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Northern North Sea tectono-stratigraphic evolution and main petroleum systems and plays

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Master of Science in 'Hydrocarbon Exploration and Exploitation'

by
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Thesis for the degree of two-year Inter-University
M.Sc. in 'Hydrocarbon Exploration and Exploitation'

To my parents and my brother

PREFACE

I would like to start by referring to the 'EAGE Field Challenge 2017' competition in which I participated as a member of the Aristotle University of Thessaloniki (AUTH) team. In this context, I had the honour to present the geological and reservoir study part of the worked out composite and thorough development and production plan of an oil-field in the northern North Sea during the final round of the competition on June 11th, 2017 in Paris. After about seven months of hard work, that included several evaluation phases on elaborations of various datasets from the northern North Sea provided by TOTAL S.A., the AUTH team was selected and presented the findings to an expert jury panel in Paris. It must be noticed that following the start of the competition on November 2016 and after the preliminary essay round evaluation on February 2017, only ten university teams (on worldwide basis) were selected among more than one hundred teams (number based on information from the jury panel), and the selected teams were further required to analyze and propose an integrated PDO (Plan for Development and Operation) for a discovered hydrocarbon accumulation in the northern North Sea. At the interim phase evaluation during April 2017, each team was required to submit a comprehensive video presentation of their work and based on this submission, the eight finalist teams were finally selected. Our work included well-logging and well test analyses, structural and depositional models, identified flow units, static reservoir property and dynamic reservoir models, as well as detailed plans for complete development facilities, operations (including detailed HSE aspects) and production. During the course of the competition, several sophisticated softwares were utilised by our team included Petrel E&P, Eclipse, Techlog, PetroMod and other relevant tools. This project has provided me with valuable skills in the integration of structural geology and sedimentology, as well as practical experience in several aspects applied to petroleum geology. It is appropriate to note here that the dataset provided by TOTAL S.A. is confidential and this is the reason that I cannot publish any part of this work. Nevertheless, the experience I gained has motivated me to further indulge in the more detailed study of the northern North Sea.

With this in mind, I decided to do a further research in the same region by utilizing the knowledge and experience derived from the 'EAGE Field Challenge 2017' competition and to focus on the detailed understanding of the geological evolution of northern North Sea and its hydrocarbon potential.

ACKNOWLEDGEMENTS

This master thesis (20 ECTS) represents the end of the Master of Science in 'Hydrocarbon Exploration and Exploitation' (120 ECTS). First and foremost, I want to thank my supervisor and director of the M.Sc. program Associate Professor Konstantinos Almpanakis for his constructive feedback and comments throughout the process, as well as for introducing the thesis topic to me.

Special thanks are given to my second supervisor Professor Filippos Tsikalas who is currently employed by Eni Norge (as Delineation Projects and Stranded Discoveries Valorisation Manager) and also holds an Adjunct Professor position at University of Oslo in Norway. Without his support, it would have been impossible for us to move on to the final round of the 'EAGE Field Challenge 2017' competition, as well as for me to successfully complete this master thesis without his strong support and valuable suggestions throughout the research.

I would also like to express my gratitude to Professor Andreas Georgakopoulos for his technical expertise and his precious advice over the last years, during both my bachelor and postgraduate studies, and the opportunity he had given me through his urge for our involvement to the 'EAGE Field Challenge 2017' competition, a project of particular relevance for my future professional career.

Moreover, I would like to thank my teammates in the 'EAGE Field Challenge 2017' competition Anastasios Nikitas (M.Sc., geologist), George Dontis (M.Sc., chemical engineer), Marios Amvrazis (M.Sc., mineral resources engineer) and George Karras (M.Sc., mechanical engineer) for their excellent cooperation and their patience throughout the 'EAGE Field Challenge 2017' competition procedure and I wish them all the best for the future.

Last but not least, I am grateful to my parents and my brother for their love, encouragement and patience that I received throughout this period of my life.

ABSTRACT

An up-to-date and best evidence synthesis of the petroleum geology evolution of the northern North Sea has been conducted though a thorough review of the tectono-stratigraphic evolution and main petroleum systems and plays in the area. In this context, a large number of earlier conducted geological and geophysical studies for the region have been utilised and a better understanding of the complexity of the different operating geological processes and their impact on hydrocarbon accumulations has been reached. The northern North Sea has had a long and complex geological history and the tectono-stratigraphic basin evolution is mainly the result of the Middle-Late Jurassic to Lower Cretaceous rifting, partly controlled by older structural elements. During this time, prominent fault-bocks were developed creating the conditions for hydrocarbon accumulations mainly on either side of the axis of the dominant Viking Graben. The pre-rift Triassic to Lower-Middle Jurassic play is the most important hydrocarbon play in the northern North Sea and comprises 75% of the discoveries. The vast majority of the traps are structural fault-assisted unconformity traps but also recently stratigraphic and combination traps have been successfully tested. Although the syn-rift Upper Jurassic and Lower Cretaceous plays comprise currently isolated discoveries, they represent emerging plays with possibly considerable potential. Paleocene and Eocene turbiditic sand-rich fan-systems have provided reservoirs with, locally, excellent reservoir properties and few prolific discoveries, encompassing a considerable future play potential. The dominant petroleum system is almost entirely Jurassic-sourced mainly from the highly organic Kimmeridge Clay Formation which was deposited during Late Jurassic and has provided the source-rock for almost all of the oil and gas. Following the commence of exploration in the area in the mid-1960s, more and more acreage became gradually available for exploration which led to world-class discoveries, such as the Brent and Ninian fields in UK sector and Statfjord, Oseberg, Gullfaks, Troll and Frigg fields in Norwegian sector. Although the northern North Sea is regarded as mature petroleum province, new finds are still made and a considerable hydrocarbon potential still exists. According to the latest estimates for the Norwegian sector of northern North Sea, ~18 Bboe are the current reserves on existing fields and discoveries, and ~4.5 Bboe are the undiscovered resources. It is expected that production will extend for at least another 50 years. Development of new workflows and processes as well as technological improvements, will help to reduce exploration risk and uncertainties in the remaining hydrocarbon potential of the northern North Sea.

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Chapter 1
INTRODUCTION

The northern North Sea is part of the North Sea (Fig. 1.1). It includes the area on both sides of the Norway-UK borderline and it is bounded by the East Shetland Platform to the west, the Norwegian mainland to the east, the North Atlantic margin to the north and the South Viking Graben to the south. The North Sea region straddles the continental shelf between several countries: Norway and Denmark in the east, UK in the west, Germany and the Netherlands in the south.

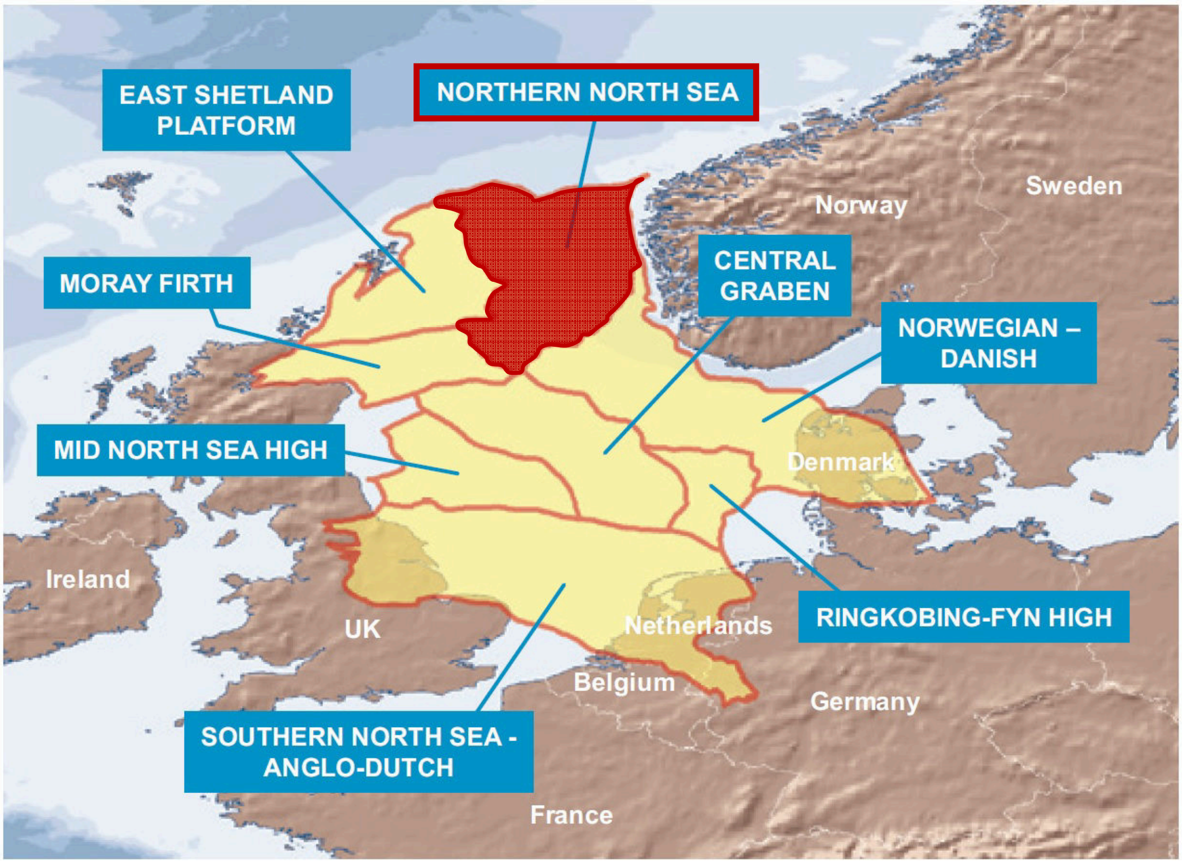


Figure 1.1: Basins of the North Sea region (modified from CGG Tellus database).

The northern North Sea, referring in general in the area between 59-62° N, is approximately 200-250 km long and 150-200 km wide and is dominated by the Viking Graben, which continues into the Sogn Graben towards the north. These grabens are flanked by the East Shetland Basin and the Tampen Spur to the west, and the Horda Platform to the east (Fig.

1.2). Water depths in the northern North Sea vary from approximately 100 m to 400 m, with the deepest parts located to the eastern and northernmost regions (Fig. 1.3).

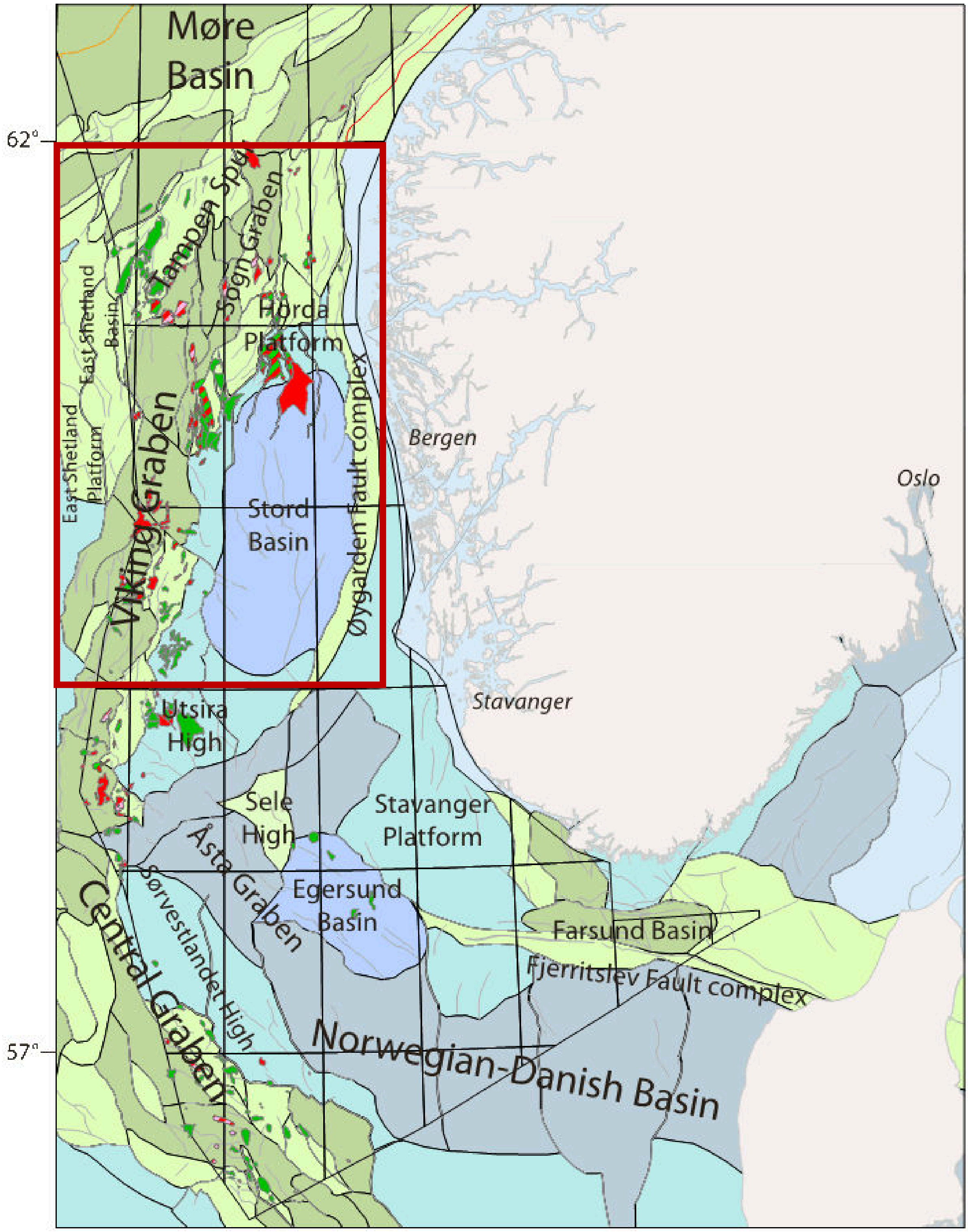


Figure 1.2: Regional map of the northern North Sea, illustrating the main structural elements (modified from NPD database).

The North Sea has proven to be a world-class hydrocarbon province. Since the first developed fields in 1971 (UK) and 1973 (Norway), some 350 and 215 exploration/appraisal wells have been drilled, respectively, resulting in 17 fields and 37 discoveries in the UK and 9 fields and 40 discoveries in Norway. Concerning the UK finds, two thirds were made in the first seven years of exploration drilling. In the Norwegian sector, discoveries have been more evenly distributed in time, with several recent successes (Halland et al., 2014).

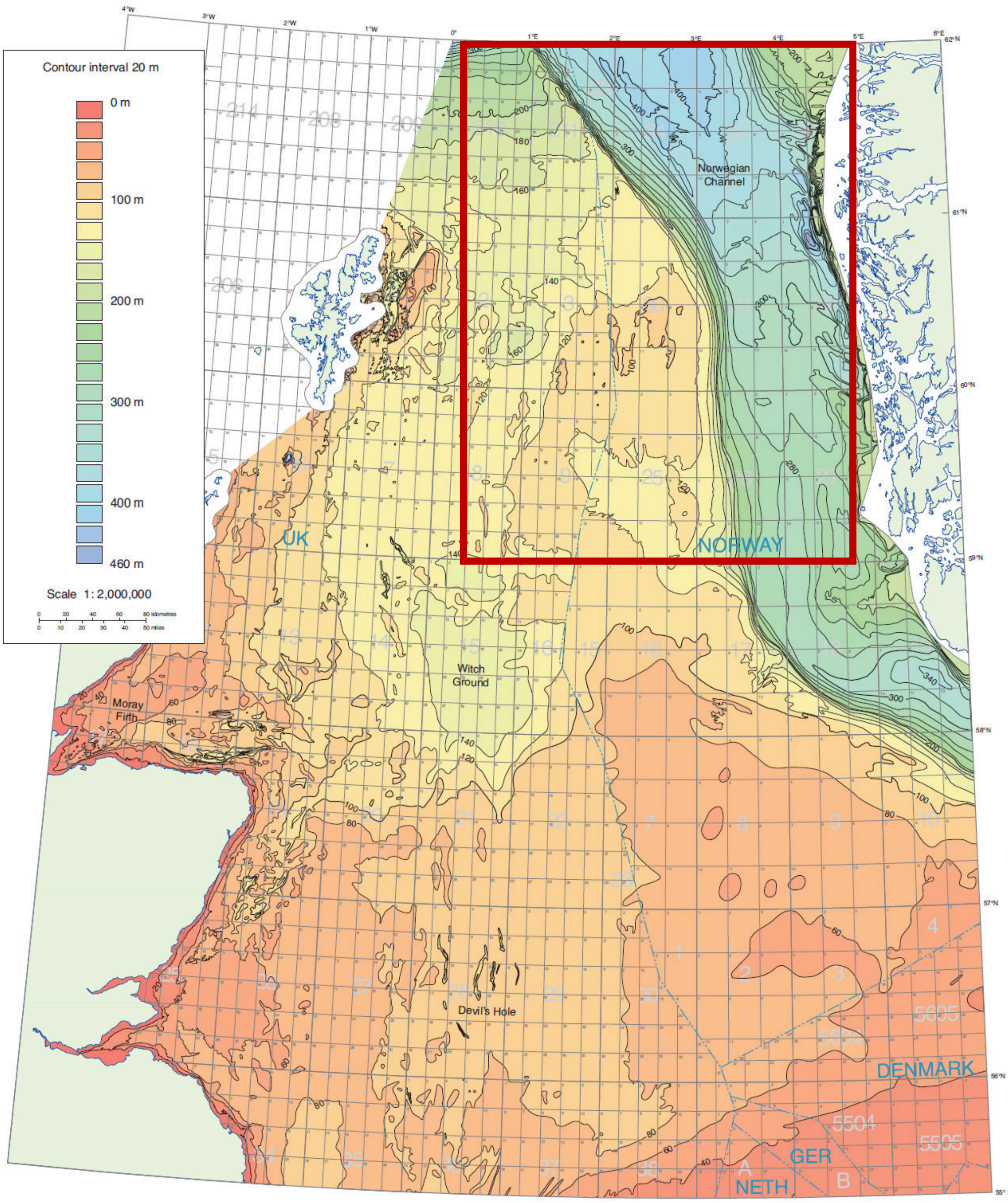


Figure 1.3: Bathymetry of the northern North Sea based on British Geological Survey (1987), and data supplied by Statoil (Evans et al., 2003).

The northern North Sea underwent a long and complex geologic evolution. The area has experienced different tectonic regimes, ranging from compressional to extensional tectonics, resulting in orogeny events, faulting, crustal extension and thermal subsidence. Due to intensive exploration during the last five decades, the geologic understanding of the area has increased dramatically and this was important to properly understand the northern North Sea basin evolution in order to decipher the development of the various geological plays and the evolution of the active petroleum systems. Seismic and sequence stratigraphy have become dominant in the analysis of sedimentary depositional systems, and major advances in the understanding of basin history and geochemistry now allow to explain and even predict the patterns of migration and entrapment of oil and gas accumulations. Innumerable advances in geophysics, many pioneered in the North Sea, have revolutionized the acquisition, processing and interpretation of seismic data. As a result, hydrocarbons can now be 'seen' directly in certain favourable circumstances and indeed the production of these hydrocarbons is often being monitored over time in North Sea fields.

The main objectives of the thesis include the following:

- Decipher the tectono-stratigraphic evolution of the northern North Sea through an extensive study between many different or similar approaches and views and summarising them in order to reach the best-evidence synthesis
- Review the main petroleum systems and plays in the area
- Achieve a better understanding of the complexity of different geological processes and their impact on hydrocarbon accumulations, as an additional research after the successful interpretation of a hydrocarbon field in the northern North Sea in the 'EAGE Field Challenge 2017' competition

Chapter 2

NORTH SEA EXPLORATION HISTORY THROUGH THE EVOLUTION OF EXPLORATION TECHNIQUES

In 1958, the Convention on the Continental Shelf adopted at the United Nations Law of the Sea Conference established that countries with coastlines had sovereign rights to explore and produce resources to a distance of 200 miles from their shore. UK passed the Continental Shelf Act of 1964 that designated quadrants and blocks to the limits shown in Figure 2.1. Neither Norway nor Denmark have actually designated their continental shelf, but the three countries (UK, Norway, Denmark) have reached an agreement in 1965 to define their maritime limits on median lines between the three countries. Subsequently UK designated the remaining area out to the median line and north of 61º N. Territorial waters up to 12 miles around UK were not subject to designation. Inland waters were defined around the coast of Norway, and the Shetland and Orkney Islands.

