressures initially dropped as water flowed from the wellbore into the reservoir then gas enters the wellbore causing a pressure increase until it reached equilibrium with the gas-bearing interval at 29 bar at the sensor depth (36 bar underpressured). Because the same pressures were repeatedly measured and gas repeatedly flowed into the wellbore, we have good confidence that the pressures truly represent the gas-bearing interval. Therefore, it represents a direct pressure measurement from the Agardhfjellet Formation and, significantly, provides direct evidence that the top seal itself is severely underpressured. The fact that gas remains in the lowermost cap rock and not in the underlying reservoir, is evidence that the cap rock must be at least equally underpressured to prevent migration from the cap rock to the reservoir.

Drillhole-4 (DH4)

DH4 is the deepest of the Longyearbyen CO_2 Lab wells at 969.7 m and also offers the most comprehensive series of pressure tests. Three distinct reservoir sections were identified and qualified (Mørk, 2013; Farokhpoor et al., 2014; Magnabosco et al., 2014; Senger et al., 2015). An upper reservoir comprising the Upper Triassic to Middle Jurassic Wilhelmøya Subgroup from *c.* 670-700 m was not directly pressure tested but is a likely candidate for absorbing significant drilling mud. The middle and lower reservoirs are situated in the Upper Triassic De Geerdalen Formation with both undergoing major long-term injection and pressure monitoring tests.

The middle reservoir is situated between 770-870 m with a pressure at least 44.3 bar below hydrostatic (approximately 41% of hydrostatic). However, pressures were still falling some 24 hours after drilling (Figure 4.D), implying that a degree of supercharging has occurred and the real formation pressure is likely lower. Injection testing was carried out in the middle reservoir section with a shut-in period of 38 days monitored, following an initial 8 hours of pressure injection. Relatively fast initial pressure fall-off was followed by extremely slow pressure fall-off, likely indicating initial fracture propagation followed by very slow equilibration towards the initial reservoir through the very low permeability matrix.

It should be noted that when the pressure sensor was removed from the wellbore following the test, the sensor and cable were dry. This is evidence of drilling fluid being lost to the formation and falling below the depth of the sensor at 768 m. This would equate to even lower pressures than those recorded to persist in the reservoir section.

The lower reservoir section is situated in the section between 870-970 m with the sensor located at 855 m The initial reservoir pressures show no evidence of supercharging and recorded a pressure of 54.5 bar below hydrostatic (35% of hydrostatic) at the sensor depth. A long-term injection and fall-off test was carried out over a period of more than three years (Figure 4.C). Initial falloff pressure shows similar findings to the middle reservoir, but the most notable characteristic of this test is the fact that pressures were still falling more than three years following injection, highlighting the extremely low reservoir permeability.

Drillhole-2 (DH2)

Although no pressure data were recorded for DH2 due to wellbore instability, a core was collected which enabled stratigraphic correlation (Braathen et al., 2012; Ogata et al., 2014) and isotope analysis (Huq et al., 2017)(Figure 7).

Fingerdjupet Subbasin

7321/7-1 (Water-wet)

This well was drilled by Mobil Exploration and sits on the western edge and deepest part of the Fingerdjupet subbasin. The primary targets were the Jurassic and Triassic reservoirs in a rotated fault block (Serck et al., 2017).

Although only three pressure measurements were taken, they were all of good quality (Anadrill-Schlumberger, 1988). The better Stø Formation exhibits underpressure of 9.5 bar which equates to 95% of hydrostatic at 2002 m TVDss. The deeper Snadd Formation is underpressured by 6 bar (98% of hydrostatic at 2366 m TVDss). The third test, at 3324.5 m in the lowermost parts of the Triassic interval exhibits slight overpressure of 12.6 bar equating to 104%.

Loss of well control due to mud losses occurred while drilling through the claystone dominated top seal of the Kolmule and Kolje Formations. Because the drilling fluid used was seawater it is clear that these intervals are also underpressured. It also shows that intervals within the top seal are permeable. The losses occurred between 1022 m and 1825 m TVDss indicating that the underpressure extends significantly into the overburden.

7321/8-1 (Water-wet)

Drilled by Norsk Hydro, this well sits in the central part of the Fingerdjupet subbasin with the primary target being the Jurassic and Triassic sandstones near the crest of a tilted fault block (Norsk-Hydro, 1988). The well reached TD in the Permian carbonates of the Røye Formation. Although water wet, residual hydrocarbons were identified in the primary target.

Fifteen good quality pressure tests in this interval yield a clear aquifer gradient consistently underpressured (Norsk-Hydro, 1988) by 8 bar (94.4% of hydrostatic at top reservoir). The well was drilled using water-based mud and did not encounter any technical problems during drilling.

7321/9-1 (Water-wet)

Also drilled by Norsk Hydro, this well is located on the eastern and shallowest part of the subbasin and also targeted a rotated fault block (Norsk-Hydro, 1989). The Stø Formation was the primary target with the Snadd Formation and Lower Cretaceous sandstones secondary targets.

This well took a single good pressure measurement in the upper Stø Formation at 1336 m TVDss (Norsk-Hydro, 1989). The formation exhibits an underpressure of 22.9 bar (83% of hydrostatic).

Minor mud losses of 13 m^3 (82 bbl) occurred at 1145 m and the drill pipe became stuck at 1377m (Norsk-Hydro, 1989). As the well was drilled overbalanced (with mud weight above hydrostatic) it is impossible to determine if underpressure was the main cause.

Underpressure is observed in all three exploration wells within the basin, but the magnitude varies between them.

Loppa High – 7222/1-1 - Aurelia Prospect (Water-wet)

This well was drilled by ENI Norge and is situated a short distance south of the Fingerdjupet subbasin on the northern Loppa high, where the stratigraphy is at a much shallower depth (Schlumberger, 2016a). The primary targets were the sandstones of the Snadd and Kobbe Formations.

Out of 20 tests, 17 were tight and 3 supercharged (Schlumberger, 2016b), highlighting the challenging nature of obtaining reliable pressure measurements in very low permeability reservoirs. However, of the three supercharged tests, two still yield figures below hydrostatic.

Two tests at 1439 and 1442 m indicate underpressures of 5.7 bar and 5.8 bar respectively (circa. 96% of hydrostatic). As previously mentioned, supercharged tests yield a maximum possible pressure so the lowest pressure measurement in this interval is almost certainly closest to the true reservoir pressure, though the severity of underpressure cannot be determined.

Three tests were also obtained via the MWD Stethoscope tool in shallower parts of the Snadd Formation between 1050 and 1160 m and indicate that the formation is at hydrostatic or slightly overpressured in this interval. It is, however, highly likely these points have been influenced by supercharging.

Major mud losses of 45 m^3 (283 bbl) per hour were encountered during coring operations at 1479 m in the Kobbe Formation. The operation was carried out overbalanced so it does not prove underpressure but does highlight that the interval can flow.

Greater Hoop Area

The Greater Hoop area is something of a geological enigma. The Wisting oil discovery in the Stø Formation is situated very close to the seabed, at approximately 650 m TVDss with a water depth of 400 m. Underpressure in the Greater Hoop area is also somewhat enigmatic where severe underpressure coexists with hydrostatic pressures within the Triassic reservoir intervals.

7324/7-1S Wisting Alternative (Water-wet)

This well was drilled by OMV Norge and is one of six wells on or in the immediate vicinity of the Wisting discovery. Of the six wells, four partially penetrated the Snadd Formation as a secondary target. Three of these appear to be normally pressured. The 7324/7-1s shows underpressure in the Snadd Formation (Schlumberger, 2013). One MDT pressure test at 1593 m indicates minor underpressuring of 6.5 bar (96% of hydrostatic). Seven supercharged MDT tests also fall below the hydrostatic. Given the high proportion of MDT tests exhibiting supercharging, it is possible that subtle underpressure has been missed in nearby wells.

