Modeling maturation, elastic, and geomechanical properties of the Draupne Formation, Offshore Norway

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Summary

Understanding shale's geomechanical and elastic properties is critical to success in conventional and unconventional plays. This understanding provides a framework for the safe extraction of hydrocarbons as well as a guide to mapping favorable source locations. The Upper Jurassic Draupne shale in the North Sea is a world class organic-rich source rock, a commendable seal for both hydrocarbon and possibly CO2, and potentially a future reservoir. As such, the Draupne Formation is an ideal candidate to study the modeling of maturation as they relate to both elastic and geomechanical properties.

Introduction

In order to understand how maturation interplays with elastic and geomechanical properties one must first understand the process of kerogen cracking as it relates to the formation of hydrocarbons within organic-rich shales. Maturation of organic-rich shales is driven by increases in temperature and pressure as burial depth increases, resulting in the decomposition of kerogen into low molecular weight hydrocarbon fluids (Kobchenko, 2011). The conversion of kerogen into hydrocarbon results in the creation of tensile fractures between lenses driving both horizontal and vertical fracturing (Texeira et al., 2017). Fracturing is cited as a likely mechanism to increase the permeability of shales providing pathways for the generated hydrocarbon (Lash and Engelder, 2005). The distribution of these kerogen lenses that could ultimately become hydrocarbon for the Draupne Formation can be seen in Figure 1.

Despite the broad ranging implications, applications, and importance of understanding shale and their maturation mechanics, assessment of these characteristics often do not contain enough data points (Badics et al., 2015). The Draupne Formation is an oil-prone shale ranging from immature to overmature with a maximum reported TOC of 20 wt.% as represented by the significant dataset shown here.

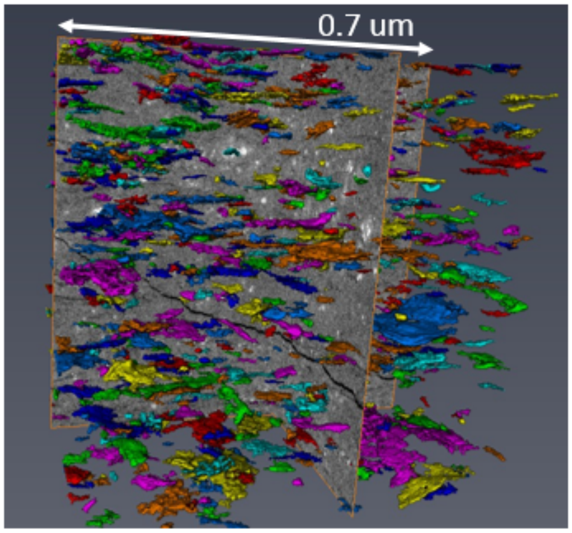

Figure 1 – 3D tomographical scanned image of the Draupne Formation from 16/8-3 S showing the distribution of kerogen lenses and their interaction with a local fracture

Method

Eleven exploration wells were available from a broad range of depths and maturities, with four of these wells located within a 3D seismic cube in the Norwegian North Sea (Figure 2). The data transects the Ling Depression, moves through the Utsira High, and into the Gudrun Terrace. Seven of these wells have been used to create a broad baseline for the maturation processes of the Draupne Shale Formation, while four wells and the seismic cube have been used to model the relationship that maturation has with both elastic and geomechanical parameters.

All eleven wells have basic petrophysical log suites, while two of the wells (16/8-3 S and 15/3-8) also have S-wave velocity data. Additionally all the wells have basic Rock-Eval pyrolysis data, with six of those wells also containing vitrinite reflectance (R_0). Four wells, including 16/8-3 S are inside of the 3D seismic cube providing a basis for the creation of both local maturation and geomechanical cubes. This was accomplished by first running a deterministic inversion in order to extract the necessary elastic parameters, and then using probability density functions

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(PDF's) in order to identify variation of maturation within the Draupne shale. The other seven wells provide a broader maturation and geomechanical framework within which to view the data.