In May 1963, the Norwegian government proclaimed sovereignty over the Norwegian Continental Shelf (NCS). A new act stipulated that the State was the landowner, and that only the King (Government) could grant licenses for exploration and production. Licenses on the NCS are awarded in mature areas during annual APA (Awards in Predefined Areas) or during ordinary licensing rounds in frontier areas. The first licensing round in Norway was announced in 1965 and the first well on the NCS, well 8/3-1 in the south-eastern part of Norway's North Sea sector, was spudded in 1966. The discovery of the Ekofisk field in 1969 started the Norwegian oil and gas adventure, and production from the field began on 15th June 1971. During the following years, several large discoveries were made in the North Sea. In the 1970s exploration activity was concentrated in this area, but gradually expanded during the 1980s northwards to the other parts of the NCS (Norwegian Sea and Barents Sea). Offshore acreage became gradually available for exploration and only a limited number of blocks were announced on each licensing round, and the most promising areas were explored first. This led to world class discoveries.

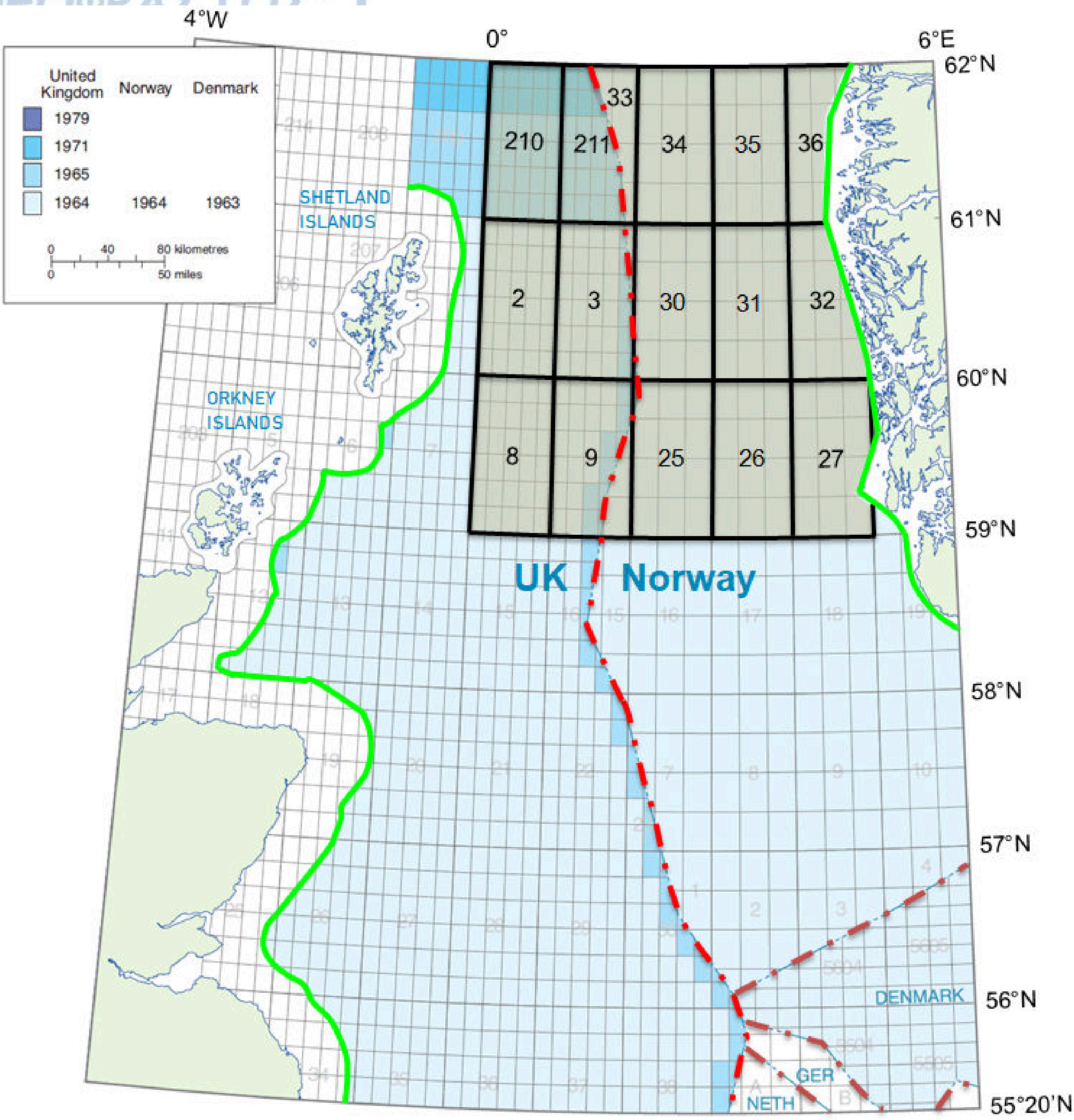


Figure 2.1: The chronology of the area designation and the North Sea area where it is shown the quadrants (thick black) and blocks (shaded black) of the northern North Sea; UK-Norway median line (bright red dashed) and Norwegian coastline/UK territorial waters (green) of the UK-Norway (modified from Evans et al., 2003).

Although the northern North Sea may be regarded as a mature petroleum province, new finds are still being made and a great petroleum potential still exists in the area. According to the 2017 Norwegian Petroleum Directorate annual resource report, published in June, many discoveries are currently being considered for development offshore Norway, while additional 'vast volume' could also be brought on-stream using new technologies to boost recovery at existing fields and exploit tight oil and gas reservoirs. One benefit of discoveries in mature areas is that there is existing infrastructure to tie into, reducing the cost and lead times to production and market. The northern North Sea is a highly explored petroleum basin where large discoveries (developed into fields) such as Troll, Statfjord, and Brage have been made. However, other large accumulations of hydrocarbons are still being discovered. The use of broadband seismic data in combination with increased geologic understanding through well data, and reservoir characterization gives insight into the stratigraphy of the area enabling increased knowledge on the petroleum plays and prospectivity.

2.1 SEISMIC SURVEYS

Drilling for hydrocarbons is very expensive and before money is spent to spud a well, a reliable strategy for pinpointing where to drill is needed. Geoscientists have a secret weapon called seismic exploration and it involves sending acoustic energy which takes the form of wavelets into the ground to get a sound picture beneath the surface. The term 'seismic' is derived from 'seism', a Greek word for earthquake. It refers to the technique used to map rock layers and properties without having to drill a well. Geophysicists set off powerful sound sources in the ocean and record the echoes as they bounce back from rock layers beneath the sea-floor.

The acquisition of seismic data on the Norwegian Continental Shelf has received more and more attention in recent years, in part due to the increased activity in the petroleum sector. There has been significant acquisition of seismic data in the area of the northern North Sea. Because this is considered a mature area, there have been many 3D surveys over the last years. The Norwegian Petroleum Directorate (NPD) has access and has been analyzing all seismic data acquisitions in this area. The aim is to determine the degree of potential overlap in the seismic surveys in the same area, but also coinciding seismic acquisition in particular areas can include resolving new geological problems and testing new technology.

The northern North Sea petroleum story would not have been possible without the invention of marine seismic techniques. These are critical to exploration today and will continue to be so for the foreseeable future. Although exploration methods such as gravity, magnetic and sea-bottom geochemical 'sniffer' surveys have their uses in defining basins, lineaments and potential hydrocarbon migration routes, seismic data are essential to define traps. The larger structures in the northern North Sea were the first to be explored; subsequently, the search has progressively been for smaller and more complex closures and for stratigraphic traps. Despite this trend, the success ratio of exploration wells to discoveries has remained relatively constant at approximately 1 in 3 over the last 30 years, mainly due to improvements in seismic technologies.

Dynamite was the universal energy source until the late 1960s, but whilst it was an excellent source, it was difficult to use and it was damaging to the environment, particularly to fish stocks. When airguns began to replace dynamite in the North Sea, the signal could be shaped and repeated more accurately, thus improving the signal-to-noise ratio and making a vast improvement in the quality of the data. Acquisition of 2D seismic data reached a peak in the early 1980s in line with the growing momentum for exploration in the North Sea. However, the increasing need to map traps more accurately led to a far-reaching change in seismic acquisition methods and to the acquisition of lines spaced only 50 m or less apart. Such surveys could be processed to investigate the structural configuration in three dimensions, and are termed 3D seismic. The decline in 2D acquisition in the 1990s arose from the growing popularity of 3D seismic data (Fig. 2.2).

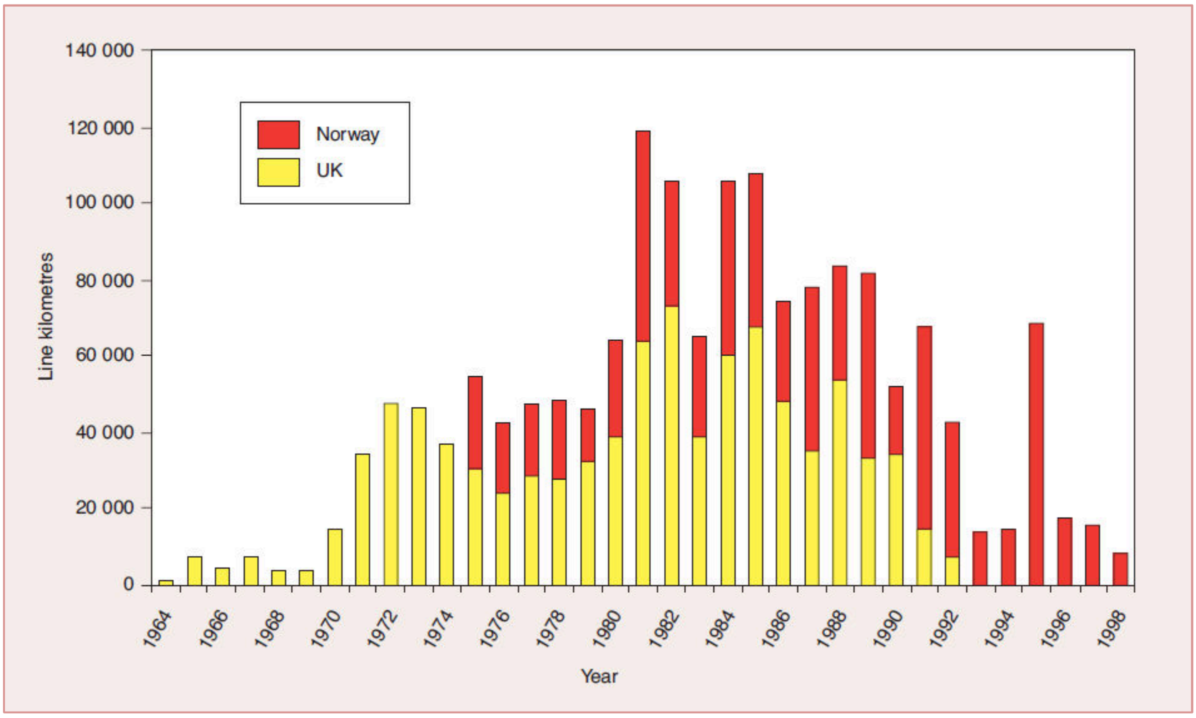


Figure 2.2: The amount of 2D seismic shot annually in Norwegian and UK waters (Evans et al., 2003).

Few 3D datasets were acquired before 1980s, and there was some early skepticism, when promised results failed to be materialized. However, as the costs of appraisal drilling increased, the use of 3D seismic data for field evaluation became common-place because the survey cost was about a third of the price of a well. Improved quality of 3D seismic data, in combination with greatly increased computational resources, have enabled the application of fully three-dimensional image enhancement and attribute extraction techniques in seismic interpretation. In three-dimensional seismic imaging, subsurface objects are depicted with images of the seismic waves that are back-scattered by the object. The local characteristics of a seismic image hold important clues as to which geological feature produced the seismic events that are observed. These image characteristics are known as seismic attributes. Amplitude attributes, such as reflection strength, give information on material properties. With seismic volume attribute analysis techniques, three-dimensional seismic interpretation can be greatly enhanced (Bahorich and Farmer, 1995; Hoogenboom et al., 1996; Steeghs and Drijkoningen, 1996). Seismic attribute maps provide a useful tool in interpreting faults, particularly those close to or below seismic resolution. Dip, relief, azimuth and amplitude maps are most useful.

Since the introduction of computers, data manipulation has become easier. With today's technology, seismic attribute maps can be created within seconds on a seismic workstation. These maps allow the seismic interpreter to identify structures such as fractures and folds, as well as sedimentological features, and are commonly incorporated into the seismic interpretation of oil fields and in exploration. However, without a sound knowledge of what information the attribute maps can yield, they may not always be used to the extent possible, and may be over-interpreted and misunderstood.

Figure 2.3 shows an integrated use of seismic attribute maps and well information on the Gullfaks Field in the Tampen Spur area, northern North Sea. Active use of attribute maps resulted in far more accurate and detailed structural maps of the Gullfaks Field. The dip maps proved most useful during the seismic reinterpretation of the Gullfaks Field (Fig. 2.3a). This sample level attribute map highlights changes in dip of an interpreted seismic reflection. The detailed maps have helped the reservoir engineers to better understand fluid flow in the reservoirs (Fig. 2.3b). The ability to 'illuminate' the interpreted seismic reflection with a computer-generated 'light source' helps to highlight any changes in dip and makes faults stand out as easily distinguished lineaments (Fig. 2.3b).

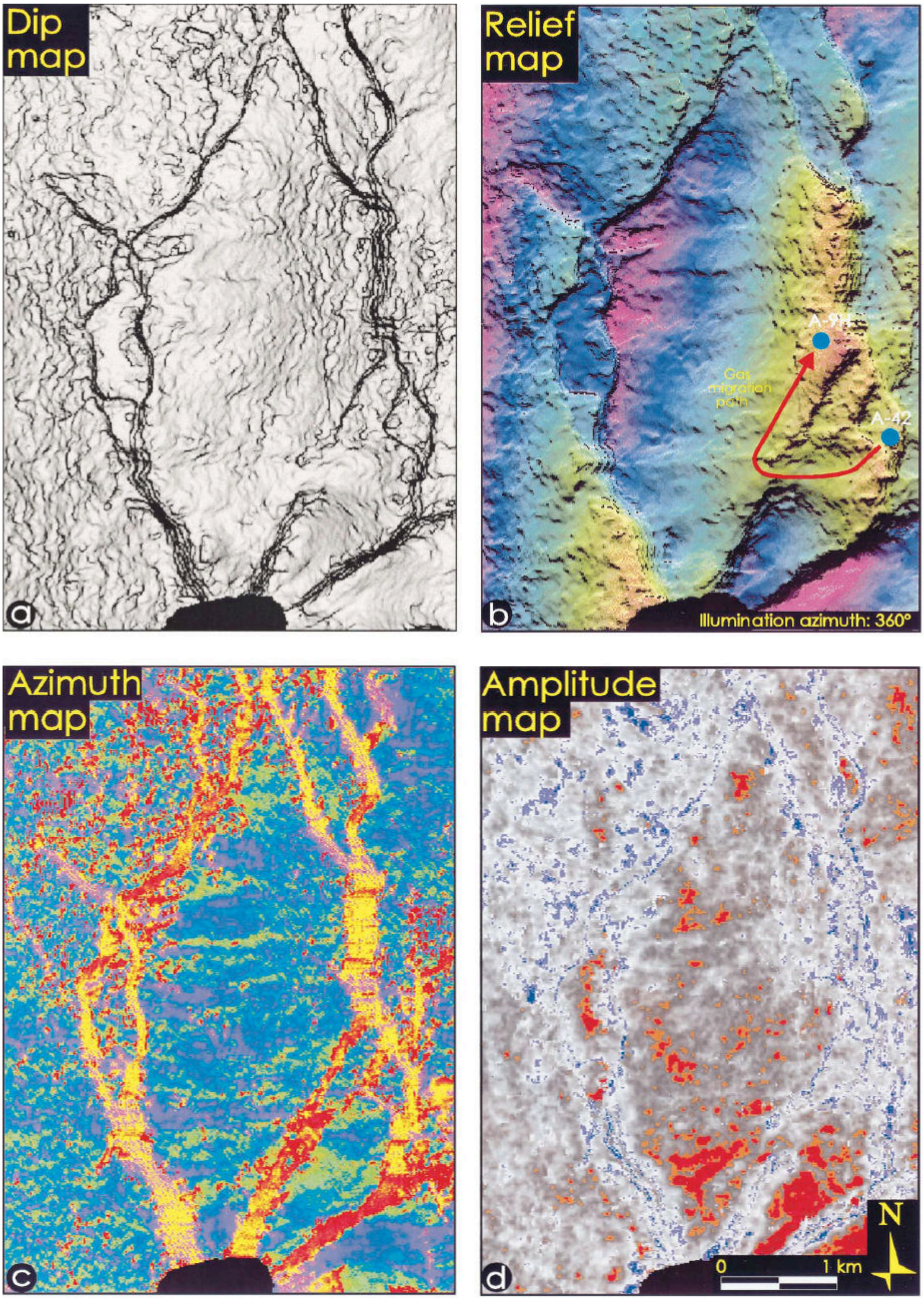


Figure 2.3: Attribute analysis in structural interpretation of the Gullfaks Field (Hesthammer and Fossen, 1997). (a) Dip, (b) Relief, (c) Azimuth and (d) Amplitude maps.

The azimuth map is highly affected by seismic noise. This problem may, to a large extent, be avoided by filtering the data prior to generating the attribute map. Figure 2.3c shows a filtered azimuth map from a fault-block on the Gullfaks Field. Yellow indicates dip to the east, green shows dip to the west, red shows dip to the southeast, and blue indicates dip to the northwest. Because the azimuth map efficiently displays larger and more general changes in dip, folds are easily recognized. Thus, the azimuth attribute map may help identify relay ramps or areas affected by drag. Several gentle folds are observed in Fig. 2.3c where the colours change from green (westerly dip) to blue (northwesterly dip).

The most commonly used sample level seismic attribute map is the amplitude map (Fig. 2.3d), which simply displays the amplitude value at any point along an interpreted seismic horizon. This type of map was probably the first attribute map used for seismic interpretation, and is commonly utilized in structural analyses (e.g. Buchanan et al., 1988; Flint et al., 1988; Voggenreiter, 1991). The amplitude map has been successfully used on the Gullfaks Field for identifying oil-filled reservoirs (the seismic response for oil-filled and water-filled sandstone is different in the field). In addition, the amplitude of a seismic reflection is typically weakened along structural lineaments such as faults. Finally, the new maps allowed for a better and more optimal planning of new wells where accuracy is crucial for success.

Another useful seismic surveying technique is the vertical seismic profile (VSP) technique that became available in the 1980s. This complemented the standard borehole seismic check-shot survey which gives a correlation of seismic time to depth. For future, seismic-while-drilling (SWD) could make an impact in eliminating the need for costly sidetracks if a well does not come in on prognosis. The drill bit itself is utilised as a seismic source, producing a record ahead of the drill bit in real time which can be interpreted to update the seismic model.

