Salt remobilization timing and its impact on two Norwegian Continental Shelf organic-rich shale formations

James R Johnson[1], François Renard[1], and Nazmul Mondol[1,2]
Njord Centre, Department of Geosciences, University of Oslo, Norway[1]
Norwegian Geotechnical Institute[2]

Summary

Two world-class source rocks from the Norwegian North Sea and the Barents Sea, the Draupne Formation and the Hekkingen Formation, respectively, are compared through a variety of techniques to understand the impact that the timing of salt mobilization has had on the maturation and geomechanical characteristics of these formations. The more recent salt diapirism has had a relatively limited impact on the Draupne Formation for well 16/8-3 S when compared to the historical regional salt diapirism at play within the Barents Sea Hekkingen Formation around well 7125/1-1. Despite the similar depositional history, this marked difference in diagenetic history has played a significant role in the variation of both maturation and, subsequently, geomechanical parameters between these two areas. This has a critical impact on the behavior of these shales in terms of both sealing and source capacity.

Introduction

Within the oil and gas industry, the presence of salt can mark some of the most productive or prospective oil and gas provinces. Primarily found in rift basins and along passive margins, most salt basins are formed during the early post-rift phase (e.g., Smith, 2008). However, some are older than the main rifting phase. Within the North and Barents Seas studied here, the Permian salt is older than the subsequent Triassic and Jurassic rifting events. Salt can play a significant role in many parts of petroleum systems. Warren (2017) highlights that it is a potential seal, although it does sometimes leak. As salt geometries are altered, they can play a major role in the migration of hydrocarbons (Hindle, 1997). Finally, due to salt's thermal capacity, it can significantly alter the thermal gradient (Daniilidis and Herber, 2017). This alteration may result in hydrocarbon maturation occurring faster than it would have otherwise within organic-rich shale, a potential source rock. However, this effect may also have an impact on a shale's geomechanical properties influencing its quality as a potential seal (Johnson et al., 2019).

Due to salt's complex and pervasive relationship within the basins they inhabit, understanding the impact of salt mobilization timing is also critical to the energy transition. Specifically, 'grey hydrogen' is turned to 'blue hydrogen' when it is coupled with carbon capture and storage (CCS) (Rystad Energy, 2021). Understanding the thermal relationship that salt has with the maturation of shales, and subsequent alteration of geomechanical parameters is critical to understanding the role these shales may play for CCS systems. The present study demonstrates how two organic-rich shales share a similar depositional history but do not share a similar diagenetic evolution due to salt remobilization (Figure 1).

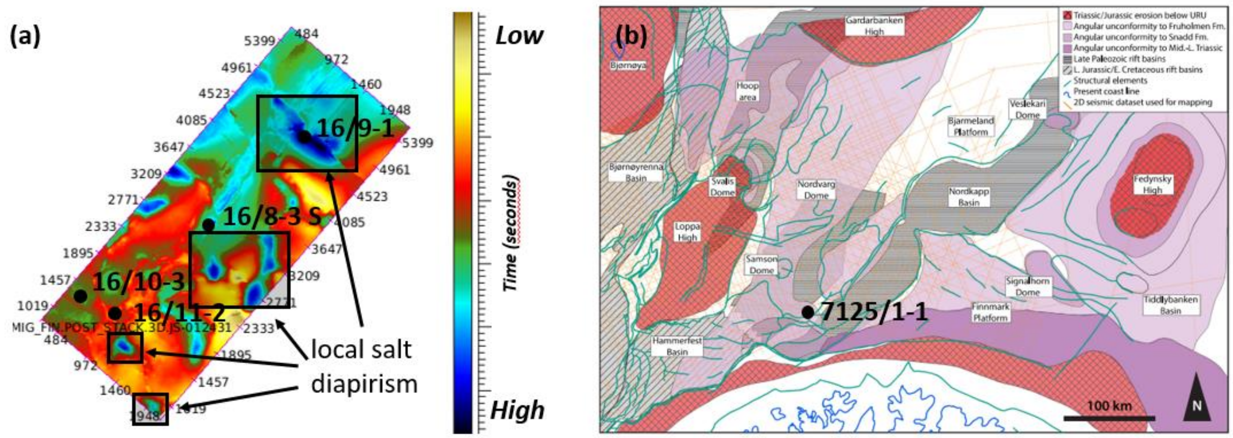

Figure 1 – (a) Recent local salt diapirism within the vicinity of well 16/8-3 S and other wells in the study area (modified from Johnson et al., 2019) and (b) Regional highs and lows resulting from historical salt diapirism with well location 7125/1-1 (modified from Muller et al., 2019).

