Hydrocarbon Potential Mapping and Organofacies Study in the Greater Balder Area, Norwegian North Sea

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Introduction

The Southern Viking Graben, from the Frigg to the Sleipner Fields, is a prolific hydrocarbon province with 255.2 mill. Sm3 oil and 429.7 bill. Sm3 gas recoverable in the Norwegian Sector (Valdresbraten, 2003). Although a mature exploration area, there remains a number of probable, but undrilled leads and prospects with considerable reserve potential. An improved, quantified understanding of this area will be an important tool in solving exploration and production problems, uncover new plays and bring new life to exploration in the area.
This study aimed at improving the understanding of lateral and vertical variations in the type of organic matter and quantification of the oil- and gas potential of the Upper Jurassic source rock section. For this purpose quantitative maps of the oil and gas potential of the Upper Jurassic source rocks in the Greater Balder Area, namely Draupne and Heather Fm, between 58°45' and 59°45' N and 1° 35' and 3°20' E in the South Viking Graben (see Fig.1) were generated. The Draupne Fm was subdivided in a syn- and postrift part for this investigation.
Various kerogen facies maps have been published for the Upper Jurassic North Sea (e.g. Baird, 1986; Cooper et al., 1987; Cornford, 1998; Isaksen & Ledje, 2001). This study however, did not aim at producing qualitative maps, but yielded quantitative maps of the oil and gas potential of the Upper Jurassic source rocks.
In the second part of this study, the vertical changes in organic matter quality and molecular content were investigated. Large variations can be observed not only laterally, but also vertically in individual well bores.
This study is part of a hydrocarbon system study in the Southern Viking Graben and the knowledge gained on the vertical and horizontal distribution of organofacies and source rock quality will be used in source rock-oil correlation and volume calculations of generated and expelled hydrocarbons.

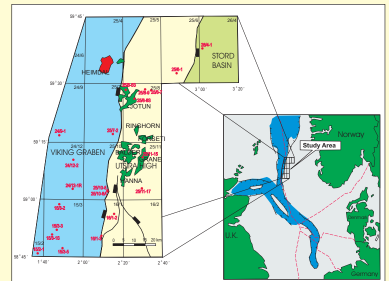


Fig. 1. Overview map of the study area showing all wells used, major oil and gas fields, as well as the main structural elements.

Quantitative Hydrocarbon Potential Mapping

Methods

- The source rock mapping was based on Rock-Eval data from 774 samples of a total of 21 wells.
- The first step was the restoration of the source rock potential. This procedure was based on the method described by Espitalie et al. (1987) and uses plots of Hydrogen Index, Production index and Bitumen Index (S1/TOC*100) from RockEval. The transformation ratio has been calculated with the following equation:

$$T_r \quad \frac{\frac{1}{\ }\;100\quad HI^0\quad HI^d}{HI^d\quad \frac{1}{\ }\;100\quad HI^d}$$

HI^0 is the average immature HI, while the HI^d values are the individual HI values at depth. The factor is an expression for the fraction of carbon atoms in the produced hydrocarbon molecules and ranges from 0.075 for methane to 0.1 when hydrogen is approaching zero. During kerogen maturation will change. For simplification, however, was used as a constant in the present study with a value of 0.086.

The transformation ratio can then be used to restore S2 and TOC with the following equations:

$$S2^0 \quad \frac{S2}{1 \quad T_r} \qquad\qquad TOC^0 \quad TOC \quad \frac{S2 \quad T_r}{1 \quad T_r}$$

- Once restored, the TOC and S2 values of the analysed samples are crossplotted and the oil and gas potential is determined using the method by Dahl et al. (1999). This method is based upon the assumption that the pyrolizable fraction of the kerogen, the S2 peak from RockEval, can be subdivided in two kerogen end-members with fixed initial hydrogen indices, representing the oil- and gas-producing portion of the kerogen. This method determines oil and gas potential for a suite of samples, not individual samples.
- The slope of the regression line through the sample population represents the average HI (see Fig. 2). The intersection of the line with the TOC axis represents the dead organic matter. The live TOC, that means the total TOC minus dead organic matter, can then be used to determine the oil and gas potential. Based on the assumption that the kerogen is a mixture of two endmember kerogens with fixed HI, an overlay like the one displayed in Fig. 2 is used to determine the contribution of the endmembers. Using the same proportions, the live TOC can then be split in oil- and gas-prone TOC.
- Source rock restoration and determination of oil and gas potential was carried out using the Petroleum Geoscience Interpretation System PeGIS. Every sample population identified within one formation was treated separately and average values have been calculated for the formations afterwards. Based on the values, quantitative maps were hand contoured.
  For this purpose, the Draupne Fm was subdivided in a synrift part (Base Draupne to Mid Volgian) and a post rift section (Mid Volgian to Ryazanian) after Rattey & Hayward (1993).