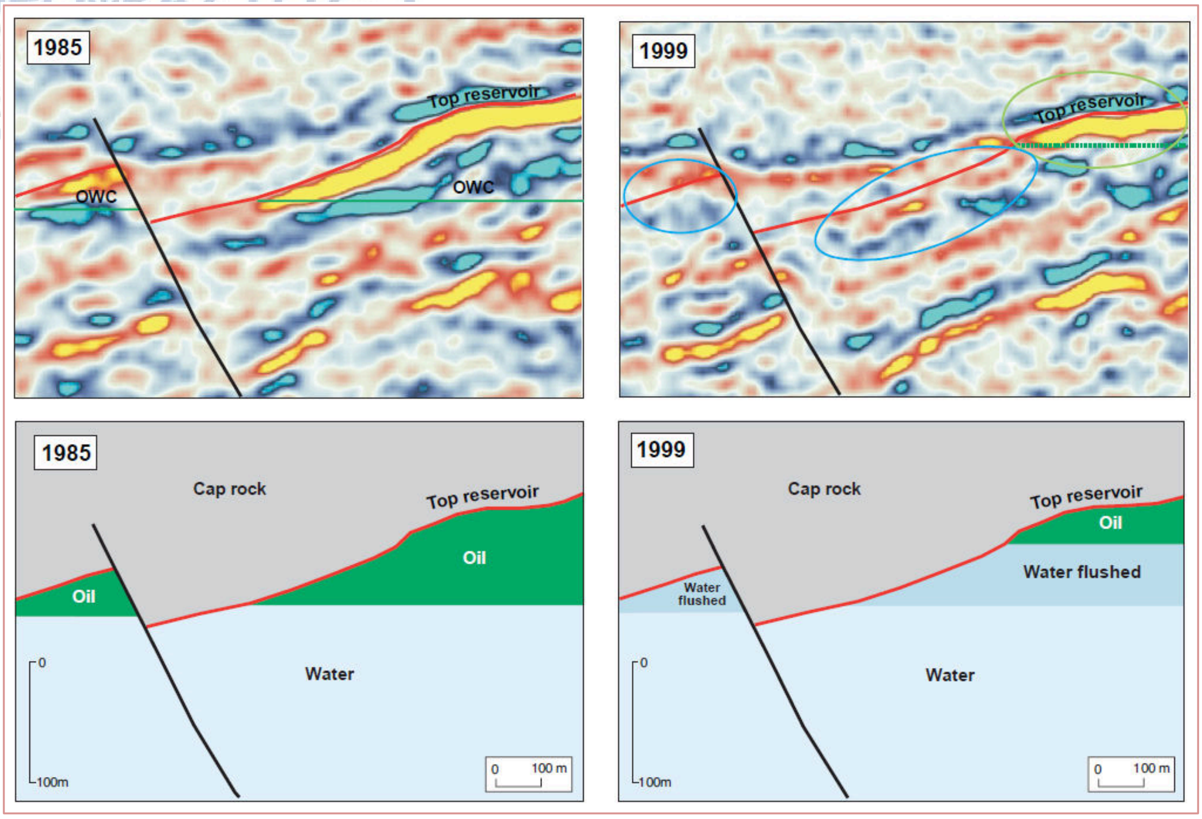


Figure 2.4: Time-lapse 4D seismic data over the Gullfaks Field (Evans et al., 2003).

Ocean-bottom cable (OBC) seismic has started to be used as a device for imaging complex reservoirs and for monitoring depletion on producing fields. Geophone cable, once laid, can be left in place for several years, allowing re-shooting of the area over time, resulting in a 4D-seismic method where the fourth dimension is time. Furthermore, OBC also allows the shear-wave component to be measured, resulting in 4C (four component) seismic data. An example of 4D seismic data over the Gullfaks Field is shown in Fig. 2.4. The seismic section on the left was acquired in 1985, and the simplified geological cross-section beneath it shows the initial position of the reservoir fluids. The seismic section on the right was acquired in 1999 and the accompanying simplified geological cross-section shows significant depletion of the oil due to extraction/production. The red and yellow colours on the seismic represent a decrease in acoustic impedance, while blue represents an increase.

2.2 SEISMIC PROCESSING

A five-fold increase in computing power for processing seismic data took place between the late 1980s and early 1990s, and this trend has continued unabated. This has enabled innovation in processing techniques to a level of sophistication far beyond the simple stacking of data. New processes include: dip move out (DMO), deconvolution before stacking, deconvolution after stacking, time migration, map migration, pre-stack time migration, and during the recent years pre-stack depth migration. Processing can now be carried out in real time onboard the survey vessel, which has enabled the acquisition parameters to be tailored to local conditions. The advances in 3D seismic processing and interpretation, the use of 4-component seismic recording utilizing sea-bed geophones, and the application of high-resolution, stratigraphic-interpretation techniques have led to far better risk analysis of the play fairways.

2.3 SEISMIC INTERPRETATION

Seismic interpretation in the 1960s and 1970s was done on paper sections, utilizing coloured pencils, maual measurement and hand contouring. The revolution in computing power in the 1980s enabled digital seismic sections to be displayed and interpreted at workstations, although initially the expense of the equipment restricted their use within any single oil company. Today, interpretation of massive 3D surveys on an individual desk-top computer is the norm, leading to quicker interpretation and high-quality digital output of maps and images. The ability to prepare ‘cubes’ of 3D-seismic data, which can then be ‘sliced’ in any direction, has radically improved visualization in three dimensions. Coherency of the data can be displayed, thus increasing the ability to detect sub-seismic features in some areas (Munns, 1999). A further technological advance is the virtual-reality room, where seismic profiles, well logs, coherency information and other data can be displayed in three dimensions.

2.4 SITE SURVEYS AND OTHER SHALLOW DATA

In-house compilations and maps produced by oil companies as part of their exploration efforts have been very important. Prior to drilling or installing any sea-bed structure, companies are required to carry out site-investigation surveys of the sea-bed and shallow geology in the immediate area. Precise regulations vary between UK and Norway, but the end product is the generation of a vast quantity of seismic and coring data. These surveys provide information on the bathymetry, the nature of the sea floor, the shallow subsurface geology, and any hazards such as gas chimneys or gas pockets in the shallow strata.

2.5 EXPLORATORY DRILLING

Although seismic surveys and geological knowledge can paint a picture of the rock structure, the properties of the rocks, as well as the presence of hydrocarbons, can only be determined by drilling into the rock layers. This is known as exploratory drilling. The progress of exploration drilling in the northern North Sea can be seen in Fig. 2.5, where the well results are summarised by decade. Exploration wells are taken as those that are included in this category for the northern North Sea.

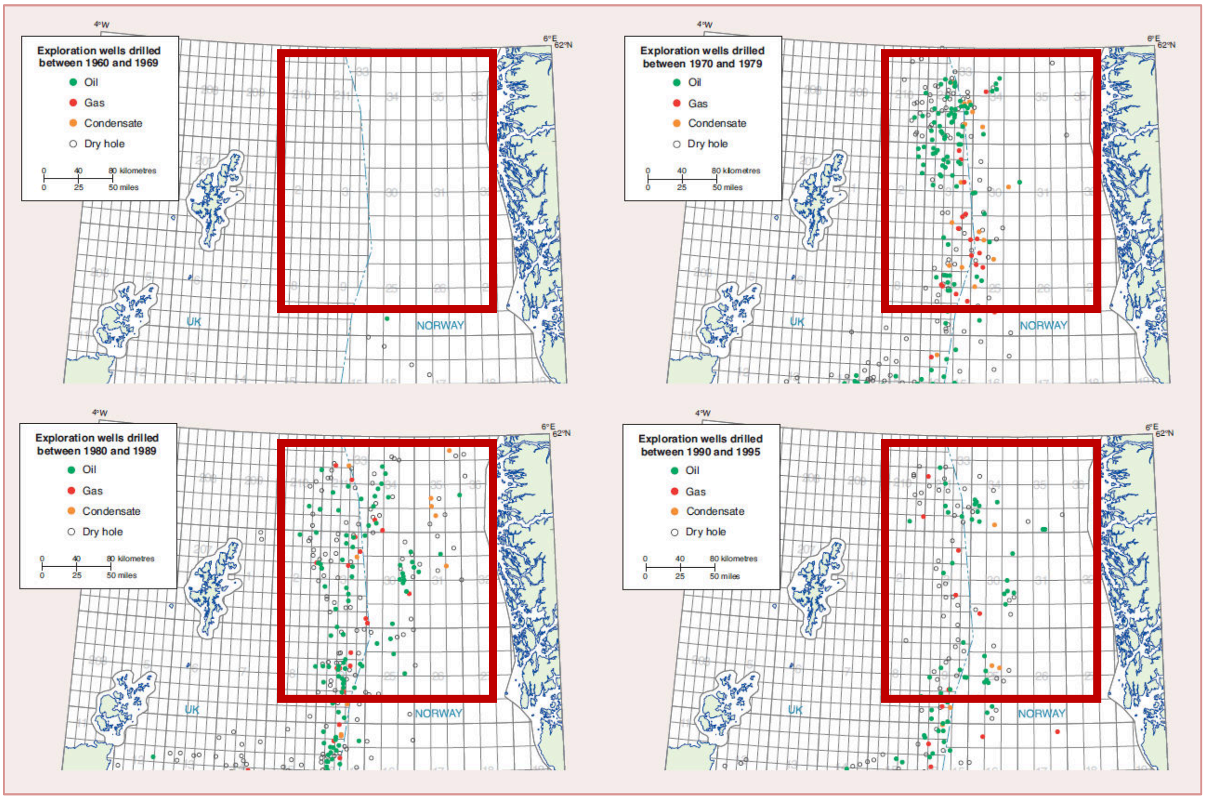


Figure 2.5: Exploration wells drilled and results by decade (Evans et al., 2003).

The amount of exploration drilling in the North Sea since 1964 has fluctuated in response to many factors, such as the influence of oil price, which itself may be affected by both political and economic global events.

2.6 APPRAISAL AND DEVELOPMENT DRILLING

Following a discovery, several appraisal wells are required to decide the extent of a field in relation, primarily, to the geological complexity of the reservoirs being evaluated. Figure 2.6 indicates that in the cost-cutting 1990s, operators reduced the number of drilled appraisal wells and were attempting to interpret fields with a single exploration well in conjunction with improved seismic data.

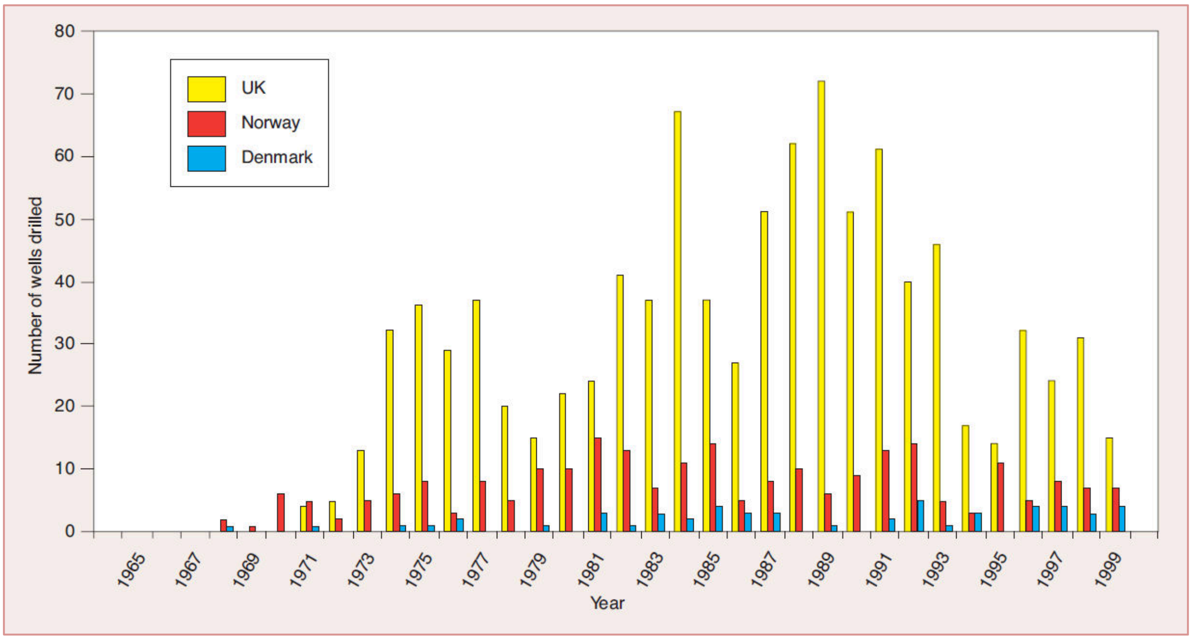


Figure 2.6: Number of appraisal wells drilled (Evans et al., 2003).

An alternative strategy may also be adopted where 'finder' wells with minimal formation evaluation are drilled to explore, followed by an appraisal well with a more comprehensive coring and logging programme only if a discovery is made. A possible trend of the reduction in the number of development wells required to produce from a field, as a result of improvements in horizontal drilling and long-reach technology, may be discerned from the fall in the Norwegian figures for the late 1990s.

2.7 WELL DRILLING

During exploration over the North Sea from the mid-1960s to today, there have been enormous changes in well-drilling and well-logging technologies. Although such technologies are applied worldwide, many innovations were first made and applied in the North Sea. Two particular examples of great economic impact are: 'horizontal' drilling that allows wells to reach out laterally for many kilometres from production platforms, and well-logging while drilling that saves significant rig time. These extraordinary technological achievements enable operators to maximize returns from each well, which in turn means higher royalty payments to mineral owners, and higher tax revenues for local and state taxing authorities. Additionally, they enable operators to exploit tight gas reservoirs, many of which were considered non-commercial at the time of discovery as well as to overcome difficult geological problems.

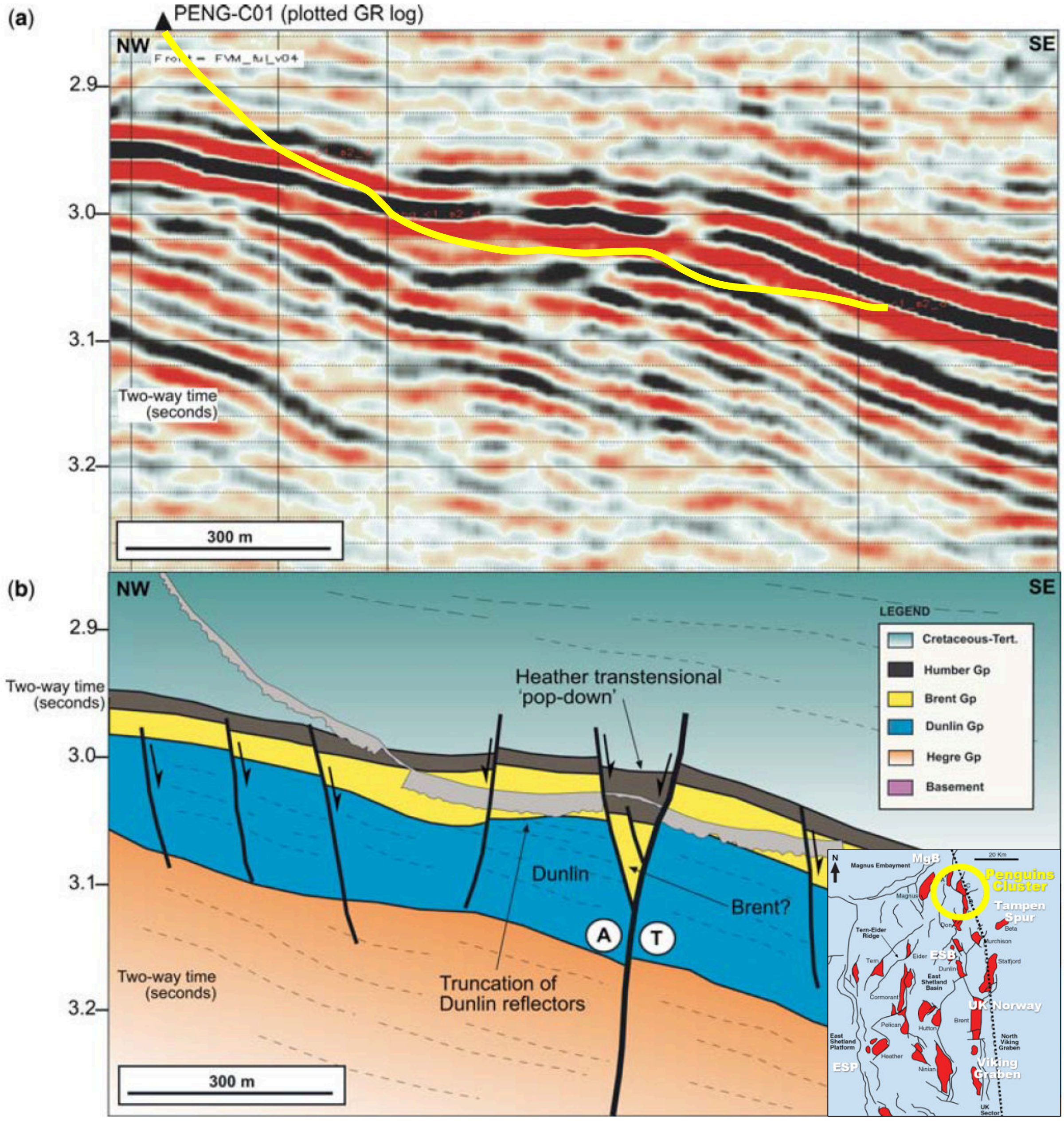


Figure 2.7: Example of a horizontal well in the northern North Sea (Domínguez, 2007): (a) uninterpreted, and (b) interpreted seismic line along the PENG-C01 well trajectory. This horizontal well was drilled through a downthrown fault block composed of Heather Fm. (Upper Jurassic) shales along the well-path. A, motion away from page; T, motion towards page.

An example of a horizontal well is illustrated in Figure 2.7. The figure shows a NW-SE seismic line and its geological interpretation along the PENG-C01 well trajectory, drilled in the central part of the Penguin C field. Whilst drilling a subhorizontal section of Brent Group

(Middle Jurassic) sandstones, PENG-C01 encountered a 300 feet-long section of Upper Jurassic Heather shales, confirmed with biostratigraphic samples, before penetrating again the Brent Group sandstones for the last 1000 feet of the well. The shale section was bounded by faults as confirmed by image logs, and is interpreted as a transtensional 'pop-down', or negative flower structure. The small scale of this feature makes it difficult to be interpreted on seismic, and only one of the faults bounding can be mapped with confidence. This seismic line also illustrates the unconformable nature of the base of the Brent Group (Middle Jurassic), seen here truncating a series of underlying Dunlin Group (Lower Jurassic) seismic reflectors.

Advanced horizontal drilling technology also produces positive results for the environment. A single horizontal well can replace the need to drill a dozen or even more vertical wells to access a similar level of resource. For the environment, this means far less air emissions, far less water usage and disposal needs, and far less land impacted to produce a similar amount of oil and natural gas.

Well-logging technology has also witnessed many improvements. These improvements, by large, are evolutionary, and are the result of innovations and new discoveries taken place in hardware, software, computing and transmission technology over the years. Among these, hardware miniaturization occupies a central place. This triggered improvements in tool design, computing, display, data compression and transmission. Discovery of new materials, new opportunities in MWD (Measurements While Drilling)/LWD (Logging While Drilling) technology, and recent focus to bind multi-disciplinary information to a common platform for integrated interpretation, are other supplementary compulsions propelling improvements.

Oil companies often require specific production and reservoir engineering recommendations. Service companies can meet this need by helping to indentify underperforming wells and then assist by providing customized solutions to improve production. On a daily-basis, oil companies must deal with many existing wells and reservoirs while trying to improve or maintain output from an increasing number of new wells. Proactive efforts to optimize the productivity of client-operated wells through production enhancement are helping to get more value out of existing wells. Operators benefit from improved production, reduced risk and more effective use of service sector knowledge and experience.

Chapter 3
GEOLOGICAL SETTING

3.1 MAIN TECTONIC ELEMENTS

Several main structural elements of the northern North Sea are located within the study area (Fig. 3.1). In the following, the main structural elements are briefly described.