Geological Background

Major salt deposition occurred in the Permian formations of the Norwegian Continental Shelf (NCS) for both the Norwegian North Sea and the Barents Sea (Gerard and Buhrig, 1990; Rossland et al., 2013). Subsequently, two major rifting events occurred during the Triassic and Jurassic in both regions (Dore et al., 1985; Faleide et al., 2008; Hansen et al., 2020). The coupling of the two rifting events, with a eustatic sea-level rise and the subsequent deep marine, anaerobic conditions, provided the requirements for the depositions of two organic-rich shale formations with predominantly Type II and II-S kerogen, the Draupne and Hekkingen Formations.

Comparing the mineralogy of the two rocks from a variety of sources, including this study, one can see that they are not vastly different in composition. For mineralogical content, both formations have clay content between 30 – 70%, quartz and feldspar content between 30 – 50%, and carbonate and pyrite content between 5 – 20 % (Figure 2). They also share similar contents in terms of clay minerals, with kaolinite representing 45 – 75%, smectite representing 5 – 25%, and Mica/Illite representing 15 – 35%. Chlorite is found in trace amounts (>1%) within the Draupne Formation and not within the Hekkingen Formation (Figure 2). Kerogen content is considered very high for both formations. Average kerogen values for the samples used in the present study, combined with those from earlier studies (Kalani et al., 2015; Skurtveit et al., 2015; Nooraiepour et al., 2017; Zadeh et al., 2017; Johnson et al., 2019; Hansen et al., 2020) within the local area are 8.5 wt. % for the Draupne and 12.2 wt.% for the Hekkingen. Interaction between the kerogen with the fabric of the non-organic component is seen for both formations in the SEM analysis at a range of scales (present study). These data further support a similar depositional history.