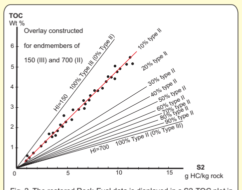


Fig. 2. The restored Rock-Eval data is displayed in a S2-TOC plot in order to determine gas and oil potential. The slope of the regression line through the sample population represents the average HI. Based on the assumption that the kerogen is a mixture of two endmember kerogens with fixed HI, an overlay like the one displayed is used to determine the contribution of the endmembers. The example shown is a mixture of 10% Type II and 90% Type III.

Results and Discussion

The highest oil and gas prone TOC for Upper and Lower Draupne Fm is encountered in the western half of the study area and in Block 25/7, dominated by mass flow sands (Figs. 3a-d). The influence of sandy mass flows from the East, the Utsira High area however, seems to be less pronounced, except in Well 25/7-2 where high overall TOC values were encountered. The areas with highest TOC values are also the deepest Graben areas with the largest subsidence and most likely the largest water depth at the time of deposition. In these topographic lows, sediment and organic matter accumulation was highest. Preservation of organic matter in the deepest areas is also probably enhanced as anoxic water conditions are best developed in these depressions with stagnant water .
The processes explained above cannot account for the unusually high values of the Blocks 25/6 and 26/4. The high values could probably be explained as a sign of a local pool-like area with stagnant water and enhanced preservation.

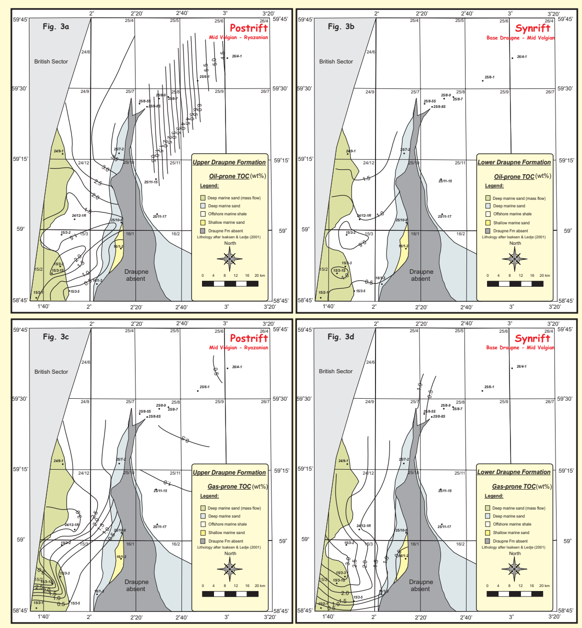
The distribution of oil and gas potential is a reflection of the varying degree of dilution of marine oil prone material by terrestrial, gas prone material.

Upper Draupne Fm:

The Upper Draupne Fm has equally high overall oil and gas potential (Figs 3a,c). The oil prone TOC in the Upper Draupne Fm is increasing from the Graben areas towards the Utsira High in a northeasterly direction (Fig. 3a).
High values are encountered in Well 25/7-2 which received deep marine sands from the East. Exceptionally high oil potential is encountered in Blocks 25/6 and 26/4. The gas prone TOC is highest in the western half of the study area and decreases towards the Utsira High (Fig. 3c).

Lower Draupne Fm:

The Lower Draupne Fm consists of a mixture of Type III land derived material and Type II marine organic matter with higher input from the land by mass flow processes, compared to the Upper Draupne Fm.
The oil prone organic matter is less abundant than the gas prone material for the greater part of the study area with values below 1 wt% (Fig. 3b). The western half of the study area shows values over 3 wt% gas prone TOC which decrease towards the Utsira High (3d).



