The Petroleum Systems of the South Viking Graben, Norway

Holger Justwan

Thesis for the degree doctor scientiarum (dr.scient.)
at the University of Bergen

February 2006

ISBN 82-308-0149-5
Bergen, Norway 2006

Printed by Allkopi Ph: +47 55 54 49 40

“…also mit anderen Worten, Öl...”

(Gerhard Polt, 1979)

Preface and Acknowledgements

The study of "*The Petroleum Systems of the South Viking Graben, Norway*" has been carried out at the Department of Earth Science of the University of Bergen, Norway. The project was funded by Esso Exploration & Production Norway A/S and the Norwegian Research Council (Grant 157825/432).

This dr.scient. thesis consists of four papers which cover various aspects of the petroleum systems in the South Viking Graben. One additional paper is added as appendix for further information on the novel technique used for source rock potential determination.

Parts of this study have been presented at the 21st International Meeting on Organic Geochemistry in Krakow and the 6th Petroleum Geology Conference in London in 2003, as well as at the 9th Norwegian Meeting on Organic Geochemistry in Trondheim in 2004 and the 22nd International Meeting on Organic Geochemistry in Seville in 2005.

This study would have not been possible without the support, help and guidance from several people and institutions: First of all, I would like to express my gratitude to my supervisor Birger Dahl, whose guidance, critical comments and knowledge of petroleum systems analysis were invaluable to me and this project. I would also like to thank my co-supervisor, Gary Isaksen, for his help in designing the project and all his comments, often lending me an additional perspective. Furthermore, the pseudo-3D basin modelling clearly would not have been possible without the technical supervision and assistance by Ivar Meisingset in countless late-night tutoring and modelling sessions.

The study of a petroleum system, especially in a mature exploration area, such as the South Viking Graben, is strongly dependent on the availability of data. I have carried out the major part of the analysis of source rock and oil samples, which have been supplied by the Norwegian Petroleum Directorate, in the laboratories of the University of Bergen. The help of Jannicke Berge Olsen and Greger Solend in the laboratory is gratefully acknowledged. I have performed additional analysis in external laboratories, including the facilities at GEUS, Copenhagen and the Norsk Hydro Research Center in Bergen. In this context, I am indebted to the management of the Norsk Hydro Research Center for granting me access to their Rock-Eval instrument and to Marian Våge for technical assistance during Rock-Eval analysis. I also received invaluable support from the Department of Reservoir Geology of GEUS in Copenhagen, where I was allowed to perform preparative MPLC on all source rock extracts and oil samples. Specifically Jørgen Bojesen-Koefoed and Peter Nytoft are thanked for their assistance in the lab and making my laboratory "marathon" in Copenhagen nonetheless enjoyable.

Despite the large number of samples analysed, additional data was required for this project. I would therefore like to thank Esso Exploration and Production Norway A/S, especially Stig Ballestad and Haakan Ledje, for supplying well logs, geochemical data, sequence stratigraphic data, as well as seismic lines and subsurface maps and for contacting partners in order to release data to me. Amerada Hess, RWE-DEA, Statoil, Eni Norge, Total, Enterprise Oil, Geolab Nor, Conoco-Philips and Norsk Hydro are thanked for their contributions.

I would like to add a personal thanks to my family for their continuous encouragement and support. And finally, I would like to thank my wife Aurélie. You have coped with all my worries, planning and stress, often nudged me in the right direction and never stopped supporting me.

Bergen, February 2006

Holger Justwan

Contents

Abstract

The Norwegian South Viking Graben (57°45'N–60°15'N) is a prolific hydrocarbon province and contains recoverable resources of 323 x 10^6 Sm^3 oil and 464 x 10^9 Sm^3 gas in four major confirmed plays of Triassic, early to Middle Jurassic, Upper Jurassic and Paleogene age. Recent activities in the area show, however, a decrease of discoveries with respect to size and frequency. After nearly 40 years, the area has now entered a mature exploration phase. An integrated petroleum systems study is performed in order to evaluate the remaining potential of this area.

Detailed source rock analysis and mapping, analysis of reservoired hydrocarbons as well as basin modelling reveal two main active petroleum systems in the area. Major source rocks for these systems are the shales of the Upper Jurassic Viking Group, including the Heather and Draupne formations, as well as the coals and coaly shales of the Middle Jurassic Vestland Group. The oil- and gas potential of these units is determined based on results from Rock-Eval analysis and mapped for the Upper Jurassic source rocks. The mapping reveals significant facies and potential variations, especially between the syn- and post-rift sections of the Draupne Formation, which are related to dilution effects and varying degrees of anoxia. This is supported by results from gas chromatography, biomarker and stable carbon isotope analysis. The up to 1600 m thick, syn-rift, lower Draupne Formation is classified as source for oil and gas but contains considerable amounts of gas-prone and inert organic matter, especially in areas that received mass flows from surrounding highs. The upper, post-rift section of the Draupne Formation, up to 330 m thick, is a rich oil-prone source, while the Heather Formation is lean and mostly gas-prone. The Middle Jurassic Hugin and Sleipner formations have a highly variable source facies but are considered to be mainly gas-prone.

Pseudo-3D basin modelling, based on source rock potential maps, selected subsurface horizons and 1D simulation of the geohistory of 46 well sites, allows the determination of timing of oil and gas generation and expulsion in the area and the calculation of expelled hydrocarbon volumes. Hydrocarbon expulsion from Upper and Middle Jurassic source rocks occurs in two main phases. The first phase of expulsion from Upper Jurassic source rocks lasts from Paleocene to mid Miocene. Peak oil and gas expulsion occurs in the Lower Miocene. Gas expulsion from Middle Jurassic source rocks begins in the Lower Eocene and is followed by oil expulsion from the Lower Miocene on, due to different kinetics and retention of generated oil in the source rock. This first phase of expulsion from Upper and Middle Jurassic source rocks is followed by a period of reduced expulsion in the later Miocene and Pliocene related to basin shallowing and reduced subsidence. A second phase of expulsion from Upper and Middle Jurassic source rocks can be observed in the Quaternary and is related to increased subsidence during this period. This short, second expulsion phase contributes 11 % of the total oil and 13 % of the total gas volume expelled in the area and is therefore of great significance.

The most oil-prone unit, the upper Draupne Formation, only contributes 24 % of the total oil volume due to insufficient levels of thermal maturity and its smaller thickness. The lower Draupne Formation is the largest contributor with 54 % of the total generated oil volume. The Heather Formation dominates gas expulsion with 38 % of the total gas volume expelled. The Middle Jurassic sources provide almost exclusively gas, except in the Greater Sleipner Area where these units have contributed minor amounts of liquid hydrocarbons.

Detailed geochemical analysis was carried out to characterise the reservoired hydrocarbons in the area, assess possible secondary alteration processes and identify the active petroleum systems by means of oil-source correlation. Interpretation of molecular and isotopic characteristics of oils along with multivariate analysis of biomarker data allows the identification of seven hydrocarbon families which can be related to the three active source horizons based on carbon isotopic and biomarker data. Three families are sourced from the Draupne Formation. The Heather Formation and the Middle Jurassic strata source one family respectively, while the remaining two families represent mixtures from Upper and Middle Jurassic sources. Analysis of typed oil volumes indicates that oil from the Upper Jurassic Draupne Formation represents 97 % of the total typed oil volume and that the Draupne Formation is indeed the major source rock in the area.

Oil-source correlation leads to the positive identification of two major petroleum systems in the area which can be named after their source rocks and the most important reservoir unit. The Viking-Rogaland (!) system, which includes

an Upper Jurassic source and a Tertiary reservoir, is proven in the entire area, whereas the Vestland-Vestland (!) systems, with source rock and main reservoir unit in the Middle Jurassic Vestland Group can only be proven south of 58°40'N.

Comparison of modelled and observed in-place volumes shows that only 1 % of the oil and between 9.7 and 12.9 % of the gas volume expelled have been found in commercial oil and gas accumulations. These values are, compared to other areas, rather low and are encouraging for further exploration of the South Viking Graben. Specifically in view of the imminent removal of the first oil installations in this mature area, exploration of remaining resources should be pursued now in order to use the advantage of existing infrastructure.

List of publications

Justwan, H., Dahl, B., 2005. Quantitative hydrocarbon potential mapping and organofacies study in the Greater Balder Area, Norwegian North Sea. In: Doré, A.G., Vining, B. (Eds.), Petroleum Geology: North-West Europe and Global Perspectives - Proceedings of the 6th Petroleum Geology Conference. Geological Society, London, pp. 1317-1329.

Justwan, H., Dahl, B., Isaksen, G.H., Meisingset, I., 2005. Late to Middle Jurassic source facies and quality variations, South Viking Graben, North Sea. Journal of Petroleum Geology 28 (3), 241-268.

Justwan, H., Dahl, B., Isaksen, G.H., 2006. Geochemical characterisation and genetic origin of oils and condensates in the South Viking Graben, Norway. Marine and Petroleum Geology 23 (2), 213-239.

Justwan, H., Meisingset, I., Dahl, B., Isaksen, G.H., submitted. Geothermal history and petroleum generation in the Norwegian South Viking Graben revealed by pseudo-3D basin modelling. Marine and Petroleum Geology.

Dahl, B., Bojesen-Koefoed, J., Holm, A., **Justwan, H.**, Rasmussen, E., Thomsen, E., 2004. A new approach to interpreting Rock-Eval S_2 and TOC data for kerogen quality assessment. Organic Geochemistry 35 (11-12), 1461-1477.

Introduction

The petroleum industry is undergoing a world wide change in view of increasing global demand, high oil prices and increasing difficulty to discover commercial hydrocarbon accumulations. Classic petroleum provinces, such as the North Sea, reach mature levels of exploration and production volumes start to decline, while exploration efforts in other parts of the world, such as West Africa, are increasing. Research is now focussed on enhanced oil recovery, sometimes called the biggest recent “discovery”, and smaller companies specialise on tail-end production in mature areas (Battié et al., 2005). Even reopening of already abandoned fields appears to be considered profitable (Mathiesen, 2005).

The Norwegian South Viking Graben (Fig. 1) is one of the areas that are now considered to be in a mature phase of exploration (Østvedt et al., 2005). This statement seems to be supported by evaluation of the remaining potential of the basin using a creaming curve, a plot of cumulative reserves discovered against exploration effort expressed by the number of wildcat wells drilled (Fig. 2). The South Viking Graben has been extensively explored since 1967, and 273

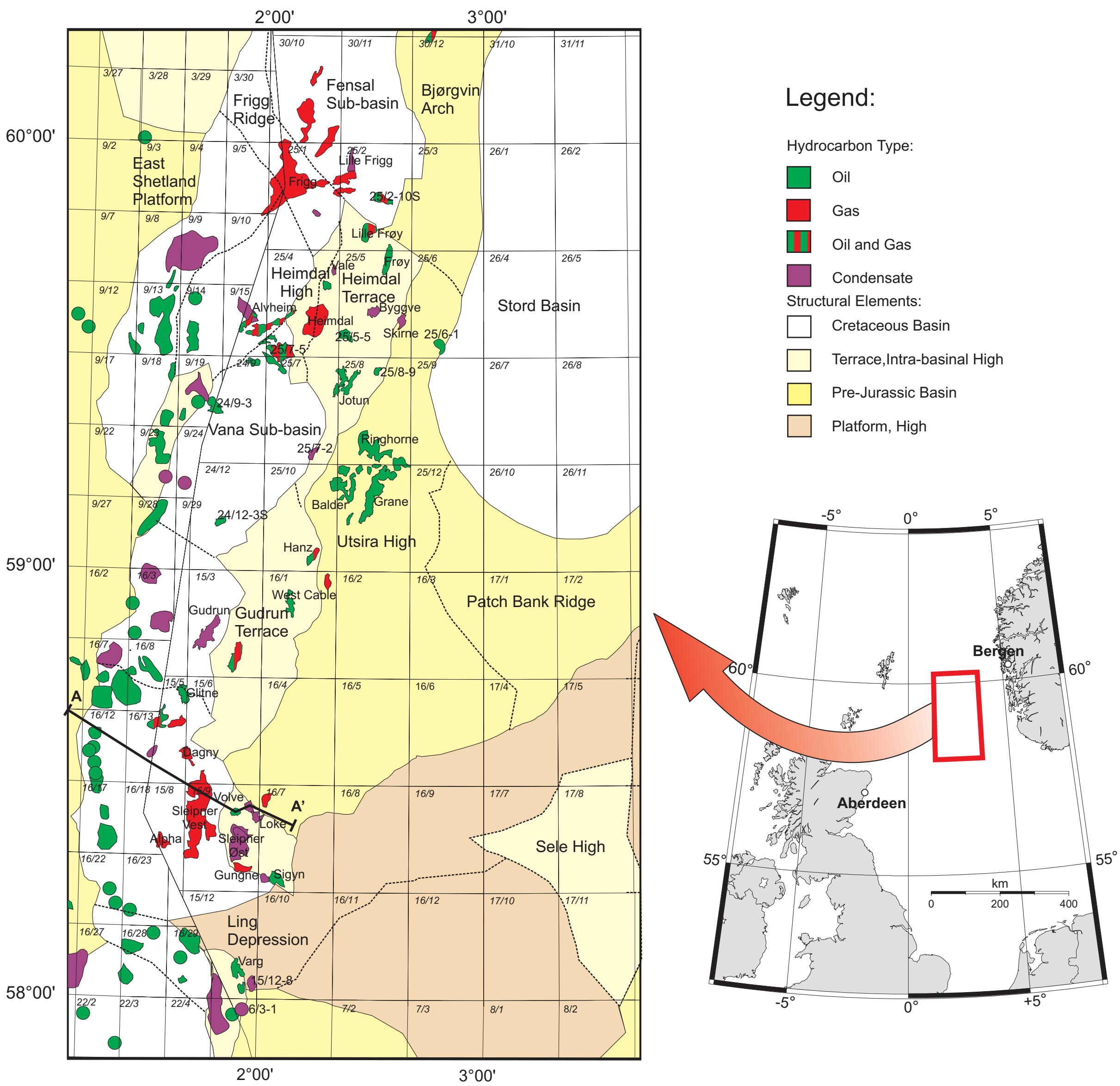

Fig. 1. Overview map of the South Viking Graben displaying all major fields and discoveries as well as structural elements (after NPD, 2005). Circular features in the UK sector indicate discoveries with unknown extent. The location of the cross section in Fig. 4 is shown by line A’-A.

exploration wells have been drilled to date. The total resources in fields and discoveries amount to 323 x 10^6 Sm^3 oil and 464 x 10^9 Sm^3 gas as well as 69 x 10^6 Sm^3 condensate and 60 x 10^6 tons of NGL (Ministry of Petroleum and Energy 2005; NPD, 2005). After the first major discoveries in the 1960s and 1970s, a longer period with only minor additions to the resources followed in the 1980s until the discovery of the Grane Field in 1991 (Fig. 2). Recently, discoveries have decreased in size and frequency, although they are still being made, e.g. Alvheim in 1998 and Vilje in 2003 (Fig. 2). The remaining resources are now assumed to be in medium to small discoveries (Østvedt et al., 2005).