7325/1-1 – Atlantis (Gas Discovery)

The 7325/1-1 well, drilled by Equinor (then Statoil), encountered gas in the Snadd Formation whilst the shallower Stø Formation was water wet with residual oil shows (Schlumberger, 2014c; Norwegian Petroleum Directorate Factpages, 2019). Ten meters of gas was proven in the Snadd Formation at 1547.5 m MD but poor reservoir quality meant further hydrocarbons could not be proven or ruled out (Norwegian Petroleum Directorate Factpages, 2019). The Stø Formation is normally pressured, but the Snadd Formation is underpressured by at least 50 bar at 1515 m TVDss. Pressure points shallower than 1400 m TVDss exhibit supercharging, so true reservoir pressures are likely lower in reality and may form a gas gradient.

The fact that the greatest magnitude of underpressure here occurs in the gas leg can be interpreted in two ways. It could be indicative of fluid cooling as gas is much more compressible than water or oil. Alternatively, it could be argued that because gas is more mobile, it is preferentially drawn into the underpressured zones. This highlights the importance of analyzing the occurrences of underpressure in a holistic and regional context.

Discussion

Adjustment times and lateral flow modelling

For an anomalous pressure (low or high) generated by a past perturbation, the time that such pressure can sustain in disequilibrium with the surroundings essentially depends on the system's ability to equilibrate or adjust to present conditions. Quantitatively speaking, the adjustment time can be approximated by the following equation:

$$t_a = l^2 \times S_s \times K^{-1}$$

where t_a is the adjustment time in years, l is half of the length of the anomalously pressured region in meters, S_s is the specific storage in 1/meters, and K is the effective hydraulic conductivity in meters per year (Neuzil, 2012).

Specific storage here is largely controlled by rock compressibility for which we used values in the reservoir interval ranging from 7×10^{-10} to 7×10^{-8} Pa^{-1}, based on common estimates for tight fractured rocks (Domenico and Mifflin, 1965; Domenico and Schwartz, 1998; Fitts, 2002; Singhal and Gupta, 2010). Hydraulic conductivity is predominantly controlled by permeability. For the reservoir intervals we use measured data shown in Table 3. For the shale intervals, where no permeability data is available, we used a range of values from the analogous Pierre Shale (western United States) which has been relatively well studied in this respect (Bredehoeft et al., 1983; Neuzil, 1993).

For the underpressured system beneath Adventdalen, Svalbard, we considered that pressure equilibration occurs either along the strata towards the outcrop beneath the fjord ~ 15 km away or through the overlying formation, depending on which route is fastest. For the nonoutcropping Fingerdjupet subbasin and Greater Hoop area, we calculated for vertical equilibration only. Some estimates of these vertical adjustment times and controlling properties are shown in Table 4.

We simulated lateral pressure equilibration times through the Wilhelmøya Subgroup-De Geerdalen reservoir using MODFLOW (McDonald and Harbaugh, 1988) in the groundwater modelling software GMS v10.4 (AQUAVEO™, 2019). The model domain comprises a 15 km long, horizontal 1-D grid consisting of 150 cells each with a width of 100 m and a height of 400 m. The modelled groundwater system was assumed confined (no dry cells allowed) and the elevation 0 m was assumed to represent hydrostatic equilibrium. All outer boundaries were no-flow conditioned except the outermost cell in one of the ends, which was assigned with a fixed hydrostatic pressure. All other cells were assigned a starting hydraulic head corresponding to an underpressure of 55 bar. A series of sensitivity scenarios were run to show the impact of variations in specific storage and hydraulic conductivity (Figure 9).

We ran three scenarios (Table 5) to capture the range of geological possibilities at the site (Figure 10). The fastest equilibrium case represents fracture dominated flow at temperatures of 25 degrees C through very incompressible rock. The mid, and reference, case is based on measured bulk average matrix permeability and porosity with flow occurring at 2° C. The long case uses the lowest measured permeability and highest measured porosity values from the drillcore (Farokhpoor et al., 2014) as these represent potential cemented zones which may occur laterally from the wellbore.

The large range in equilibration times shows the challenges of modelling such a heterogeneous reservoir. The longest equilibration case is based on the lowest measured permeabilities and highest porosities; this combination is extremely unlikely to exist in reality and to pervade from the wellbore to outcrop. The low case is more feasible as water injection tests showed flow through fractures (Mulrooney et al., 2019), however these injection tests were carried out in excess of 100 bar (UNIS CO_2 Lab AS, 2015 and references therein; Mulrooney et al., 2019) causing the reopening or formation of fractures. The mid case probably reflects the most likely flow conditions but still does not fully incorporate the complexity of the system, e.g. changes with fractures as pressures equilibrate and the variation of temperature with depth.

On Svalbard, because of the relatively long equilibration times it is not feasible that any past or ongoing hydrological processes can explain the observed severe underpressure. In contrast, a past geological forcing event inducing anomalous pressure may still influence the present system. Vertical adjustment times in the Greater Hoop area also indicate a geological forcing event over the past tens to hundreds of thousands of years. The Fingerdjupet subbasin may retain abnormal pressures for an event up to tens of millions of years in past, due to the very thick, low-permeability caprock and sealing basin-bounding faults.

Presence of underpressure

In Svalbard underpressure has not been observed in historical exploration wells and its presence in the wells of the Longyearbyen CO_2 Lab came as a surprise. It could be that the underpressure occurrence is somewhat isolated and dependent on burial history and uplift, which varies significantly throughout Svalbard and the Barents Sea (Braathen et al., 1995; Dimakis et al., 1998; Henriksen et al., 2011). Alternatively, it is possible that previous wells in Svalbard simply did not observe underpressure due to the lack of any direct pressure tests on the Jurassic or Triassic reservoirs and their extremely low permeabilities. Notably the persistent pressure monitoring in the Longyearbyen CO_2 Lab wells was taken over long timescales in static shut-in wells which also enabled fluid losses, the same would be unlikely to be observed in the hydrocarbon exploration wells.

In the Greater Hoop area the Jurassic Stø Formation is shallow, permeable and well-plumbed in the area, resulting in it being normally pressured (Klausen et al., 2018). Underpressure is observed in the Snadd Formation in two wells some 50 km apart. However, both of these wells are located immediately adjacent to other wells that encountered hydrostatic pressure in the same intervals. The Stø Formation is highly permeable (Table 3), well-connected, and sits at very shallow depths in the Greater Hoop area, resulting in hydrostatic pressures.

The formations crop out extensively along the coastline and beneath Adventfjorden (and Isfjorden) approximately 15 km to the northwest. Critically, there is no evidence of a major lateral pressure seal, with outcrop locations matching the subtle regional dip (Major and Nagy, 1972; Ogata et al., 2014). Strontium isotope analysis by Huq et al. (2017) indicates the lack of lateral seal between drill site 1 and drill site 2 (Figure 7), in the Longyearbyen CO_2 Lab. It is likely that the very low permeability reservoirs restrict flow and help maintain the below hydrostatic pressures.

Similarly, the Greater Hoop area does not demonstrate clear evidence of lateral seals and the Snadd Formation reservoir has very low permeability. The isolated occurrences of underpressure in the Snadd Formation likely occur due to the reservoir connectivity and permeability or due to local variations in the mechanism causing underpressure.

Whilst the Stø Formation is normally pressured in the Greater Hoop area, it is underpressured in all wells of the Fingerdjupet subbasin. The Stø Formation is of poor reservoir quality in the central and western parts of the basin but comparatively good in the east (Table 3). The bounding faults of the Fingerdjupet subbasin (Serck et al., 2017) may act as effective pressure seals.