The differences between the Upper and Lower Draupne Fms oil and gas potential result from a significant change of environment from the Lower to the Upper Draupne Fm. The Lower Draupne Fm was deposited during active tectonism in a restricted marine environment with considerable terrestrial input by mass flows. After cessation of the rifting more open marine conditions were established, the area drowned and was covered with euxinic mud (Rattey & Hayward 1993) and the terrestrial input decreased. The higher gas potential of the Lower Draupne Fm can be explained by the dilution of marine by terrestrial material transported by mass flows from the East Shetland Platform.

Vertical Organofacies Distribution

- The evaluation of the organic geochemical properties of the Upper Jurassic section showed that there is a great deal of variation in the quality of organic matter also vertically.
- The general observation in the study area is a Hydrogen Index increase upwards from the Heather Fm to the Upper Draupne Fm due to an upward increase in Type II kerogen dominance and a shift towards a more marine environment. This is supported by biomarker parameters (see Fig. 4) and was also observed by other authors (Huc et al., 1985; Dahl & Speers, 1985).
- Only five wells do not show this upward increase in marine dominance: Well 15/2-1, 15/3-3, 16/1-2, 24/12-1R and 25/7-2. They show a slight backshift to a more terrestrial influenced environment within the Upper Draupne Fm. This shift could be related to the transport of terrestrial organic matter from the flanks of the Graben to the site of deposition.
  The fact that this shift occurs only in some wells can be caused by the complex stratigraphic situation with missing and condensed sections and interfingering mass flows. In order to understand the complexity of organofacies variations in the study area, the geochemical data should have been reviewed in a sequence stratigraphic framework. This however was not feasible due to a lack of data.

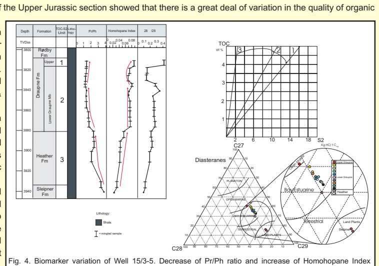


Fig. 4. Biomarker variation of Well 15/3-5. Decrease of Pr/Ph ratio and increase of Homohopane Index indicate upward increase of anoxia. The abundance of the C27 diasteranes is increasing upwards indicating a shift towards a more marine dominated environment.

- Decreasing Pr/Ph ratio and increase in Homohopane index upwards for most wells indicates an upward increase in anoxia. In some wells, however, i.e. Well 15/2-1, 15/3-3, 15/3-5 15/3-1S, 24/9-1 and 16/1-2 the top section of the Upper Draupne Fm was deposited under more oxic conditions. This was also observed by Thomas et al. (1985). This development could be the result of a minor regressive phase leading to a slight oxygenation of the area as indicated by the geochemical data.
  The C_{27}-C_{29} regular- and diasterane ratio was also used to assess the degree of terrestrial vs. marine input. Apart from a few wells (e.g. 15/3-5) where a steady shift towards a more marine environment could be observed in the diasterane ratio (Fig. 4), the data shows rather little variation and indicates a mixed input.
- Large variation of the absolute values of the biomarker parameters inhibits the identification of special value regimes for the Pr/Ph ratio, Homohopane Index and C_{27}-C_{29} regular- and diasteranes valid for all wells. In general it can be stated: The Heather Fm products will have low Homohopane Indices, high Pr/Ph ratios and a strong terrestrial sterane signal, while the products deriving from the Lower Draupne Fm will have lower Pr/Ph ratios, higher Homohopane Indices and a more marine sterane signature. Highest marine input will be typical for the Upper Draupne Fm, and products are bound to have the lowest Pr/Ph ratio and the highest Homohopane Index.

Bisnorhopane in the analysed sections

- Bisnorhopane is encountered throughout the North Sea area as several studies showed (e.g. Huc et al., 1985; Dahl & Speers, 1985; Dahl, 1987), but it is not occurring throughout the stratigraphic column and thought to be a useful oil to source and oil to oil correlation parameter (Huc et al., 1985; Dahl, 1987).