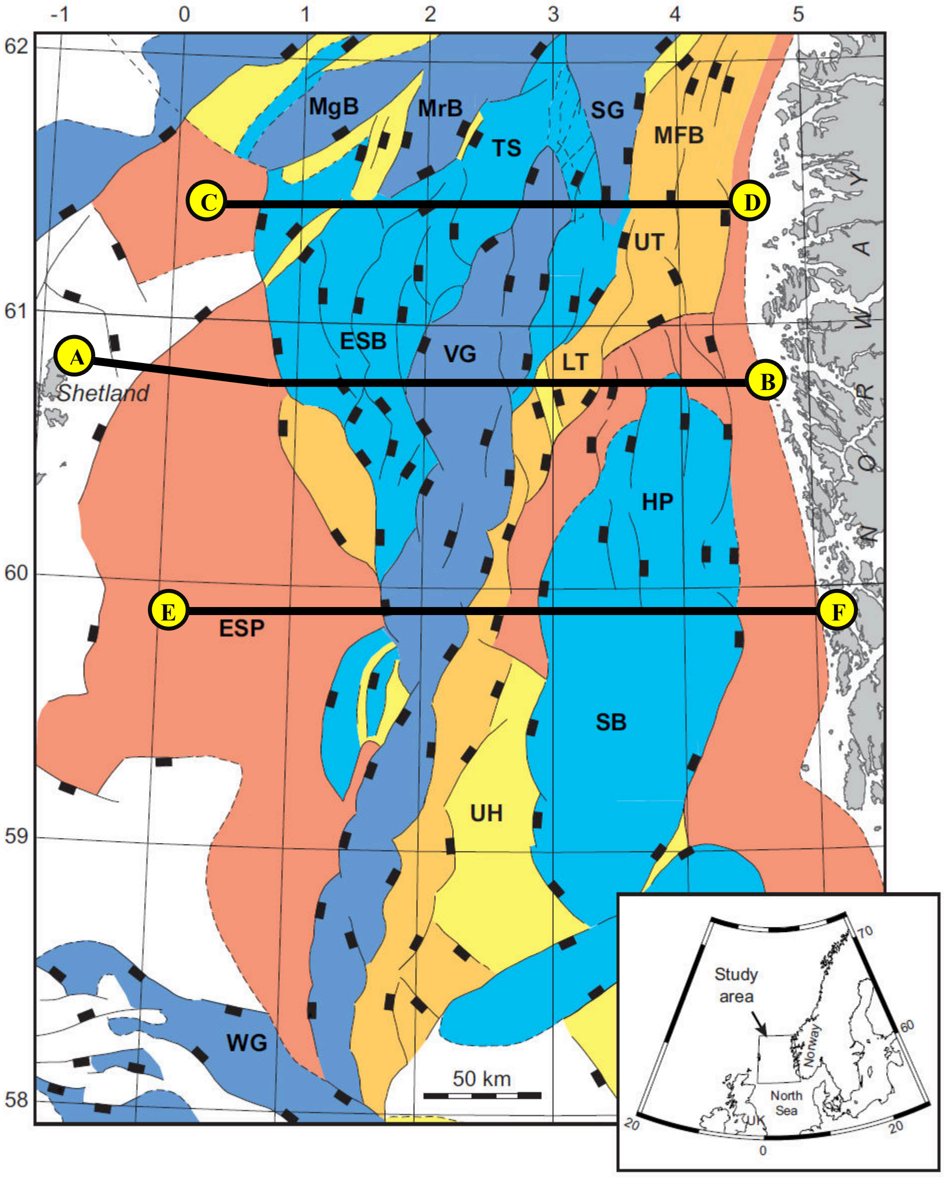


Figure 3.1: Structural framework of the northern North Sea, as seen at base Cretaceous level (modified from Faleide et al., 2004). Main structural elements: ESB, East Shetland Basin; ESP, East Shetland Platform; HP, Horda Platform; LT, Lomre Terrace; UT, Uer Terrace; MgB, Magnus Basin; MrB, Marulk Basin; MFB, Måløy Fault Blocks; SB, Stord Basin; SG, Sogn Graben; TS, Tampen Spur; UH, Utsira High; VG, Viking Graben; WG, Witch Ground Graben. Location of regional seismic transects (Figs. 3.2-3.4) are indicated.

Northern Viking Graben

The Viking Graben (VG) is an example of an intracratonic basin (Fig. 3.1) situated on continental crust in the North Sea (Faleide et al., 2015). The Viking Graben was first formed during several phases of extensional tectonic movements starting in the Bathonian and continuing through to the Oxfordian (Thomas and Coward, 1996). Several major fault blocks started to tilt, creating highs, some of which formed islands in the central area close to where the northern Viking Graben would develop during the Late Jurassic. Older Jurassic strata were eroded on the fault-block highs (Hesthammer and Fossen, 1999; McLeod and Underhill, 1999; McLeod et al., 2000).

The northern Viking Graben (Fig. 3.2) appears to display extensional tectonics in a more simplified and more easily observable form since it is north of the Permian salt basins; it has not experienced extensive uplift and erosion during the Middle Jurassic, and is further north of the major compressional effects of the Alpine orogeny. Two rifting episodes can be recognized: Late Permian-Early Triassic and Bathonian-Ryazanian (Badley et al., 1988). Besides being a good place to test the stretching models, the northern North Sea is of enormous economic importance. With estimated recoverable reserves of 16 billion barrels of oil, the northern Viking Graben is the most significant oil province in Western Europe (Ziegler, 1977).

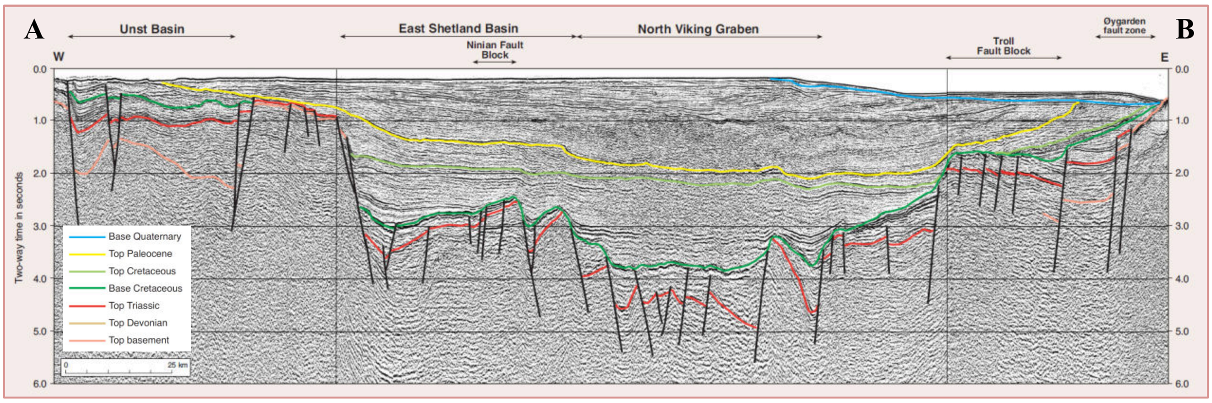


Figure 3.2: North Viking Graben (Evans et al., 2003). Transect location in Fig. 3.1.

Sogn Graben

The northern Viking Graben and its margins extend northwards into the Sogn Graben (SG) as it is shown in Figure 3.1, and both are underlain by an older Permian-Triassic rift basin, the axis of which is believed to lie beneath the present-day Horda Platform. Structures in this area are characterized by large tilted fault-blocks with sedimentary basins located in asymmetric half-grabens associated with lithospheric extension and crustal thinning (Faleide et al., 2010).

Within the Jurassic-Cretaceous North Sea basin, the syn-rift sequence is separated from the post-rift sequence by the 'base Cretaceous' or 'late Cimmerian' unconformity. In the northern Viking Graben interior, the unconformity is generally more curved and associated with onlap. Towards the northernmost end of the Viking Graben, the Sogn Graben and the transition to the Møre Basin (farther north of the northern North Sea), the unconformity becomes to an increasing degree offset by faults (Fig. 3.3). These south-to-north changes in configuration demonstrate the diachronous character of the rift. More extensive fault activity is, however, evident in the northernmost Viking Graben and the Sogn Graben. These areas are adjacent to the Møre Basin, which underwent significant NW-SE extension in the Cretaceous (Graue, 1992; Blystad et al., 1995; Grunnaleite and Gabrielsen, 1995; Doré et al., 1999). The narrower width of the Sogn Graben might had been caused by confined extension from the Møre-Trøndelag sinistral strike-slip fault complex.

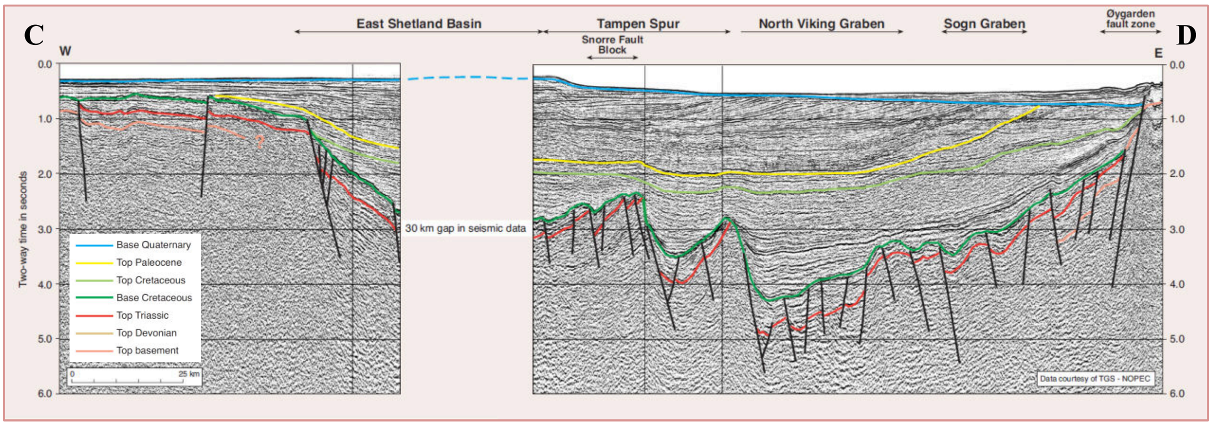


Figure 3.3: Northernmost North Sea (Evans et al., 2003). Transect location in Fig. 3.1.

Tampen Spur

The Tampen Spur (TS) is bordered to the east by the northern part of the Sogn Graben and to the west by the Marulk and Magnus Basins (Fig. 3.1). The Tampen Spur high is located in the middle of several oil-mature to gas-mature source-rock kitchens and most of the structures might receive petroleum migrating from several different directions. The most successful traps are clustered on the Tampen Spur on the eastern flank of the Viking Graben where the three largest oilfields, Statfjord, Brent, and Gulfacks, are located.

East Shetland Basin

The East Shetland Basin (ESB) is a narrow structure between the East Shetland Platform and the Tampen Spur (Fig. 3.1). The Tampen Spur is a partly fault-bounded high between the East Shetland Basin and the northern Viking Graben. These are essentially syn-rift structures with limited or no structural/topographic expression during the Tertiary. Both extensional and compressional (or transpressional) features occur in the East Shetland Basin as syn-rift structures. The extensional structures include the well-known tilted fault blocks (Fig. 3.2) and relatively undocumented listric normal faults that occur on the crestal and flank areas of the larger blocks. Slope failure and degradation along active fault scarps were the main mechanisms of listric faulting. The regional thickness patterns documented by Badley et al. (1988) and the lithology of the Triassic and Jurassic rocks described by Vollset and Doré (1984) further suggest that the Horda Platform area in particular was developed as an opposing half-graben system facing the East Shetland Basin.

East Shetland Platform

The ESP (East Shetland Platform) forms the NW margin of the North Sea Basin, between the Scottish Massif and the Viking Graben (Fig. 3.1). It was uplifted and tilted during mid-Paleocene time, sourcing the thick deep-water sands above the Viking Graben, the northern Central Graben and the Outer Moray Firth Basin. Rapid erosion of Devonian and Permian-Triassic sandstones generated sands that were transported by large river systems to deep-water submarine fans. These sands are up to 1 km thick in parts of the Viking Graben.

The East Shetland Platform formed a regional high throughout the Mesozoic and Tertiary with only a thin Triassic to Recent succession preserved (Fig. 3.4). Complex seismic reflections are seen within the basement and may indicate basement thrust duplexes and lateral ramps, recording Caledonide deformation. The platform was subject to limited subsidence during the Mesozoic, so that Paleozoic strata are much less deeply buried here than in the rift axis to the east. The eastern part of the East Shetland Platform is overlain by up to 2 km of Tertiary deposits, but these thin to the west, pinching out around 80 km east of the Shetland Islands.

Horda Platform

The Horda Platform (HP) is a prominent structural high, located to the east of the deeply faulted Viking Graben in the northern North Sea (Fig. 3.1). The Horda Platform post-dates the Triassic rift period as sediment deposition of this age can be seen to infill half grabens at depth. Jurassic sediments are found to be sub-horizontal in large parts of the Horda Platform, allowing for a clear contrast from dipping lower Triassic strata. The structural evolution of the Horda Platform observed to have started since Paleocene time; indeed, the significant Mesozoic faulting, which took place on the Viking Graben, has only weakly affected the Horda Platform so that the majority of the sequence were not deformed (Fig. 3.4).

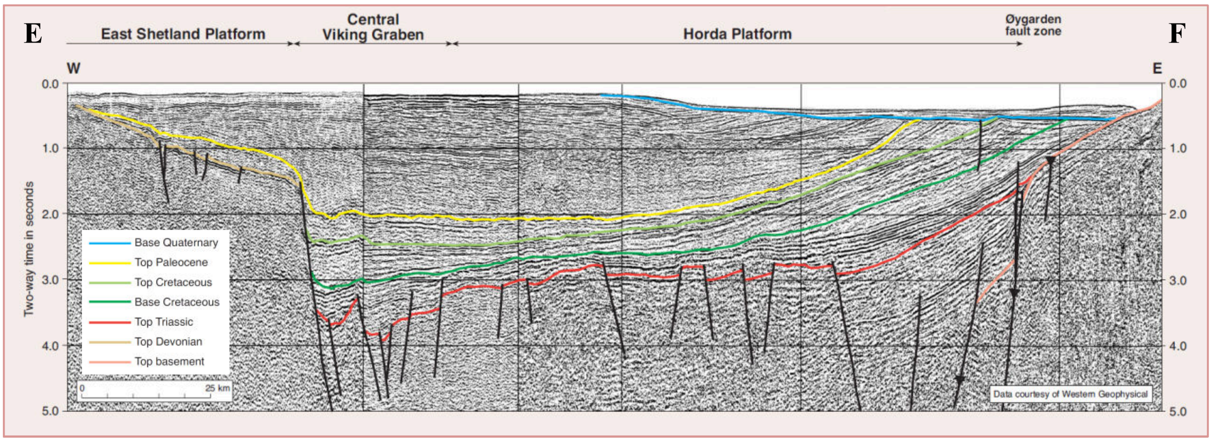


Figure 3.4: Horda platform (Evans et al., 2003). Transect location in Fig. 3.1.

Stord Basin

The Stord Basin (SB) is an east-sloping extensional, NNW-trending basin that lies to the east of the Viking Graben in the Norwegian waters of the northern North Sea. It is located south of the Horda Platform west of the major Øygarden Fault Zone and east of the Utsira High which separates if from the Viking Graben to the west (Fig. 3.1).

The basement of the Stord Basin was consolidated during the Early Paleozoic Caledonian orogeny, and is correlated with basement seen onshore mainland Norway between Stavanger and Bergen. The basin formed by extension with normal faulting beginning in Triassic time and continuing episodically into the Middle and Late Jurassic. Seismic reflection profiles show that the normal faults which affect the sedimentary section are steeply dipping and are approximately planar. Some of these faults were reactivated during Early Tertiary. This reactivation reversed earlier-accumulated normal displacement and created relative structural highs out of previous structural lows.

3.2 STRATIGRAPHIC FRAMEWORK

The northern North Sea rift evolved over at least two Late Paleozoic-Mesozoic rift phases, and was built on a basement that consisted of Proterozoic and Caledonian rocks with variable Caledonian fabrics and Devonian extensional shear zones (Fossen, 2010). These pre-rift basement structures have been studied in considerable detail onshore western Norway, northern Scotland and East Greenland. However, in the northern North Sea, the nature and influence of pre-rift structures are enigmatic.

The northern North Sea rift developed mainly as a result of a Late Permian-Early Triassic extension phase followed by thermal cooling and subsidence from the Early-Middle Triassic to Middle Jurassic, and a Middle-Late Jurassic to Early Cretaceous extension phase followed by Cretaceous post-rift subsidence (Badley et al., 1988; Gabrielsen et al., 1990; Ziegler, 1990; Underhill and Partington, 1993 and 1994; Færseth, 1996; Odinsen et al., 2000; Lervik, 2006). The northern North Sea rift basin developed on a highly heterogeneous basement that experienced Caledonian orogenic deformation and Devonian post-orogenic extension (Færseth, 1996; Odinsen et al., 2000; Fossen et al., 2016).

Reservoirs are found in strata with ages ranging from Devonian to Eocene. Pre-rift reservoirs are found in fault-block structures activated during rifting and can be of any age prior to the Late Jurassic. Syn-rift reservoirs are restricted to strata actually deposited during maximum extension and include rocks of Late Jurassic to earliest Cretaceous age. Post-rift reservoirs formed after rifting and range in age from Early Cretaceous to Eocene. Seals are diverse, depending upon the structural setting and reservoir age. Pre-rift reservoirs commonly have seals formed by fine-grained, post-rift sedimentary sequences that drape the Late Jurassic to earliest Cretaceous structures. Contemporaneous shales such as the Kimmeridge Clay Formation seal many syn-rift reservoirs. Fields with post-rift reservoirs generally require seals in fine-grained Tertiary rocks. In most of the North Sea Graben, source rocks have been continuously buried since deposition. A generalised stratigraphy of the North Sea is shown in the Figure 3.5.

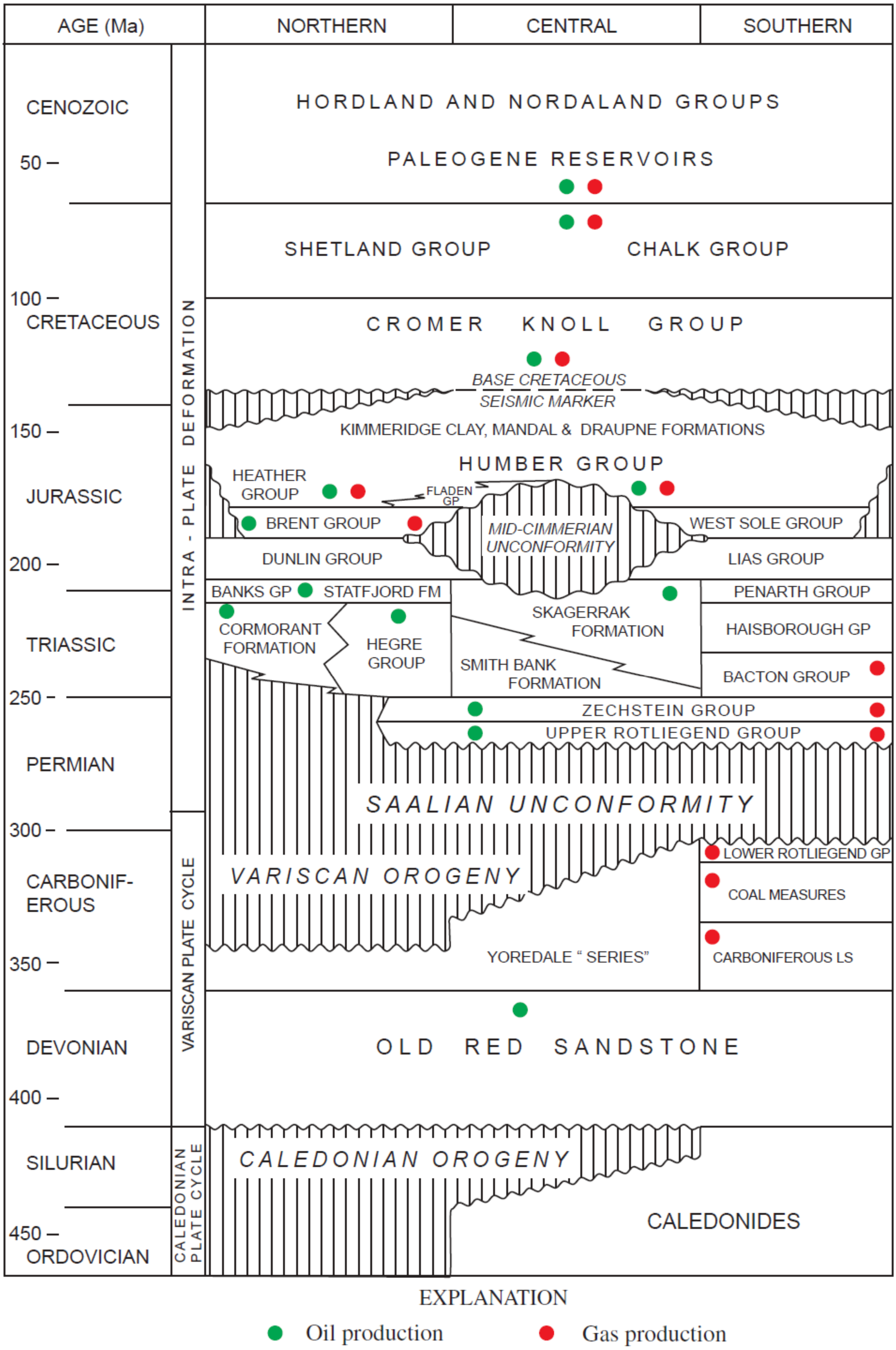


Figure 3.5: Stratigraphic summary of the North Sea region (Brennand et al., 1998).