It is important to note that evidence of underpressure is not confined to the reservoir intervals but also likely extends into the cap rock. Well 7321/7-1 in the Fingerdjupet subbasin experienced major mud losses in 800 m of predominantly claystone caprock (Anadrill-Schlumberger, 1988). As the section was drilled using seawater and gel, the pressure must have been below hydrostatic to cause such losses into the formation. Complications from this lost circulation resulted in the section taking some 92 days to complete. It also highlights the presence of zones within the interval of sufficient permeability to allow flow of significant quantities of drilling fluid into the formation.

Cause of underpressure

Underpressure caused by hydrocarbon production and subsequent depletion is relatively common and well documented (Teufel et al., 1991; Lee and Wattenbarger, 1996; Addis, 1997;

Hillis, 2001). Naturally occurring underpressure in petroleum provinces, caused by geological perturbations, is relatively poorly understood.

Natural underpressure can exist in either equilibrated or disequilibriated systems (Neuzil, 1995). Equilibrated systems occur due to their present geological surroundings, such as areas with downdip outflow at lower elevations as observed in the Western Great Artesian Basin in Australia (Love et al., 2013). Disequilibriated systems cannot be explained by present day settings and have been caused by “geological forcing” (Neuzil, 1995; Neuzil, 2015) in the past and are still in the process of equilibrating to hydrostatic. Underpressure in petroleum provinces is more often attributed to systems in disequilibrium because they are typically deeper and protected from the effects of groundwater flow.

While the normal compaction of shales and their propensity to produce overpressure is relatively well understood (Swarbrick and Osborne, 1998; Swarbrick et al., 2001), how they may decompact, dilate or fracture during uplift is poorly studied. Nevertheless, severe underpressure in ultralow permeability shale and marls (Neuzil, 1993; Neuzil and Provost, 2014; Vinard, 1999) in recently uplifted areas is evidence of this mechanism in effect. Reservoir intervals become underpressured as the decompacting shale seal draws fluid from the reservoir leaving them both underpressured. In the reservoir interval it is possible that dissolution increases the pore space without increasing fluid volume (Neuzil, 1995).

Cooling is typically documented as a cause for underpressure in hydrocarbons rather than water due to the small volume change cooling has on water (Corbet and Bethke, 1992). In basin-centered gas systems the downdip gas leg is typically abnormally pressured with the updip aquifer being normally pressured (Law, 2002; Law and Dickinson, 1985).

Differential water flow is proposed to occur where a regionally dipping and vertically sealed reservoir has a lower rate of meteoric recharge in the updip outcrops as it does in the downdip discharge area (Nelson and Gianoutsos, 2011; Nelson et al., 2015).

Although termed the "hydrostatic" gradient, in reality on geological timescales it is very dynamic. Because of this, hydraulic pressures in the subsurface are likely to be out of equilibrium when the hydrostatic gradient changes. This is particularly the case where the reservoir is well sealed and hydraulic pressures dissipate slowly. Changes in the hydrostatic gradient may for example relate to changes in the water table or sea level, or changes in salinity (e.g. influx of meteoric or seawater).

Cooling related to uplift has occurred throughout the Cenozoic in the Barents shelf. As previously mentioned, cooling is likely to influence hydrocarbons rather than water. In Svalbard and the Fingerdjupet subbasin underpressures are observed in aquifers and, the magnitude, are unlikely to have been caused by cooling. In the Greater Hoop area, the greatest magnitude of underpressure occurs in gas bearing channelized sandstones and has likely been influenced by cooling. An alternative hypothesis is that gas is more mobile and thus may have migrated into the low permeability underpressured interval.

Sea-level rise accompanies deglaciation and may generate underpressure on any reservoirs below sea level, as is the case in all wells of our study area. Hydrostatic gradients in our study are based on present-day sea levels. As sea-level rise is much faster than sea-level fall (Landvik et al., 1998) it can leave subsurface pressures out of equilibrium. Poorly connected reservoirs with a rigid pore framework are more likely to be out of equilibrium with present-day hydrostatic gradients. During sea-level rise the maximum magnitude of underpressure generated is the same as the hydrostatic gradient, typically 0.1007 bar/m.

Underpressure formed by fluid shrinkage and sea-level rise should result in equal magnitudes of underpressure regardless of location. It may simply represent the different degrees to which underpressure has equilibrated back to hydrostatic pressure. An increase in pore volume can explain the differences in underpressure as numerous factors will influence the magnitude. This includes the initial reservoir properties, the lateral and vertical connectivity, and the pore volume increase in the lithology where the increase occurs. In Svalbard fractures have reopened due to recent uplift (Ogata et al., 2014; Van Stappen et al., 2018). It is likely that they both contribute towards a pore volume increase in the reservoir and shales. In addition, they may enhance vertical connectivity into the decompacted and fractured top seal.

The formation of permafrost may contribute to forming underpressure. Dobrynin and Serebryakov (1989) suggest that the formation of permafrost results in the hydrostatic gradient beginning at the base of the permafrost. Subsequent thawing of the permafrost hypothetically leaves the paleohydrostatic pressure out of equilibrium. However, we do not observe hydrostatic pressures beginning at the base-permafrost in Svalbard or in other parts of the world where thick permafrost persists (Osterkamp and Payne, 1981; Kamath et al., 1987; Majorowicz and Hannigan, 2000). If this were true it would render drilling without loss of well control impossible in much of the prolific petroleum provinces of the North American Arctic. Furthermore, as the majority of water in permafrost remains in situ, hydrostatic equilibrium would be achieved immediately during thawing. In reality, permafrost likely contributes to underpressure to a minor extent due to the volume increase and expulsion of water during formation and slightly reduced hydrostatic gradient. Subsequent thawing can lead to minor underpressures with a maximum magnitude of 0.011 bar per meter (0.049 psi per foot) of permafrost thickness.

Table 6 summarizes the geological feasibility of every proposed mechanism of underpressure generation. There may be contributions from multiple mechanisms in the formation of underpressure. However, the likely dominant mechanism that consistently explains the development of underpressure throughout the study area is unloading and fracturing. Fracturing is prevalent in both the cap rock and reservoir, but the lower connected pore volume prior to decompaction and its much greater thickness in the shale it is more sensitive to such changes pore volume increase. The shale interval is more likely to also elastically decompact (Neuzil and Pollock, 1983). Underpressure exists in the cap rock in Svalbard and the Fingerdjupet subbasin (Anadrill-Schlumberger, 1988). Further evidence of fluid mixing in the cap rock from isotope data (Huq et al., 2017) also suggests this mechanism. Whether caused by elastic dilation of the shales or the reopening of fractures, underpressure has most likely been caused by glacial cycles and deglaciation. Figure 11 shows the mechanism whereby fluids are initially removed from the system by glacial build-up, and then relatively rapid deglaciation causes the decompacted shales to draw fluids from adjacent reservoirs. Fluid cannot infiltrate the voids created at fast enough rates to reach hydrostatic equilibrium due to the extremely low reservoir permeability. There was likely a further minor contribution to underpressuring due to sea level rise, permafrost formation and thawing, and fluid cooling on the order of a few bar for each process.

Implications of underpressure

The potential implications and impacts underpressure can have on the petroleum system are illustrated in Figure 12. The most immediate threat underpressure poses is to drilling. Underpressure in the formation means pressure in the wellbore is always higher (or overbalanced) which can lead to drilling mud losses into the formation (Majidi et al., 2008). If drilling fluid losses are at a high rate it can lead to loss of well control. The same process can also lead to differential sticking of the drill pipe which, in the worst case, may result in the drill string needing to be cut. Drilling fluid entering the formation can also lead to formation damage (Jilani et al., 2002) and can complicate petrophysical logging and potentially lead to missed pay (Ceyhan et al., 2016). Underpressure in the reservoir will also impact the storage potential and phase of any injected gas, such as carbon dioxide, into the reservoir (Baklid et al., 1996).