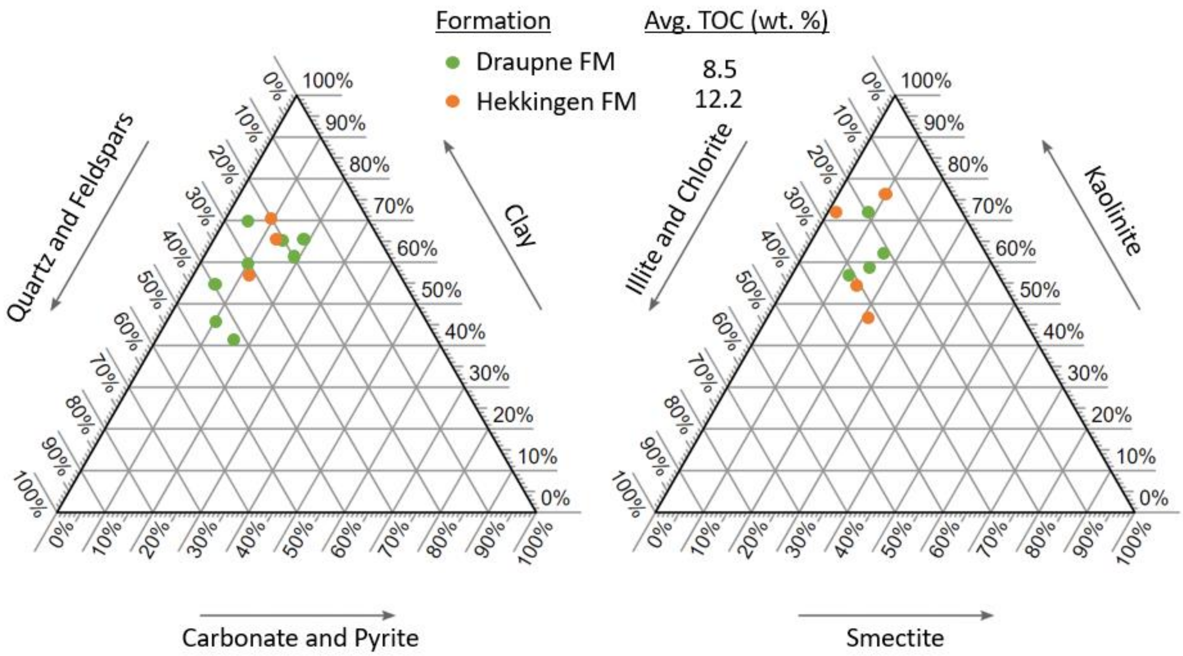

Figure 2 – Ternary diagrams are showing compiled bulk mineralogy and clay compositions for wells within the study area (Kalani et al., 2015; Skurtveit et al., 2015; Nooraiepour et al., 2017; Zadeh et al., 2017; Hansen et al., 2020; present study).

While both organic-rich shales were buried experiencing diagenesis, the Hekkingen Formation experienced significant subsequent uplift as the result of salt remobilization (Baig et al., 2016; Muller et al., 2019). Exhumation of the Hekkingen Formation in the Barents Sea is estimated to be between 0.4 – 3.0 km, coinciding with major erosional events (Henriksen et al., 2011; Baig et al., 2016). This did not occur in the same way for the Draupne Formation in the North Sea, with exhumation ranging from 0.0 – 0.7 km (Hansen et al., 2017; Baig et al., 2019). While the impact of salt diapirism on organic-rich shales can be seen in both the North Sea (Johnson et al., 2019) and the Barents Sea (present study), the difference in the geomechanical properties of the shales is profound.

Method

This study focuses on a 120 km area around two wells, 16/8-3S in the Norwegian North Sea and 7125/1-1 in the Barents Sea who penetrated the Draupne and Hekkingen Formations, respectively (red dots in Figure 3, left). These two formations are considered geologically equivalent in time (Figure 3, right). Nine wells penetrate the Draupne Formation, and five wells penetrate the Hekkingen Formation (red, yellow, and purple dots in Figure 3, left). These wells are used to establish broad geochemical and rock physics trends for their respective areas. The disparity between the numbers of wells used for the North Sea compared to the Barents Sea is explained by the presence of greater well data availability in the North Sea study area (NPD, 2021), as seen in Figure 3.