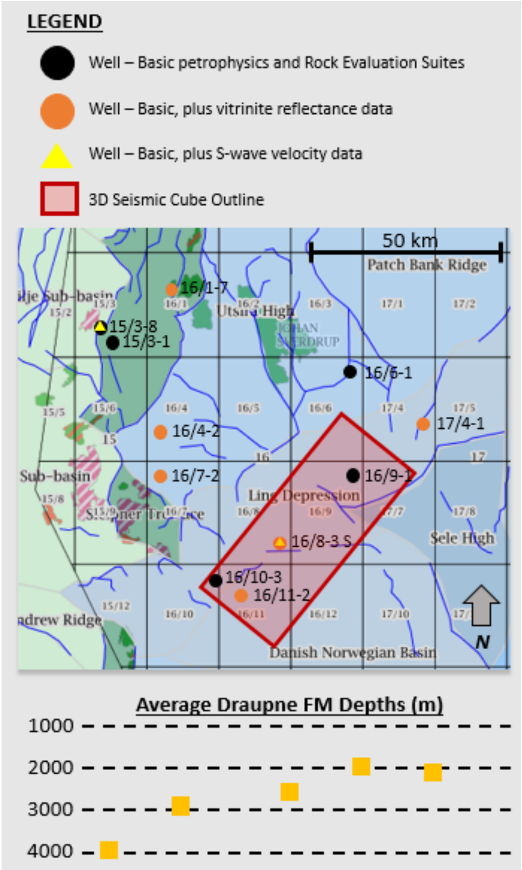

Figure 2 – Study area location outlining the seismic location, number of wells and availability of data. Map shows the study area, structural elements, and nearby fields

The maturation framework utilizes a broad range of analysis of the petrophysical and Rock-Eval data suites. For the seismic, maturation facies were defined utilizing a modified model of the relationship between total organic carbon (TOC) and Hydrogen Index (HI) put forth by Vernik and Landis (1996) which sought to model vitrinite reflectance (R_0) data. While both Passey's method (1990) and Schmoker's method (1979) were tested, Schmoker's method was found to deviate less from the TOC as measured from the Rock-Eval data. Geomechanical parameters were calculated for both wireline logs and seismic including Poission's ratio and Young's modulus. Poisson's ratio is calculated as follows:

$$\nu = \frac{V_p^2 - 2V_s^2}{2(V_p^2 - V_s^2)}$$

Where Vp and Vs are P-wave and S-wave velocity respectively. Young's modulus is calculated using the equation:

$$E = \rho V_E^2$$

Where V_E is a product of Vp and Vs, and ρ is density.

A comparison between the calculated geomechanical parameters and the maturation analysis reveals the relationship between them both regionally and locally.

Results and Discussion

The cracking of solid kerogen into the resulting hydrocarbons has a direct impact on the mechanical nature of shale (Vernik, 1994). Building an understanding of the maturation first allows one to frame the mechanical changes of the shale within that. Plotting Hydrogen Index (HI) against T_{max} shows that the Draupne Formation's kerogen is mainly Type II, with some Type III (Figure 3a) utilizing trends determined by Espitalie et al., (1985). In this area of the North Sea a clear, but broad relationship can be shown between depth and vitrinite reflectance (Figure 3b) with an R^2 value of 0.72. A comparison of the same relationship derived by Isaksen and Ledje (2001) for the Draupne Formation comprised similar results. Both of these plots show that maturation ranges from immature into the oil generation window, and begins to approach the gas window in places. Hydrogen Index (HI) and TOC (wt.%) can be used to model vitrinite reflectance (R_0) after Vernik and Landis (1996) in wells where Ro is not available (Figure 3c).