3.2.1 Paleozoic

The Paleozoic successions in the northern North Sea are not as well mapped and understood as younger strata in the North Sea sedimentary basins. This is due to great burial depths, but also because the Paleozoic has been regarded as of low economic interest in this area. However, Paleozoic sediments of Cambrian-Ordovician, Devonian-Carboniferous and Permian age are found in wells in the northern North Sea. Paleozoic mudstones and shales from the northern North Sea have TOC values in the range of 0.1-14.4 wt%, while Upper Paleozoic coals in the area have TOC values in the range of 17-80 wt%.

Thick red continental sediments, which in UK sector are known as Old Red Sandstone (Fig. 3.5), were deposited in Devonian time in response to the extensional collapse of the Caledonides. Although Devonian sediments in the northern North Sea have been reached in only a few wells, there are reasons to believe that Devonian sediments are present regionally in the deeper parts of the pre-Triassic half-grabens beneath the Horda Platform, Viking Graben and East Shetland Basin. The presence of Upper Paleozoic rocks, of both Devonian and Lower Permian age (Rotliegendes) (Fig. 3.5), has also been confirmed by drilling on the East Shetland Platform. Seismic data reveal large sedimentary basins beneath the platform, thought to contain Upper Paleozoic (Devonian-Carboniferous) rocks (Faleide et al., 2010).

Following the markedly dry climate which prevailed through Devonian time in the North Sea region, the Carboniferous period gradually became more humid. Ziegler (1990a) suggested that the absence of Upper Carboniferous rocks within the northern North Sea area (Fig. 3.5) may be attributed to non-deposition, but the presence of reworked Westphalian sporomorphs in the overlying Mesozoic deposits and in Denmark (Nielsen and Koppelhus, 1991) might suggest that there had been widespread deposition followed by regional uplift and erosion during Late Carboniferous and Early Permian.

The absence of Permian sediments in the northern part of the northern North Sea indicates that the graben developed mainly from the Griensbachian period and onwards. The Permian succession is, however, difficult to be restored due to later Mesozoic subsidence and Tertiary inversion. In addition, the difficulty in determining the Permian-Triassic boundary complicates the detailed understanding. In general, the Permian rocks of the central and northern North Sea consist of a lower sequence termed the Rotliegend Group, that largely comprises sandstones with local basal volcanic, and an upper sequence of carbonates and evaporites with local clastic rocks that form the Zechstein Group (Fig. 3.6).

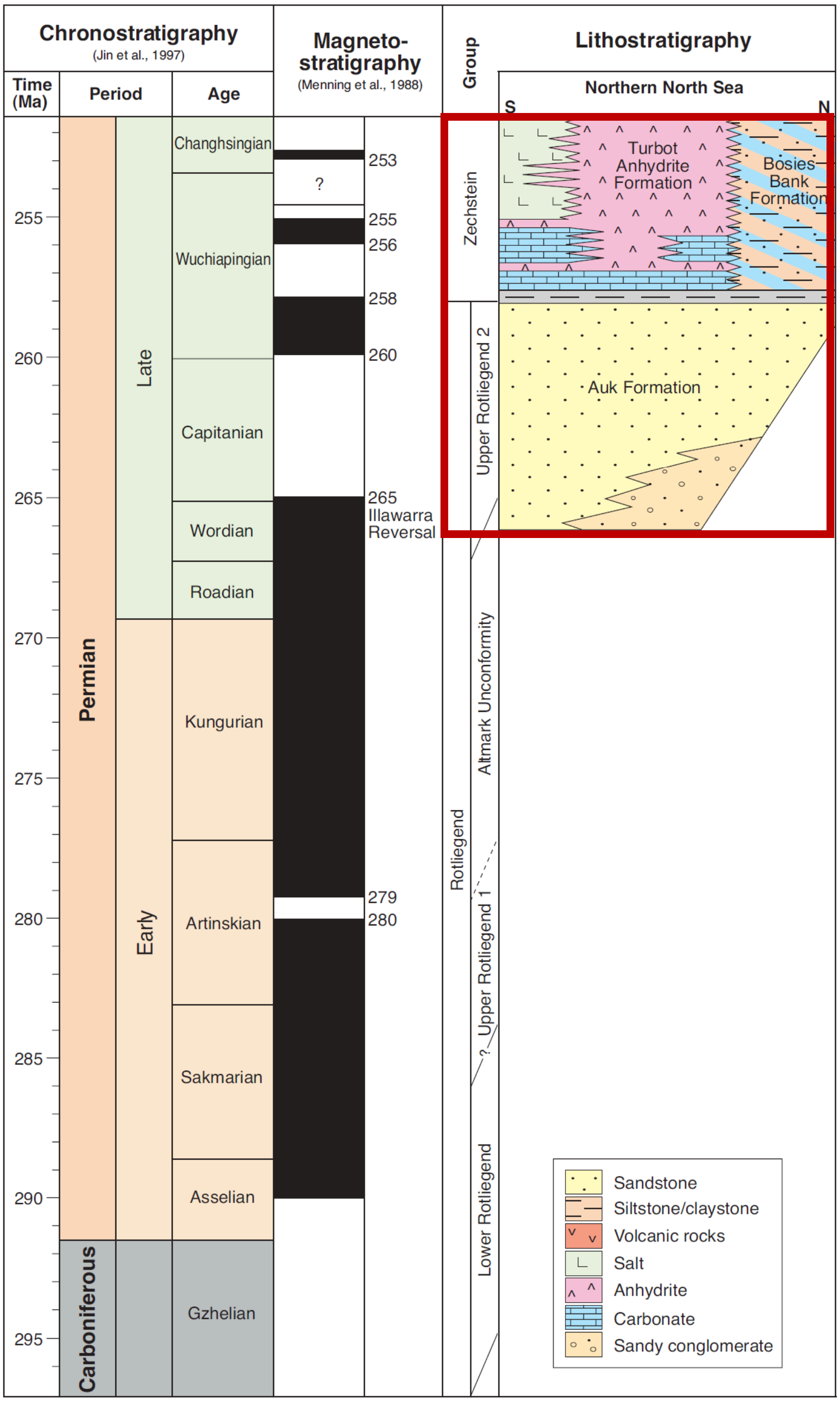


Figure 3.6: Permian stratigraphic chart of the northern North Sea (Evans et al., 2003).

By the Early Permian, the North Sea was entering a semi-desert climatic zone similar to that of modern Arabia (Glennie, 1997) or the southern Sahara. During later Permian times, this part of Laurasia occupied a latitudinal position similar to that of a tradewind desert such as the modern Sahara.

3.2.2 Mesozoic

Triassic

The Triassic strata of the northern North Sea were initially subdivided into three formations: Smith Bank, Skagerrak and Cormorant formations (Fig. 3.7) defined within the informal 'Triassic group' (Deegan and Scull, 1977). The succession was poorly understood at that time as few wells had been drilled into the Triassic monotonous and non-fossiliferous continental red beds. Triassic rocks are widely distributed in the central and northern North Sea and contain about 5% of the petroleum reserves (Goldsmith et al., 2003).

In an attempt to unify UK and Norwegian Triassic and Jurassic lithostratigraphical nomenclature Vollset and Doré (1984) revised the nomenclature, defining a group with three formations: the Hegre Group with the Teist, Lomvi and Lunde formations. According to the international lithostratigraphical guide (Salvador, 1994), the already defined Cormorant Formation has preference to be upgraded to group level instead of introducing a new name. Cameron (1993) claimed that some of the lithostratigraphic units could not be recognized in the UK sector, e.g. the Lomvi Formation, although Frostick et al. (1992) reported the Formation from the Beryl Basin, and thus the formation has also been identified in the UK sector.

The subsequent middle Triassic to early Jurassic post-rift stage is considerably better known. Subsidence in the northern North Sea accompanied by faulting, stepping down from the Viking Graben axis (Steel and Ryseth, 1990). Table 3.7 shows the proposed sequence stratigraphy for the northern North Sea and suggested links to the chronostratigraphy and to the main lithostratigraphies.

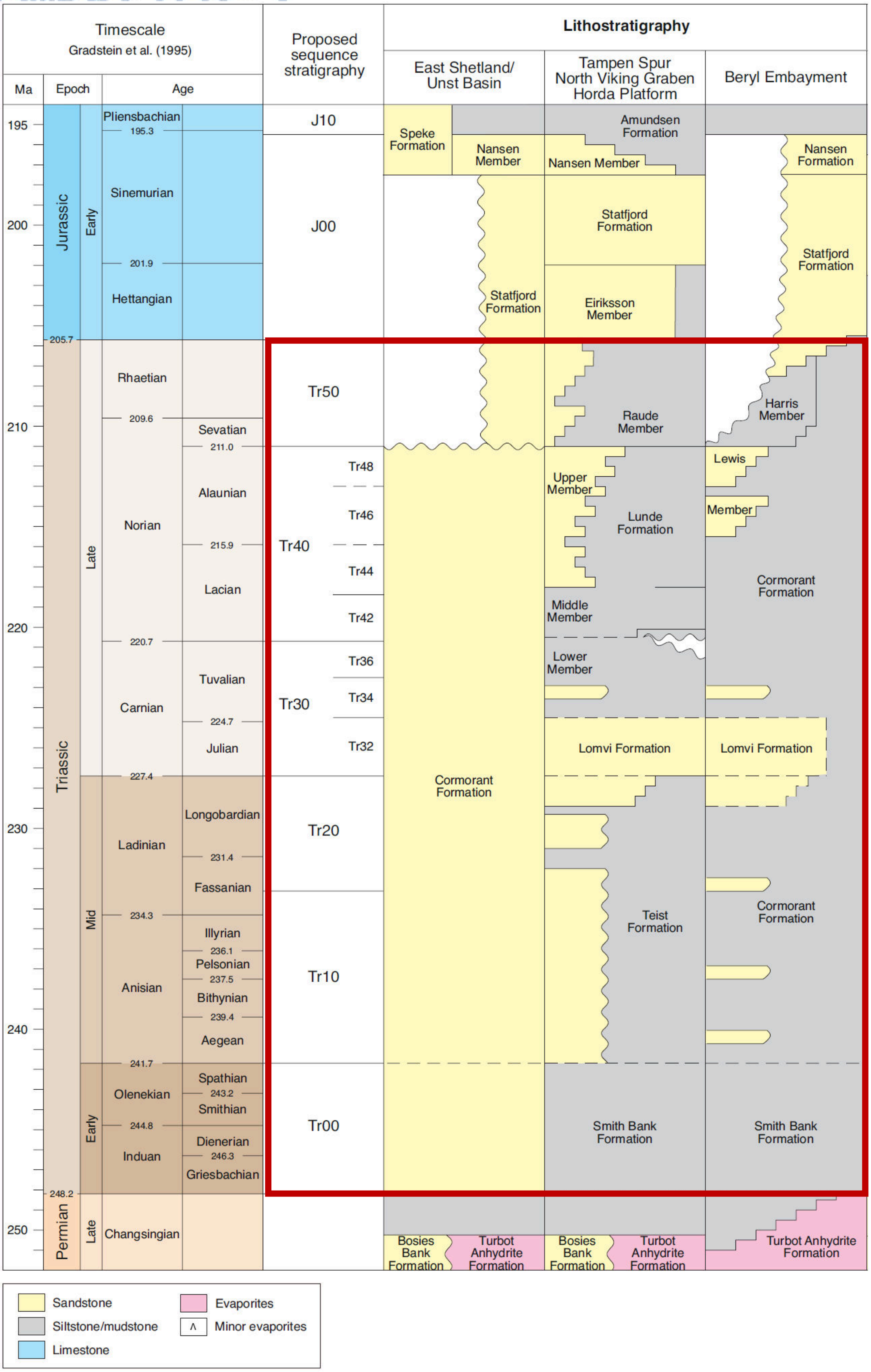


Figure 3.7: Triassic sequence-stratigraphic scheme of the northern North Sea (Evans et al., 2003).

Jurassic

Towards the end of the Triassic, the climate became more humid and the depositional environment became fluvial and then changed to marine with a corresponding rise in sea level during Early Jurassic (Faleide et al., 2010). In most of the northern North Sea region the Lower Jurassic strata overlie conformably the Triassic sequence.

In the northern North Sea, fluvial-marine sandstones of the Lunde and Statfjord formations were deposited in the Viking Graben. These form important reservoirs in some fields (e.g. Snorre Field). The sandstones and lean marine shales of the Dunlin Group overlie the Statfjord Formation. The most important reservoir, the Brent Group then overlies the Dunlin Group (Faleide et al., 2010). The lower section of the Brent Group comprises upward coarsening, micaceous sandstones of the Etive and Rannoch formations. The middle section, the Ness Formation, represents fluvial-deltaic facies with channel, crevasse sand, lagoonal and coal deposits. The uppermost section, the Tarbert Formation, comprises well-sorted sandstones formed by reworked deltaic deposits, representing a marine transgression (Faleide et al., 2010).

Late Jurassic was characterized by subsidence, rotation and erosion of tilted fault blocks in the Viking Graben (Fraser et al., 2002). Transgression at the same time (Oxfordian) covered the graben with a thick drape of organic rich argillaceous sediments. These sediments became the Viking Group (Vollset and Dore, 1984). The lower and upper shale members are referred to as the Heather and Draupne (Kimmeridgian Clay Formation equivalent) formations, respectively, and they form the main source rocks in the northern North Sea.

The first formal lithostratigraphic nomenclature for this offshore area was proposed in a UK-Norwegian collaborative report by Deegan and Scull (1977) that spanned the two national sectors. Subsequent formal revisions have taken place separately in all three sectors: in Norway by Vollset and Doré (1984), in Denmark by Jensen et al. (1986) and Andsbjerg and Karen Dybkjær (2003), and in the UK by Richards et al. (1993) as it is shown in the Figure 3.8.

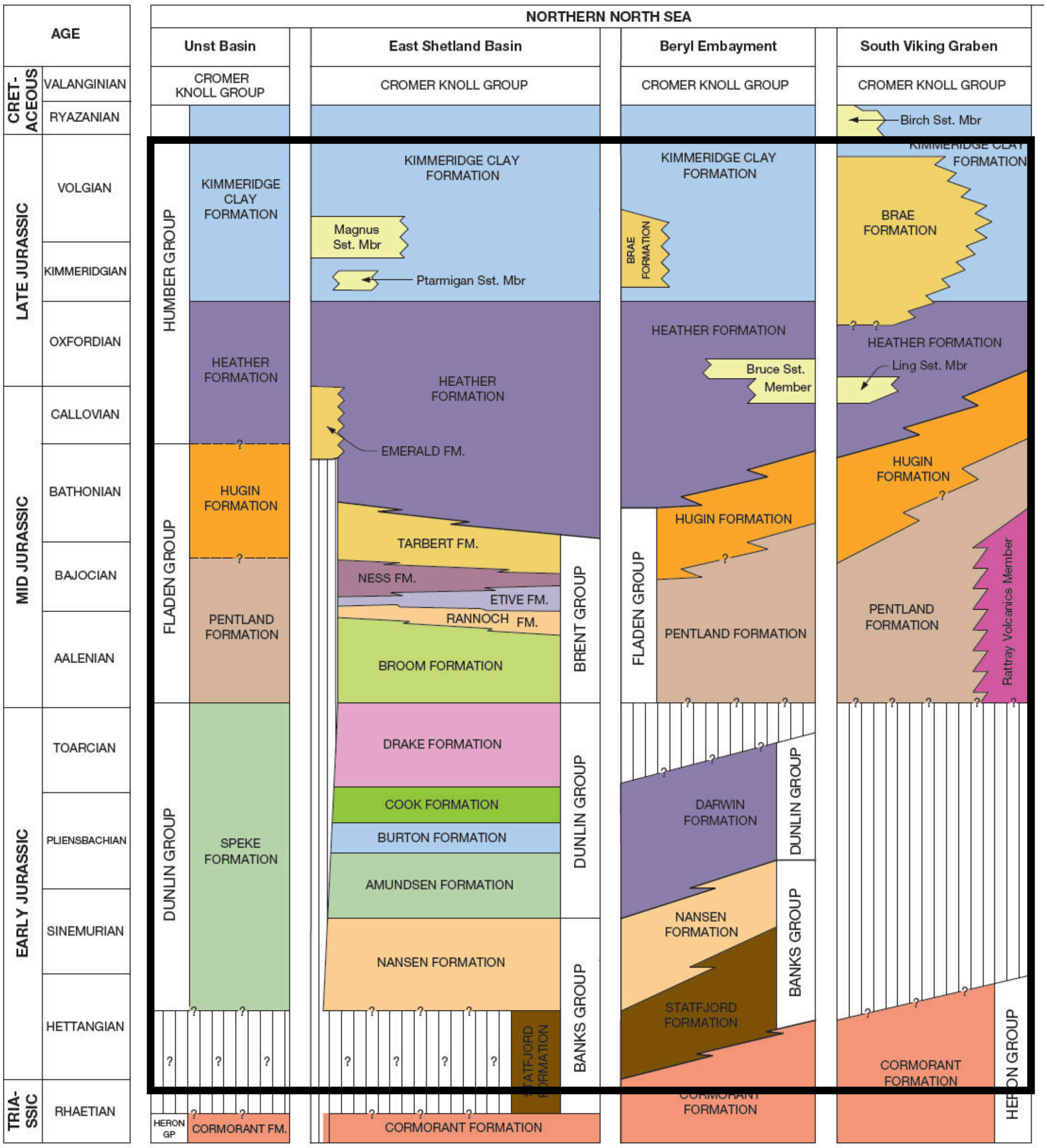


Figure 3.8: Lithostratigraphic nomenclature scheme for the Jurassic of the UK northern North Sea (Richards et al., 1993).

North of 59º N the Brent Group is present everywhere (Fig. 3.9). It is overlain by the Viking Group, the lower part of which is of Middle Jurassic age, and comprises the lower Heather Formation and local sandstones such as the Frensfjord and Krossfjord formations in the north-east. In the northern North Sea, the Brent Group thickness commonly varies from 100 to 300 m, but may reach 500 m. It is dominantly composed of shallow-marine to nearshore and nonmarine sandstones, and comprises the five formations (Fig. 3.8) whose initial letters form the word Brent (Broom, Rannoch, Etive, Ness, Tabert), as well as the Oseberg Formation.

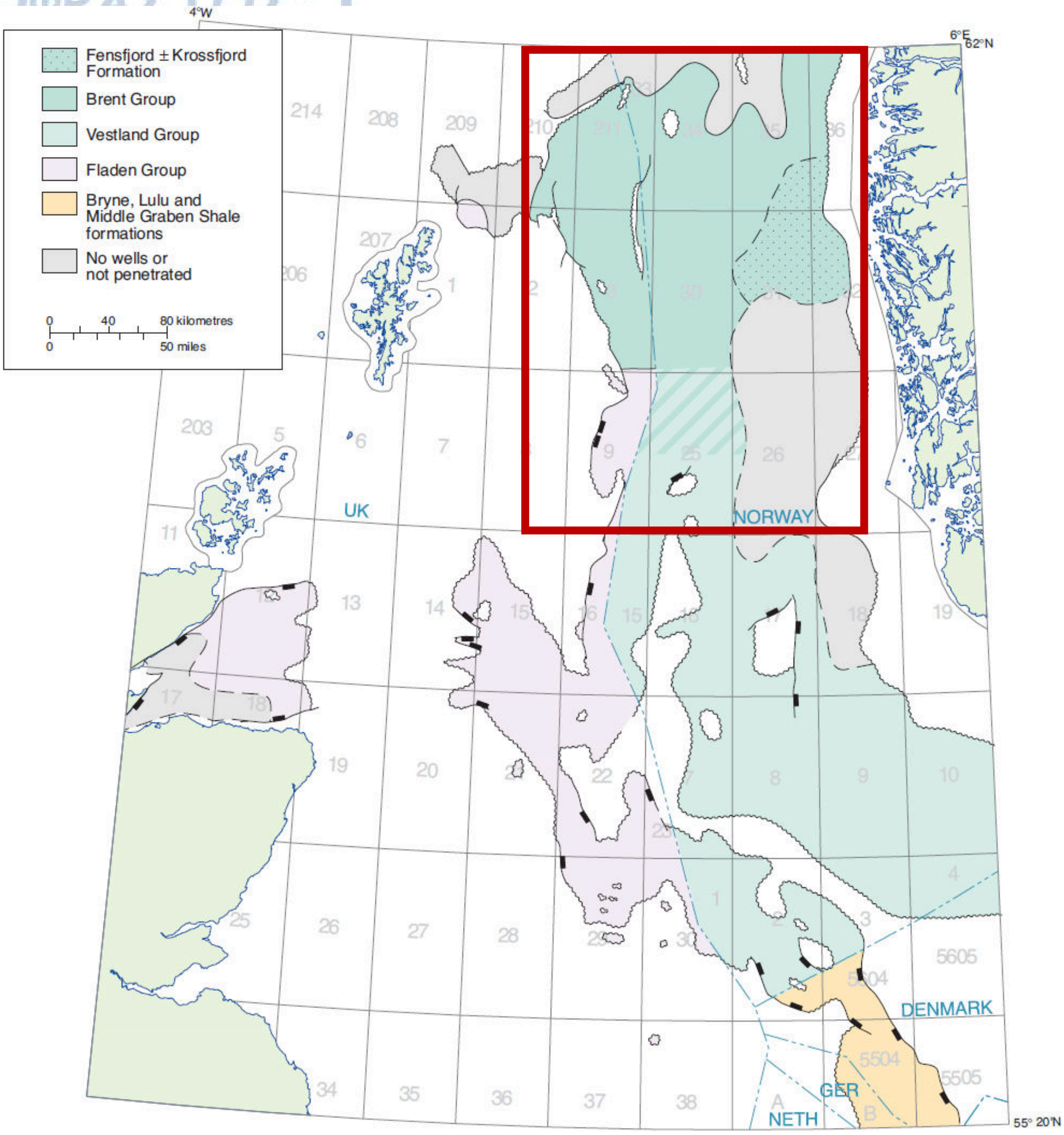


Figure 3.9: The distribution of Middle Jurassic lithostratigraphic units (Evans et al., 2003).