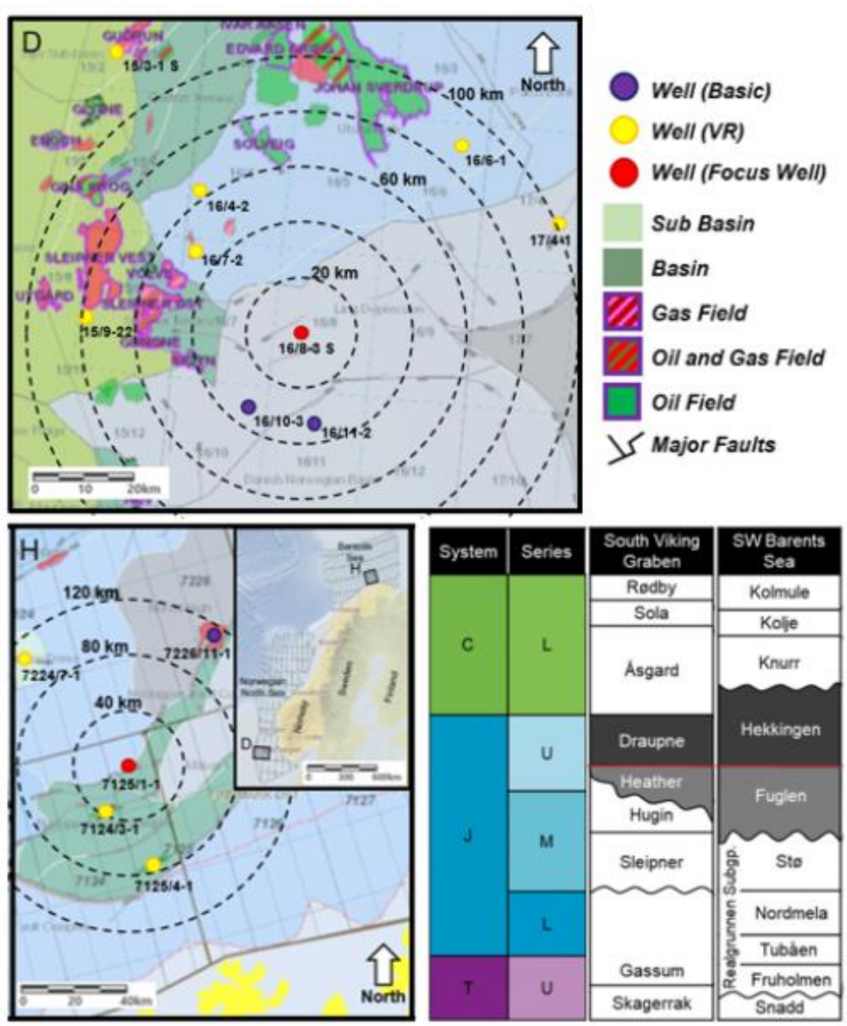

Figure 3 – Well locations (red, purple, and yellow dots) and data availability (D) with geological timing of the two organic-rich formations studied, Draupne (South Viking Graben) and Hekkingen (SW Barents Sea) (H). The inset shows a map of Scandinavia with the locations of the two maps shown on the left side of the figure. Modified from NPD (2021). Geological timing of the Draupne and Hekkingen Formations (bottom right)

Geochemical data are available through Rock-Eval measurements from thirteen of these wells, including Hydrogen Index (HI), Oxygen Index (OI), total organic carbon (TOC), S2, T_{max}, and vitrinite reflectance (R_o). The vitrinite reflectance (Ro) data provides the best proxy for maturation (Tissot and Welte, 1984) where available. However, there are notoriously fewer data points for R_o, many of which are unreliable for other geochemical types (NPD, 2021). Therefore, other crossplots quantify shale maturation, such as HI versus TOC (modified from Vernik and Landis, 1996). Kerogen type and its likely origin are ascertained using S2 versus TOC plot, while HI versus T_{max} (modified from Isaksen and Ledje, 2001) is used to confirm understanding of both kerogen type and maturation trends. This study also uses SEM and XRD analysis to compare the mineralogical makeup of the two formations. Furthermore, the relationship between the organic matter and the non-organic components of the formations is obtained utilizing SEM analysis.

Rock physics analysis carried out focuses on understanding the geomechanical parameters of the two formations. Perez and Marfurt (2014) proposed a rock physics template that explores the geomechanical parameters in terms of Young's Modulus (E) and Poisson's ratio (**υ**). These two parameters are calculated:

$$\upsilon = \frac{V_p^2 - 2V_s^2}{2V_p^2 - 2V_s^2} \quad (1)$$

$$\mathrm{E} = \rho V_s^2 \frac{3V_p^2 - 4V_s^2}{V_p^2 - V_s^2} \quad (2)$$

where, V_P is P-wave velocity, V_S is S-wave velocity, and ρ is bulk density obtained from well logs. This model was updated by Mondol (2018), who highlighted the critical nature the detailed composition of the shale has on these parameters utilizing compositional end-members (i.e., quartz, kerogen, clay, and carbonate). Johnson et al. (2019) further appended this model, highlighting a clear relationship between TOC content and the degree of maturation in terms of geomechanical parameters. This work Johnson et al. (2019) is extended to include wells from the Barents Sea, Hekkingen Formation in the present study.

Results

The Draupne and the Hekkingen Formations centered around wells 16/8-3 S and 7125/1-1 are compared utilizing a broad swathe of techniques. The study uses two wells that reached historically equivalent maximum depths and temperature regimes (Baig et al., 2016; Zadeh et al., 2017; Baig et al., 2019). In these two wells, results show that different levels of maturation produced various geomechanical parameters.