The important question arising from the analysis of Fig. 2 is whether the area is still in a mature phase or has surpassed this stage and is already "creamed". The latter would imply that no further commercial discoveries are to be expected. Is another inflexion in the creaming curve possible, as in 1991 when the Grane Field was discovered, or will the development follow a hyperbolic curve with no further major discoveries?

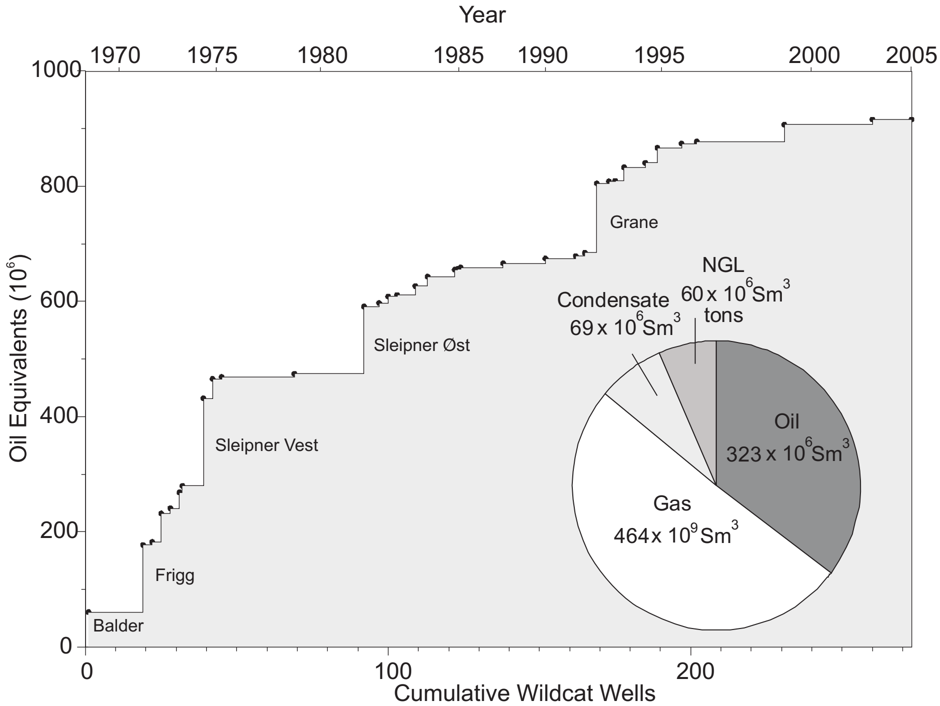

Fig. 2. Creaming curve for the Norwegian South Viking Graben showing total recoverable resources (as the sum of oil, gas, condensate and NGL) expressed in oil equivalents. Only resource classes 0-5 have been used from estimates in Ministry of Petroleum and Energy (2005) (see also Table 1). Total resources include 464 x 10^6 Sm^3 oil, 323 x 10^9 Sm^3 gas, 67 x 10^6 Sm^3 condensate and 60 x 10^6 tons NGL (inset). Additional resources were all assigned to the original discovery.

The Norwegian Petroleum Directorate is promoting exploration of "*older but still attractive*" areas (Vaage Melberg, 2005) and stresses that although exploration has been long under way in some areas, several blocks have not been drilled at all or at least not recently. The fact that the industry still takes interest is shown by the award of seven licenses in 14 blocks in the South Viking Graben in predefined areas in 2005. The challenge in the area is now to develop new play concepts and to continue exploration for smaller and subtle traps near existing infrastructure (Hanslien and Olsen, 2000). Nearby infrastructure is especially important for smaller discoveries for which the construction of production facilities is not economical. Since the first fields are being shut down in the area, such as the Frigg gas field in 2004, and decommissioning of oil installations is imminent, exploration and evaluation of the remaining prospects should be carried out in the near future to use the advantage of existing infrastructure.

Objectives

In view of the exploration history of the area, this study attempts to shed light on the future prospectivity of the Norwegian South Viking Graben and aims at facilitating future exploration efforts and derisking of remaining prospects by increasing the understanding of the active petroleum systems in the area.

A petroleum system has been defined by Magoon and Dow (1994) as "*…a pod of active source rock and all related oil and gas and … all the essential elements and processes needed for oil and gas accumulations to exist*". These essential elements and processes include source-, overburden-, reservoir- and seal rocks and generation, migration, accumulation and trap formation (Fig. 3). Hydrocarbon accumulations can only be expected in an exploration area if all these elements and processes are present. Source rocks of sufficient quality and thickness, which have to undergo burial and related thermal maturation to generate petroleum, are required for an operating petroleum system. Once expelled, the hydrocarbons need to migrate in suitable carrier beds to reservoir rocks, where they remain if an adequate trap and seal exists. The presence of an active petroleum system can only be identified by geochemical correlation of source rocks and petroleum.

Integration of different data types and study of all elements and processes is essential to understand a petroleum system in its entity since all the parts of a petroleum system are tightly related. A thorough evaluation of a petroleum system can give valuable information at all maturity stages of a basin from frontier exploration areas to well explored mature areas, such as the South Viking Graben.

This study is not the first to deal with various aspects of the petroleum systems in the South Viking Graben during the long exploration history of the area. Source rocks have been extensively studied and mapped (e.g. Goff, 1983; Field, 1985; Thomas et al., 1985; Baird, 1986; Cornford, 1998; Isaksen and Ledje, 2001; Isaksen et al., 2002; Kubala et al., 2003), and reservoired hydrocarbons have been analysed and correlated (e.g. Bhullar et al., 1998; Isaksen et al., 2002). The studies of Goff (1983), Barnard and Bastow (1991), Bhullar et al. (1998), Munz et al. (1999), Isaksen and Ledje (2001), di Primio (2002), Isaksen et al. (2002) and Kubala et al. (2003) have greatly improved the understanding of secondary migration in the area. In addition, maturation of source rocks and hydrocarbon generation has been studied in the area (e.g. Goff, 1983; Wei et al., 1990; Ghazi, 1992). Unfortunately, very few new published papers have incorporated the vast amounts of data generated in nearly 40 years of exploration, and no integrated study of the South Viking Graben has been published, although integrated approaches have been published for smaller geographical subareas (e.g. Bhullar et al., 1999; Isaksen et al., 2002). The most recent and extensive account of the petroleum geology of the North Sea is presented by Evans et al. (2003), but the immense size of the study area renders a detailed evaluation of geographic subareas, such as the South Viking Graben, impossible.

This thesis represents the first published study which focuses in particular on the South Viking Graben and investigates the petroleum systems and the remaining potential of the area by integration of geochemical analysis, mapping and geothermal modelling. It consists of four scientific papers covering various elements and processes of the petroleum systems (Fig. 3) and a general synthesis which highlights the most important factors of the petroleum systems and discusses the remaining potential of the area. The aspects investigated in the individual papers include source rocks (*Paper 1 and 2*), their maturation and resulting hydrocarbon generation (*Paper 4*) and migration of hydrocarbons (*Paper 3, 4*). The identification of the active petroleum systems is achieved by oil-source correlation (*Paper 3*) (Fig. 3). One additional paper (*Paper 5*) discusses the novel technique employed in *Paper 1 and 2* and is added as appendix for further explanation.

The papers, listed below, will in the following be referred to as *Paper 1 to 5*.

Paper 1: **Justwan, H**., Dahl, B., 2005. Quantitative hydrocarbon potential mapping and organofacies study in the Greater Balder Area, Norwegian North Sea. In: Doré, A.G., Vining, B. (Eds.), Petroleum Geology: North-West Europe and Global Perspectives - Proceedings of the 6th Petroleum Geology Conference. Geological Society, London, pp. 1317-1329.

***Paper 2*:** **Justwan, H**., Dahl, B., Isaksen, G.H., Meisingset, I., 2005. Late to Middle Jurassic source facies and quality variations, South Viking Graben, North Sea. Journal of Petroleum Geology 28 (3), 241-268.

***Paper 3*:** **Justwan, H**., Dahl, B., Isaksen, G.H., 2006. Geochemical characterisation and genetic origin of oils and condensates in the South Viking Graben, Norway. Marine and Petroleum Geology 23 (2), 213-239.

***Paper 4*:** **Justwan,** H., Meisingset, I., Dahl, B., Isaksen, G.H., submitted. Geothermal history and petroleum generation in the Norwegian South Viking Graben revealed by pseudo-3D basin modelling. Marine and Petroleum Geology.

***Paper 5*:** Dahl, B., Bojesen-Koefoed, J., Holm, A., **Justwan, H**., Rasmussen, E., Thomsen, E., 2004. A new approach to interpreting Rock-Eval S_2 and TOC data for kerogen quality assessment. Organic Geochemistry 35 (11-12), 1461-1477.

The main objectives of the initial phase of the study (*Paper 1 and 2*) were to map thickness as well as oil and gas-potential of the Upper Jurassic source rocks subdivided into isochronous units and to understand the controls on the source rock potential in the area. *Paper 1* presents the initial results of the source rock analysis in a subregion of the area, while *Paper 2* covers the entire South Viking Graben in a more detailed manner. Source rock analysis in *Paper 1 and 2* should furthermore uncover regional variations in molecular source facies. The objectives of *Paper 3* were to characterise produced oils and condensates by detailed oil-oil and oil-source correlation as well as the evaluation of secondary alteration of hydrocarbons. The study of the molecular source rock facies in *Paper 1 and 2* is used as direct input for the oil-source correlation study (Fig. 3). *Paper 3* presents the first published oil-oil and oil-source correlation covering the entire South Viking Graben. *Paper 4* deals with the geohistory of the source- and overburden rocks and hydrocarbon generation in the South Viking Graben, which have been investigated by means of 1D simulation of 46 individual well sites and subsequent pseudo-3D basin modelling. The source rock maps for the Upper Jurassic as well as the Rock-Eval data for the Middle Jurassic source rocks presented in *Paper 2* are vital input to the basin model (Fig. 3). At present, the aspect of migration is not covered by a separate study, although an evaluation of drainage areas has been carried out in *Paper 4. Paper 3* offers also information on migration routes based on oil-oil and oil-source correlation. Oil-source correlation established in *Paper 3* can be used in the identification of the active petroleum systems in the area (Fig. 3). In addition, volumetric calculations using the established genetic oil-source correlations were used to determine the significance of the respective source rock systems. Combined, the four papers allow the evaluation of the most important aspects of the petroleum systems in the area and their efficiency, which is used to evaluate the remaining hydrocarbon potential of the area. Figure 3 shows which elements and processes of the petroleum systems have been studied in *Paper 1 to 4* and how the papers are related to each other.

Paper 5 was added as an appendix to give a more detailed explanation of the method applied for oil and gas potential mapping in *Paper 1 and 2*. This method, based on the principle that kerogen consists of a mixture of oil- and gas-prone endmembers, uses Rock-Eval S2 and TOC data in cross-plots to determine the amount of inert and oil- and gas-prone organic matter. The method represents an alternative to the use of pyrolysis GC or visual kerogen description data when only Rock-Eval data is available.

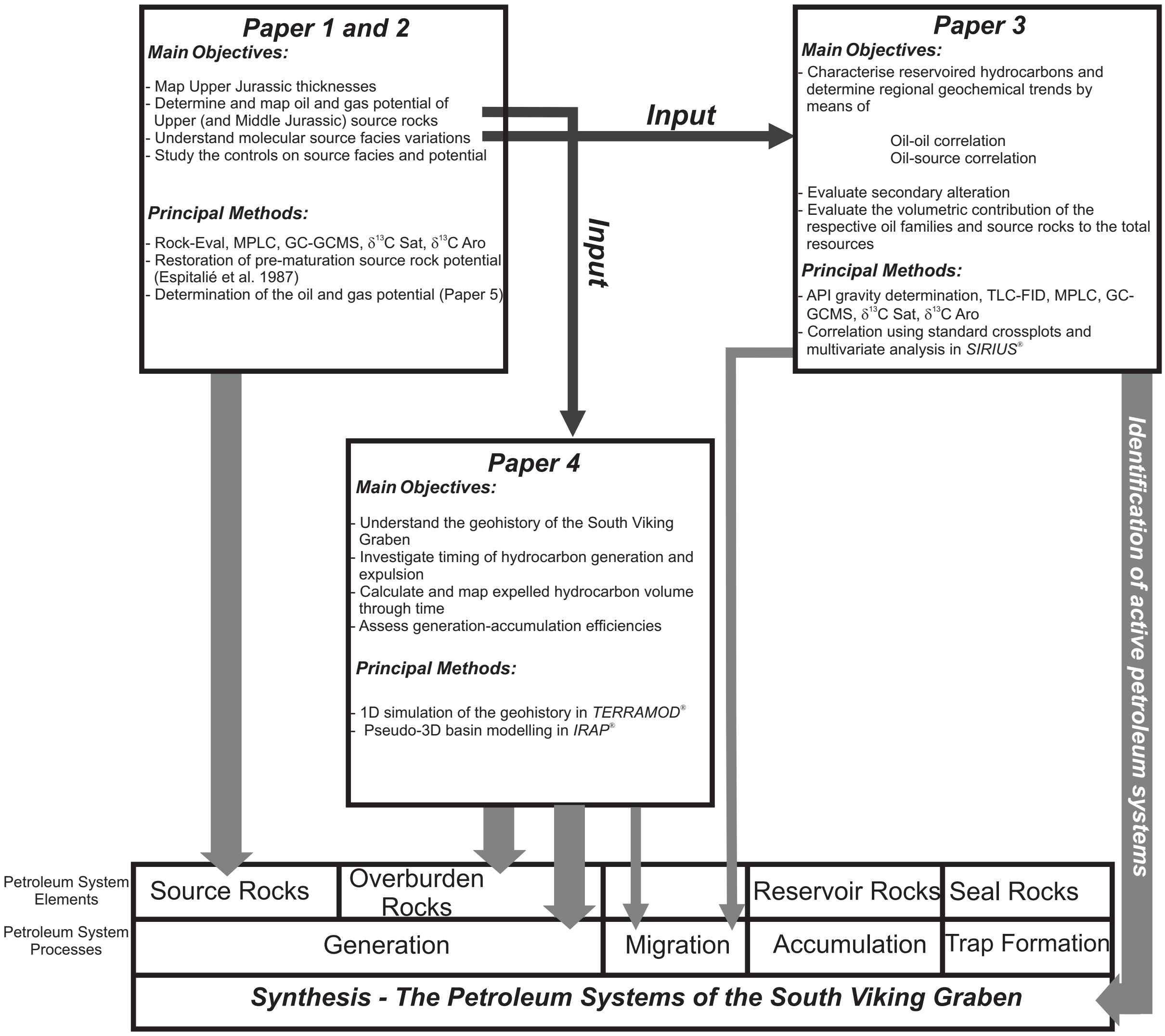

Fig. 3. Integration of different data types and aspects is important in order to develop a comprehensive understanding of a petroleum system. This flow chart illustrates the essential elements and processes of a petroleum system (after Magoon and Dow, 1994) and the contribution of the respective papers of this thesis to the overall understanding of the petroleum systems in the South Viking Graben. Main objectives, methods as well as the connections between different parts of this study are indicated. The elements reservoir and seal rocks and the processes trap formation and accumulation have been covered by literature study.