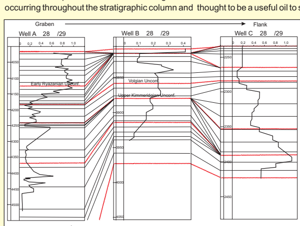


Fig. 5. Comparison of the Upper Jurassic section of three wells using the ratio of 17 (H), 21 (H)-28,30-bisnorhopane to 17 (H),21 (H)-30 norhopane. The correlation of the three analysed sections shows that high values are encountered in the top section in the two basinal wells A and B. These two wells both show a gradual decrease of the ratio downwards. Well C, however shows the opposite, an increase downwards.
(Ideally one should only consider immature sections because of the maturity dependence of the ratio. Note also the different depth scales !!!)

- Various sources, among them direct production by anaerobic bacteria (Katz and Elrod, 1983) and terrestrial plants (Seifert et al., 1978), have been proposed. The controls on the abundance of BNH are also widely discussed (Grantham et al., 1980; Moldowan et al., 1985; Bojesen-Koefoed et al., 2001). Association with high sulfur contents and anoxia is discussed and other studies (Dahl, 1987, this study) show, that the relative abundance of BNH is also decreasing with increasing maturity.
- It has been shown by Dahl (1987) that the ratio of 17 (H), 21 (H)-28,30-bisnorhopane to 17 (H),21 (H)-30 norhopane varies with stratigraphic position and can possibly be used as marker in the fairly complete Upper Jurassic section of the Oseberg Area. Based on this study it was attempted to obtain similar observations in the Greater Balder Area. The results are displayed in Fig. 5.
- Dahl (1987) observed in the stratigraphically fairly complete Upper Jurassic section of the Oseberg Back Basin that the ratio was decreasing rapidly from very high values in the Late Kimmeridgian to Early Ryazanian to very low values approaching zero. The distribution of bisnorhopane in the Southern Viking Graben seems to be different. The basinal wells A and B show a general decrease downwards, but well C on the flank of the Utsira High shows the opposite. Comparison of the Upper Jurassic sections in the Southern Viking Graben however is difficult, as sequence stratigraphic data reveals missing and condensed sections. In addition to this, there is a considerable difference in thickness.

Summary and Conclusions

- The distribution of the total restored TOC in the area is strongly related to depositional environment, sea floor topography, preservation of organic matter in the sediment and the dilution of marine by terrestrial organic matter by input via mass flows.
- The Upper and Lower Draupne Fm show significant differences and variability in oil and gas potential. While the upper postrift section shows equally high oil and gas potential, the lower, synrift section mostly exhibits gas potential. The differences between the Upper and Lower Draupne Fms oil and gas potential result from a significant change of environment and magnitude of input of terrestrial organic matter from the Lower to the Upper Draupne Fm.
- Exceptionally high oil potential is encountered on the flank of the Stord Basin and in Block 25/7, which is in the drainage area for the Balder Field.
- The general observation in the study area is a Hydrogen Index increase upwards from the Heather Fm to the Upper Draupne Fm. This increase is resulting from an upward increase in Type II kerogen and a shift from a more terrestrial towards a more marine environment
- A simple facies model could be set up for the area, based on average Hydrogen Indices (Fig. 6).
- Large variation of the absolute values of the biomarker parameters inhibits the identification of special value regimes for the Pr/Ph ratio, Homohopane Index and C_{27}-C_{29} regular- and diasteranes valid for all wells. However, the general differences of the three analysed formations allow to make some general assumptions on the molecular content of HC products from the analysed section.

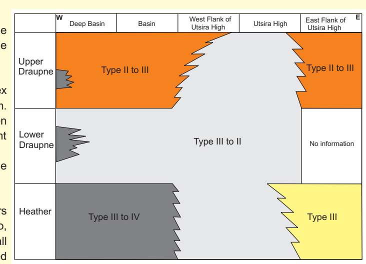


Fig. 6. Simplified organofacies model of the area: Organofacies varies both vertically and horizontally. The Type II contribution is increasing upwards and towards East within the Upper Draupne Fm. The influence of terrestrial and reworked organic matter is more dominant in the western part of the basin and decreasing upwards and is related to the Brae sands.

- Correlation of the Upper Jurassic section using bisnorhopane is difficult in the Greater Balder Area due to incompleteness of the section. Similar features as in the Oseberg Area could not be observed.

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