Analysis utilizing XRD and SEM have revealed that while there are differences, the Draupne and Hekkingen Formations are broadly similar in terms of organic and non-organic composition. Those differences include a typically slightly higher organic matter (OM) content for the Hekkingen Formation, confirmed by both geochemical and well log analysis (Figure 2). Additionally, the Draupne Formation shows a larger variation in mineralogical content for the categories clay, as well as quartz and feldspar (Figure 2). This seems to be due to the presence of feldspars more than quartz. Kaolinite content also appears to be typically higher in the Draupne Formation, with more Illite/Mica than in the Hekkingen Formation. These differences are also apparent looking at the SEM data. Furthermore, the interaction between organic matter and inorganic matter is readily visible. Clear soft-sediment deformation can be seen at multiple scales, while the association between frambroidal pyrite and kerogen lenses is abundant on some of the closer zooms in the SEM analysis.

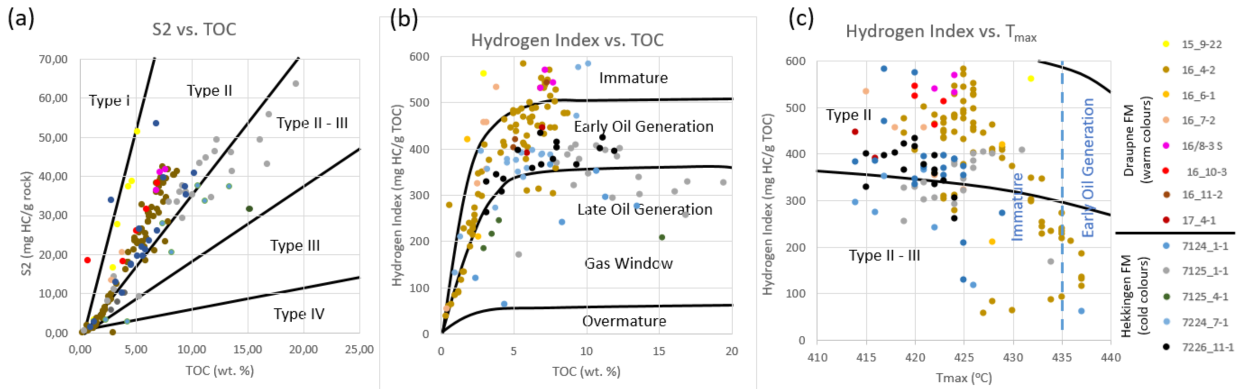

Figure 4 – Crossplots of geochemical data of the Draupne and Hekkingen formations. (a) S2 vs. TOC crossplot is used for discerning kerogen type. (b) Hydrogen Index (HI) vs. TOC is used for determining maturation. (c) Hydrogen Index vs. T_{max} is used for discerning both kerogen type and maturation. Dots are colored according to the well data it comes from.

Maturation levels of the two areas and kerogen type are obtained from the geochemical analysis. Crossplots of S2 versus TOC and HI versus T_{max} show that the predominant kerogen types are Type II and Type II-III (Figure 4a and 4c). Although the vitrinite reflectance (R_o) data was both limited and poor, the trends in the available data show a reasonable correlation with an R^2 value of 0.72 as defined by Equation 3:

$$R_o = \frac{d - 1259.6}{6985} \qquad (3)$$

where, R_o is vitrinite reflectance, and d is depth in meters. However, comparing the wells in the area shows that Hekkingen Formation appears to be typically more mature. This separation in maturation is visible in Figure 4b showing the crossplot of HI versus. TOC. Note the relative position of well 16/8-3 S in the immature window, while well 7125/1-1 has the majority of its data points in the early oil generation window. The difference in maturation is not as clear utilizing the crossplot of HI versus T_{max}. However, this seems broadly related to the data from well 16/4-2, with the other data generally agreeing with this trend. Again, note the relative position of the data from well 16/8-3 S compared to well 7125/1-1 (Figure 4c).