Underpressure in the top seal also poses a significant risk to drilling, particularly in fractured or faulted zones where flow can occur. As underpressure cannot be countered by adjusting the drilling mud density below that of water, we recommend using high viscosity or clay-modifying drilling muds through such zones. Problems during well drilling for the Longyearbyen CO_2 Lab led to the successful application of potassium chloride (KCl) saturated mud while drilling through a detachment zone in the Jurassic shales. Pressure differences influence fluid flow pathways. If underpressure generation coincides with fluid migration, then it can influence both the lateral and vertical migration direction. Due to the similar influencing mechanisms it is feasible that underpressure generation occurred at a time of tertiary migration in the study area (Ohm et al., 2008) which adds further complication to migration models. Similarly, pressure differences can lead to tilted hydrocarbon contacts, particularly in low permeability reservoirs (Dennis et al., 2005).

Pressure differences are often used to ascertain fluid communication through stratigraphy or faults (Smith, 1980). In a typical hydrocarbon province lateral or vertical relative pressure differences would lead to the inference of seal between them. However, in the case of the Barents Sea, underpressure has developed geologically recently and is nonuniformly distributed. Using simple pressure differences as evidence of long-term sealing is challenged because of this, particularly in the low-quality reservoirs of the Barents shelf,

The occurrence of underpressure in the top seal may result in a reduction of its sealing potential in terms of both its fracture pressure (Hillis, 2000) and the capillary entry pressure, and should be taken into account during any seal analysis together with the fluid pressures in the bounding formations (Ingram et al., 1997). In the Barents Sea this may be important in the retention of commercially viable oil and leakage of economically unviable gas (Clayton and Hay, 1994; Zolotukhin et al., 2015).

Conclusions

The unique geological setting of the northwestern Barents shelf has resulted in underpressure being encountered both onshore Svalbard and in the offshore petroleum province in the correlatable Jurassic and Triassic formations. In Svalbard the underpressured seal and reservoir section is also exhumed to enable direct geological observation of the interval of interest. The main findings of this study are:

- Modelling and observations indicate underpressure has formed geologically recently
- Recent uplift has occurred here as with other cases of underpressure in petroleum provinces
- Underpressure should be anticipated and care should be taken drilling the Jurassic shale and sandstone intervals of the Fingerdjupet subbasin and Triassic intervals of the Greater Hoop area
- The greatest magnitudes of underpressure occur in low permeability intervals juxtapose thick shales
- Caution should be taken when using pressure differences as evidence for effective long-term seals
- Supercharging is a common effect of tight rocks in the study area and may equilibrate on timescales of days to years

Acknowledgements

This research is funded by the Research Centre for Arctic Petroleum Exploration (ARCEx) partners and the Research Council of Norway (grant number 228107). We sincerely appreciate data access to results from the Longyearbyen CO2 lab project (http://co2-ccs.unis.no) and to the DISKOS database. Ikon Science, Schlumberger and Cegal generously provided UNIS with academic licenses for RokDoc, Petrel and the Blueback Toolbox, respectively. We are grateful to Fridjtof Riis (NPD) and Alex Edwards (Ikon Science) for fruitful and insightful discussions and input. Finally, we appreciate the insightful and constructive comments from Hanneke Verweij, an anonymous reviewer and the editor Dr. Robert Merrill.

References

Abay, T., D. Karlsen, B. Lerch, S. Olaussen, J. Pedersen, and K. Backer-Owe, 2017, Migrated petroleum in outcropping Mesozoic sedimentary rocks in Spitsbergen: Organic geochemical characterization and implications for regional exploration: Journal of Petroleum Geology, v. 40, p. 5-36.

Addis, M., 1997, The stress-depletion response of reservoirs: SPE annual technical conference and exhibition, p. 11.

Anadrill-Schlumberger, 1988, End of Well (Drilling) Report. Well 7321/7-1, p. 351.

AQUAVEO™, 2019, Groundwater Modeling System 10.4.4.

Baig, I., J. I. Faleide, J. Jahren, and N. H. Mondol, 2016, Cenozoic exhumation on the southwestern Barents Shelf: Estimates and uncertainties constrained from compaction and thermal maturity analyses: Marine and Petroleum Geology, v. 73, p. 105-130.

Baklid, A., R. Korbol, and G. Owren, 1996, Sleipner Vest CO2 disposal, CO2 injection into a shallow underground aquifer: SPE Annual Technical Conference and Exhibition.

Belitz, K., and J. D. Bredehoeft, 1988, Hydrodynamics of Denver Basin: Explanation of subnormal fluid pressures: AAPG Bulletin, v. 72, p. 1334-1359.

Bergh, S. G., A. Braathen, and A. Andresen, 1997, Interaction of basement-involved and thin-skinned tectonism in the Tertiary fold-thrust belt of central Spitsbergen, Svalbard: AAPG Bulletin, v. 81, p. 637-661.

Berthelsen, O., 2019, APA 2019 - Large interest for the Norwegian Continental Shelf, *in* B. O., and T. C. CNagell, eds., Oslo, Norway, Norwegian Government Security and Service Organisation.

Betlem, P., K. Senger, and A. Hodson, 2019, 3D thermobaric modelling of the gas hydrate stability zone onshore central Spitsbergen, Arctic Norway: Marine and Petroleum Geology, v. 100, p. 246-262.

Braathen, A., K. Bælum, H. H. Christiansen, T. Dahl, O. Eiken, H. Elvebakk, F. Hansen, T. H. Hanssen, M. Jochmann, and T. A. Johansen, 2012, The Longyearbyen CO 2 Lab of Svalbard, Norway—initial assessment of the geological conditions for CO 2 sequestration: Norwegian Journal of Geology/Norsk Geologisk Forening, v. 92, p. 353-376.

Braathen, A., S. G. Bergh, and H. D. Maher, Jr, 1995, Structural outline of a Tertiary Basement-cored uplift/inversion structure in western Spitsbergen, Svalbard: Kinematics and controlling factors: Tectonics, v. 14, p. 95-119.

Braathen, A., S. G. Bergh, and H. D. Maher, Jr, 1999, Application of a critical wedge taper model to the Tertiary transpressional fold-thrust belt on Spitsbergen, Svalbard: Geological Society of America Bulletin, v. 111, p. 1468–1485.

Bredehoeft, J. D., C. Neuzil, and P. Milly, 1983, Regional flow in the Dakota aquifer: A study of the role of confining layers: US Geological Survey Water Supply Paper, v. 2237.

Brekke, H., H. I. Sjulstad, C. Magnus, and R. W. Williams, 2001, Sedimentary environments offshore Norway—an overview, Norwegian Petroleum Society Special Publications, v. 10, Elsevier, p. 7-37.

Cavanagh, A. J., R. Di Primio, M. Scheck-Wenderoth, and B. Horsfield, 2006, Severity and timing of Cenozoic exhumation in the southwestern Barents Sea: Journal of the Geological Society, v. 163, p. 761-774.

Ceyhan, A. G., M. Bravo, and K. Walrond, 2016, Supercharging Assessment in Formation Pressure Measurements Made While Drilling by Deliberately Pulsed Circulation in a Carbonate Reservoir: SPWLA 57th Annual Logging Symposium, p. 1-15.

Christiansen, H. H., B. Etzelmüller, K. Isaksen, H. Juliussen, H. Farbrot, O. Humlum, M. Johansson, T. Ingeman-Nielsen, L. Kristensen, and J. Hjort, 2010, The thermal state of permafrost in the Nordic area during the International Polar Year 2007–2009: Permafrost and Periglacial Processes, v. 21, p. 156-181.

Clayton, C., and S. Hay, 1994, Gas migration mechanisms from accumulation to surface: Bulletin of the Geological Society of Denmark, v. 41, p. 12-23.