There is a reasonable correlation between modeled values of vitrinite reflectance (R_0) and actual values. However, since vitrinite reflectance is a good proxy for maturation (Tissot and Welte, 1984) the same crossplot can form the basis for a maturation index when given appropriate cutoffs. The maturation index was applied to both petrophysical and seismic data. In order to do this, TOC is first divided into two categories based on the quantity of organic carbon. Since the vast majority of TOC for this region sits between 5 – 12% TOC (Hansen et al., 2019), TOC has been broken down into medium and high TOC where 5 wt.% is used as the cutoff for medium TOC. Then, vitrinite reflectance curves were utilized to define the level of maturation. The product of these two curves can be broken out into five categories (Table 1).

Table 1 – Catergorizes cutoffs for TOC and R_0

Category	***TOC (wt.%)***	***VR (% R_0)***
Medium TOC	< 5	-
High TOC, Immature	> 5	> 0.5
High TOC, Early Oil Generation	> 5	0.5 – 0.75
High TOC, Late Oil Generation	> 5	0.75 – 1.3
High TOC, Gas Generation	> 5	< 1.3

Given the data utilized, this transect of the Norwegian North Sea shows results that range from Medium TOC through to High TOC, Late Oil Generation.

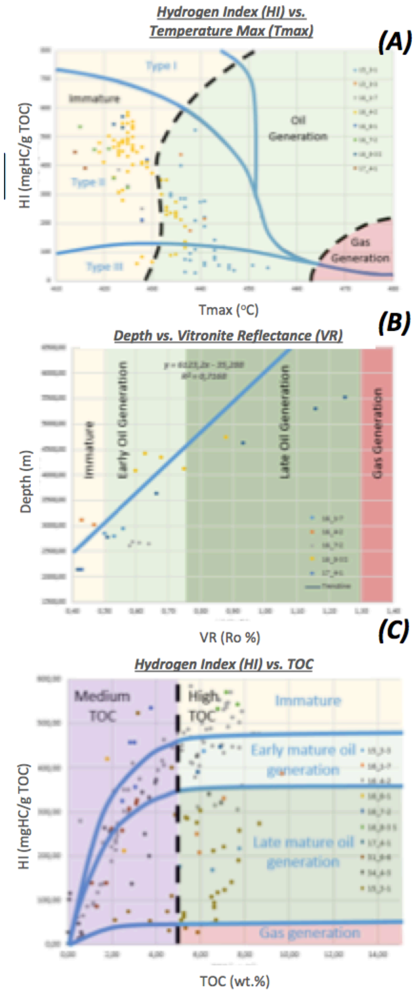

Figure 3 – Analysis utilizing Rock Eval suites were used to define both kerogen type and maturation window. (A) Hydrogen Index vs. Tmax (B) Depth vs. Vitrinite Reflectance (C) Hydrogen Index vs. Total Organic Carbon

Once maturation has been defined it can be compared to the geomechanical and elastic properties for both the wells and the seismic cube. Where S-wave data was available for the well logs it was utilized. Comparisons with the wireline log data reveals clear trends differentiating the four categories seen in this region (Figure 4).

While TOC is a major driver for variation in both elastic and geomechanical properties of organic-rich shale, this can be further broken down by where the shale is in the maturation process. The separation due to maturation is especially apparent in the geomechanical parameters (Figure 5b), showing that immature organic-rich shales have higher values of Poisson's ratio and lower values of Young's Modulus. This would seem to indicate that there are two trends at play. First, an increase in TOC will result in a more brittle rock. This confirms modeling by Mondol (2018) that shows that there is an increase in brittleness due to increased kerogen content. Second, as the rock moves from immature through to late oil generation organic-rich shales become increasingly brittle. It is likely that the combination of these processes drives the creation of fracture networks in shales.