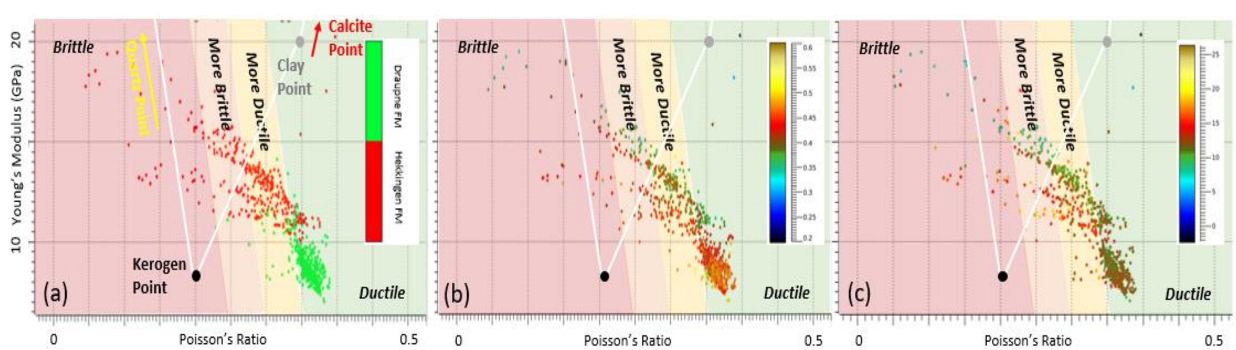

Figure 5 – Geomechanical analysis (modified from Perez and Marfurt, 2014) with salient end-member mineralogical points (modified from Mondol, 2018) of the (a) Draupne and Hekkingen Formations geomechanical parameters within the study areas compared with (b) porosity (%) and (c) TOC (wt. %).

Comparing the geomechanical parameters of the two areas utilizing all of the available wells, or just the two wells highlighted in this study, show the same trends. For simplicity, the template defined here focuses on the differences between wells 16/8-3 S and 7125/1-1. Utilizing a geomechanical rock physics template from Perez and Marfurt (2014), Young's modulus is displayed on the y-axis, and Poisson's ratio is displayed on the x-axis (Figure 5). The z-axis (color) in the three different panels displays the Draupne and Hekkingen Formation points (Figure 5a) in the two wells used in the present study (red points, Figure 3), porosity (Figure 5b), and TOC (Figure 5c). Porosity seems generally higher for the Hekkingen Formation than for the Draupne Formation. TOC values vary significantly for both formations, but one can see that the Hekkingen Formation shows general higher values than the Draupne Formation. Finally, one can see that the Draupne Formation plots predominantly in the ductile regime while the Hekkingen Formation plots predominantly in the transitionary regimes of more ductile and more brittle.

Discussion

The maturation of organic-rich shales is complex with a multitude of factors influencing it. Further to this, the sealing capacity of shales depends on more than just maturation, with temperature-pressure regime, mineralogy, shale fabric, TOC content, and more all playing a role (Johnson et. al., 2019; Rahman et al., 2020). However, the difference in both maturation and geomechanical parameters exhibited by the Draupne and Hekkingen Formations is significant given similar depositional history. The two main wells in this study, 16/8-3 S and 7125/1-1 have similar maximum depths and burial temperatures (Baig et al., 2016; Zadeh et al., 2017; Baig et al., 2019; present study). Slightly higher levels of TOC within the Hekkingen Formation may have assisted maturation, and specifically the changes in geomechanical parameters (Johnson et al., 2019). Vandenbroucke and Largeau (2007) suggest higher levels of TOC are associated with greater proportions of smectite and illite, which is seen in this study for the Hekkingen. Greater proportions of smectite and illite are also considered to make for a better seal (Mondol, 2007) which may revoke some of the maturation effects on the quality of the seal. So, while the proportion of hard to soft minerals and variations in clay mineralogy itself may have some influence on the different geomechanical responses, it is more likely that the subsequent diagenetic history played a larger role in the variation seen today.