Corbet, T. F., and C. M. Bethke, 1992, Disequilibrium fluid pressures and groundwater flow in the Western Canada sedimentary basin: Journal of Geophysical Research: Solid Earth, v. 97, p. 7203-7217.

Davis, T., 1984, Subsurface pressure profiles in gas-saturated basins: AAPG Memoir, v. 38, p. 189-203.

Dennis, H., P. Bergmo, and T. Holt, 2005, Tilted oil–water contacts: modelling the effects of aquifer heterogeneity: Geological Society, London, Petroleum Geology Conference series, p. 145-158.

Dickey, P. A., and W. C. Cox, 1977, Oil and gas in reservoirs with subnormal pressures: AAPG Bulletin, v. 61, p. 2134-2142.

Dimakis, P., B. I. Braathen, J. I. Faleide, A. Elverhøi, and S. T. Gudlaugsson, 1998, Cenozoic erosion and the preglacial uplift of the Svalbard–Barents Sea region: Tectonophysics, v. 300, p. 311-327.

Dobrynin, V., and V. Serebryakov, 1989, Geologic-Geophysical Methods of Predicting Abnormal Formation Pressures: Moscow, Russia, Nedra Publishing, 287 p.

Domenico, P., and M. Mifflin, 1965, Water from low-permeability sediments and land subsidence: Water Resources Research, v. 1, p. 563-576.

Domenico, P. A., and F. W. Schwartz, 1998, Physical and chemical hydrogeology, v. 506, Wiley New York.

Doré, A., and E. Lundin, 1996, Cenozoic compressional structures on the NE Atlantic margin; nature, origin and potential significance for hydrocarbon exploration: Petroleum Geoscience, v. 2, p. 299-311.

Dypvik, H., and V. Zakharov, 2012, Fine-grained epicontinental Arctic sedimentation–mineralogy and geochemistry of shales from the Late Jurassic-Early Cretaceous transition: Norwegian Journal of Geology/Norsk Geologisk Forening, v. 92, p. 65-87.

Eide, C. H., T. G. Klausen, D. Katkov, A. A. Suslova, and W. Helland-Hansen, 2017, Linking an Early Triassic delta to antecedent topography: Source-to-sink study of the southwestern Barents Sea margin: GSA Bulletin, v. 130, p. 263-283.

Elvebakk, H., 2010, Results of borehole logging in well LYB CO2, Dh4 of 2009, Longyearbyen, Svalbard, p. 35.

Faleide, J. I., S. T. Gudlaugsson, and G. Jacquart, 1984, Evolution of the western Barents Sea: Marine and Petroleum Geology, v. 1, p. 123-150.

Faleide, J. I., A. Solheim, A. Fiedler, B. O. Hjelstuen, E. S. Andersen, and K. Vanneste, 1996, Late Cenozoic evolution of the western Barents Sea-Svalbard continental margin: Global and Planetary Change, v. 12, p. 53-74.

Faleide, J. I., E. Vågnes, and S. T. Gudlaugsson, 1993, Late Mesozoic-Cenozoic evolution of the south-western Barents Sea in a regional rift-shear tectonic setting: Marine and Petroleum Geology, v. 10, p. 186-214.

Farokhpoor, R., E. G. B. Lindeberg, O. Torsæter, M. B. Mørk, and A. Mørk, 2014, Permeability and relative permeability measurements for CO2-brine system at reservoir conditions in low permeable sandstones in Svalbard: Greenhouse Gases: Science and Technology, v. 4, p. 36-52.

Fitts, C. R., 2002, Groundwater science: London, Elsevier, 467 p.

Gabrielsen, R. H., I. Grunnaleite, and E. Rasmussen, 1997, Cretaceous and tertiary inversion in the Bjørnøyrenna Fault Complex, south-western Barents Sea: Marine and Petroleum Geology, v. 14, p. 165-178.

Gautier, D. L., K. J. Bird, R. R. Charpentier, A. Grantz, D. W. Houseknecht, T. R. Klett, T. E. Moore, J. K. Pitman, C. J. Schenk, J. H. Schuenemeyer, K. Sørensen, M. E. Tennyson, Z. C. Valin, and C. J. Wandrey, 2009, Assessment of Undiscovered Oil and Gas in the Arctic: Science, v. 324, p. 1175-1179.

Gies, R. M., 1984, Case history for a major Alberta deep basin gas trap: the Cadomin Formation: AAPG Memoir, v. 38, p. 115 - 140.

Gjelberg, J., and R. J. Steel, 1995, Helvetiafjellet Formation (Barremian-Aptian), Spitsbergen: characteristics of a transgressive succession, Norwegian Petroleum Society Special Publications, v. 5, Elsevier, p. 571-593.

Glørstad-Clark, E., J. I. Faleide, B. A. Lundschien, and J. P. Nystuen, 2010, Triassic seismic sequence stratigraphy and paleogeography of the western Barents Sea area: Marine and Petroleum Geology, v. 27, p. 1448-1475.

Gradstein, F. M., E. Anthonissen, H. Brunstad, M. Charnock, O. Hammer, T. Hellem, and K. S. Lervik, 2010, Norwegian Offshore Stratigraphic Lexicon (NORLEX): Newsletters on Stratigraphy, v. 44, p. 73-86.

Gradstein, F. M., J. G. Ogg, M. Schmitz, and G. Ogg, 2012, The geologic time scale 2012, elsevier.

Grantz, A., P. E. Hart, and V. A. Childers, 2011, Geology and tectonic development of the Amerasia and Canada Basins, Arctic Ocean: Geological Society, London, Memoirs, v. 35, p. 771-799.

Haldorsen, S., M. Heim, and M. van der Ploeg, 2012, Impacts of climate change on groundwater in permafrost areas: case study from Svalbard, Norway: Climate Change Effects on Groundwater Resources: A Global Synthesis of Findings and Recommendations, p. 323-340.

Hao, X., J. Zhang, T. Dazhen, L. Ming, W. ZHANG, and L. Wenji, 2012, Controlling factors of underpressure reservoirs in the Sulige gas field, Ordos Basin: Petroleum Exploration and Development, v. 39, p. 70-74.

Henriksen, E., H. Bjørnseth, T. Hals, T. Heide, T. Kiryukhina, O. Kløvjan, G. Larssen, A. Ryseth, K. Rønning, and K. Sollid, 2011, Uplift and erosion of the greater Barents Sea: impact on prospectivity and petroleum systems: Geological Society, London, Memoirs, v. 35, p. 271-281.

Hillis, R., 2000, Pore pressure/stress coupling and its implications for seismicity: Exploration Geophysics, v. 31, p. 448-454.

Hillis, R. R., 2001, Coupled changes in pore pressure and stress in oil fields and sedimentary basins: Petroleum Geoscience, v. 7, p. 419-425.

Hinna, C. H., A. Escalona, B. Bryn, and S. Haaland, 2016, Seismic Characterization of Lower Cretaceous Clinoform Packages in the Fingerdjupet Sub-basin, Southwestern Barents Sea: 78th EAGE Conference and Exhibition 2016.

Hodson, A. J., A. Nowak, E. Holmlund, K. R. Redeker, A. V. Turchyn, and H. H. Christiansen, 2019, Seasonal dynamics of Methane and Carbon Dioxide evasion from an open system pingo: Lagoon Pingo, Svalbard: Frontiers in Earth Science, v. 30, p. 1-12.

Hornum, M. T., 2018, Postglacial Rebound, Permafrost Growth, and its Impact on Groundwater Flow and Pingo Formation, University of Copenhagen, Copenhagen, Denmark, 105 p.

Humlum, O., A. Instanes, and J. L. Sollid, 2003, Permafrost in Svalbard: a review of research history, climatic background and engineering challenges: Polar research, v. 22, p. 191-215.