The following synthesis chapter presents a full evaluation of the petroleum systems of the South Viking Graben. It is based on summaries of the individual papers, additional information on the geological and exploration history of the area and is complemented by literature reviews dealing with migration, reservoir rocks, trapping and seals. The respective chapters on source rocks, reservoired hydrocarbons and maturation and generation also contain a detailed discussion of the methods used in *Papers 1 to 4*. The conclusions include an evaluation of the remaining hydrocarbon potential of the South Viking Graben.

Synthesis – The Petroleum Systems of the South Viking Graben

1. Overview

1. 1. Exploration history

Oil was first discovered in the South Viking Graben in 1967 in Paleocene sandstones on the Utsira High in what would later be the Balder Field. Its discovery represents the onset of intense exploration in the area, although this field did not start production until 1999. At present, 273 exploration wells have been drilled in the Norwegian sector. There are currently 12 producing fields and 16 to be developed, while production from 6 fields already ceased (Table 1). In addition, there are 15 discoveries which seem at present unlikely to be developed. The oil accumulations in the area contain a wide range of oil types from the heavy biodegraded oils in Grane with 19.4° to the light condensates in Sigyn with 55.8° API gravity (Table 1).

The early phase of exploration in the North Sea focused on Permian targets after the discovery of the giant Groningen Field in the Netherlands in 1959. Soon after, the lower Tertiary became the focus of interest in the area (Brennand et al., 1998) and oil and gas was found in the Balder, Frigg and Heimdal fields (Fig. 2). The Tertiary play has since been the most prolific in the area with 266 x 10^6 Sm^3 of oil and 273 x 10^9 Sm^3 gas recoverable (Ministry of Petroleum and Energy, 2005). The discovery of the Brent Field in the East Shetland Basin led to the exploration of Middle Jurassic reservoirs in fault block settings. This new play concept resulted in the discovery of Sleipner Vest in 1974 in the South Viking Graben (Brennand et al., 1998). The Upper Jurassic was also pursued as target and hydrocarbons were found for example in the Gudrun discovery in 1975. At present, there are four major confirmed plays in the area including the Paleogene play, the Upper Jurassic play, the early to Middle Jurassic play and the Triassic play (*Paper 3*). The Paleogene play, comprising a Paleogene reservoir and an Upper Jurassic source, is by far the most successful (*Paper 3*).

The last major discovery was the Grane Field in 1991, and the area is now considered to have reached a mature state of exploration (Østvedt et al., 2005).

1.2. Geological setting

The South Viking Graben is an asymmetric rift graben influenced by two major periods of extension of Permo-Triassic and Middle to Upper Jurassic age (Fig. 4). The graben is flanked by the East Shetland Platform in the west and steps up with numerous fault blocks to the east, where it is bound by the Utsira High (Figs. 1, 4). The oldest sediments in the study area are encountered in Well 25/10-2R and are of Permian age (Isaksen et al., 2002). During this period, eolian and evaporitic sediments were deposited in the region (Ziegler, 1992). The first phase of extension affected the entire South Viking Graben area at the transition of the Permian and the Triassic (Færseth, 1996). Clastic sediments were deposited during the Triassic in arid to semi-arid climates in intra-continental basins (Fisher and Mudge, 1998), such as the arenaceous mudstones of the Lower Triassic Smith Bank Formation (Goldsmith et al., 2003) and the sandy alluvial fan deposits of the Skagerrak Formation (Figs. 4, 5). At the transition from the Triassic to the Jurassic the sandstones of the Statfjord Formation were deposited which record the transition from a continental through a marginal marine to the marine environment of the overlying Dunlin Group (Goldsmith et al., 2003) (Fig. 5). A second phase of rifting commenced in the late Toarcian with uplift at the triple junction of the Central-, Viking and Witch Ground Graben. This phase of uplift caused significant erosion of underlying sediments. Lower Jurassic argillaceous to sandy marine sediments of the Dunlin Group are therefore sparse south of 59° N in the study area (Fig. 5) (Skarpnes et al., 1980). Doming related to the uplift and associated erosion led to redeposition of the sediments and the formation of the Brent Delta in the northern half of the study area (Graue et al., 1987). Sea-level rise in the latest Bajocian to earliest Bathonian caused the retreat of the delta and led to the deposition of the Vestland Group, including the coal bearing coastal plain sediments of the Sleipner Formation and the overlying shallow marine to

Table 1

Recoverable resources from fields and discoveries in the Norwegian South Viking Graben (after Ministry of Energy and Petroleum (2005), NPD (2005)) and additional information, including discovery year, production status, main reservoir unit, trap type and API gravity (average) of the oil phase. In addition to the fields listed, there are 15 discoveries which are not likely to be developed at present (Ministry of Petroleum and Energy, 2005). Reserves for Ennoch are not stated although development is likely. All hydrocarbons in the area are reservoired in clastic sediments.

Field	Discovery Year [c]	Status [c]	Main Reservoir	Trap Type	API Gravity*	Resources Oil 10^6 Sm^3	Gas 10^9 Sm^3	Cond. 10^6 Sm^3	NGL 10^6 tonne
Frøy[a]	1987	shut down	Mid Jurassic	3	37.5	5.6	1.6	0.1	0
Nordøst Frigg[a]	1974	shut down	Lower Eocene	1	-	0	11.6	0	0
Lille Frigg[a]	1975	shut down	Mid Jurassic	3	41.6	1.3	2.2	0	0
Frigg[a]	1971	shut down	Lower Eocene	1	-	0	116.2	0.5	0
Øst Frigg[a]	1973	shut down	Lower Eocene	1	-	0	9.2	0.1	0
Odin[a]	1974	shut down	Lower Eocene	1	-	0	27.3	0	0
Glitne[a]	1995	Producing	Paleocene	1	32.1	7.2	0	0	0
Varg[a]	1984	Producing	Late Jurassic	2	34.4	12.1	0	0	0
Balder+Ringhorne[a]	1967+1970	Producing	Paleocene+Lower Eocene	1	23.6	58.9	1.6	0	0
Grane[a]	1991	Producing	Paleocene	1	19.4	120.3	0	0	0
Jotun[a]	1995	Producing	Paleocene	1	36.5	25.4	0.7	0	0
Sleipner Vest[a]	1974	Producing	Mid Jurassic	2	44.9	0	108.1	28.1	8.1
Sleipner Øst[a]	1981	Producing	Paleocene+Mid Jurassic	1	54.6	0	65.8	27.1	12.5
Gungne[a]	1982	Producing	Triassic	3	54.2	0	9.9	3.1	1.3
Sigyn[a]	1982	Producing	Triassic	3	55.8	0	6.1	4.6	3
Vale[a]	1991	Producing	Mid Jurassic	3	52.5	1.8	2.4	0	0
Skirne+Byggve[a]	1990+1991	Producing	Mid Jurassic	3	52.9	1.6	6.7	0	0
Heimdal[a]	1972	Producing	Heimdal	3	?	7.1	42.1	0	0
Volve[a]	1993	PDO approved	Triassic+Mid Jurassic	1	27.8	11	12	0	0.2
Alvheim[a]	1998	PDO approved	Paleocene	1	35.3	23.5	5.7	0	0
Vilje[a]	2003	PDO approved	Paleocene	1	?	8.9	0	0.1	0
25/5-5[a]	1995	Planning phase	Paleocene	1	28.9	3.5	0.1	0	0
Dagny[a]	1978	Planning phase	Mid Jurassic	3	43.5	0	3.8	1.2	0.2
25/11-16[a]	1992	Planning phase	Heimdal	1	?	3.6	0	0	0
Varg Sør[a]	2001	Planning phase	Late Jurassic	2	?	0	4.3	1.4	0
15/3-1S[a]	1975	Planning phase	Late Jurassic	1	?	15.2	8.4	0	5.4
Peik 24/6-1[b]	1985	Dev. likely**	Mid Jurassic	3	48.8	0	2	0.3	0
24/9-5 [b]	1994	Dev. likely**	Paleocene	1	?	7.06	0.88	0	0
15/8-1 Alpha [b]	1982	Dev. likely**	Mid Jurassic	3	43.7	0	4.1	1	0.5
15/3-4 [b]	1982	Dev. likely**	Mid Jurassic	3	42	7.6	3.8	0	0
15/5-2 [b]	1978	Dev. likely**	Triassic	3	?	0	4.9	0.4	0
16/7-2 [b]	1982	Dev. likely**	Paleocene	1	48.3	0	1.8	0.5	0.3
25/8-4 [b]	1992	Dev. likely**	Paleocene	1	?	1	0	0	0
6/3-1 [b]	1985	Dev. likely**	Triassic+Mid Jurassic	1	35/52.8	0.4	0.9	0	0

Data source: [a] Ministry of Energy and Petroleum (2005); [b] NPD (2005); *API gravities of main liquid HC phase from Justwan et al. (2006) or NPD (2005); ** Development likely; Trapping style: 1 = stratigraphic+structre; 2= stratigraphic+structure+salt tectonics; 3=structural trap;

fluviodeltaic deposits of the Hugin Formation (Fig. 5) (Rattey and Hayward, 1993). Continued sea-level rise during the Jurassic rifting episode led to the deposition of the organic rich Viking Group. This unit includes the Heather and Draupne formations, which are the major source rocks in the area (Fig. 5) (Goff, 1983; Field, 1985; Cornford, 1998). The Heather Formation and the lower section of the Draupne Formation contain a series of sands shed as deep marine fans or slope aprons from the surrounding highs (Fig. 5). After cessation of the rifting in the Middle Volgian, these sandy systems disappear, and the upper section of the Draupne Formation was deposited as a draping clay layer in the area (Fig. 4, 5). The Lower Cretaceous was characterised by the deposition of shales and mudstones, while the Upper

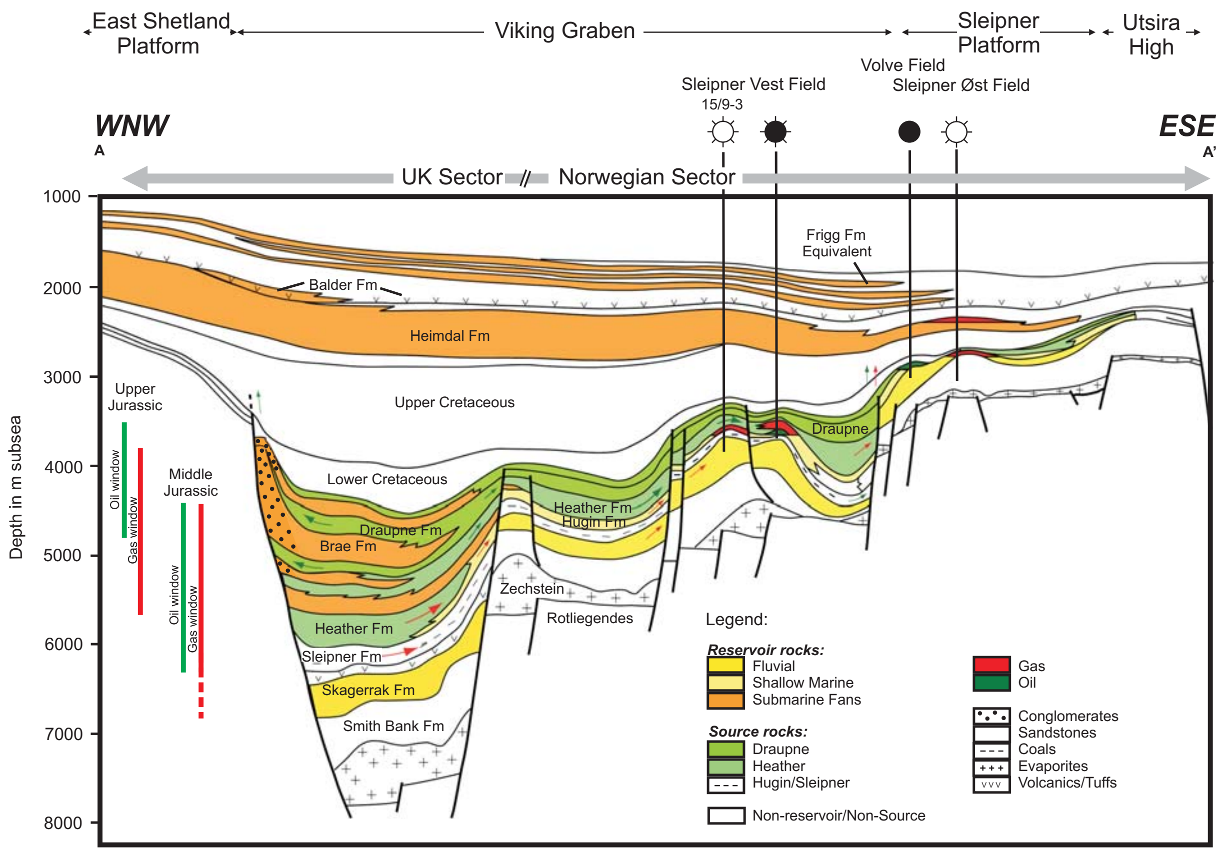

Fig. 4. Schematic structural WNW-ESE cross-section displaying principal source and reservoir rocks and general structure of the South Viking Graben (modified from Isaksen et al., 1998). Depth of the oil and gas window ($Tr_{Oil/Gas}$ = 5-90 %) for Upper and Middle Jurassic source rocks is taken from *Paper 4*. For location of the cross-section see Fig. 1.

Cretaceous in the study area is mostly mudprone with carbonatic intervals (Fig. 5) (Oakman and Partington, 1998). Basin wide subsidence occurred from Late Cretaceous on and uplift and erosion of the East Shetland Platform gave rise to the deposition of Paleocene and Eocene submarine fans including the Frigg Formation as well as the Balder and Heimdal formations of the Rogaland Group (Fig. 4, 5).