The diagenetic history varied significantly between the two basins (Baig et al., 2016; Baig et al., 2019; Muller et al., 2019; Hansen et al., 2020). Proximity to the increased thermal capacity provided by salt mobilization would account for the maturation difference seen between the Draupne and Hekkingen Formations within the study areas. Indeed, Daniilidis and Herber (2017) highlight that the temperature gradient can be significantly altered by the presence of salt. The impact of the increased local temperature gradient can have an effect on the degree of maturation and the geomechanical parameters of the shales. Johnson et al. (2019) show this effect of salt locally within the Draupne Formation. However, the combination of both earlier, and potentially comparably prolonged exposure to increased thermal activity in the Hekkingen Formation (Muller et al., 2019) best accounts for the variation in geomechanical parameters.

Conclusion

Salt has a critical role in altering the geomechanical parameters of all rock it is exposed to. In the case of organic-rich shale, the maturation of kerogen lenses and fluid expulsion from them may cause the initial growth of microfractures. The subsequent fracturing as the microfractures expand and connect have a large influence on the shale's strength. Mineralogy and clay composition, in addition to TOC content, will have a role on how well the shale mechanical properties evolve with geological history in terms of being a potential seal. The comparison between the Draupne and Hekkingen formations shows how organic-rich shales with a similar depositional history may reach different levels of maturation and geomechanical states as the result of a varied diagenetic history.Variation in diagenetic history has an influence on the quality that the two formations have in terms of being considered as a potential source rock, or potential seal. In terms of CCS, the long-term influence of mineralogy, clay composition, and TOC content must be considered as the present geological state is bound to change.

Acknowledgements

We thank the Norwegian Research Council for providing funding through the Prometheus project Prometheus (RCN #267775). Further, thanks for the helpful conversations that are extended to Maya Kobchenko and Manzar Fawad. Data is made available through the public databases DISKOS (https://portal.diskos.cgg.com/whereoil-data/) and NPD (https://factpages.npd.no/en/wellbore). Academic software licenses have been provided by Lloyd's Register for Interactive Petrophysics, CGG for both Jason and Hampson-Russell, and Schlumberger for Petrel.

References

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

Baig, I., Faleide, J.I., Mondol, N.H., and Jahren, J., 2019, Burial and exhumation history controls on shale compaction and thermal maturity along the Norwegian North Sea basin margin areas, Marine and Petroleum Geology, vol. 104, pgs. 61 - 85

Daniilidis and Heber, 2017, Salt intrusions providing new geothermal exploration target for higher energy recovery at shallower depths, Energy, vol. 118, 658 – 670

Dore, A.G., Vollset, J. and Hamar, G.P., 1985, Correlation of the offshore sequences referred to the Kimmeridge Clay Formation – relevance to the Norwegian Sector, Petroleum Geochemistry in Exploration of the Norwegian Shelf, vol. 1, pgs. 27 - 37

Faleide, J.I., Tsikalas, F., Breivik, A.J., Mjede, R., Ritzmann, O., and Engen, O., 2008, Structure and evolution of the continental margin off Norway and the Barents Sea, vol. 31, pgs. 82 - 91

Gerard and Buhrig, 1990, Seismic facies of the Permian section of the Barents Shelf: analysis and interpretation, Marine and Petroleum Geology, vol. 7, pgs. 234 - 252

Hansen, J.A., Yenwongfai, H.D., Fawad, D., and Mondol, N.H., 2017, Estimating exhumation using experimental compaction trends and rock physics relations, with continuation into analysis of source and reservoir rocks: central North Sea, offshore Norway. SEG, vol. 2017, pgs. 3971 - 3975

Hansen, J.A., Mondol, N.H., Tsikalas, F., and Faleide, J.I., 2020, Caprock characterization of Upper Jurassic organic-rich shales using acoustic properties, Norwegian Continental Shelf, Marine and Petroleum Geology, vol. 121

Henriksen, E., Bjornseth, H.M., Hals, T.K., Heide, T., Kiryukhina,T., and Klovjan, O.S., 2011, Uplift and erosion of the greater Barents Sea: impact on prospectivity and petroleum systems, Arctic Petroleum Geology, vol. 25, pgs. 271 - 281