Huq, F., P. C. Smalley, P. T. Mørkved, I. Johansen, V. Yarushina, and H. Johansen, 2017, The Longyearbyen CO2 Lab: Fluid communication in reservoir and caprock: International Journal of Greenhouse Gas Control, v. 63, p. 59-76.

Ingram, G., J. Urai, and M. Naylor, 1997, Sealing processes and top seal assessment, Norwegian Petroleum Society Special Publications, v. 7, Elsevier, p. 165-174.

Jensen, L., and K. Sørensen, 1992, Tectonic framework and halokinesis of the Nordkapp Basin, Barents Sea, Structural and tectonic modelling and its application to petroleum geology, Elsevier, p. 109-120.

Jilani, S., H. Menouar, A. Al-Majed, and M. Khan, 2002, Effect of overbalance pressure on formation damage: Journal of Petroleum Science and Engineering, v. 36, p. 97-109.

Kamath, A., S. Godbole, R. Ostermann, and T. Collett, 1987, Evaluation of the stability of gas hydrates in northern Alaska: Cold Regions Science and Technology, v. 14, p. 107-119.

Klausen, T. G., R. Müller, M. Poyatos-Moré, S. Olaussen, and E. Stueland, 2019a, Tectonic, provenance and sedimentological controls on reservoir characteristics in the Upper Triassic to Middle Jurassic Realgrunnen Subgroup–Southwest Barents Sea: Geological Society, London, Special Publications, v. 495, p. **25**.

Klausen, T. G., R. Müller, J. Slama, and W. Helland-Hansen, 2017, Evidence for Late Triassic provenance areas and Early Jurassic sediment supply turnover in the Barents Sea Basin of northern Pangea: Lithosphere, v. 9, p. 14-28.

Klausen, T. G., R. Müller, J. Sláma, S. Olaussen, B. Rismyhr, and W. Helland-Hansen, 2018, Depositional history of a condensed shallow marine reservoir succession: stratigraphy and detrital zircon geochronology of the Jurassic Stø Formation, Barents Sea: Journal of the Geological Society, v. 175, p. 130-145.

Klausen, T. G., B. Nyberg, and W. Helland-Hansen, 2019b, The largest delta plain in Earth's history: Geology, v. 47, p. 470-474.

Klausen, T. G., A. E. Ryseth, W. Helland-Hansen, R. Gawthorpe, and I. Laursen, 2014, Spatial and temporal changes in geometries of fluvial channel bodies from the Triassic Snadd Formation of offshore Norway: Journal of Sedimentary Research, v. 84, p. 567-585.

Koevoets, M., T. Abay, Ø. Hammer, and S. Olaussen, 2016, High-resolution organic carbon–isotope stratigraphy of the Middle Jurassic–Lower Cretaceous Agardhfjellet Formation of central Spitsbergen, Svalbard: Palaeogeography, Palaeoclimatology, Palaeoecology, v. 449, p. 266-274.

Koevoets, M., Ø. Hammer, and C. T. Little, 2019, Palaeoecology and palaeoenvironments of the Middle Jurassic to lowermost Cretaceous Agardhfjellet Formation (Bathonian-Ryazanian), Spitsbergen, Svalbard: Norwegian Journal of Geology, v. 99, p. 1-24.

Landvik, J. Y., S. Bondevik, A. Elverhøi, W. Fjeldskaar, J. Mangerud, O. Salvigsen, M. J. Siegert, J.-I. Svendsen, and T. O. Vorren, 1998, The last glacial maximum of Svalbard and the Barents Sea area: ice sheet extent and configuration: Quaternary Science Reviews, v. 17, p. 43-75.

Langrock, U., R. Stein, M. Lipinski, and H. J. Brumsack, 2003, Late Jurassic to Early Cretaceous black shale formation and paleoenvironment in high northern latitudes: examples from the Norwegian-Greenland Seaway: Paleoceanography and Paleoclimatology, v. 18, p. 19.1 - 19.16.

Lasabuda, A., J. S. Laberg, S.-M. Knutsen, and P. Safronova, 2018, Cenozoic tectonostratigraphy and pre-glacial erosion: A mass-balance study of the northwestern Barents Sea margin, Norwegian Arctic: Journal of Geodynamics, v. 119, p. 149-166.

Law, B., G. Ulmishek, and V. Slavin, 1998, Abnormal Pressure in Hydrocarbon Environments, Vol. 70: AAPG Memoir, Tulsa, p. 264.

Lazear, G. D., 2009, Fractures, convection and underpressure: hydrogeology on the southern margin of the Piceance basin, west-central Colorado, USA: Hydrogeology journal, v. 17, p. 641-664.

Lee, W. J., and R. A. Wattenbarger, 1996, Gas reservoir engineering: SPE Textbook Series, v. 5: Richardson, Texas, Society of Petroleum Engineers, 349 p.

Liu, G., and E. Roaldset, 1994, A new decompaction model and its application to the northern North Sea: First break, v. 12, p. 81-89.

Love, A. J., D. Worthing, S. Fulton, P. Rousseau-Gueutin, and S. De Ritter, 2013, Groundwater recharge, hydrodynamics and hydrochemistry of the Western Great Artesian Basin, v. 2: Canberra, Australia, National Water Commission, 264 p.

Mádl-Szőnyi, J., E. Pulay, Á. Tóth, and P. Bodor, 2015, Regional underpressure: a factor of uncertainty in the geothermal exploration of deep carbonates, Gödöllő Region, Hungary: Environmental Earth Sciences, v. 74, p. 7523-7538.

Magnabosco, C., A. Braathen, and K. Ogata, 2014, Permeability model of tight reservoir sandstones combining core-plug and Miniperm analysis of drillcore; Longyearbyen CO: Norwegian journal of geology, v. 94, p. 189-200.

Maher, H. D., Jr, 2001, Manifestations of the Cretaceous High Arctic Large Igneous Province in Svalbard: The Journal of Geology, v. 109, p. 91-104.

Majidi, R., S. Z. Miska, M. Yu, L. G. Thompson, and J. Zhang, 2008, Modeling of drilling fluid losses in naturally fractured formations: SPE Annual Technical Conference and Exhibition, p. 11.

Major, H., and J. Nagy, 1972, Geology of the Adventdalen map area: with a geological map, Svalbard C9G 1: 100 000.

Majorowicz, J., and P. Hannigan, 2000, Natural gas hydrates in the offshore Beaufort–Mackenzie basin—study of a feasible energy source II: Natural resources research, v. 9, p. 201-214.

Marshall, C., J. Uguna, D. J. Large, W. Meredith, M. Jochmann, B. Friis, C. Vane, B. F. Spiro, C. E. Snape, and A. Orheim, 2015, Geochemistry and petrology of palaeocene coals from Spitzbergen—Part 2: Maturity variations and implications for local and regional burial models: International Journal of Coal Geology, v. 143, p. 1-10.

McDonald, M. G., and A. W. Harbaugh, 1988, A modular three-dimensional finite-difference ground-water flow model, Techniques of Water-Resources Investigations, Book 6: Reston, Virginia, US Geological Survey, p. 2.5 - E.8.

Mørk, M. B. E., 1999, Compositional Variations and Provenance of Triassic Sandstones from the Barents Shelf: Journal of Sedimentary Research, v. 69, p. 690-710.

Mørk, M. B. E., 2013, Diagenesis and quartz cement distribution of low-permeability Upper Triassic–Middle Jurassic reservoir sandstones, Longyearbyen CO2 lab well site in Svalbard, Norway: AAPG Bulletin, v. 97, p. 577-596.

Mouchet, J.-P., and A. Mitchell, 1989, Abnormal pressures while drilling: origins, prediction, detection, evaluation, v. 2: Paris, France, Editions Technip.

Mulrooney, M. J., L. Larsen, J. Van Stappen, B. Rismyhr, K. Senger, A. Braathen, S. Olaussen, M. B. E. Mørk, K. Ogata, and V. Cnudde, 2019, Fluid flow properties of the Wilhelmøya Subgroup, a potential unconventional CO2 storage unit in central Spitsbergen: Norwegian Journal of Geology, v. 99, p. 85-116.