Three further episodes of uplift, erosion and subsequent deposition of sand-rich units are recorded in the Oligocene and Miocene (Rundberg and Eidvin, 2005). The most significant uplift episode is responsible for basin shallowing and a widespread unconformity in the Middle Miocene (Fig. 5) (Løseth and Henriksen, 2005; Rundberg and Eidvin, 2005). Pliocene sediments were deposited in response to further uplift of the Scotland Shetland area. The Quaternary was dominated by high subsidence rates reaching up to 300 m/Ma and deposition of glaciomarine sediments

.

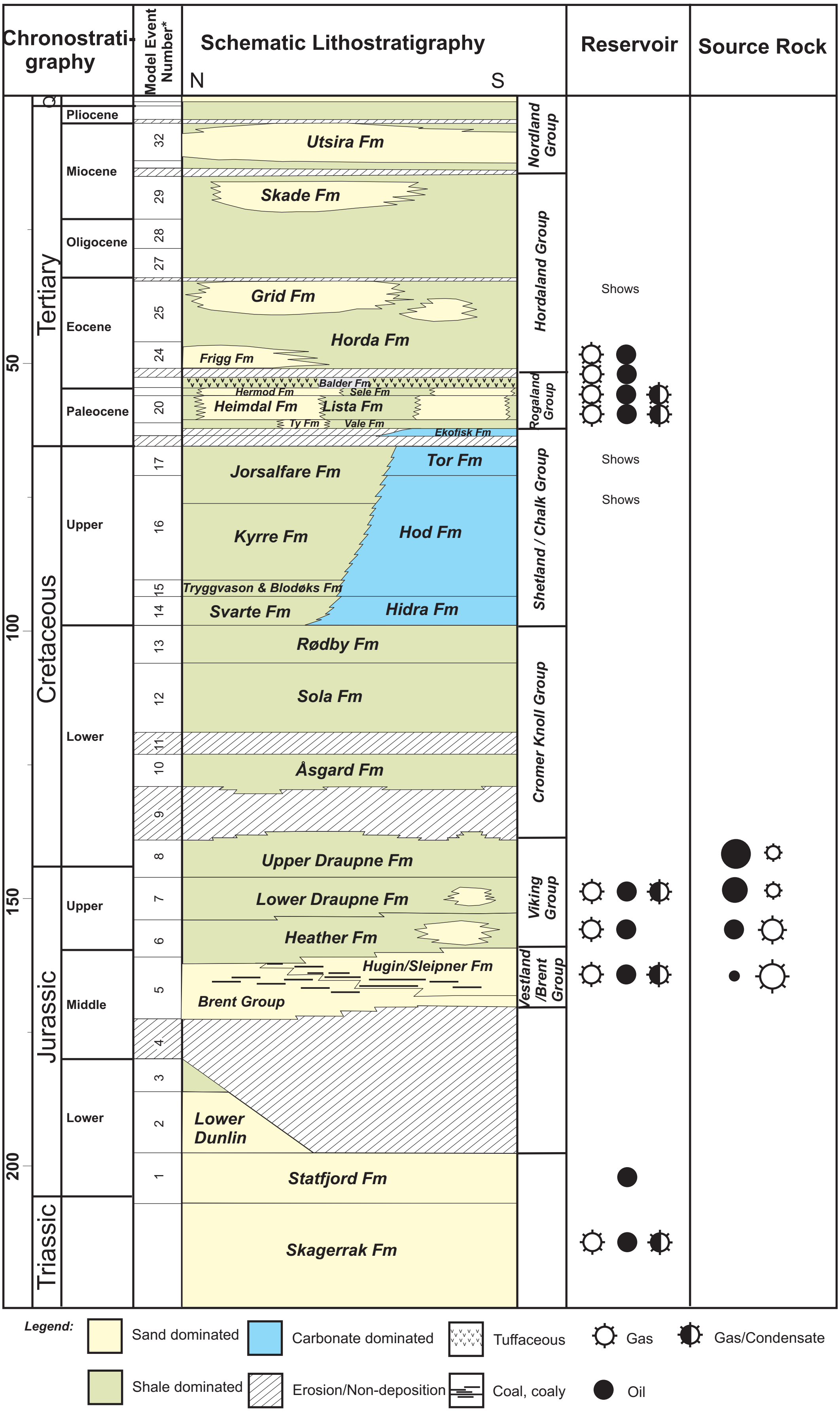

Fig. 5. Generalised stratigraphic column for the South Viking Graben. Stratigraphic intervals containing source or reservoir rocks are indicated. Principal hydrocarbon type in the reservoirs and principal hydrocarbon products generated from source rocks are indicated by symbols. The symbol size for the source rock products indicates the dominating product. (*Model events used in *Paper 4*)

2. Source rocks (Paper 1 and 2)

Several active source rock horizons have been identified previously in the South Viking Graben, including the Upper Jurassic Draupne and Heather formations (e.g. Goff, 1983; Field, 1985; Isaksen and Ledje, 2001) as well as the coals and carbargillites of the Middle Jurassic Hugin and Sleipner formations (Larsen and Jaarvik, 1981; Isaksen et al., 2002). In addition, the shales of the Dunlin Formation have been proposed as a source rock unit (Jones et al., 2003). They are, however, in general too lean and inertinitic to serve as source rock for oil and gas in this area (Thomas et al., 1985; Husmo et al., 2003). The variation of facies and quality of the source rocks in the South Viking Graben has been studied in *Paper 1 and 2*. *Paper 1* discusses source rock quality of Upper Jurassic source rocks in a geographical subarea of the South Viking Graben, the Greater Balder Area. The study area was considerably enlarged in *Paper 2* to cover the entire South Viking Graben. The increased quantity of data available for *Paper 2* compared to *Paper 1* allowed the refinement of some of the assumptions of *Paper 1*. In addition, thicknesses of Upper Jurassic source rocks could be mapped in *Paper 2*. In order to unravel regional variations in source rock potential, thickness and molecular properties and to understand the development of the Middle and Upper Jurassic source rock system, the following methods have been applied in *Paper 1 and 2*:

The geochemical properties of cutting samples were investigated by Rock-Eval, GC and GCMS (*Paper 1, 2*) as well as carbon isotopic analysis (*only Paper 2*). The Upper Jurassic section was subdivided into syn- and post-rift segments based on sequence stratigraphic information and well log pattern. Isochore thickness maps for the Heather, the lower (syn-rift) and the upper (post-rift) Draupne Formation were generated from depth maps based on this subdivision (*Paper 2*). This pragmatic approach was chosen since subdivision was not possible from seismic data. Incorporation of sequence stratigraphic information and dating allowed the evaluation of sediment accumulation rates. Traditionally, pyrolysis GC (e.g. Pepper, 1991; Pepper and Corvi, 1995) or visual kerogen description data (e.g. Mukhopadhyay et al., 1985) is employed to determine the oil and gas potential of source rocks. Unfortunately, this type of data is often scarce in large regional geochemical data bases such as the one available for this study. Therefore, readily available Rock-Eval data were used in combination with the method described in *Paper 5* to determine the oil and gas potential of the Upper Jurassic sections. This method uses Rock-Eval S2 and TOC in a cross-plot to deconvolute the contribution of inert, gas-prone and oil-prone material to the overall TOC of a source rock unit (*Paper 5*). All Rock-Eval data have first been maturity corrected using the method by Espitalié et al. (1987). The resulting information on oil and gas potential was subsequently used to create maps. The Middle Jurassic section was only evaluated using maturity corrected bulk Rock-Eval data due to a lack of data (*Paper 2*). Further evaluation of quality variations within the Upper and Middle Jurassic source rock system has been achieved using molecular and isotopic data and interpretation of their regional and stratigraphic variations. Rock-Eval data and molecular data were used together with information on sediment accumulation rates in an attempt to derive more information on the controls on source rock deposition and preservation.

The study of the Upper and Middle Jurassic source rocks in the South Viking Graben (*Paper 1, 2*) shows that their facies and quality are highly variable in a stratigraphic and regional sense. The Middle Jurassic source rocks show wide ranges of TOC and Hydrogen Index (HI) values as a function of their mixed lithology including sand, shale and coaly shale, but generally low maturity corrected HI values typical for gas-prone rocks (*Paper 2*). According to Isaksen et al. (1998), the Middle Jurassic coals and carbargillites in the area show the potential to generate gas and to minor extent liquids. The Upper Jurassic source rocks display a trend of increasing oil potential upwards and show strong influence of dilution by inert and gas-prone material transported by mass flows from surrounding highs (*Paper 1, 2*). These mass flows were triggered by the rifting activity and are typically encountered in the syn-rift section, while the post-rift section shows little or no mass flow influence (Fraser et al., 2003). The up to 930 m thick Heather Formation is with average maturity corrected TOC and HI values of 3.6 wt% and 184 kg HC/t C_{org} a relatively lean, mostly gas-prone source and has received large amounts of gas-prone as well as inert material from surrounding highs through mass flow processes. The lower Draupne Formation of up to 1600 m thickness shows an even higher influence of gas-prone and inert material concentrated in areas that received mass flows. The oil potential is, however, higher than in the Heather Formation. Average restored TOC and HI values for the lower Draupne Formation are 4.1

wt% TOC and 234 kg HC/t C_{org}. Most oil-prone unit with 5.3 wt% TOC and 340 kg HC/t C_{org} is the up to 330 m thick upper Draupne Formation. It was deposited after cessation of the rifting in the area and is therefore virtually free of mass flow influence.

The observed dilution effect by gas-prone and inert material is amplified by clastic dilution. Average linear sediment accumulation rates are highest in the Heather Formation (20 m/Ma) and decrease drastically to the upper Draupne Formation with 7 m/Ma. Low accumulation rates and reduced clastic dilution coupled with reduced dilution by gas-prone and inert material and widespread anoxia are therefore responsible for the highest concentrations of oil-prone organic matter in the upper Draupne Formation (*Paper 2*), not as assumed in *Paper 1* enhanced preservation in pool-like areas of stagnant water.

Molecular and isotopic data support the source rock mapping data and indicate increased marine, oil-prone influence upwards. Detailed molecular analysis also revealed the gradual decrease of oxygenation upwards (*Paper 1, 2*) and the spreading of anoxic conditions in the area (*Paper 2*), as suggested by the upward decrease of the Pr/Ph and the C_{34}/C_{35} homohopane ratio and the increase in relative abundance of 17α(H),21β(H)-28,30-bisnorhopane. An attempt was made to use bisnorhopane as stratigraphic marker in the area (*Paper 1*). Although this failed, the results yielded valuable information relating the occurrence of bisnorhopane to the degree of oxygenation of the source rock at time of deposition. The decrease of oxygenation observed is probably related to a gradual ascent of the O_2:H_2S interface from Callovian to the Ryazanian. Interpretation of Pr/Ph ratios together with TOC data has shown that the degree of oxygenation affects the oil potential.

The oil and gas potential of the Upper Jurassic source rocks in the area is therefore controlled by the interplay of clastic dilution, dilution by gas-prone and inert organic matter and the degree of oxygenation.

3. Reservoired hydrocarbons (Paper 3)

The reservoirs in the South Viking Graben contain a wide range of hydrocarbons of different composition. The Frigg area in the north (Fig. 1) is predominantly gas-prone, while the Greater Balder Area (Fig. 1) contains large volumes of oil (Table 1). Detailed geochemical analysis of source rock samples as well as oil and condensate samples from all major accumulations in the area was carried out to characterise reservoired hydrocarbons in the area and establish genetic relationships between oils and source rocks.

Analysis of 61 oil and condensate samples included determination of API gravity, group type determination by TLC-FID and preparative group type separation by MPLC. This was followed by GC and GCMS of the saturate hydrocarbon fraction and carbon isotopic analysis of the saturate and aromatic fractions. Data for five additional oil samples has been acquired from NPD (2005). Variations in API gravity with depth have been investigated to establish regional trends useful for API gravity prediction. The thermal maturity of the oils and condensates has been evaluated based on sterane and hopane isomerisation parameters. Assessment of biodegradation and subsequent ranking on the scale of Peters and Moldowan (1993) was based on API gravities, gross geochemical composition as well as inspection of GC and GCMS data of the saturate hydrocarbon fractions. After selection of correlation parameters not affected by maturation or secondary alteration processes, including tricyclic terpanes and carbon isotopic composition, oil-oil correlation was performed. Conventional cross-plots of parameters as well as multivariate analysis using *SIRIUS*® have been used in this process. Detailed molecular data from *Paper 1 and 2* was used for correlation with source rocks in the area. The differences in molecular and isotopic characteristics of the Upper and Middle Jurassic source rock sections have been determined based on all available data, and the established oil families have been related to specific source rock sections.

The oils and condensates in the South Viking Graben span a wide range of API gravities from heavy oils with 17.1° to light hydrocarbons with 64.7° API. Separate depth trends have been discovered for accumulations in reservoirs of Tertiary and Pre-Tertiary age. A rapid increase in API gravity with depth of 6.1° API/100 m is observed in the Tertiary system, while the loosely correlated samples from Pre-Tertiary accumulations show a less rapid decrease with only 3.0° API/100 m. A similar relationship has been observed by Barnard and Bastow (1991). The very heavy oils, such as the oils from the Balder and Grane fields, have been affected by biodegradation. Although

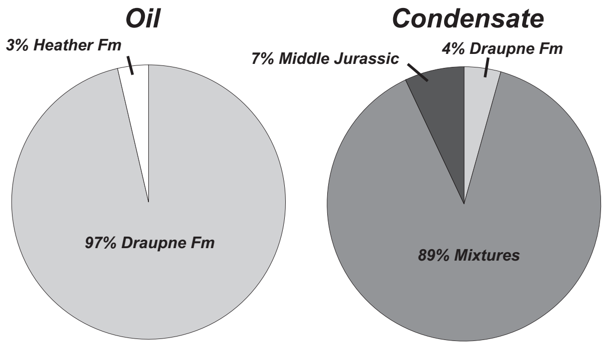

Fig. 6. Pie charts indicating the genetic origin of analysed oil and condensate samples. The correlation in *Paper 3* suggests that the largest volume of oil (97 %) originates from the Draupne Formation, while 89 % of the condensates can be considered mixtures from Upper and Middle Jurassic source rocks.

biodegradation is a widespread phenomenon in the South Viking Graben, degraded oils have only been encountered in reservoirs of Tertiary age. The analysed sample set includes samples reaching biodegradation levels of up to 6 on the scale of Peters and Moldowan (1993). Samples from the Balder, Grane and Ringhorne fields show signs of multiple charge phases. Only slightly degraded present day n-alkane envelopes suggest minor biodegradation, while the presence of 25-norhopane is evidence of a remnant phase of severe degradation. Evaluation of geochemical information in combination with associated depth and reservoir temperature indicates that the regional cut-off value for biodegradation in the South Viking Graben is 70°C.