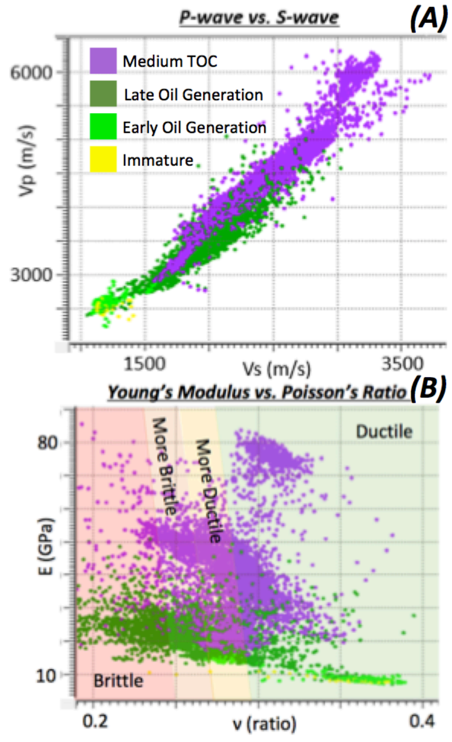

Figure 4 – Comparison of the maturation index (Z-axis) with elastic and geomechanical properties. (A) P-wave vs. S-Wave Velocity (B) Young's modulus vs. Poisson's ratio

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Utilizing seismic it is possible to map the distribution of maturation facies, as well as elastic and geomechanical parameters regionally (Figure 5). This process can provide further insight into local variations of maturation, as well as elastic and geomechanical parameters, which occur. This in turn, can provide deeper insight into the relationship that exists between all three parameters.

The Draupne Formation stands out rather starkly against the underlying sandstone-dominated Vestland Group, with low P-Impedance values. The contact between the Draupne shale and the overlaying Cromer Knoll Group is also visible (Figure 5b). This is shown equally well by Poisson's ratio (Figure 5c) where the Draupne Formation is shown to have relatively high values in comparison to the underlaying and overlaying formations. Analysis of the maturation index (Figure 5d) shows that maturation has a tendency to increase along the direction of regional dip. However, a direct comparison with the seismic data reveals that salt-tectonism has a major impact upon the rate of maturation. This is particularly evident around the salt intrusions (Figure 5a), which is both relatively shallow and relatively mature regionally. This would seem to indicate that the salt intrusion has acted as a regional heating mechanism for the Draupne Formation. Furthermore, a comparison between geomechanical parameters and the maturation index confirm that both increasing TOC and maturation has a direct correlation with brittleness.

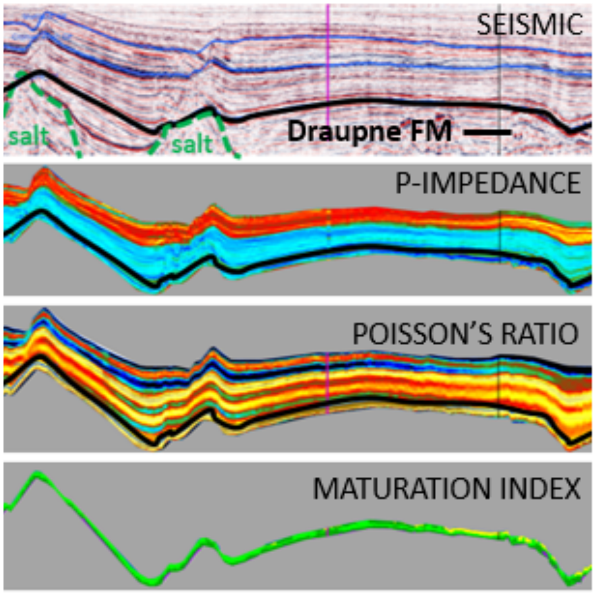

Figure 5 – Comparison of seismic (A), P-Impedance (B), Poisson's ratio (C), and the maturation index (D) along an arbitrary line running NE-SW through the survey

Conclusions

Understanding maturation of shale is critical to understanding organic-rich shales as sources, seals, and potential reservoirs. Additionally, recent interest in using the Draupne Formation for CO2 sequestration provides additional incentive to understand fully the link between maturation and seal integrity. It has been shown that a clear trend exists between not only TOC content and both the elastic and geomechanical parameters, but that the maturation of organic-rich shale from immature to late-oil generation has a significant impact on these parameters as well. Understanding this relationship fully provides a framework for indirect measurements of fracturing critical to understanding many elements of the petroleum system.

Acknowledgements

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