Nelson, P. H., N. J. Gianoutsos, and L. O. Anna, 2013, Outcrop control of basin-scale underpressure in the Raton Basin, Colorado and New Mexico: The Mountain Geologist, v. 50, p. 37-63.

Neuzil, C., 1993, Low fluid pressure within the Pierre Shale: a transient response to erosion: Water Resources Research, v. 29, p. 2007-2020.

Neuzil, C., 1995, Abnormal Pressures as Hydrodynamic Phenomena: American Journal of Sciences, v. 295, p. 742-786.

Neuzil, C., 2012, Hydromechanical effects of continental glaciation on groundwater systems: Geofluids, v. 12, p. 22-37.

Neuzil, C., and D. Pollock, 1983, Erosional unloading and fluid pressures in hydraulically" tight" rocks: The journal of geology, v. 91, p. 179-193.

Neuzil, C. E., 2015, Interpreting fluid pressure anomalies in shallow intraplate argillaceous formations: Geophysical Research Letters, v. 42, p. 4801-4808.

Norsk-Hydro, 1988, Final Report. Well 7321/8-1, p. 175.

Norsk-Hydro, 1989, Final Well Report. Well 7321/9-1, p. 125.

Norwegian Petroleum Directorate Factpages, 2019, Norwegian Petroleum Directorate Factpages, Stavanger, Norway, Norwegian Petroleum Directorate.

Nøttvedt, A., M. Cecchi, J. G. Gjelberg, S. E. Kristensen, A. Lønøy, A. Rasmussen, E. Rasmussen, P. H. Skott, and P. M. v. Veen, 1993, Svalbard-Barents Sea correlation: a short review, *in* T. O. Vorren, E. Bergsager, Ø. A. Dahl-Stamnes, E. Holter, B. Johansen, E. Lie, and T. B. Lund, eds., Arctic Geology and Petroleum Potential, v. NPF Special Publication 2: Amsterdam, Elsevier, p. 363-375.

Nyland, B., 2018, Announcement of Awards in Predefined Areas (APA) 2018, Stavanger, Norway, Norwegian Petroleum Directorate.

Nyland, B., L. Jensen, J. Skagen, O. Skarpnes, and T. Vorren, 1992, Tertiary uplift and erosion in the Barents Sea: magnitude, timing and consequences: Structural and Tectonic Modelling and its Application to Petroleum Geology, p. 153-162.

O'leary, N., N. White, S. Tull, V. Bashilov, V. Kuprin, L. Natapov, and D. Macdonald, 2004, Evolution of the Timan–Pechora and south barents sea basins: Geological Magazine, v. 141, p. 141-160.

Ogata, K., K. Senger, A. Braathen, J. Tveranger, and S. Olaussen, 2014, The importance of natural fractures in a tight reservoir for potential CO2 storage: a case study of the upper Triassic–middle Jurassic Kapp Toscana Group (Spitsbergen, Arctic Norway): Geological Society, London, Special Publications, v. 374, p. 395-415.

Ohm, S., L. Larsen, S. Olaussen, K. Senger, T. Birchall, T. Demchuk, A. Hodson, I. Johansen, G. O. Titlestad, D. A. Karlsen, and A. Braathen, 2019, Discovery of shale gas in organic-rich Jurassic successions, Adventdalen, Central Spitsbergen, Norway: Norwegian Journal of Geology, v. 99, p. 28.

Ohm, S. E., D. A. Karlsen, and T. Austin, 2008, Geochemically driven exploration models in uplifted areas: Examples from the Norwegian Barents Sea: AAPG Bulletin, v. 92, p. 1191-1223.

Olaussen, S., A. Dalland, T. Gloppen, and E. Johannessen, 1984, Depositional environment and diagenesis of Jurassic reservoir sandstones in the eastern part of Troms I area, Petroleum Geology of the North European Margin, Springer, p. 61-79.

Olaussen, S., G. B. Larssen, W. Helland-Hansen, E. P. Johannessen, A. Nøttvedt, F. Riis, B. Rismyhr, M. Smelror, and D. Worsley, 2018, Mesozoic strata of Kong Karls Land, Svalbard, Norway; a link to the northern Barents Sea basins and platforms: Norwegian Journal of Geology/Norsk Geologisk Forening, v. 98, p. 1-69.

Olaussen, S., K. Senger, A. Braathen, S. A. Grundvåg, and A. Mørk, 2019, You learn as long as you drill; research synthesis from the Longyearbyen CO2 Laboratory, Svalbard, Norway: Norwegian Journal of Geology, v. 99.

Osterkamp, T., and M. Payne, 1981, Estimates of permafrost thickness from well logs in northern Alaska: Cold Regions Science and Technology, v. 5, p. 13-27.

Person, M., D. Butler, C. W. Gable, T. Villamil, D. Wavrek, and D. Schelling, 2012, Hydrodynamic stagnation zones: A new play concept for the Llanos Basin, ColombiaGeohorizon: AAPG bulletin, v. 96, p. 23-41.

Polteau, S., B. W. Hendriks, S. Planke, M. Ganerød, F. Corfu, J. I. Faleide, I. Midtkandal, H. S. Svensen, and R. Myklebust, 2016, The Early Cretaceous Barents Sea sill complex: distribution, 40Ar/39Ar geochronology, and implications for carbon gas formation: Palaeogeography, Palaeoclimatology, Palaeoecology, v. 441, p. 83-95.

Puckette, J., and Z. Al-Shaieb, 2003, Naturally underpressured reservoirs: applying the compartment concept to the safe disposal of liquid waste: Southwest Section AAPG Convention.

Riis, F., and W. Fjeldskaar, 1992, On the magnitude of the Late Tertiary and Quaternary erosion and its significance for the uplift of Scandinavia and the Barents Sea: Structural and tectonic modelling and its application to petroleum geology, p. 163-185.

Rismyhr, B., T. Bjærke, S. Olaussen, M. Mulrooney, and K. Senger, 2019, Facies, palynostratigraphy and sequence stratigraphy of the Wilhelmøya Subgroup (Upper Triassic–Middle Jurassic) in western central Spitsbergen, Svalbard: Norwegian Journal of Geology, v. 99, p. 35-64.

Ryseth, A., 2014, Sedimentation at the Jurassic–Triassic boundary, south-west Barents Sea: indication of climate change: From Depositional Systems to Sedimentary Successions on the Norwegian Continental Margin, v. 187, p. 214.

Schlumberger, 2013, OMV (Norge) AS Wisting Alternative 7324/7-1 S 12.25in Section MDT Acquisition & Processing Report, p. 46.

Schlumberger, 2014a, MDT Pressures and Sampling- Field Print, Statoil, Apollo, 7324/2-1, p. 151.

Schlumberger, 2014b, OMV (Norge) AS Wisting 7324/7-2 8.5in Section MDT Acquisition & Processing, p. 357.

Schlumberger, 2014c, Statoil Atlantis 7325/1-1 12.25in and 8.5in Section MDT Acquisition & Processing Report, p. 162.

Schlumberger, 2014d, Statoil Isfjell 7220/2-1 8.5 in Section MDT Acquisition & Processing Report, p. 111.

Schlumberger, 2014e, Statoil Mercury 7324/9-1 8.5in Section MDT Acquisition & Processing Report, p. 177.

Schlumberger, 2014f, Statoil Pingvin 7319/12-1 12.25 in Section MDT Acquisition & Processing, p. 95.

Schlumberger, 2015, OMV Wisting 7324/8-2 8.5in Section MDT Acquisition and Processing Report, p. 54.

Schlumberger, 2016a, Eni Norge AS Exploration 7222/1-1 12.25in Section FPWD RM Report, p. 59.