The level of thermal maturity of the analysed oil samples, established by saturate biomarker ratios, indicates that the bulk of the samples has been generated from the onset of oil generation to the early stages of main oil generation. The highest maturity signature is shown by samples from Sleipner Øst, Vest and Well 15/8-1, whereas samples from Sigyn, Loke, Well 15/12-8 and 16/1-4 show the lowest maturities. Since all reservoired hydrocarbons are mixtures from sources of different facies and/or maturity stages (Wilhelms and Larter, 2004), these maturity determinations can, however, only be coarse estimates.

Detailed evaluation of biomarker parameters as well as carbon isotopic composition of saturate and aromatic fractions enabled the identification of seven different oil families and two subfamilies. Multivariate analysis of the biomarker data fully supported this subdivision. After thorough analysis and determination of characteristic features of the respective source rock units, the established oil families were successfully related to source rock units. This allowed an association of 84 % of all oil and condensate resources in the Norwegian South Viking Graben with a primary source rock horizon. The dominance of the Draupne Formation is overwhelming in the area, as 97 % of all typed recoverable oil resources are Draupne Formation sourced, while the Heather Formation only contributes 3 % (Fig. 6). Almost all condensates, on the other hand, originate from the Middle Jurassic source rocks or represent mixtures from Upper and Middle Jurassic sources (Fig. 6).

Hydrocarbons sourced from the Upper Jurassic Draupne Formation are most widespread and can be grouped in 3 families. More than 91 % of the total Draupne sourced oil volume is reservoired in Paleogene rocks (Fig. 7). The Heather Formation was associated with one family which is only encountered north of 59'30°N in reservoirs of Pre-Tertiary age. Purely Middle Jurassic sourced hydrocarbons were only encountered in the Sigyn Field to the east of Sleipner. Although no discrete mixing models have been

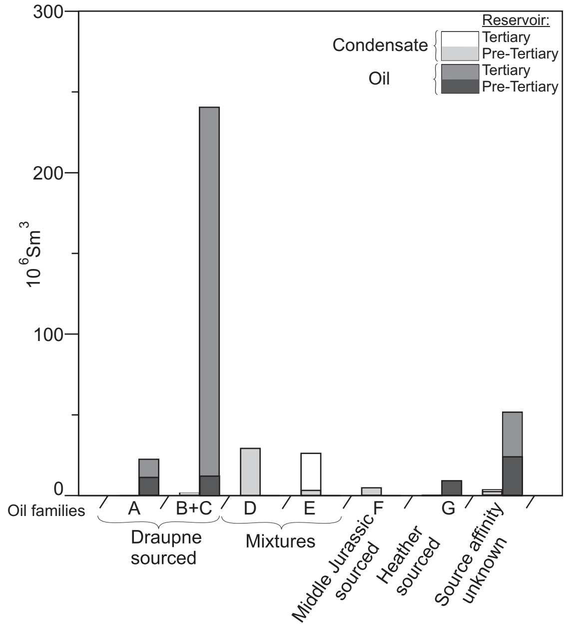

Fig. 7. Oil typing in *Paper 3* reveals seven families related to three main source rock horizons. A total of 84 % of the resources on Norwegian sector could be typed. The results support the fact that the Draupne Formation is the main source for liquid hydrocarbons in the area and show that the most prolific play model is "Draupne source-Paleogene reservoir".

developed based on geochemical parameters, mixing of hydrocarbons from different sources is evident in the Sleipner area, where Middle and Upper Jurassic derived liquids mix in different proportions. The distribution of oil families in the area, especially in the Sleipner area south of 58’40°N, can be used to constrain the migration history in the area.

4. Maturation and generation (Paper 4)

A map based pseudo-3D basin model was used to investigate geothermal history and petroleum generation in the South Viking Graben. In order to do that, the geohistory of 38 well and 8 pseudo-well sites has been simulated using a forward modelling approach with the software *TERRAMOD*®. 1D-model output data was then used in combination with subsurface maps and source rock potential maps to create a pseudo-3D basin model with the mapping software *IRAP*®.

The conceptual input model for the 1D simulation comprises 36 isochronous geological events of Lower Jurassic to Quaternary age (Fig. 5), which were determined from completion logs, seismic, subsurface maps as well as sequence stratigraphic information. 1D model optimisation was carried out by iterative matching of modelled TTI vitrinite reflectance with measured vitrinite reflectance data as well as matching of porosity and borehole temperature data. Sterane and hopane isomerisation data were employed as check parameters. The heatflow history of the area was determined by matching modelled temperature, vitrinite reflectance as well as sterane and hopane data to observed values. Timing and magnitude of the peak heatflow during the Jurassic rifting episode is based on a geological model of the area as well as data from Dahl and Yükler (1991) and Dahl and Augustson (1993). Hydrocarbon generation from Upper Jurassic source rocks was modelled using four component compositional kinetic schemes after Burnham and Dahl (1993) and Dahl and Meisingset (1996), while the scheme of Espitalié et al. (1988) was used to model generation from Middle Jurassic sources. Upon completion of the 1D simulations, the model output was transferred to the simulation database, *BASXYZ*, and a pseudo-3D model was set up in *IRAP*® from the 1D model outputs, source rock potential maps (*Paper 2*) and depth maps for 13 stratigraphic horizons. In addition, simplified bulk source rock maps for the Middle Jurassic were created from information on shale and coal content and Rock-Eval data. Missing depth maps were interpolated and structural reconstruction based on stepwise removal of layers, decompaction and application of paleo-water depth maps was carried out.

Transformation ratio maps for four pseudo-components were created from maps of the modelled vitrinite reflectance and the relationship between modelled Ro and transformation ratios (after Dahl and Meisingset, 1996) applying kriging with external drift algorithms.

Generated and expelled hydrocarbon volumes were calculated from source rock potential maps based on transformation ratio maps and algorithms for primary and secondary cracking after Braun and Burnham (1992) as well as a saturation controlled expulsion model. In order to match observed hydrocarbons volumes associated with Middle Jurassic sources as identified in *Paper 3*, expulsion parameters for Middle Jurassic source rocks were adjusted to retain the bulk of the generated liquids in the source rock and let them be cracked to gas before expulsion.

The results of the modelling have shown that the geohistory of the area can be subdivided into five distinct periods after the source rock deposition in the Middle and Upper Jurassic, starting with a period characterised by low subsidence rates in the Lower Cretaceous (Fig. 8). The onset of rapid subsidence occurred in the Upper Cretaceous. Even higher subsidence rates are typical for the Paleocene to Oligocene period. Basin shallowing, related to uplift, caused reduction in subsidence rates in the Miocene and Pliocene (Fig. 8). The Quaternary showed renewed subsidence related to the glaciations. The source rocks in the area have only reached maturity in the graben, while the flanks and the adjacent highs remain immature. Mapping of modelled present day transformation ratios revealed that Middle Jurassic source rocks have not realised their entire hydrocarbon potential in the graben, while the lower Draupne and Heather Formation nearly exhausted their potential in the deeper sections due to faster reaction kinetics. As the shallowest unit, the upper Draupne Formation, which is the richest source, is not fully mature in the South Viking Graben. Onset of kerogen transformation at a level of 5 % occurred as early as the Lower Cretaceous for the deepest parts of the graben for the Middle Jurassic source rocks. The Heather Formation commenced hydrocarbon generation also in the Lower Cretaceous but in a broader area than the Middle Jurassic source rocks. The lower

Draupne Formation reached transformation ratios of 5 % from the Paleocene to the Oligocene in the main part of the graben. The shallowest unit, the upper Draupne Formation, followed earliest in the Paleocene with the major parts of the graben reaching 5 % of kerogen transformation in the Eocene to Middle Miocene.
Hydrocarbon generation and expulsion are strongly controlled by the basin development, as suggested by two distinct

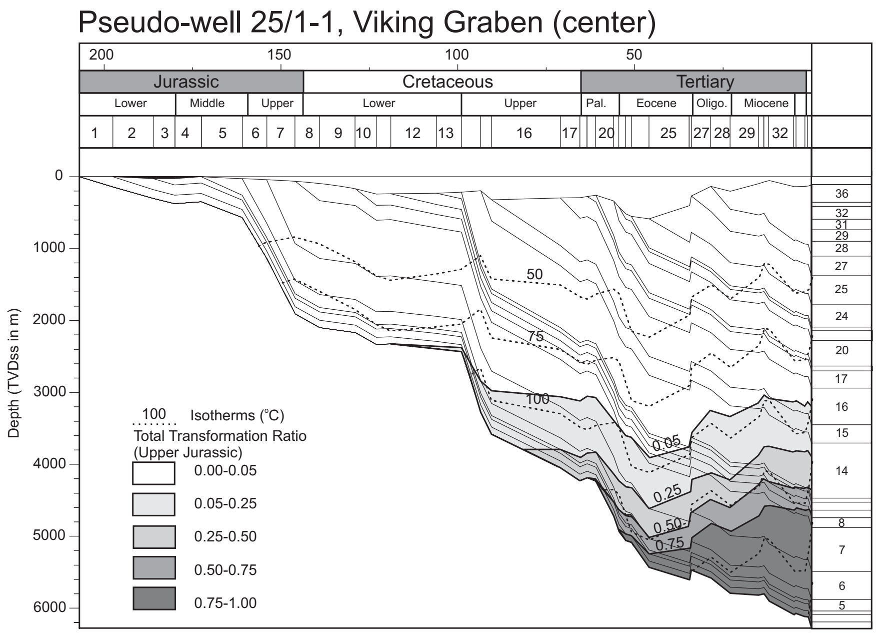

Fig. 8. Geohistory plot for a pseudo-well location (P25/1-1) in the Greater Frigg Area. The transformation ratio development displayed applies to the Upper Jurassic source rocks.

phases of hydrocarbon expulsion related to subsidence in the early Tertiary and the Quaternary. Reduced expulsion of hydrocarbons can be observed from Middle Miocene to the Pliocene related to basin shallowing and reduced subsidence rates. According to the expulsion model applied, onset of major oil and gas expulsion from Upper Jurassic source rocks was in the Paleocene (61 Ma). This phase peaked in the Lower Miocene and ended in the mid Miocene. The first expulsion phase from Middle Jurassic source rocks began somewhat later due to different expulsion behaviour and kinetics of this source rock unit. Gas was expelled from the Lower Eocene on, while oil was first expelled from the Lower Miocene on, due to higher expulsion thresholds for oil in the coaly Middle Jurassic source rocks. All source rocks showed reduced expulsion in the later part of the Miocene and Pliocene related to basin shallowing. Renewed expulsion in the second, Quaternary phase is related to the rapid subsidence during this period.

Modelling suggests that a total of 74198 x 10^6 Sm^3 oil and 8218 x 10^9 Sm^3 gas has been generated in the area. The Greater Frigg kitchen in blocks 25/1 and 30/10 is the most gas-prone area, while the Greater Balder kitchen in blocks 24/9 and 24/12 is the most oil-prone area. Oil expelled from the lower Draupne Formation dominates in the South Viking Graben with 54 %, while only 21.5 % of all oil is expelled from the Heather Formation. The limited thickness and lack of maturation of the upper Draupne Formation are responsible for the fact that only 24 % of all oil derives from this formation, although *Paper 1 and 2* have shown that this is the richest source. The Sleipner and Hugin formations only expel liquid hydrocarbons in the southern part of the study area and contribute 0.5 % to the total liquid yield. The Heather Formation dominates gas expulsion with 38 % of the total yield for the area, followed by the lower Draupne Formation with 31 % and the Middle Jurassic with 26 %. The highly oil-prone upper Draupne Formation only contributes 5 % of the total expelled gas. When discussing expelled hydrocarbon volumes in the area, the significance of the Quaternary phase of subsidence is evident since more than 11 % of all oil and 13 % of all gas was expelled in this second phase.
The modelled expelled oil and gas volumes allow the evaluation of the remaining potential of the area by calculation of generation-accumulation efficiencies. Comparison of modelled volumes with estimates of in-place volumes

calculated from average recovery factors and reported recoverable volumes from Ministry of Petroleum and Energy (2005) and Eriksen et al. (2003) yielded generation-accumulation efficiencies between 1.01 and 1.06 % for oil and between 9.67 and 12.89 % for gas.
Compared to values from other petroleum systems, as for example in Magoon and Valin (1994), these values are low and indicate that significant volumes were either lost or are still to be found. These values are therefore encouraging for further exploration of the area.

5. Migration

A number of different secondary migration processes seem to be active in the South Viking Graben. They range from very short distance migration to long distance vertical migration processes.
A major problem in this area is that the most important source rock unit, the Upper Jurassic Draupne Formation, is not directly over- or underlain by carrier beds (Barnard and Bastow, 1991; Kubala et al., 2003). Especially the migration of hydrocarbons sourced from Upper Jurassic rocks into the Paleocene and Eocene reservoirs remains poorly understood (Johnson and Fisher, 1998). At present, it is assumed that hydrocarbons migrate into Middle Jurassic sandstone intervals and continue lateral, eastward-oriented migration through Jurassic sandstones until migration conduits terminate against faults. This long distance, up-flank migration is best developed in fairly unfaulted areas with regionally extensive sandstone units as in the Sleipner area (Kubala et al., 2003). Subsequent vertical migration occurs along fault planes of the western margin of the Utsira High into the Tertiary system (Barnard and Bastow, 1991; Isaksen and Ledje, 2001; Kubala et al., 2003). This process is facilitated by fault reactivation in the early Tertiary (Barnard and Bastow, 1991). Migration continued in the Tertiary system, where subtle late Cenozoic tectonic movements influenced the lateral migration directions (Larter et al., 2000). The Middle Jurassic as well as the early Tertiary both have to be considered as carrier beds for accurate secondary migration modelling and used in combination with information on fault pattern and structural reconfiguration of the area through time.
Further modes of secondary migration in the area include short distance migration in cases where source and reservoir are juxtaposed or interbedded, as for example in the Gudrun Field, and vertical migration processes in the Frigg area (Kubala et al., 2003). Different mechanisms have been proposed for the vertical migration through an extensive shale overburden in the Frigg area, including overpressure induced diffusion and hydrodynamic transport of gas in solution (Goff, 1983) and migration through faults and microfractures (Kubala et al., 2003).
Although a specific study of the secondary migration with associated simulations has not been undertaken, information on secondary migration has been obtained in *Paper 3* and *Paper 4*. Oil typing and establishment of genetic relationships followed by mapping of the distribution of the various oil families (*Paper 3*) revealed important secondary migration features. Migration in the Pre-Tertiary system is evident in the area north of 59°30'N, where Heather Formation sourced hydrocarbons have been found. Complex mixing has been observed in the Greater Sleipner area, where Draupne sourced hydrocarbons from the northwest mix with Middle Jurassic sourced hydrocarbons from the southwest. The light hydrocarbons in the Sigyn Field represent the Middle Jurassic endmember and probably an early charge phase before the migration routes into the field were shut down (*Paper 3*).
Eight mega drainage areas charging geographic subregions in the area have been identified in *Paper 4* based on analysis of orthocontour maps of the Top Middle Jurassic surface as carrier bed. Drainage area determination at five different time steps also reveals significant changes in basin configuration during the Tertiary. These changes affect the Stord Basin and the drainage towards the Norwegian mainland, while the configuration of the deep basinal area remains largely unaffected.