Hindle, A., 1997, Petroleum migration pathways and charge concentration: a three-dimensional model, AAPG Bulletin, vol. 81, pgs. 1451 - 1481

Isaksen, G.H., and Ledje, H.I., 2001, Source rock quality and hydrocarbon migration pathways within the greater Utsira High area, Viking Graben, Norwegian North Sea: AAPG Bulletin, vol. 85, pgs. 861 - 883

Johnson, J.R., Hansen, J.A., Renard, F., and Mondol, N.H., 2019, Modeling maturation, elastic, and geomechanical properties of the Draupne Formation, offshore Norway, SEG, vol. 2019, pgs. 3251 - 3401

Kalani, M., Jahren, J., Mondol, N.H., and Faleide, J.I., 2015, Petrophysical implications of source rock microfracturing, International Journal of Coal Geology, vol. 143, pgs. 43–67

Mondol, N.H., Bjorlykke, K., Jahren, J., and Hoeg, K., 2007, Experimental mechanical compaction of clay mineral aggregates – Changes in physical properties of mudstones during burial, Marine and Petroleum Geology, vol. 24, pgs. 289 - 311

Mondol, N.H., 2018, Seal quality prediction using E-Poisson's ratio rock physics template – A case study from the Norwegian Barents Sea: Geoconvention 2018

Muller, R., Klausen, T.G., Faleide, J.I., Olaussen, S., Eide, C.H., and Suslova, A., Linking regional unconformities in the Barents Sea to compression-induced forebulge uplift at the Triassic-Jurassic transition, Tectonophysics, vol. 765, pgs. 35 - 51

Nooraiepour, M., Mondol, N.H., Hellevang, H., and Bjørlykke, K., 2017, Experimental mechanical compaction of reconstituted shale and mudstone aggregates: investigation of petrophysical and acoustic properties of SW Barents Sea cap rock sequences. Marine Petroleum Geology, vol. 80, pgs. 265–292

NPD, 2021, Norwegian Petroleum Directorate Fact Pages, http://factpages.npd.no/factpages/

Perez, R., and Marfurt, K., 2014, Mineralogy-based brittleness prediction from surface seismic data: Application to the Barnett Shale: Interpretation, vol. 2, pgs. 1 – 17

Rahman, M.D.J., Fawad, M., and Mondol, N.H., 2020, Organic-rich shale caprock properties of potential CO2 storage sites in the northern North Sea, offshore Norway, Marine and Petroleum Geology, vol. 122

Rossland, A., Escalona, A., and Rolfsen, R., 2013, Permian-Holocene tectonostratigraphic evolution of the Mandal High, Central Graben, North Sea, AAPG Bulletin, vol. 97, pgs. 923 – 957

Rystad Energy, 2021, Energy Transition Webinar: Hydrogen – all hype, or a huge opportunity? March 4, 2021

Skurtveit, E., Grande, L., Ogebule, O.Y., Gabrielsen, R.H., Faleide, J.I., and Mondol, N.H., 2015, Mechanical testing and sealing capacity of the Upper Jurassic Draupne formation, North Sea, 49th US Rock Mechanics/Geomechanics Symposium Expanded Abstracts ARMA-2015-331. American Rock Mechanics Association, San Francisco, California

Vandenbroucke and Largeau, 2007, Kerogen origin, evolution, and structure, Organic Geochemistry, vol. 38, pgs. 719 - 833

Vernik, L., and Landis, C., 1996, Elastic anisotropy of source rocks – implications for hydrocarbon generation and primary migration: AAPG Bulletin, vol. 80, pgs. 531 – 544.

Warren, J.K., 2017, Salt usually seals, but sometimes leaks: Implications for mine and cavern stabilities in the short and long term, Earth-Science Reviews, vol. 165, pgs. 302 - 341

Zadeh, M.K., Mondol, N.H., and Jahren, J., 2017, Velocity anisotropy of Upper Jurassic organic-rich shales, Norwegian Continental Shelf: Geophysics, vol. 82, pgs. 61 – 75.