Cretaceous

The Cretaceous deposits have been divided into two major groups corresponding with the division between the Early and Late Cretaceous epochs. The Cromer Knoll Group is of Early Cretaceous age and consists of fine-grained, argillaceous, marine sediments with varying content of chalk. It is widely distributed in the Norwegian sector but the thickness varies as it was deposited over an irregular topography formed during the Late Jurassic rifting. The Cromer Knoll Group is thickest in the northern North Sea in the Sogn Graben where it is thought to attain a thickness close to 1400 m. The Shetland Group is of Late Cretaceous age. It consists mostly of chalk in central parts of the North Sea, however, in the northern North Sea it is mainly composed of siliciclastics and marls. The thickness of the package ranges from 1000 to 2000 m (Isaksen and Tonstad, 1989).

3.2.3 Cenozoic

During Early Paleocene, submarine fans developed along the faulted basin margins in the west and spread out and overlapped in such way that they formed near-continuous sandstone bodies that became finer grained distally and eventually wedged out towards the basin centre. As implied in Figure 3.10, the largest volume of sandy sediment input into the basin occurred during deposition of the Lista Formation during the Middle Thanetian (Liu, 1995), which was also the time of peak uplift of the surrounding areas (Ziegler, 1990b).

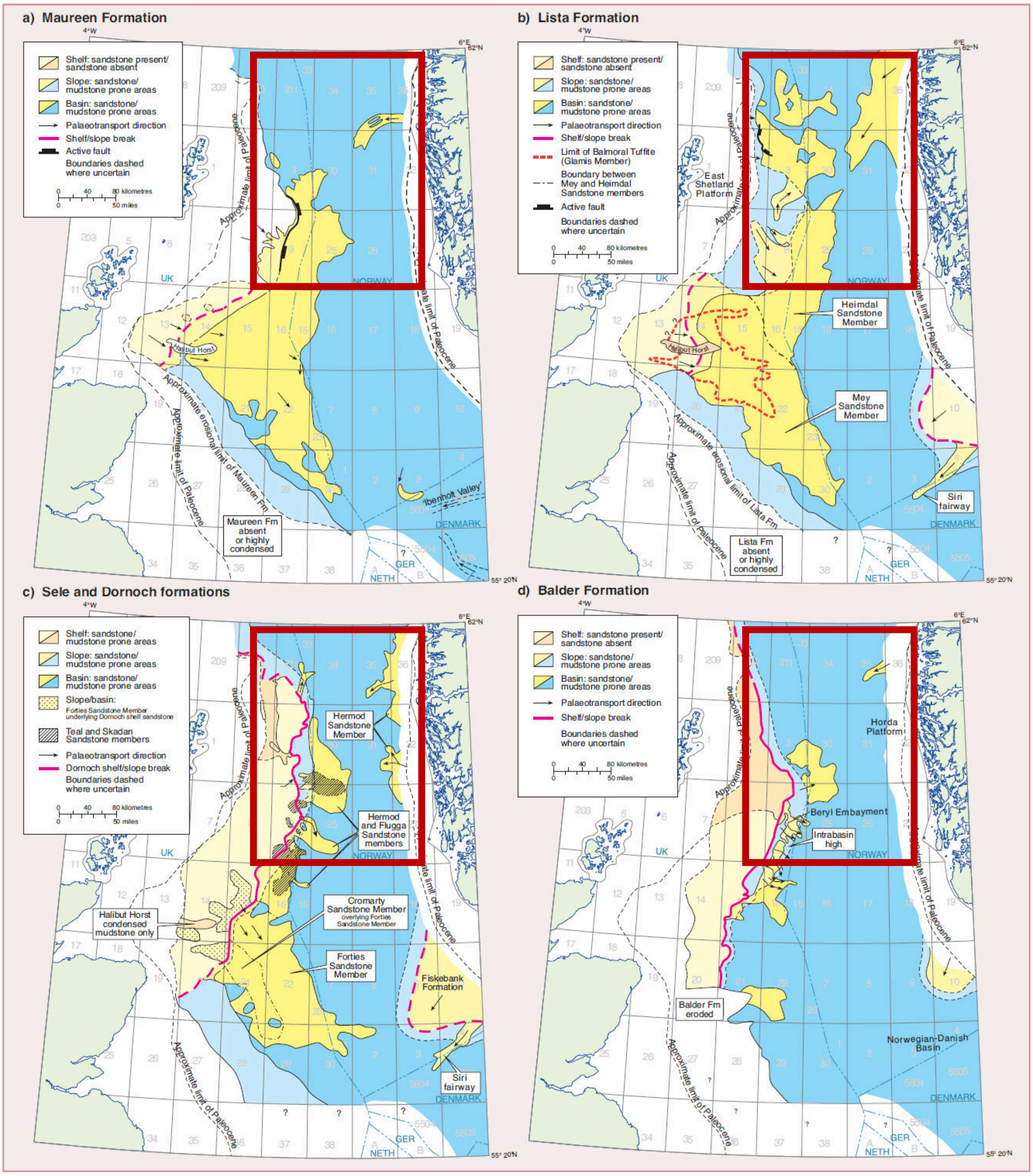


Figure 3.10: Paleocene paleogeographic maps (Evans et al., 2003).

A gradual rise in relative sea level then submerged the more prominent intrabasinal highs, and marine muds were deposited over these highs and in distal basinal areas (Deegan and Scull, 1977). The first formal lithostratigraphic nomenclature for the Paleocene of the North Sea was proposed by Deegan and Scull (1977), and this still forms the basis of current terminology (Fig. 3.11).

Volcanism in the region, related to the incipient North-East Atlantic spreading, terminated in Eocene times at around 52 Ma (Joppen and White, 1990), and sea-floor spreading during the Early Eocene placed the North Sea in compression between the spreading sea-floor ridge and the Alpine mountain belt (Knott et al., 1993). This compression provided a mechanism for basin-margin uplift, resulting in several hundreds of meters of deep submarine-fan and hemipelagic sediments being deposited in the basinal depocentres of the Viking and Central grabens. The maximum thickness of the Eocene succession is in the Viking Graben where it is over 800 m thick, although only slightly thicker than in the Central Graben. With sediment supply, especially that of coarse-grained clastics, diminishing throughout the Eocene the character of the depositional system became quite different to that of the large, stacked, submarine fans that had been such a feature of the Paleocene. The majority of the early Eocene submarine-fan systems deposited much smaller, more localized fans, and the Middle to Late Eocene systems became typically more channelized. The four palaeogeographic maps (Fig. 3.10) illustrate the depositional environments and sandstone distribution for the Maureen, Lista, Sele/Dornoch and Balder formations.

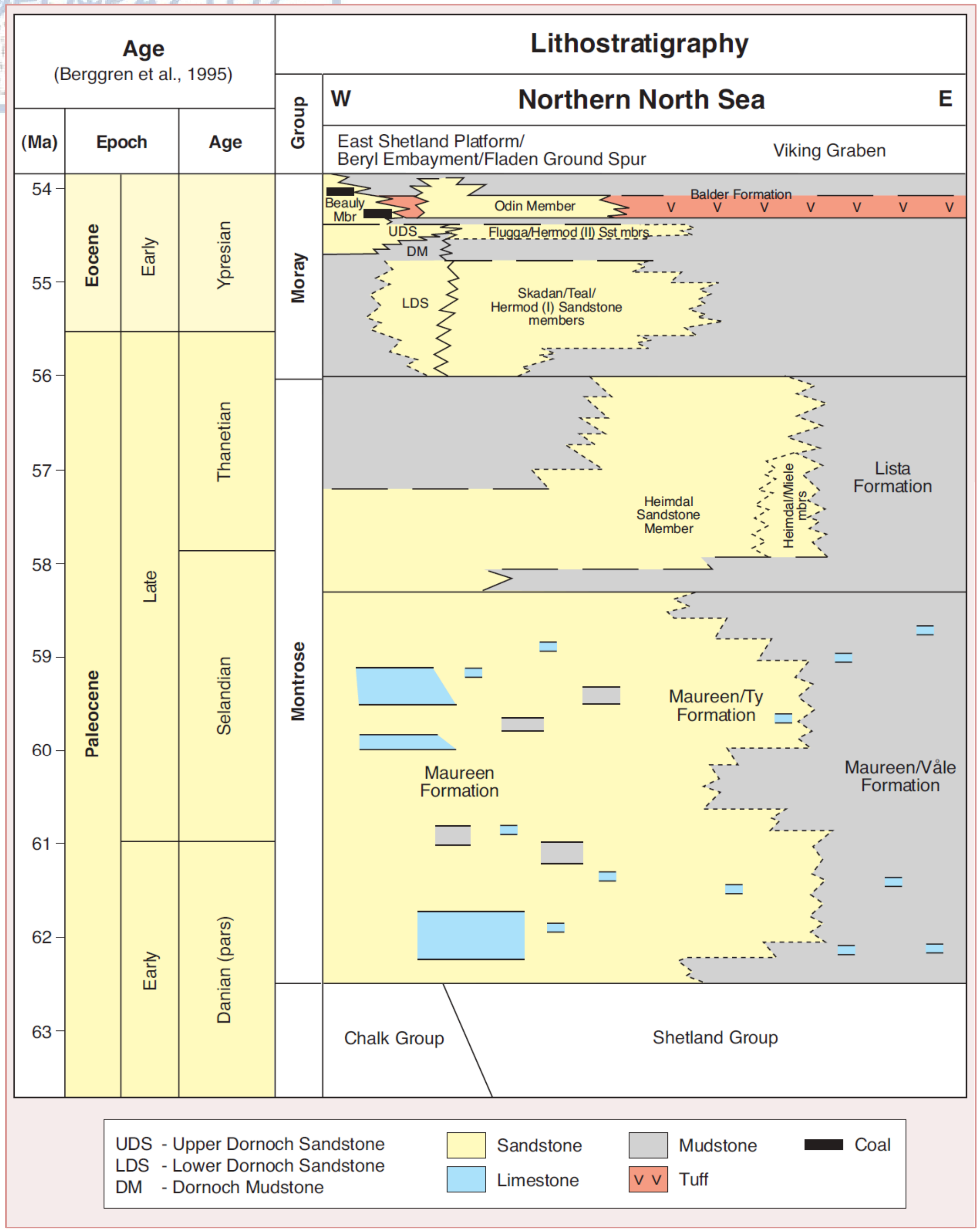


Figure 3.11: Lithostratigraphy of the Paleocene (Evans et al., 2003).

The long-term trend in the global d^{18}O record, based on carbonate from deep-sea calcareous benthic foraminifera, shows that the Early Eocene Climatic Optimum (EECO) was followed by a 17 My long trend towards cooler conditions with most of the changes occurring during the Early-Middle Eocene (50-48 Ma), Late Eocene (40-36 Ma) and Early Oligocene (35-34

Ma) (Fig. 3.12). This was a profound change in climate regime from a greenhouse climate, prevailing since the Mesozoic, to a modern ice-house climate (Zachos et al., 2001). A generally lowered, but fluctuating eustatic sea level was caused by growing and waning ice sheets primarily in Antarctica, but probably also in Greenland. A d^{18}O-record, based on carbonate from molluscs collected from onshore strata, shows that the climate became much cooler also in Scandinavia (Buchardt, 1978). The general lithostratigraphy of the Late Paleogene and Neogene is illustrated in Figure 3.12. On the right-hand side of the diagram there are some paleoclimatic data including a global deep-sea oxygen curve and periods with ice-sheets in the Antarctica and northern hemisphere (after Zachos et al., 2001), and a global sea-level curve after Hardenbol et al. (1998). Changes in depositional patterns and tectonic events are also indicated.

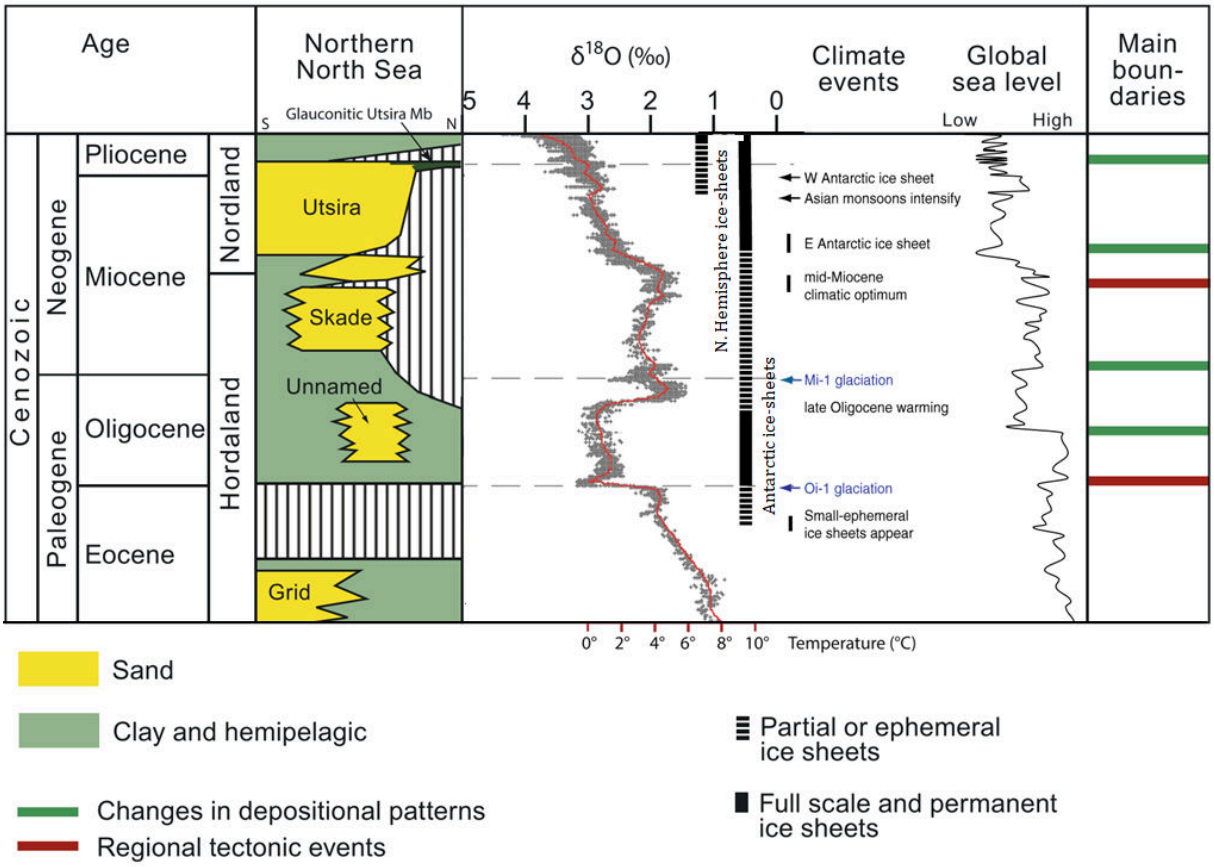


Figure 3.12: General view of the Late Paleogene and Neogene lithostratigraphy in the northern North Sea (modified after Rundberg and Eidvin, 2005; Rasmussen et al., 2008; Eidvin et al., 2010, 2013d).

Throughout the Oligocene and Miocene, the water depth in the Viking Graben was gradually shallowing, probably because of the high sedimentation rates and deltaic progradation from the west. The Cenozoic stratigraphy of the North Sea has been divided into three groups: the Rogaland, Hordaland and Nordland Groups.

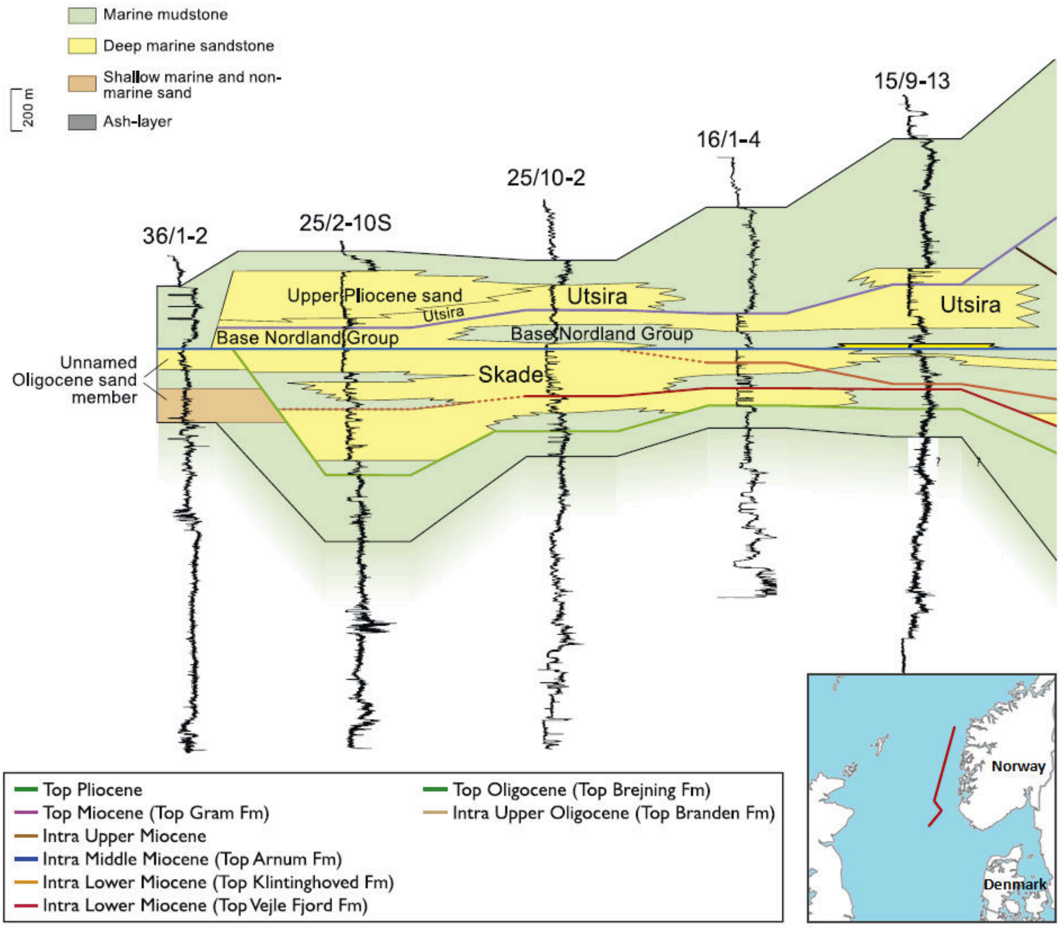


Figure 3.13: Correlation panel of the Oligocene to Pliocene succession of the northern North Sea (modified after Edvin et al., 2010).

Rogaland Group

The Rogaland Gp is subdivided into twelve formations. In general, the sequences start off from the west as more proximal and interfinger with more distal sediments to the east. The group is widely developed in the northern and central North Sea. The base of the group is the contact with underlying chalk or marl sequences of the Shetland Group. The upper boundary is defined by the change from laminated tuffaceous shales (Balder Formation) to sediments of the Hordaland Group. The Rogaland Group is thickest in the west in the UK sector (about 700 m), thinning eastwards and southwards with recorded borehole thicknesses in the order of 100 m. Depositionally, the Rogaland Group represents submarine fan/gravity flow sediments transported into deeper water. The sand bodies are generally lobe shaped and pass laterally into silt and mudstones to the east.