6. Reservoir rocks

After complex migration through faults and Middle Jurassic as well as Tertiary strata, hydrocarbons have accumulated in reservoirs of Triassic to Tertiary age (Fig. 5, Table 1). All major hydrocarbon accumulations encountered in the Norwegian South Viking Graben have been found in clastic reservoirs.

The oldest reservoir units are the sandy alluvial fan deposits (Steel and Ryseth, 1990) of the Skagerrak Formation of Triassic age (Fig. 5), where oil, gas and condensate have been encountered. The Rhaetian to Aalenian aged sandstones of the Statfjord Formation, deposited mainly in fluvial environment (Ryseth, 2001), contain oil for example in the Ringhorne Field (Fig. 5). Of greater economic importance are the reservoir units of Middle Jurassic age, which can contain oil, gas as well as condensate. Accumulations in these reservoirs include the Sleipner Vest Field and the Lille Frigg Field. The Hugin Formation (Fig. 4, 5) contains shallow marine shoreface sandstones (Vollset and Doré, 1984) with up to 22 % porosity and 0.4 D permeability in the Sleipner Øst Field (Østvedt, 1987), whereas the Sleipner Formation comprises fluviodeltaic sandstones, shales and coal. The Brent Group reservoirs comprise sandstones deposited in shallow marine to coastal plain environment.

Although the Upper Jurassic Draupne and Heather formations are more commonly regarded as the primary source rocks in the area, they also contain important reservoir units containing oil, gas and condensate (Fig. 5). These units accumulated in two main depositional environments, including shallow marine coastal and deep marine slope apron fan systems of the Brae trend (Stow et al., 1982; Rattey and Hayward, 1993). The sands show excellent reservoir properties of up to 30 % porosity and 2 D permeability (Fraser et al., 2003). Intra-Heather Formation sandstones deposited in middle to lower shoreface to lower offshore transition setting are the reservoir in the Varg Field (Battié et al., 2005), while the deep marine intra Draupne Formation sandstones form the reservoir in the Gudrun Field.

The reservoirs of Paleogene age, especially in the Rogaland Group, are volumetrically most important in the South Viking Graben (Fig. 7). The biggest oil and gas accumulations are in Tertiary rocks including the Balder, Grane, Heimdal and Frigg fields. These reservoir units are deep marine fan sandstones deposited in response to the uplift of the East Shetland Platform in the early Tertiary (Isaksen and Tonstad, 1989; Jenssen et al., 1993). Most prominent Paleocene reservoir unit is the Heimdal Formation (Fig. 4, 5) with porosities well above 20 % and permeabilities in the Darcy range (Bergslien, 2002). But hydrocarbons are also encountered in the sands of the Balder and Hermod formations. While oil, gas and condensate have been found in the Heimdal and Hermod formations, the Balder Formation has only yielded oil and gas in the area (Fig. 5). Minor shows have been encountered in the Grid Formation of Eocene age, but the Lower Eocene Frigg Formation can be considered as the youngest significant reservoir unit. The Frigg Formation in the area has been found to contain oil and gas (Fig. 5). This unit comprises submarine fan sandstones reaching porosities of 2 to 32 % and permeabilities from 1.2 to 1.6 D in the Frigg gas field (Heritier et al., 1979).

7. Trap formation, seal rocks and accumulation

The trapping style in the South Viking Graben is variable and includes structural and stratigraphic traps, combinations of both types as well as traps influenced by salt tectonics (Table 1).

Triassic traps in the South Viking Graben are of structural nature in rotated fault block settings and formed during the Jurassic rifting episode (Pegrum and Spencer, 1990; Goldsmith et al., 2003). Reservoirs are commonly sealed by Lower to Upper Jurassic shales or subcrop below the near base Cretaceous unconformity (Johnson and Fisher, 1998). The majority of Lower to Middle Jurassic accumulations are in tilted fault block traps which developed during the mid to late Jurassic rifting episode (Pegrum and Spencer, 1990). Seals are commonly the Upper Jurassic shale or, in case of erosional truncation, the Cretaceous shales (Pegrum and Spencer, 1990). Combination of salt movement, Jurassic rifting and reactivation of older faults is responsible for trap formation in the Middle Jurassic reservoirs of the Sleipner area (Husmo et al., 2003). The trapping style for accumulations in Upper Jurassic units is highly variable and includes structural and stratigraphic traps or combination traps also formed during the Jurassic rifting (Pegrum and Spencer, 1990; Johnson and Fisher, 1998). Pure stratigraphic traps are rare, while combination traps such as the

intra Draupne Formation slope apron fans as in Well 25/7-2, are common. Cap rocks are the Upper Jurassic shales or overlying shaly units of Cretaceous age. Accumulation of hydrocarbons in the traps formed during the Jurassic rifting episode is therefore possible from the start of the first major expulsion phase in the Paleocene.
Several trapping mechanisms are encountered in Paleocene reservoirs. Although structural traps and stratigraphic traps related to lateral pinchout occur, combination traps are most widespread in the Paleocene and have shown to be the most successful exploration target in the South Viking Graben. These traps are related to depositional geometry of the reservoir sandstones, enhancement by differential compaction of the surrounding shale envelope and deformation and remobilisation processes (Pegrum and Ljones, 1984; Jenssen et al., 1993). According to Pegrum and Ljones (1984) and Jenssen et al. (1993), trap formation occurred between the Lower and Late Eocene. Eocene accumulations also show combination traps as for example in the Frigg Field (Heritier et al., 1979). Trap formation also occurred in the Eocene soon after reservoir deposition. Cap rocks for Paleocene and Eocene traps are the Lower to Middle Eocene shales. Hydrocarbon accumulation in Paleogene reservoirs is therefore first possible after trap formation and seal rock deposition in the Eocene (34.5 Ma).

8. Summary and conclusions

At least three petroleum systems can be identified in the South Viking Graben based on the occurrence of seven distinct oil types and their relation to three active source horizons established in *Paper 3* (Draupne Formation, Heather Formation and Middle Jurassic Vestland Group). Naming of the petroleum systems strictly following the convention of Magoon and Dow (1994) is difficult since there are numerous reservoir horizons involved. Predominant reservoir units associated with oil families in the area have been determined in *Paper 3*. The Heather and Draupne sourced systems were grouped and named Viking-Rogaland (!) petroleum system after the source rocks in the Viking Group and the predominant reservoirs in the Rogaland Group of Tertiary age (Fig. 9a). In addition to this system, the Vestland-Vestland (!) system, named after the Middle Jurassic source rocks of the Vestland Group and the associated sandstone reservoirs in the same unit (Fig. 9b), can be identified. These names are of pure theoretical nature and different names might be applied to geographical subregions, such as the Greater Balder Area, where the Draupne-Heimdal (!) system has been identified (*Paper 4*).
In addition to the Rogaland Group reservoirs, the Viking-Rogaland (!) petroleum system includes reservoir horizons in the Upper Jurassic Draupne and Heather Formation, the Middle Jurassic sandstones of the Brent and Vestland Groups, the Lower Jurassic Statfjord Formation and the Triassic Hegre Group (Fig. 9a). More than 91 % of all Upper Jurassic sourced oils are reservoired in Tertiary rocks of the Rogaland Group (Fig. 7). As mentioned before, oil typing has shown that 97 % of all Upper Jurassic sourced oils have a Draupne Formation origin, while only 3 % appear to be sourced from the Heather Formation (Fig. 6). The fact that some Draupne sourced oils show a geochemical signature most consistent with the upper Draupne Formation could be related to preferential drainage of this unit or overprint by a later charge phase from the upper Draupne Formation. Cap rock for the Tertiary reservoirs are the Lower Eocene shales, while the Upper and Middle Jurassic reservoirs are capped by Upper Jurassic shales or, in case of structural traps with erosion, Lower or Upper Cretaceous shales might act as seal. Upper and Middle Jurassic shales form the seal for Triassic reservoirs. Trap formation occurred during the Jurassic rifting episode for the Pre-Tertiary reservoirs (Goldsmith et al., 2003; Husmo et al., 2003), while trap formation occurred in the Eocene for the Tertiary reservoirs. Detailed pseudo-3D basin modelling (*Paper 4*) has shown that the first phase of expulsion from the Upper Jurassic source rocks started in the Paleocene and lasted until the beginning of the Middle Miocene (Fig. 9a). As a result of the basin shallowing and uplift in the Miocene, a phase of reduced expulsion occurred in the area from the Middle Miocene to the Pliocene. A phase of renewed expulsion in response to rapid burial followed in the Quaternary (Fig. 9a). The main phase of expulsion from Upper Jurassic source rocks therefore began slightly before trap formation. Estimates show that until the end of the trap and seal formation in the late Eocene (34.5 Ma) only 11 % of the total oil and 12 % of the gas volumes were lost.
Only Viking Group sourced hydrocarbons in Tertiary reservoirs have been found to be biodegraded. This is due to the fact that the Tertiary reservoir temperatures have never surpassed 70 °C which has been established as the regional

cut-off temperature for biodegradation in the area (*Paper 3*). The geographical extent of the petroleum system can be defined after Magoon and Dow (1994) as the pod of active source rock and the area that includes accumulations originating from the source rock. The maximum geographical extent of the petroleum system is shown in Figure 10. The Viking-Rogaland (!) petroleum system has been proven by oil-source correlation in the entire South Viking Graben and extends as far east as 2°50’ W on the Utsira High (Fig. 10). Hydrocarbons with a strong Heather Formation signature can only be found in reservoirs of Pre-Tertiary age north of 59°30’N (*Paper 3*). Minor contributions from the Heather Formation are likely in the remaining part of the study area, but the degree of mixing is difficult to determine due to the geochemical similarities of Heather and Draupne Formation.

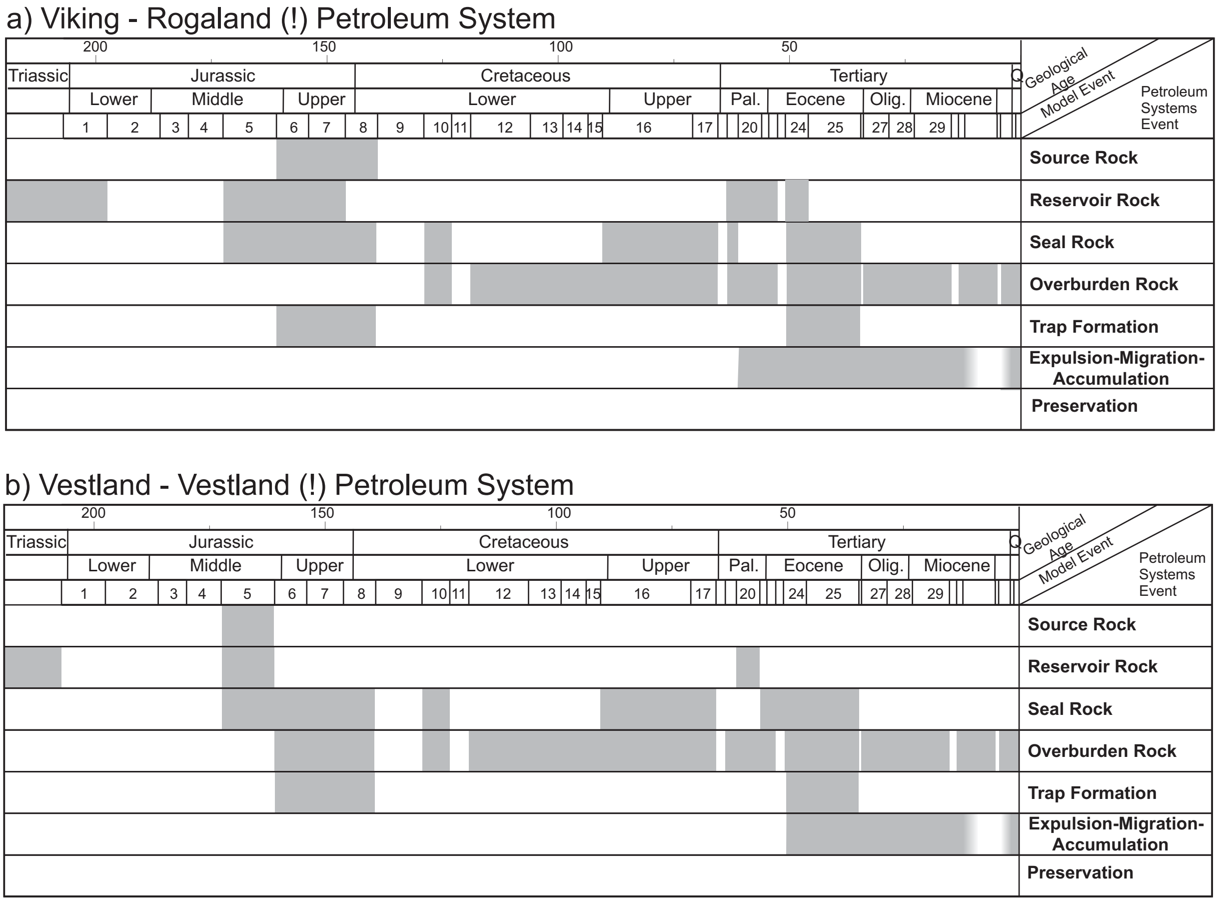

Fig. 9. Petroleum systems charts for the South Viking Graben. Two major systems have been identified and named after convention (Magoon and Dow, 1994). The first system (a) comprises the Upper Jurassic source rocks of the Viking Group (Draupne and Heather Formation) and the Paleogene Rogaland Group (Balder, Heimdal, Hermod formations) as the main reservoir. The source rocks of the second system (b) are the Middle Jurassic Hugin and Sleipner Formation of the Vestland Group, while the main reservoir units are the sands of Middle Jurassic age in the Vestland Group. Since the petroleum systems remain active, there is no preservation time. Critical moment for both systems is at present, as the source rocks are currently at maximum burial depth.