Schlumberger, 2016b, ENI Norge AS Exploration 7222/1-1 12.25in Section XPT Acquisition & Processing Report, p. 59.

Scott, A. R., W. Kaiser, and W. B. Ayers Jr, 1994, Thermogenic and secondary biogenic gases, San Juan basin, Colorado and New Mexico--implications for coalbed gas producibility: AAPG Bulletin, v. 78, p. 1186-1209.

Senger, K., P. Brugmans, S.-A. Grundvåg, M. M. Jochmann, A. Nøttvedt, S. Olaussen, A. Skotte, and A. Smyrak-Sikora, 2019, Petroleum, coal and research drilling onshore Svalbard: a historical perspective: Norwegian Journal of Geology, v. 99, p. 1-30.

Senger, K., S. Planke, S. Polteau, K. Ogata, and H. Svensen, 2014, Sill emplacement and contact metamorphism in a siliciclastic reservoir on Svalbard, Arctic Norway: Norwegian Journal of Geology/Norsk Geologisk Forening, v. 94, p. 155-169.

Senger, K., J. Tveranger, A. Braathen, S. Olaussen, K. Ogata, and L. Larsen, 2015, CO2 storage resource estimates in unconventional reservoirs: insights from a pilot-sized storage site in Svalbard, Arctic Norway: Environmental Earth Sciences, v. 73, p. 3987-4009.

Serck, C. S., J. I. Faleide, A. Braathen, B. Kjølhamar, and A. Escalona, 2017, Jurassic to Early Cretaceous Basin Configuration(s) in the Fingerdjupet Subbasin, SW Barents Sea: Marine and Petroleum Geology, v. 86, p. 874-891.

Singhal, B. B. S., and R. P. Gupta, 2010, Applied hydrogeology of fractured rocks, Springer Science & Business Media.

Smelror, M., and G. B. Larssen, 2016, Are there Upper Cretaceous sedimentary rocks preserved on Sørkapp Land, Svalbard?: Norwegian Journal of Geology, v. 96, p. 1-12.

Smelror, M., O. Petrov, G. B. Larssen, and S. Werner, 2009, Geological history of the Barents Sea: Trondheim, Norway, Geological Survey of Norway (NGU), 135 p.

Smith, D. A., 1980, Sealing and nonsealing faults in Louisiana Gulf Coast salt basin: AAPG Bulletin, v. 64, p. 145-172.

Sorenson, R. P., 2005, A dynamic model for the Permian Panhandle and Hugoton fields, western Anadarko basin: AAPG bulletin, v. 89, p. 921-938.

Stordal, T., 2018, Resource Report, Exploration, 2018, p. 38.

Swarbrick, R., and M. Osborne, 1998, Mechanisms that generate abnormal pressure: an overview: AAPG Memoir, v. 70, p. 13-43.

Teufel, L. W., D. W. Rhett, and H. E. Farrell, 1991, Effect of reservoir depletion and pore pressure drawdown on in situ stress and deformation in the Ekofisk field, North Sea: The 32nd US Symposium on Rock Mechanics (USRMS), p. 10.

Titlestad, G. O., 2012, UNIS CO2-lab AS Program for Water injection test in well DH7a, p. 38.

Tóth, J., 2009, Gravitational Systems of Groundwater Flow: Theory, Evaluation, Utilization: Cambridge, UK, Cambridge University Press.

Tveranger, J., K. Senger, and O. Pettersen, 2014, Final Report, WP 5 Flow Predictability, 2012-2013, p. 61.

UNIS CO_2 Lab AS, 2015, Longyearbyen CO_2 lab - Phase II Final Report, v. Report 2010-02, http://co2-ccs.unis.no/Pdf/Longyearbyen%20CO2%20lab%20Phase%202%20Report_10_2015.pdf, p. 86.

Van Stappen, J. F., R. Meftah, M. A. Boone, T. Bultreys, T. De Kock, B. K. Blykers, K. Senger, S. Olaussen, and V. Cnudde, 2018, In situ triaxial testing to determine fracture permeability and aperture distribution for CO2 sequestration in Svalbard, Norway: Environmental science & technology, v. 52, p. 4546-4554.

Wangen, M., A. Souche, and H. Johansen, 2016, A model for underpressure development in a glacial valley, an example from Adventdalen, Svalbard: Basin Research, v. 28, p. 752-769.

Weatherford, 2017, Core Analysis Well: 7222/1-1, Client: Eni Norge AS, Country:Norway, Field:Exploration, Well:7222/1-1 (Aurelia), p. 95.

Worsley, D., 2008, The post-Caledonian development of Svalbard and the western Barents Sea: Polar Research, v. 27, p. 298-317.

Xie, X., J. J. Jiao, Z. Tang, and C. Zheng, 2003, Evolution of abnormally low pressure and its implications for the hydrocarbon system in the southeast uplift zone of Songliao basin, China: AAPG bulletin, v. 87, p. 99-119.

Zolotukhin, A., F. Mellemvik, A. Bourmistrov, I. Overland, A. Bambulyak, and O. Gudmestad, 2015, Barents Sea oil and gas 2025: Three scenarios, *in* A. Bourmistrov, A. Zolotukhin, F. Mellemvik, I. Overland, A. Bambulyak, and O. Gudmestad, eds., International Arctic Petroleum Cooperation: Barents Sea Scenarios: London, UK, Routledge.

Vitae

Thomas Birchall – Department of Geoscience, University of Oslo, Blindern, Oslo, Norway & University Centre in Svalbard, Svalbard, Norway; Thomas.birchall@unis.no

Tom Birchall is a PhD fellow in at the University of Oslo and based at UNIS in Svalbard. He works on pore pressure regimes of the Barents shelf. He holds an MSc in Petroleum Geoscience from Aberdeen University and a BSc from Durham, UK. He most recently worked as an exploration geologist with Maersk Oil in Aberdeen, Houston and Copenhagen.

Kim Senger – Department of Arctic Geology, University Centre in Svalbard, Norway; kims@unis.no

Kim Senger holds a position of associate professor of Structural Geology and Basin Analysis at UNIS. He has PhD and MSc degrees from the Universities of Bergen and Tromsø, Norway, and BSc from the University of Otago, New Zealand. His current research interests include CO_2 sequestration, the impacts of igneous intrusions in petroleum environments, and integration of geophysical and petrophysical methods in hydrocarbon exploration.

Mikkel Toft Hornum – Department of Arctic Geology, University Centre in Svalbard, Norway & University of Copenhagen, Denmark; toftmikkel@gmail.com

Mikkel Toft Hornum is a research assistant at the University Centre in Svalbard. He holds an MSc in Geology from The University of Copenhagen where he is due to start a PhD position at the University of Copenhagen in early 2020. His research interest is on sub-permafrost groundwater systems and periglacial hydrology using numerical transport and inverse hydrogeochemical modelling.

Snorre Olaussen – University Centre in Svalbard, Norway; Snorre.olaussen@unis.no

Snorre Olaussen holds a position of Professor in Arctic Petroleum Geology at UNIS. He holds a PhD from the University of Bergen in 1984 and spent more than 30 years as an exploration geologist at Equinor, Saga Petroleum and Eni. His main interests are petroleum geology, carbonate and siliciclastic sedimentology, sequence stratigraphy and regional studies of the north Atlantic and circum-arctic.

Alvar Braathen – University of Oslo, Blindern, Oslo, Norway; Alvar.braathen@geo.uio.no

Alvar Braathen holds a position as a professor of structural geology at the University of Oslo, Norway. He received an MSc and PhD from the University of Tromsø, Norway. His Research focuses on the tectonics of sedimentary basins, covering extensional and compressional tectonics. His work includes rift-basin development, fault zone characterization and fold-thrust belt geology - all inspired by outcrop studies.