Hordaland Group

The Hordaland Group ranges from Eocene to Early Miocene age. In the northern North Sea the deposits are a couple of hundred metres thick. Marine claystones of brown to light-grey colour are the dominant deposits, with presence of minor sandstones at various levels. The sandstones are generally very fine to medium grained and are often interbedded with claystones. The Hordaland Group is subdivided into the Frigg, Grid, Skade and Vade formations. The first three formations are sourced from the East Shetland Platform. Within the Norwegian sector they are only recognized in the western parts of the central and southern North Sea. The Vade Formation is only distributed in Quadrant 2, within the Central Graben (Isaksen and Tonstad, 1989). The Norlex division of the Hordaland Group in the area east of the Viking Graben is divided into the Lark and Horda Formations. The Lark formation constitutes two siliciclastic members, the Skade Member and an unnamed member (Gradstein et al., 2010). The Brygge Formation makes up the entire Hordaland Group in the Norwegian Sea (Dalland et al., 1988).

The Lower Miocene comprises the topmost part of the Hordaland Group. In large parts of the Viking Graben, a sandy section, sourced from the East Shetland Platform, makes up a great proportion of the Lower Miocene unit. These sands are referred to as the Skade Formation and reach a gross thickness of up to 300 m (well 16/1-4) (Fig. 3.13). The deposition of the Skade Formation represents a southern shift in coarse clastic influx to the basin from the East Shetland Platform, relative to Oligocene time. In most parts, the deposits are turbiditic in origin and were probably deposited in quite deep parts of the shelf. According to investigation, the sands were deposited between approximately 24 and 15.5 Ma and they represent a huge sand volume comparable to the Utsira Formation. It has been suggested that they are a result of a new tectonic uplift event affecting the East Shetland Platform, possible associated with a renewed compressional tectonic phase along the northwest European margin (Rundberg and Eidvin, 2005). The Skade sands pinch out to the east and north. In the Tampen area, the Lower Miocene strata comprise mainly mud-prone lithologies in a distal setting. Just south of 61º N and northwards, the Lower Miocene unit is only present in the central basin and absent at the margins to the west and east. In the northernmost North Sea, between 61º30’ and 62º N, the unit has been completely eroded (Rundberg and Eidvin, 2005).

Nordland Group

The Nordland Group ranges in age from late mid-Miocene to Holocene. It is characterised by a relatively symmetrical basin fill with the greatest thickness being in the central part of the basin. The pre-Pleistocene portion of the Nordland Group typically comprises grey mudstone, with local sandstones mainly developed in the basal part. The gamma-ray well-log response from the argillaceous section is generally higher than from the mudstones of the Westray/Hordaland groups below due to the potassium-rich nature of the sediments that contain abundant mica, illite and K-feldspar (Rundberg, 1989).

The only formation that has been formally recognised in the Miocene to Pliocene succession is the Utsira Formation (Isaksen and Tonstad, 1989), although a number of post-Eocene sand units have been identified and informally termed the "Hutton Sands" by oil companies. The succession above the Utsira Formation consists of unconsolidated clays and sands. The uppermost part consists of glacial deposits.

The Norlex division of the Nordland Group in the area east of the Viking Graben also includes only one formation, the Kai Formation. Within the Kai Formation lies the Utsira Member (Gradstein et al., 2010). On the mid-Norwegian continental shelf, Dalland et al. (1988) defined the Early Miocene to Late Pliocene Kai Formation and the Late Pliocene-Pleistocene Naust Formation. The corresponding sediments in the North Sea Basin belong to the Nordland Group but have not been divided into specific formations. The Kai Formation is of Early Miocene to Late Pliocene age. It consists of alternating claystone, siltstone and sandstone with limestone stringers. The Naust Formation is of Late Pliocene age. It is laterally continuous along the mid-Norwegian continental shelf. The formation consists of interbedded claystone, siltstone and sand, occasionally with very coarse clastics in the upper part (Dalland et al., 1988). A revised post-Eocene lithostratigraphic Nomenclature is proposed (Fig. 3.14). Within the Hordaland (upper part) and Nordland groups, only two major sandy sections have been defined (Utsira and Skade formations) whereas the remaining lithologies have remained undifferentiated (Isaksen & Tonstad 1989).

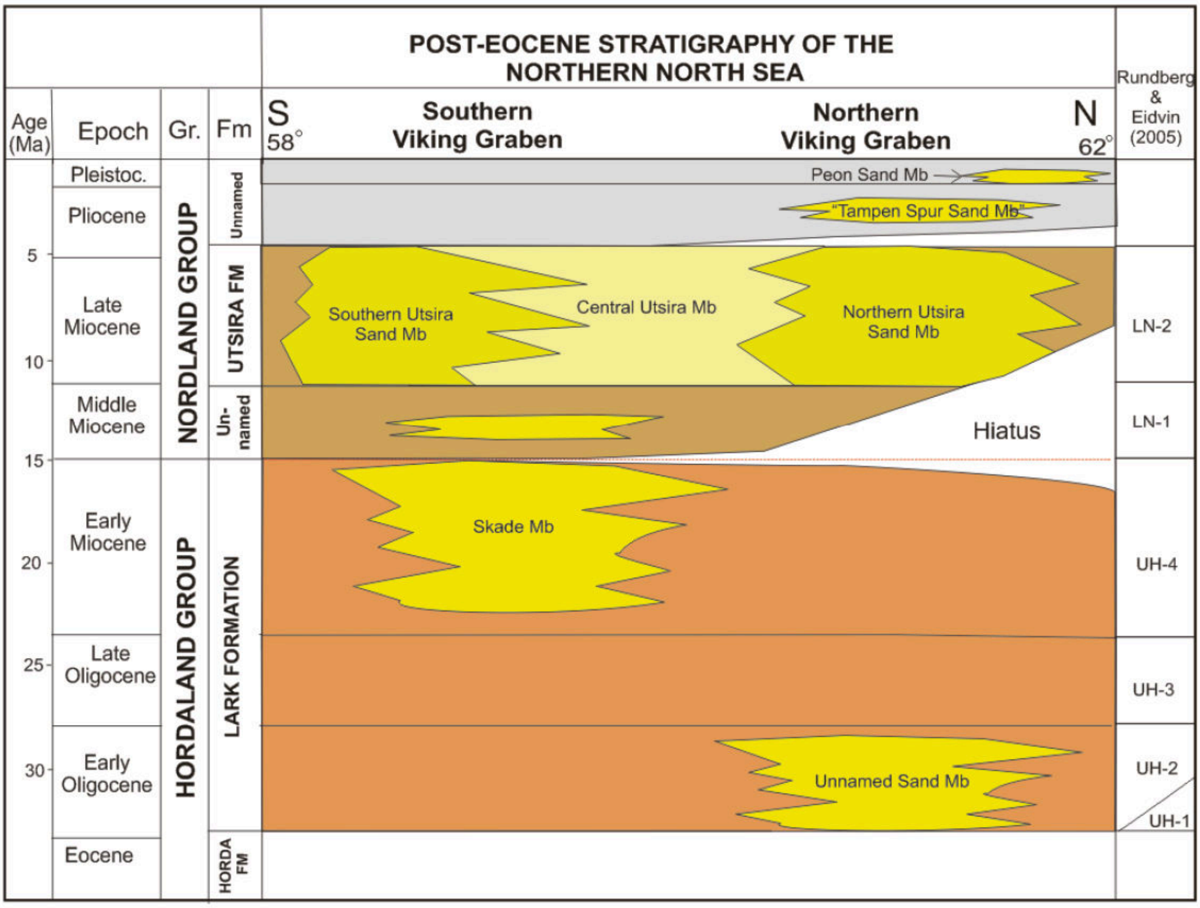


Figure 3.14: Proposed lithostratigraphic subdivision of post-Eocene strata in the northern North Sea (Eidvin and Rundberg, 2007).

Chapter 4
CRUSTAL STRUCTURE

4.1 PALEOZOIC CONTINENTAL COLLISION AND PLATE ACCRETION

The crustal tectonic framework of the region developed in four main convergent tectonic episodes (McKerrow et al., 2000):

1) The Ordovician or Taconic/Grampian Orogeny from about 460 to 450 Ma
2) The Caledonian Orogeny from about 425 to 400 Ma (peak)
3) The Devonian or Acadian Orogeny around 400 Ma and
4) The Variscan/Appalachian Orogeny from 400 to 300 Ma

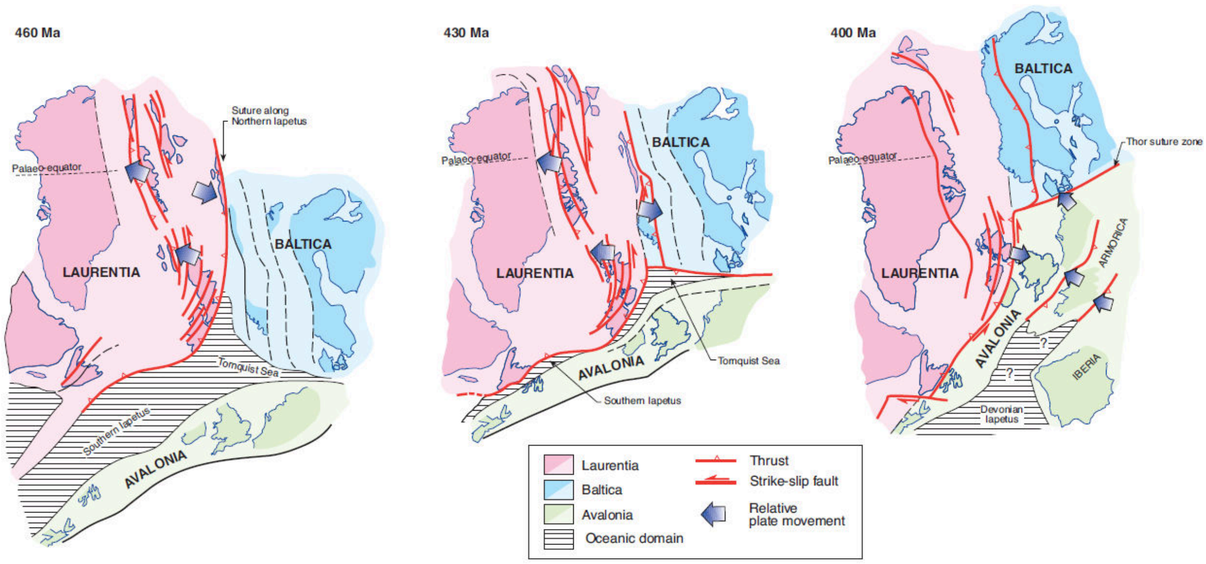


Figure 4.1: Evolution of the Caledonides in the North Atlantic (modified from Klemperer and Hobbs, 1991).

The Caledonian Orogeny is the most important one of the above main convergent episodes for the North Sea region as it has provided the crustal grain where the later sedimentary cover was deposited. According to the plate reconstructions of Soper et al. (1992a), Caledonide collision involved three-way convergence between Baltica, Laurentia and Avalonia (Fig. 4.1). The northern and southern Iapetus oceans separated Laurentia from Baltica and Avalonia, and the Tornquist Sea between Avalonia and Baltica formed the third arm of the triple convergence zone. The north-westerly trending Thor or Tornquist suture zone located along the line of closure of the Tornquist Sea was fundamental to the subsequent tectonic development of north-west Europe as it formed the south-western margin of the thick lithosphere of Archean-Proterozoic Baltica. Earlier, this lineament may have acted as an extensional plate margin during Late Proterozoic to Early Paleozoic times.

There is faunal (e.g. Cocks, 1982), sedimentological (e.g. Noblet, 1990) and paleomagnetic (e.g. Van der Voo, 1982) evidence that in Europe an older (Caledonian) orogenic belt resulted from the collision of Baltica and Laurentia (Fig. 4.2), followed in time by a younger (Variscan) orogeny when Gondwana and Laurasia (Laurentia together with Baltica, Fig. 4.2) joined. In Paleozoic times, the Scandinavian Caledonides and the Variscides came about by similar but independent evolutions. Convergence between Laurentia and Baltica during the Ordovician and early Silurian (500-430 Ma) closed the latest Precambrian-Cambrian North Iapetus Ocean. The last deep-water marine sedimentation and the peak of the Caledonian orogeny indicate collision in the mid-Silurian to early Devonian (425-400 Ma, e.g. Harland and Gayer 1972; Robert and Sturt 1980; Gee 1982; Milnes et al., 1997).

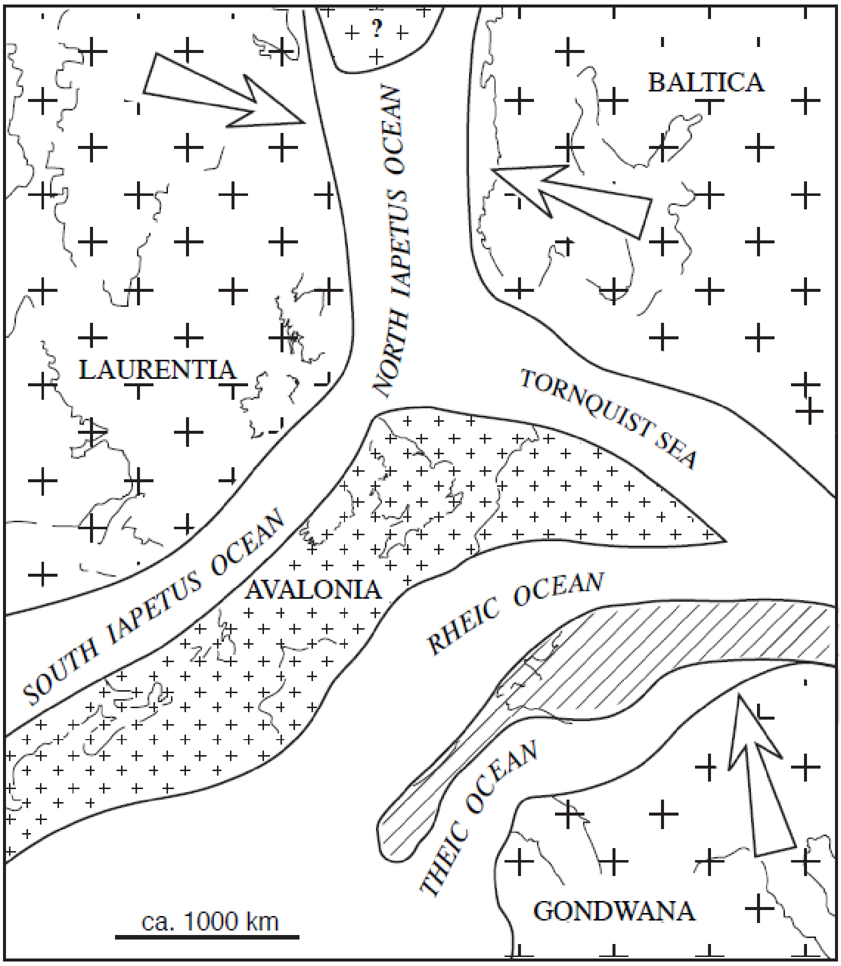


Figure 4.2: Bulk distribution of continental masses in Silurian times (ca. 430 Ma) and approximate directions of relative closure vectors (after Ziegler, 1986; Scotese, 1990).

During the same period, the northward motion of Gondwana closed the Rheic and Theic oceanic domains. In the early Devonian (ca. 395 Ma) Gondwana collided with the recently assembled Laurasia (Bard, 1980; Matte, 1986; Franke, 1989b). Caledonian east-west contraction stopped when north-south Early-Variscan contraction began (directions are given in a present-day reference frame). From this time onward, the two orogens evolved differently. The Scandinavian Caledonides underwent extension (Hossack, 1984; McClay, 1986; Norton, 1986; Séguret, 1989), while the Variscides were recording early collision. Synchronism between extension in the Caledonides and early contraction in the Variscides suggests that the Early Devonian evolution of the two belts may not totally be disconnected. Later on, the Variscides recorded active continent-continent collision (e.g. Matte, 1986; Franke, 1989b) from Early Devonian to Early-Middle Carboniferous (390-330 Ma, Pin and Peucat, 1986). This was followed by post-thickening extension (Malavieille, 1993; Burg et al., 1994) from Middle Carboniferous to Permian (330-300 Ma, Costa, 1990).

When continental lithospheres converge, the convergence can be accommodated by continental subduction or by continent-continent collision, and commonly continent-continent collision follows continental subduction. One of the main differences between both convergence zones is that, during continental subduction, contractional structures are localised along the Wadatti-Benioff zone. In contrast, during continent-continent collision, deformation migrates away from the plate boundaries so that both continental crusts are strongly affected by intra-crustal deformation. In both Scandinavian Caledonides and Variscan belt, continent-continent subduction is inferred to have followed continental subduction. The Scandinavian Caledonides are a nearly linear, 1800 km long belt with a rather simple structure. Crustal-scale sections (Fig. 4.3) illustrating the geometry of the Scandinavian Caledonides for the Late Silurian vary according to relative proportions of two models:

1) Horizontal pure shear (Andersen and Jamtveit, 1990; Andersen et al., 1994) and thick-skinned tectonics (Norton, 1986) assume that pressures of 16 to 30 kbar recorded in the eclogites witness at least 100 km crustal thickening by whole crustal imbrication due to the continent-continent collision (Fig. 4.3a).
2) On the other hand, continental subduction (Fig. 4.3b) assumes that the high-pressures were reached during subduction of the Baltica continental lithosphere below Laurentia (Séranne, 1989; Andersen, 1991; Fossen and Rikkelid, 1992; Wilk and Cuthbert, 1994).

The horizontal pure shear model assumes the building of a crustal wedge several tens of kilometers thick, and the relative pervasive distribution of deformation within the collided continental margins. In contrast, the continental subduction assumes that deformation is mainly restricted to the Wadatti-Benioff zone and that the internal deformation of the subducted continental crust is relatively less important.

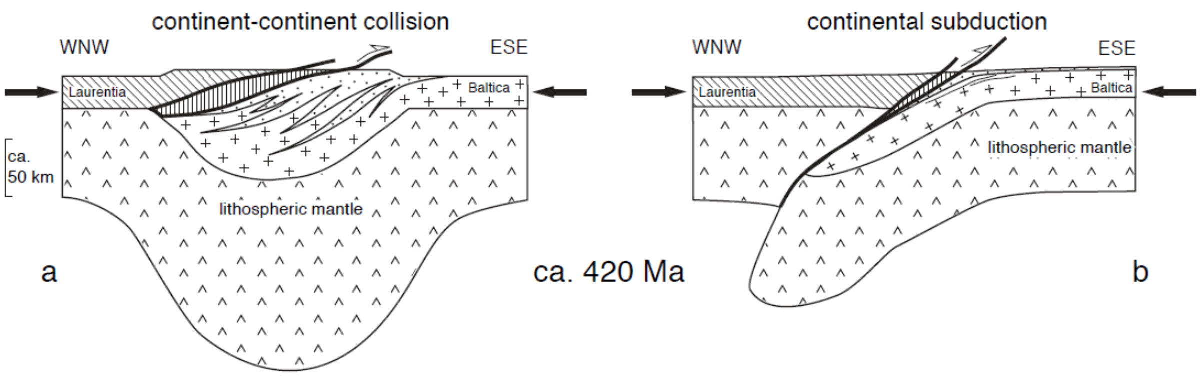


Figure 4.3: Two contrasted models of convergence zone have been proposed for the Scandinavian Caledonides: (a) symmetric thickening model adapted from Andersen and Jamtveit (1990a) and (b) continental subduction.

4.2 NORTH SEA: AN INTRACRATONIC BASIN

The North Sea is an example of an intracratonic basin, meaning a basin which lies on continental crust. The prerequisite for forming major sedimentary basins on continental crust is that the crust (and mantle lithosphere) is thinned, resulting in subsidence to maintain isostatic equilibrium. The North Sea has been subjected to periods of stretching/thinning and subsidence during late Carboniferous, Permian Early Triassic and Late Jurassic times. Each rift phase was followed by a thermal cooling stage, characterised by regional subsidence in the basin areas. Figure 4.4 shows the main structural elements of the northern North Sea, including major, fault-bounded structural highs and intervening basinal areas.