The Vestland-Vestland (!) petroleum system comprises the coaly source rocks of the Middle Jurassic Hugin and Sleipner formations (Vestland Group) and the main reservoir units in the Middle Jurassic Vestland Group (Fig. 9b). Over 64 % of all Middle Jurassic sourced liquid hydrocarbons are reservoired in Middle Jurassic sandstone reservoirs (Fig. 7). The only accumulation identified to be exclusively sourced by the Middle Jurassic is the Sigyn Field. Over 89 % of the condensate volumes typed are mixtures of Upper and Middle Jurassic derived hydrocarbons (Fig. 7). Secondary reservoir units include the Paleocene Heimdal Formation as well as the Triassic Skagerrak Formation. Trapping style and timing is similar to the Viking-Rogaland (!) system. Gas expulsion commenced in the Lower Eocene, while oil expulsion began in the lowest Miocene. Also this petroleum system shows, although less pronounced, two phases of expulsion with renewed expulsion in the Quaternary (*Paper 4*). This first expulsion phase ended in the mid Miocene. The second phase of expulsion in the Quaternary is even of greater magnitude than the

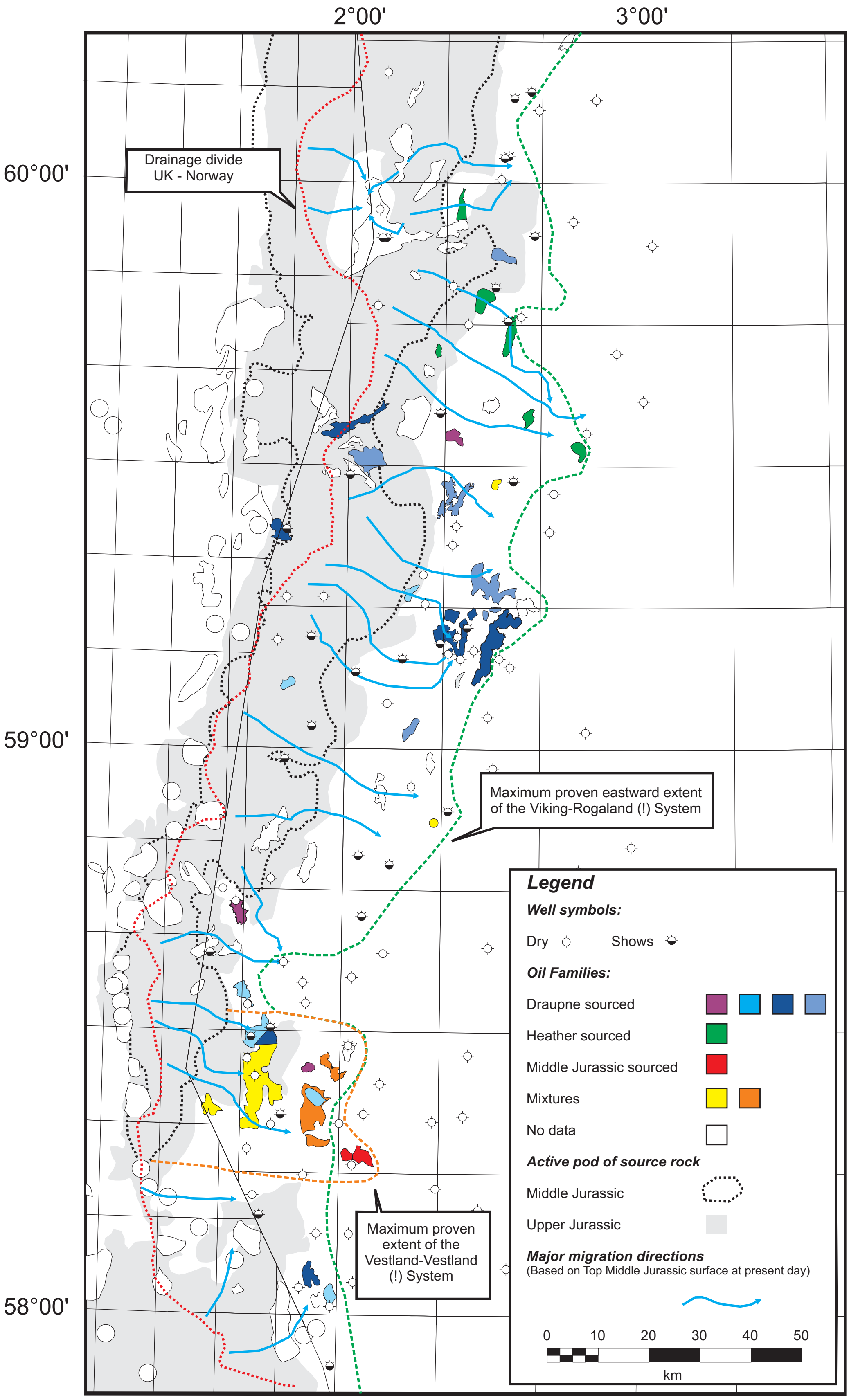

Fig. 10. Petroleum systems map of the South Viking Graben showing fields and discoveries in the area, active pods of source rock for the Upper and Middle Jurassic source rock system, maximum extent of the Viking-Rogaland (!) and Vestland-Vestland (!) petroleum systems as well as distribution of oil families in the area. The pod of active source rock represents the area that expelled more than 1 Sm^3/m^2 oil or 25 Sm^3/m^2 gas. Major secondary migration pathways based on the Top Middle Jurassic surface are also shown as well as location of dry wells and wells with shows.

previous episode. Expulsion occured also before trap formation in the Vestland-Vestland (!) petroleum system (Fig. 9b). Similar to the Viking-Rogaland (!) system, only little hydrocarbon volume (less than 1 % of the oil and 5 % of the total gas volume) has been lost before the last episode of trap formation in the late Eocene (34.5 Ma).

The Vestland-Vestland (!) petroleum system is only proven in the Greater Sleipner Area in the southern half of the study area by the occurrence of Hugin/Sleipner Formation sourced hydrocarbons for example in the Sigyn Field in block 16/7 (Fig. 10) (*Paper 3*). Hydrocarbons showing a possible contribution from Middle Jurassic sources have been found also further north in wells 16/1-4 and 25/8-9. Since these results might be biased by inter-laboratory variation or could be caused by mixing of Draupne and Heather sources, these occurrences were ignored. The fact that the Vestland-Vestland (!) system is restricted to the Sleipner area is probably related to the greater thickness of coals and carbargillites within the Middle Jurassic in this area. The fact that both petroleum systems are active in this area causes complex mixing of hydrocarbons.

In order to assess the remaining hydrocarbon potential of the area, the generation-accumulation efficiencies have been evaluated (*Paper 4*). It was not possible to evaluate the efficiencies for the two petroleum systems separately since not all hydrocarbon accumulations in the area have been typed and correlated to source rocks. It was, however, possible to assess the overall efficiency of the petroleum province of the South Viking Graben. Published recoverable volumes for Norwegian and UK fields in the drainage polygons within the South Viking Graben from NPD (2005) and Eriksen et al. (2003) have been converted to in-place volumes by application of average recovery factors for oil and gas fields. The results have been compared to modelled hydrocarbon volumes. Using a variation of recovery factors, the generation-accumulation efficiencies vary between 1.01 to 1.06 % for oil and 9.67 and 12.89 % for gas. Compared to other published values for generation-accumulation efficiencies (e.g. Dahl and Yükler, 1991; Magoon and Valin, 1994; Kubala et al., 2003) these values are low. This suggests that large hydrocarbon volumes were either lost or have not yet been found in the area. Initial calculations suggest that only insignificant amounts have been lost before trap formation.

The results should therefore be encouraging for further exploration in the South Viking Graben. Although the area can be deemed mature, it is not creamed and offers remaining hydrocarbon potential.

Perspectives and future work

Understanding the geology of a basin requires knowledge of many processes and their interactions. Integration of data is therefore essential in a data driven process such as hydrocarbon exploration. A number of different data types have been successfully employed and integrated in this study of the petroleum systems of the South Viking Graben. Available time, samples or funds occasionally limited the investigation of specific elements. In lack of more detailed data, simplified, pragmatic approaches, such as the method to map Upper Jurassic thicknesses (*Paper 2*), were chosen eventually to proceed further with the project.

Several major elements and processes of the petroleum system have been studied including source rocks (*Paper 1 and 2*), generation (*Paper 4*) and reservoired hydrocarbons (*Paper 3*). Two aspects of the petroleum system, migration and seal rocks, are not sufficiently covered at present and should be examined in follow-up projects. Evaluation of remaining prospects in the area is not possible without the study of secondary migration and evaluation of seal capacities and associated leakage processes. Basin modelling output from *BasinAssist* can be directly used in the buoyancy driven secondary migration model *SEMI* (Sylta, 1991), also capable of conducting equation of state calculations, to evaluate the volume of hydrocarbons in the traps and their physical properties. In this process, knowledge about faults acting as leakage zones or fluid barriers and distribution of overpressure as flow restriction is required. Based on the established geohistory and information on pressure as well as cap rock strength, the maximum oil and gas column heights could be evaluated and enable a more complete prospect evaluation.

In addition to the study of secondary migration and leakage, the present study of the petroleum systems of the South Viking Graben offers several other possibilities for further study or follow-up projects. Among those are a comparison of the TOC-S2 method (*Paper 5*) with other methods of determination of oil and gas potential and further investigation of the controls on source rock facies and potential, including elemental analysis and determination of sulphur isotopic composition of source rock samples. The analysis of reservoired hydrocarbons (*Paper 3*) could benefit from incorporation of gas data and oil samples from the remaining unsampled fields and discoveries which were not available for this project. In combination with gas-source correlation and a volumetric mixing model for the area, this would allow full volumetric assessment of the identified genetic hydrocarbon families and assessment of generation-accumulation efficiencies for each source rock unit. Furthermore, PVT data could be used to verify genetic relationships established by oil-source correlation in *Paper 3* and to assess maturity, mixing and phase separation (di Primio, 2002).

Most critical improvement and possibilities for future work following *Paper 4* include the incorporation of more detailed depth maps. Especially volumetric assessment of the expelled hydrocarbons from Middle Jurassic sources would be greatly improved using more detailed depth maps.

To improve the estimates of hydrocarbon generation and expulsion, a detailed kinetic study of Upper and Middle Jurassic source rocks could be conducted. Using different kinetic models for the Upper Jurassic source rock sections would honour their geochemical differences as suggested by Keym et al. (2006).

Although limitations of the pseudo-3D model have been pointed out in *Paper 4*, a sensitivity analysis and risking of model results as presented for example in Thomsen (1998) has not been performed. Uncertainty analysis could assist in evaluation of the level of confidence of the results.

A further addition to *Paper 4*, which would also be beneficial for the investigation of the petroleum systems, would be the investigation of fluid inclusions. The incorporation of fluid inclusion data would be helpful to constrain basin modelling, migration pathways and timing as well as trap-fill history, PVT properties and fluid composition (Munz, 2001; Tseng and Pottorf, 2002).

References

Baird, R.A., 1986. Maturation and source rock evaluation of Kimmeridge Clay, Norwegian North Sea. AAPG Bulletin 70 (1), 1-11.

Barnard, P.C., Bastow, M.A., 1991. Petroleum generation, migration, alteration, entrapment and mixing in the central and northern North Sea. In: England, W.A., Fleet, A.J. (Eds.), Petroleum Migration. Geological Society Special Publication 59, pp. 167-190.

Battié, J.E., Siggerud, E.I.H., Tveiten, O.G., 2005. Extending the life of the Varg Field, a tail-end production opportunity. In: Doré, A.G., Vining, B. (Eds.), Petroleum Geology: North-West Europe and Global Perspectives - Proceedings of the 6th Petroleum Geology Conference. Geological Society, London, pp. 415-439.

Bergslien, D., 2002. Balder and Jotun; two sides of the same coin? A comparison of two Tertiary oil fields in the Norwegian North Sea. Petroleum Geoscience 8 (4), 349-363.

Bhullar, A.G., Karlsen, D.A., Backer-Owe, K., Seland, R.T., Le Tran, K., 1999. Dating reservoir filling; a case history from the North Sea. Marine and Petroleum Geology 16 (7), 581-603.

Bhullar, A.G., Karlsen, D.A., Holm, K., Backer-Owe, K., Le Tran, K., 1998. Petroleum geochemistry of the Frøy Field and Rind discovery, Norwegian continental shelf; implications for reservoir characterization, compartmentalization and basin scale hydrocarbon migration patterns in the region. Organic Geochemistry 29 (1-3), 735-768.

Braun, R.L., Burnham, A.K., 1992. PMOD; a flexible model of oil and gas generation, cracking, and expulsion. Organic Geochemistry 19 (1-3), 161-172.

Brennand, T.P., van Hoorn, B., James, K.H., Glennie, K.W., 1998. Historical review of North Sea exploration. Petroleum Geology of the North Sea; Basic Concepts and Recent Advances. Blackwell, Oxford, pp. 1-41.

Burnham, A.K., Dahl, B., 1993. Compositional Modelling of Kerogen Maturation. In: Øygard, K. (Ed.), Poster session from the 16th Meeting on Organic Geochemistry. Stavanger, pp. 241-246.

Cornford, C., 1998. Source rocks and hydrocarbons of the North Sea. In: Glennie, K.W. (Ed.), Petroleum Geology of the North Sea; Basic Concepts and Recent Advances. Blackwell, Oxford, pp. 376-462.

Dahl, B., Augustson, J.H., 1993. The influence of Tertiary and Quaternary sedimentation and erosion on hydrocarbon generation in Norwegian offshore basins. In: Doré, A.G., Augustson, J.H., Hermanrud, C., Stewart, D.J., Sylta, Ø. (Eds.), Basin Modelling; Advances and Applications. NPF Special Publication 3, pp. 419-431.

Dahl, B., Meisingset, I., 1996. Prospect resource assessment using an integrated system of basin simulation and geological mapping software: examples from the North Sea. In: Doré, A.G., Sinding-Larsen, R. (Eds.), Quantification and Prediction of Petroleum Resources. NPF Special Publication 6, pp. 237-251.

Dahl, B., Yükler, A., 1991. The role of petroleum geochemistry in basin modeling of the Oseberg area, North Sea. In: Merrill, R.K. (Ed.), Source and Migration Processes and Evaluation Techniques. AAPG Treatise of Petroleum Geology, pp. 65-85.

di Primio, R., 2002. Unraveling secondary migration effects through the regional evaluation of PVT data; a case study from Quadrant 25, NOCS. Organic Geochemistry 33 (6), 643-653.

Eriksen, S.H., Andersen, J.H., Grist, M., Stoker, S., Brzozowska, J., 2003. Oil and gas resources. In: Evans, D., Graham, C., Armour, A., Bathurst, P. (Eds.), The Millennium Atlas: Petroleum Geology of the Central and Northern North Sea. Geological Society, London, pp. 345-358.

Espitalié, J., Marquis, F., Sage, L., 1987. Organic geochemistry of the Paris Basin. In: Brooks, J., Glennie, K.W. (Eds.), Petroleum Geology of Northwest Europe. Graham & Trotman, London, pp. 71-86.

Espitalié, J., Ungerer, P., Irwin, I., Marquis, F., 1988. Primary cracking of kerogens. Experimenting and modeling C_1, C_{2-5}, C_{6-15} and C_{15+} classes of hydrocarbons formed. Organic Geochemistry 13 (4-6), 893-899.

Evans, D., Graham, C., Armour, A., Bathurst, P., 2003. The Millennium Atlas: Petroleum Geology of the Central and Northern North Sea. London, Geological Society.

Færseth, R.B., 1996. Interaction of Permo-Triassic and Jurassic extensional fault-blocks during the development of the northern North Sea. Journal of the Geological Society of London 153 (6), 931-944.

Field, J.D., 1985. Organic geochemistry in exploration of the northern North Sea. In: Thomas, B.M., Doré, A.G., Larsen, R.M., Home, P.C., Eggen, S.S. (Eds.), Petroleum Geochemistry in Exploration of the Norwegian Shelf. Graham and Trotman, London, pp. 39-57.

Fisher, M.J., Mudge, D.C., 1998. Triassic. In: Glennie, K.W. (Ed.), Petroleum Geology of the North Sea; Basic Concepts and Recent Advances. Blackwell, Oxford, pp. 212-244.

Fraser, S.I., Robinson, A.M., Johnson, H.D., Underhill, J.R., Kadolsky, D.G.A., Connell, R., Johannessen, E.P., Ravnas, R., 2003. Upper Jurassic. In: Evans, D., Graham, C., Armour, A., Bathurst, P. (Eds.), The Millennium Atlas: Petroleum Geology of the Central and Northern North Sea. Geological Society, London, pp. 157-189.

Ghazi, S.A., 1992. Cenozoic uplift in the Stord Basin area and its consequences for exploration. Norsk Geologisk Tidsskrift 72 (3), 285-290.

Goff, J.C., 1983. Hydrocarbon generation and migration from Jurassic source rocks in the E Shetland Basin and Viking Graben of the northern North Sea. Journal of the Geological Society of London 140 (3), 445-474.

Goldsmith, P.J., Hudson, G., van Veen, P., 2003. Triassic. In: Evans, D., Graham, C., Armour, A., Bathurst, P. (Eds.), The Millennium Atlas: Petroleum Geology of the Central and Northern North Sea. Geological Society, London, pp. 105-127.

Graue, E., Helland-Hansen, W., Johnson, J., Lomo, L., Nøttvedt, A., Ronning, K., Ryseth, A., Steel, R., 1987. Advance and retreat of Brent delta system, Norwegian North Sea. In: Brooks, J., Glennie, K.W. (Eds.), Petroleum Geology of Northwest Europe. Graham & Trotman, London, pp. 915-937.

Hanslien, S., Olsen, R.G., 2000. Future challenges in exploring the remaining hydrocarbon potential of the Norwegian Continental Shelf. In: Ofstad, K., Kittilsen, J.E., Alexander-Marrack, O. (Eds.), Improving the Exploration Process by Learning from the Past. NPF Special Publication 9, pp. 259-271.

Heritier, F.E., Lossel, P., Wathne, E., 1979. Frigg Field; large submarine-fan trap in lower Eocene rocks of North Sea Viking graben. AAPG Bulletin 61 (11), 1999-2020.

Husmo, T., Hamar, G.P., Høiland, O., Johannessen, E.P., Rømuld, A., Spencer, A.M., Titterton, R., 2003. Lower and Middle Jurassic. In: Evans, D., Graham, C., Armour, A., Bathurst, P. (Eds.), The Millennium Atlas: Petroleum Geology of the Central and Northern North Sea. Geological Society, London, pp. 129-155.

Isaksen, D., Tonstad, K., 1989. A revised Cretaceous and Tertiary lithostratigraphic nomenclature for the Norwegian North Sea. NPD Bulletin 5.

Isaksen, G.H., Curry, D.J., Yeakel, J.D., Jenssen, A.I., 1998. Controls on the oil and gas potential of humic coals. Organic Geochemistry 29 (1-3), 23-44.

Isaksen, G.H., Ledje, K.H.I., 2001. Source rock quality and hydrocarbon migration pathways within the greater Utsira High area, Viking Graben, Norwegian North Sea. AAPG Bulletin 85 (5), 861-883.

Isaksen, G.H., Patience, R., van Graas, G., Jenssen, A.I., 2002. Hydrocarbon system analysis in a rift basin with mixed marine and nonmarine source rocks; the South Viking Graben, North Sea. AAPG Bulletin 86 (4), 557-591.

Jenssen, A.I., Bergslien, D., Rye-Larsen, M., Lindholm, R.M., 1993. Origin of complex mound geometry of Paleocene submarine-fan sandstone reservoirs, Balder Field, Norway. In: Parker, J.R. (Ed.), Petroleum Geology of Northwest Europe; Proceedings of the 4th Conference. Geological Society, London, pp. 135-143.

Johnson, H.D., Fisher, M.J., 1998. North Sea plays; geological controls on hydrocarbon distribution. In: Glennie, K.W. (Ed.), Petroleum Geology of the North Sea; Basic Concepts and Recent Advances. Blackwell, Oxford, pp. 463-547.

Jones, E., Jones, B., Ebdon, C., Ewen, D., Milner, P., Plunkett, J., Hudson, G., Slater, P., Ross, J., Kubala, M., Jolley, D., Groves, S., Sawyers, M., Wathne, E., 2003. Eocene. In: Evans, D., Graham, C., Armour, A., Bathurst, P. (Eds.), The Millennium Atlas; Petroleum Geology of the Central and Northern North Sea. Geological Society, London, pp. 261-227.

Keym, M., Dieckmann, V., Horsfield, B., Erdmann, M., Galimberti, R., Kua, L.-C., Leith, L., Podlaha, O., 2006. Source rock heterogeneity of the Upper Jurassic Draupne Formation, North Viking Graben and its relevance to petroleum generation studies. Organic Geochemistry 37 (2), 220-243.

Kubala, M., Bastow, M., Thompson, S., Scotchman, I., Øygard, K., 2003. Geothermal regime, petroleum generation and migration. In: Evans, D., Graham, C., Armour, A., Bathurst, P. (Eds.), The Millennium Atlas: Petroleum Geology of the Central and Northern North Sea. Geological Society, London, pp. 289-315.

Larsen, R., M., Jaarvik, L.J., 1981. The geology of the Sleipner field complex. Norwegian Symposium on Exploration. Elsevier, Amsterdam, pp. NSE/15.

Larter, S.R., Aplin, A.C., Bowler, B., Lloyd, R., Zwach, C., Hansen, S., Telnæs, N., Sylta, Ø., Yardley, G., Childs, C., 2000. A drain in my graben; an integrated study of the Heimdal area petroleum system. Journal of Geochemical Exploration 69-70, 619-622.

Løseth, H., Henriksen, S., 2005. A Middle to Late Miocene compression phase along the Norwegian passive margin. In: Doré, A.G., Vining, B. (Eds.), Petroleum Geology: North-West Europe and Global Perspectives - Proceedings of the 6th Petroleum Geology Conference. Geological Society, London, pp. 845-859.

Magoon, L.B., Dow, W.G., 1994. The petroleum system. In: Magoon, L.B., Dow, W.G. (Eds.), The Petroleum System; From Source to Trap. AAPG Memoir 60, pp. 3-24.

Magoon, L.B., Valin, C.Z., 1994. Overview of petroleum system case studies. In: Magoon, L.B., Dow, W.G. (Eds.), The Petroleum System; From Source to Trap. AAPG Memoir 60, pp. 329-338.

Mathiesen, E., 2005. Focus: technology. In: Vaage Melberg, E. (Ed.), Norwegian Continental Shelf. NPD, Norwegian Continental Shelf 3/2005, pp. 14-15.

Ministry of Petroleum and Energy 2005. Facts 2005 - The Norwegian Petroleum Activity. Norwegian Ministry of Petroleum and Energy, Oslo, 194 pp.

Mukhopadhyay, P.K., Hagemann, H.W., Gormly, J.R., 1985. Characterization of kerogens as seen under the aspect of maturation and hydrocarbon generation. Erdöl und Kohle, Erdgas, Petrochemie vereinigt mit Brennstoff-Chemie 38 (1), 7-18.

Munz, I.A., 2001. Petroleum inclusions in sedimentary basins, systematics, analytical methods and applications. Lithos 55 (1-4), 195-212.

Munz, I.A., Johansen, H., Holm, K., Lacharpagne, J.C., 1999. The petroleum characteristics and filling history of the Frøy Field and the Rind discovery, Norwegian North Sea. Marine and Petroleum Geology 16 (7), 633-651.

NPD, 2005. The NPD's Fact-pages. (accessed 08.07.2005) http://www.npd.no/engelsk/cwi/pbl/en/index.htm.

Oakman, C.D., Partington, M.A., 1998. Cretaceous. In: Glennie, K.W. (Ed.), Petroleum Geology of the North Sea; Basic Concepts and Recent Advances. Blackwell, Oxford, pp. 294-349.

Østvedt, O.J., 1987. Sleipner Øst. In: Spencer, A.M. (Ed.), Geology of the Norwegian Oil and Gas Fields. Graham & Trotman, London, pp. 243-252.

Østvedt, O.J., Blystad, P., Magnus, C., 2005. Assessment of undiscovered resources on the Norwegian Continental Shelf. In: Doré, A.G., Vining, B. (Eds.), Petroleum Geology: North-West Europe and Global Perspectives - Proceedings of the 6th Petroleum Geology Conference. Geological Society, London, pp. 55-64.

Pegrum, R.M., Ljones, T.E., 1984. 15/9 Gamma gas field offshore Norway, new trap type for North Sea Basin with regional structural implications. AAPG Bulletin 68 (7), 874-902.

Pegrum, R.M., Spencer, A.M., 1990. Hydrocarbon plays in the northern North Sea. In: Brooks, J. (Ed.), Classic Petroleum Provinces. Geological Society Special Publication 50, pp. 441-470.

Pepper, A.S., 1991. Estimating the petroleum expulsion behaviour of source rocks; a novel quantitative approach. In: England, W.A., Fleet, A.J. (Eds.), Petroleum Migration. Geological Society Special Publication 59, pp. 9-31.

Pepper, A.S., Corvi, P.J., 1995. Simple kinetic models of petroleum formation; Part I, Oil and gas generation from kerogen. Marine and Petroleum Geology 12 (3), 291-319.

Peters, K.E., Moldowan, J.M., 1993. The Biomarker Guide; Interpreting Molecular Fossils in Petroleum and Ancient Sediments. Englewood Cliffs, Prentice Hall.

Rattey, R.P., Hayward, A.B., 1993. Sequence stratigraphy of a failed rift system; the Middle Jurassic to Early Cretaceous basin evolution of the central and northern North Sea. In: Parker, J.R. (Ed.), Petroleum Geology of Northwest Europe: Proceedings of the 4th Conference. Geological Society, London, pp. 215-249.

Rundberg, Y., Eidvin, T., 2005. Controls on the depositional history and architecture of the Oligocene-Miocene succession, northern North Sea. In: Wandås, B. (Ed.), Onshore-Offshore Relationships on the North Atlantic Margin. NPF Special Publication 12, pp. 207-238.

Ryseth, A., 2001. Sedimentology and palaeogeography of the Statfjord Formation (Rhaetian-Sinemurian), North Sea. In: Martinsen, O.J., Dreyer, T. (Eds.), Sedimentary Environments Offshore Norway. NPF Special Publication 10, pp. 67-86.

Skarpnes, O., Hamar, G.P., Jakobsson, K.H., Ormaasen, D.E., 1980. Regional Jurassic setting of the North Sea north of the Central Highs. The sedimentation of the North Sea reservoir rocks. Norsk Petroleumsforening, Oslo, pp. 8.

Steel, R., Ryseth, A., 1990. The Triassic-Early Jurassic succession in the northern North Sea; megasequence stratigraphy and intra-Triassic tectonics. In: Hardman, R.F.P., Brooks, J. (Eds.), Tectonic Events Responsible for Britain's Oil and Gas Reserves. Geological Society Special Publication 55, pp. 139-168.

Stow, D.A.V., Bishop, C.D., Mills, S.J., 1982. Sedimentology of the Brae Oilfield, North Sea; fan models and controls. Journal of Petroleum Geology 5 (2), 129-148.

Sylta, Ø., 1991. Modelling of secondary migration and entrapment of a multicomponent hydrocarbon mixture using equation of state and ray-tracing modelling techniques. In: England, W.A., Fleet, A.J. (Eds.), Petroleum Migration. Geological Society Special Publication 59, pp. 111-122.

Thomas, B.M., Møller-Pedersen, P., Whitaker, M.F., Shaw, N.D., 1985. Organic facies and hydrocarbon distributions in the Norwegian North Sea. In: Thomas, B.M., Doré, A.G., Larsen, R.M., Home, P.C., Eggen, S.S. (Eds.), Petroleum Geochemistry in Exploration of the Norwegian Shelf. Graham and Trotman, London, pp. 3-26.

Thomsen, R.O., 1998. Aspects of applied basin modelling: sensitivity analysis and scientific risk. In: Düppenbecker, S.J., Illiffe, J.E. (Eds.), Basin Modelling: Practice and Progress. Geological Society Special Publication 141, pp. 209-221.

Tseng, H.-Y., Pottorf, R.J., 2002. Fluid inclusions constraints on petroleum PVT and compositional history of the Greater Alwyn

- South Brent petroleum system, northern North Sea. Marine and Petroleum Geology 19 (7), 797-809.

Vaage Melberg, E., 2005. Older but still attractive. In: Vaage Melberg, E. (Ed.), Norwegian Continental Shelf. NPD, Norwegian Continental Shelf 3/2005, pp. 11.

Vollset, J., Doré, A.G., 1984. A revised Triassic and Jurassic Lithostratigraphic Nomenclature of the Norwegian North Sea. Norwegian Petroleum Directorate Bulletin 59.

Wei, Z.P., Hermanrud, C., Lerche, I., 1990. Numerical basin modelling of the Sleipner Field, North Sea. Terra Nova 2 (1), 31-42.

Wilhelms, A., Larter, S.R., 2004. Shaken but not always stirred. Impact of petroleum charge mixing on reservoir geochemistry. In: Cubitt, J.M., England, W.A., Larter, S.R. (Eds.), Understanding Petroleum Reservoirs: Towards an Integrated Reservoir Engineering and Geochemical Approach. Geological Society Special Publication 237, pp. 27-35.

Ziegler, P.A., 1992. North Sea rift system. Tectonophysics 208, 55-75.