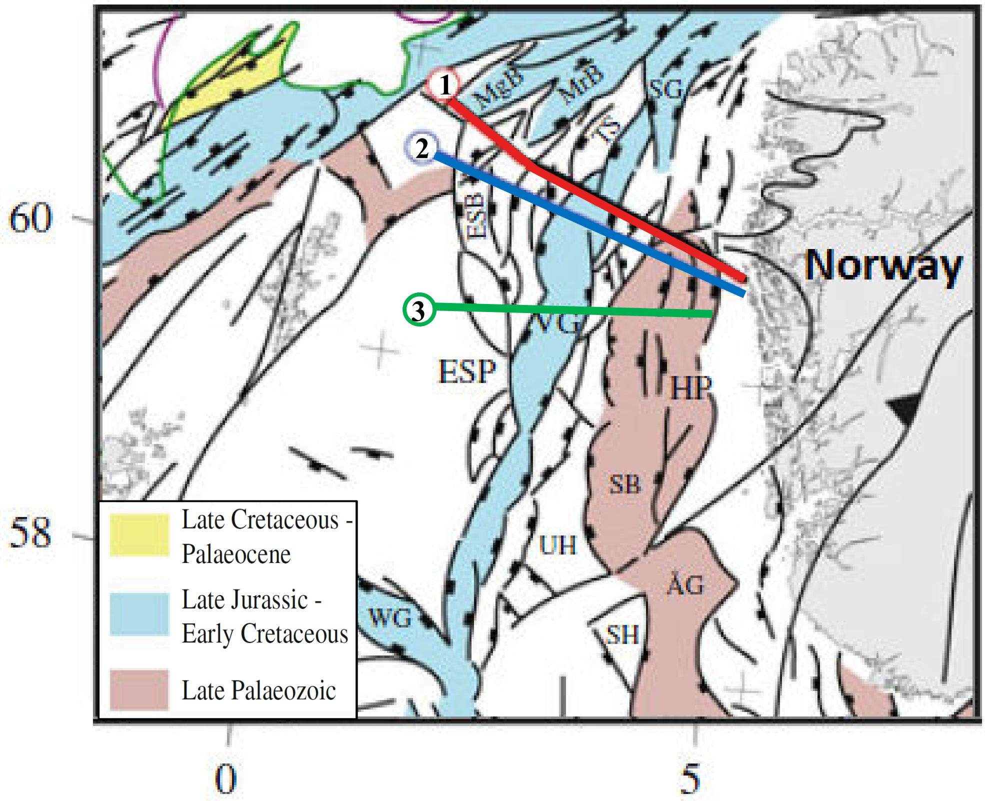


Figure 4.4: Main structural elements in the northern North Sea and adjacent areas (modified/updated from Faleide et al. 2008). Location of interpreted crustal transects (red and green) and seismic example (blue) shown in Figs. 4.5-4.7. ESB = East Shetland Basin, ESP = East Shetland Platform, HP = Horda Platform, MgB = Magnus Basin, MrB = Marulk Basin, SB = Stord Basin, SG = Sogn Graben, SH = Sele High, TS = Tampen Spur, UH = Utsira High, VG = Viking Graben, ÅG = Åsta Graben.

The northern North Sea sedimentary cover, ranging in age from Devonian to Cenozoic, overlays Precambrian and Lower Paleozoic crust that has undergone deformation during the Caledonian Orogeny. As mentioned above, the sedimentary basins have developed in the area of the earlier collision zone between the continents Laurentia and Baltica, and the Eastern Avalonia microcontinent. The closure of the Iapetus Ocean and the Tornquist Sea, and the subsequent collision between the three continents, occurred during Late Ordovician to Silurian times, and formed the Caledonian mountains. Figure 4.5 shows the major crustal features and present-day structural relationship between the three plates (Laurentia, Baltica, Avalonia) involved in the Caledonian collision.

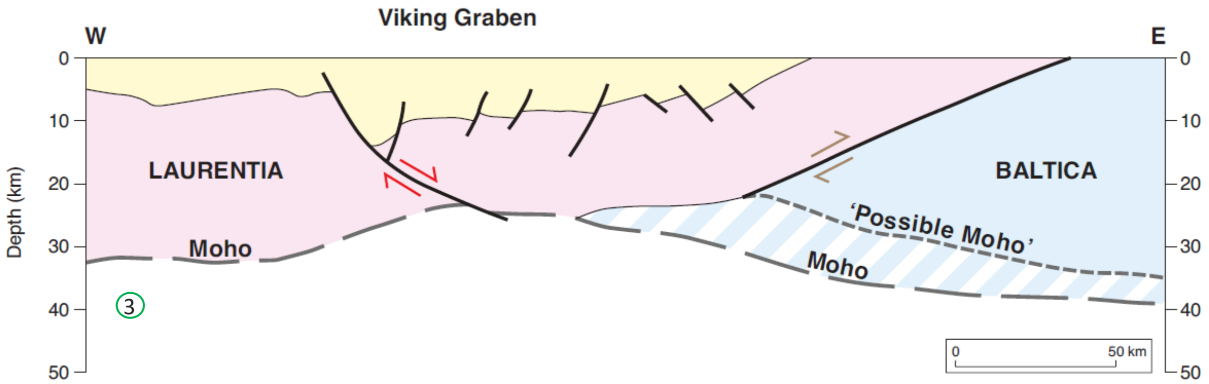


Figure 4.5: The Caledonian structure in the northern North Sea, interpreted from seismic profile NSDP 84-2 by Christiansson et al. (2000). See Fig. 4.4 for location.

The northern North Sea province is dominated by the Viking Graben, which continues into the Sogn Graben towards the north. These grabens are flanked by the East Shetland Basin and the Tampen Spur to the west, and the Horda Platform to the east (Fig. 4.4). These are Jurassic-Cretaceous features, and the main crustal thinning took place in the late Middle to Late Jurassic, followed by thermal subsidence and sediment loading in the Cretaceous. However, the Viking Graben and its margins are underlain by an older major rift basin of assumed Permian-Early Triassic age. The axis of this rift system is thought to lie beneath the present Horda Platform (Fig. 4.4). It is bounded by the East Shetland Platform in the west and the Øygarden Fault Zone in the east. Structures within this area are characterised by large rotated fault blocks with sedimentary basins in asymmetric half-grabens associated with lithospheric extension and crustal thinning (Fig. 4.6). The area was presumably also strongly affected by post-orogenic (post-Caledonian) extension in Middle to Late Devonian times.

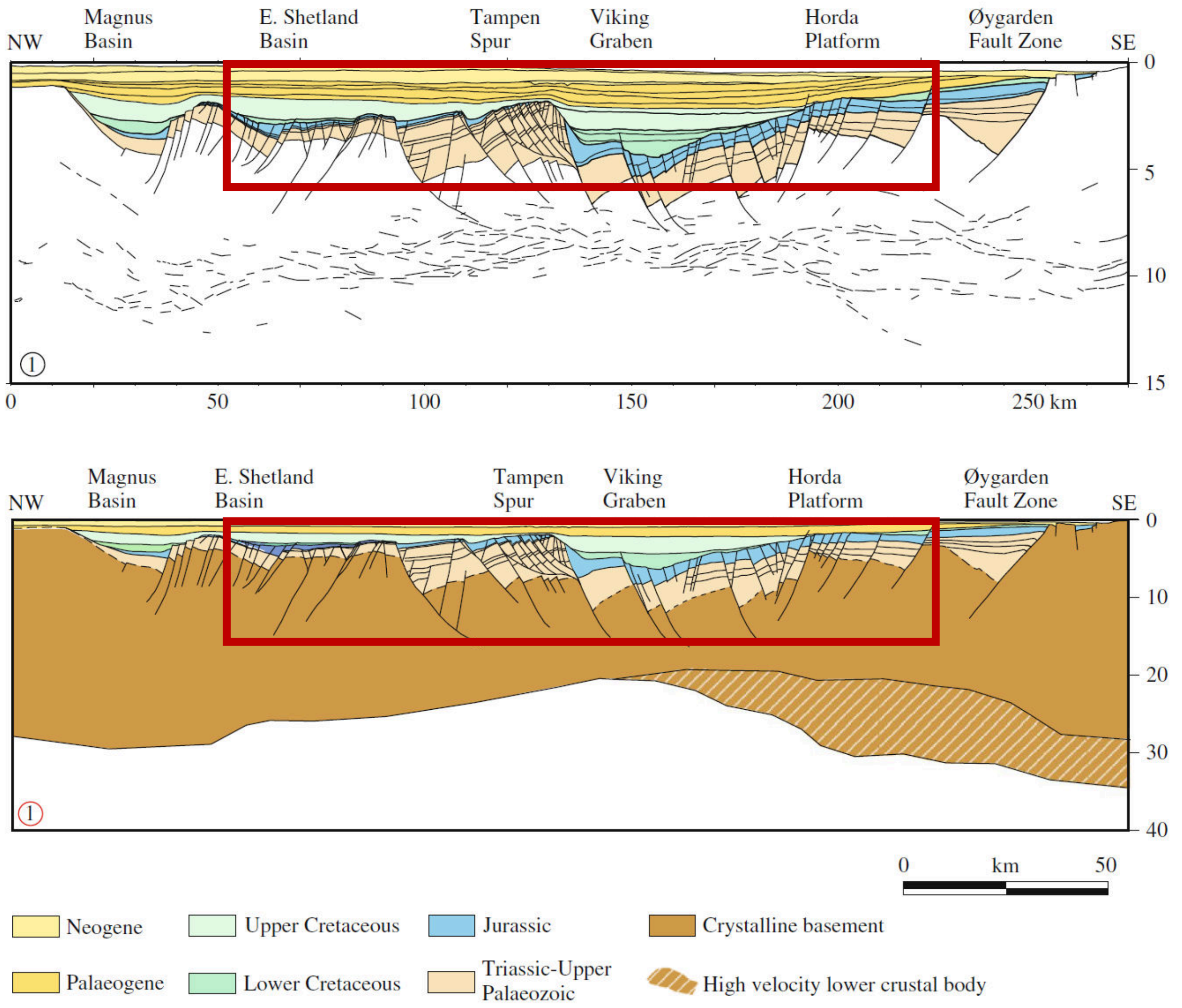


Figure 4.6: Interpreted regional deep seismic line and crustal transect across the northern North Sea (modified from Christiansson et al. 2000). See Fig. 4.4 for location.

The seismic data normally used in hydrocarbon exploration are restricted to a two-way-traveltime (TWTT) window of 0 to 6 or 7 seconds, typically corresponding to 9-12 km depth for an average velocity of 3-3.5 km/s. These data have been collected in order to image features in the upper crust such as detailed stratigraphic relationships and the geometry of sedimentary basins. Crustal-scale structures can be identified only on deeper seismic-reflection profiles recorded with a 0 to 15 seconds TWTT window in order to penetrate to 50 km or deeper into the Earth. There is a major unconformity between the Cretaceous and the Jurassic sequences (Base Cretaceous Unconformity, BCU) except in the deep parts of the rifts where there may have been continuous sedimentation (Figs. 4.6 and 4.7). The Base Cretaceous Unconformity is very well marked on most seismic sections from the North Sea.

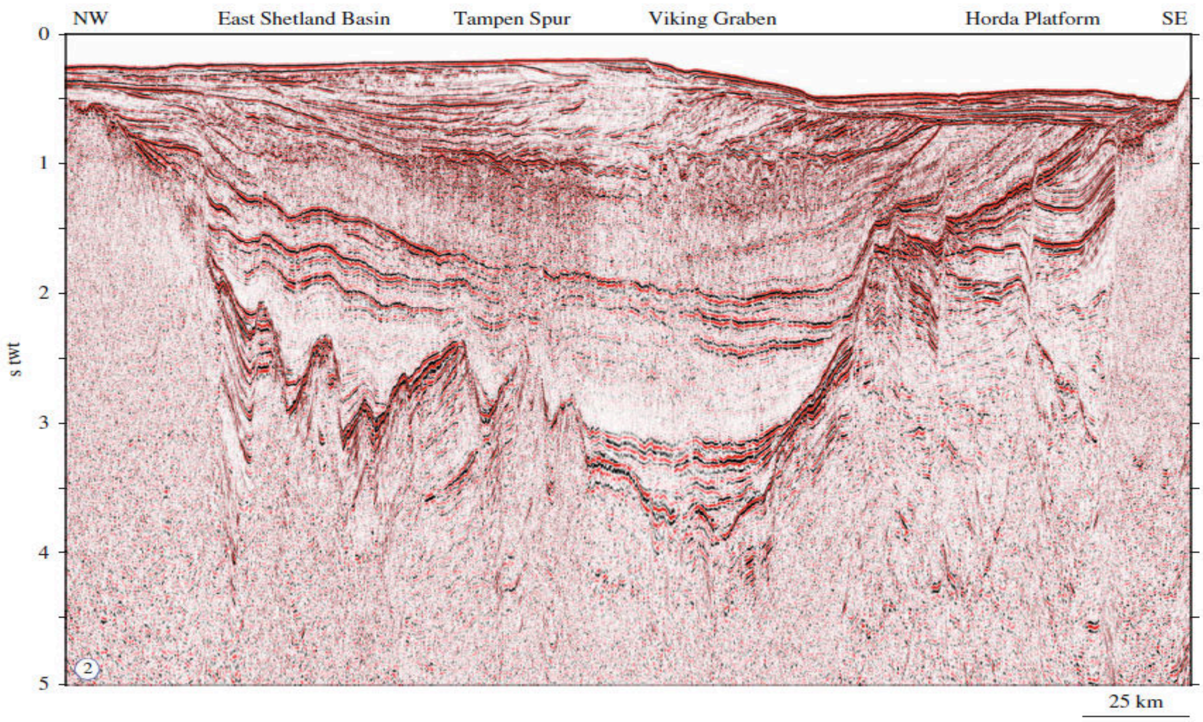


Figure 4.7: Regional seismic line across the northern North Sea (courtesy Fugro and TGS). See Fig. 4.4 for location. Related stratigraphy is indicated within the reference rectangle of Fig. 4.6.

The upper crust is best displayed on high-quality conventional seismic reflection data (0-7 s twt) whereas the middle and lower crust is best studied on deep seismic reflection data (0-15 s twt). The transect in Figure 4.8 is oriented NW-SE and crosses the Magnus Graben and Horda Platform and it was acquired and processed in 1984-1985 by GECO on behalf of BIRPS (British Institutions Reflection Profiling Syndicate) and several oil companies. Reprocessing improved definition of lower crustal structure, and the Moho can now be observed as a contrast in reflective character.

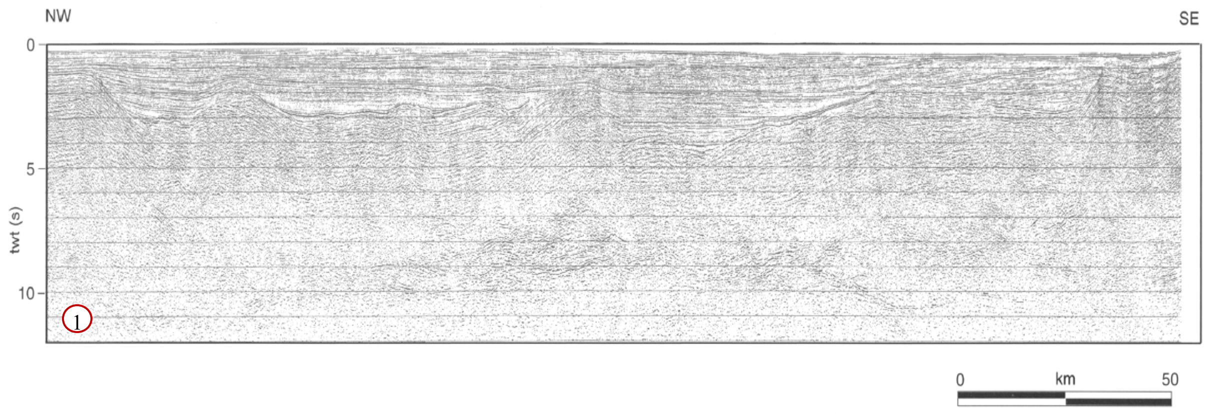


Figure 4.8: Deep seismic reflection profile across the northern North Sea (Christiansson et al., 2000). See Fig. 4.4 for location.

The Mohorovicic discontinuity, or Moho, is seismically defined as a first-order velocity discontinuity where P-wave velocities abruptly increase from 6.7-7.2 km/s to values of 7.6-8.6 km/s, marking the crust-mantle boundary. Lateral variations in the reflection characteristics of the Moho occur on the same scale as those in the lower crust. In places, the Moho is represented by a simple, strong reflector (Fig. 4.9) with lateral continuity at the base of the reflective lower crust; elsewhere it may not be marked by a reflection but can be interpreted to lie at the lower limit of reflective lower crust.

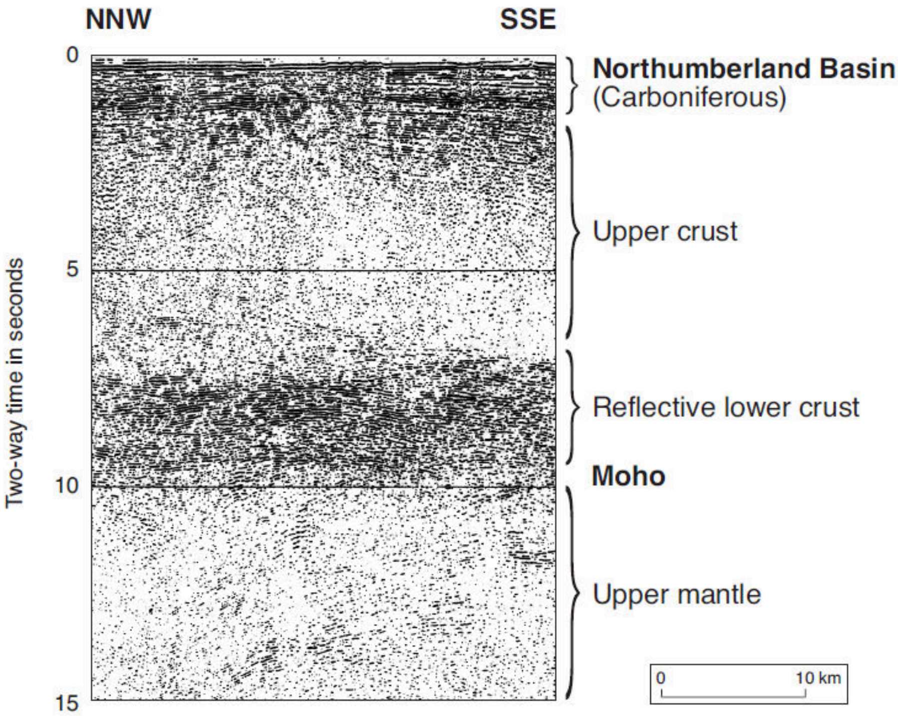


Figure 4.9: Seismic characteristics of the lithosphere (Evans et al., 2003).

A clear and simple explanation of the basic stages of crustal and basin evolution, as well as the change of extension direction of the northern North Sea from Caledonian collision until the early Cretaceous period is illustrated in Fig. 4.10:

a) Devonian: Gravitational collapse of Caledonian thrust sheets in the Devonian results in the formation of shear zones and sedimentary basins. Devonian basins are observed onshore western Norway, and also potentially in the East Shetland Basin (Platt and Cartwright, 1998), and Horda Platform.

b) Permian-Early Triassic: Permian-Triassic faults may have nucleated preferentially in regions affected by Devonian extension, and steep Permian-Triassic faults may sole out onto these shear zones at depth.

c) Late Triassic: During Late Triassic the region experienced tectonic quiescence and thermal subsidence following the Permian-Early Triassic rift phase.

d) Early-Middle Jurassic: During Aalenian, the central North Sea thermal dome has been developed and resulted in extensive uplift, and the formation of the Moray Firth-Central Graben-Viking Graben triplete rift system. The proto-Viking Graben trended slightly obliquely to major Permian-Triassic basins. The collapse of the thermal dome may have formed a proto-North Viking Graben structural template. Distal-buried faults on the Horda Platform and Western Norway associated with Permian-Triassic rifting were not reactivated.

e) Late Jurassic: Regional extension focused in the North Viking Graben region. Permian-Triassic faults in the Horda Platform that lie closest to the rift axis reactivate.

f) Early Cretaceous: Strain continues to focus on the Gullfaks-Visund Fault into the Early Cretaceous and Permian-Triassic faults on the Horda Platform reactivate diachronously toward the basin margin.

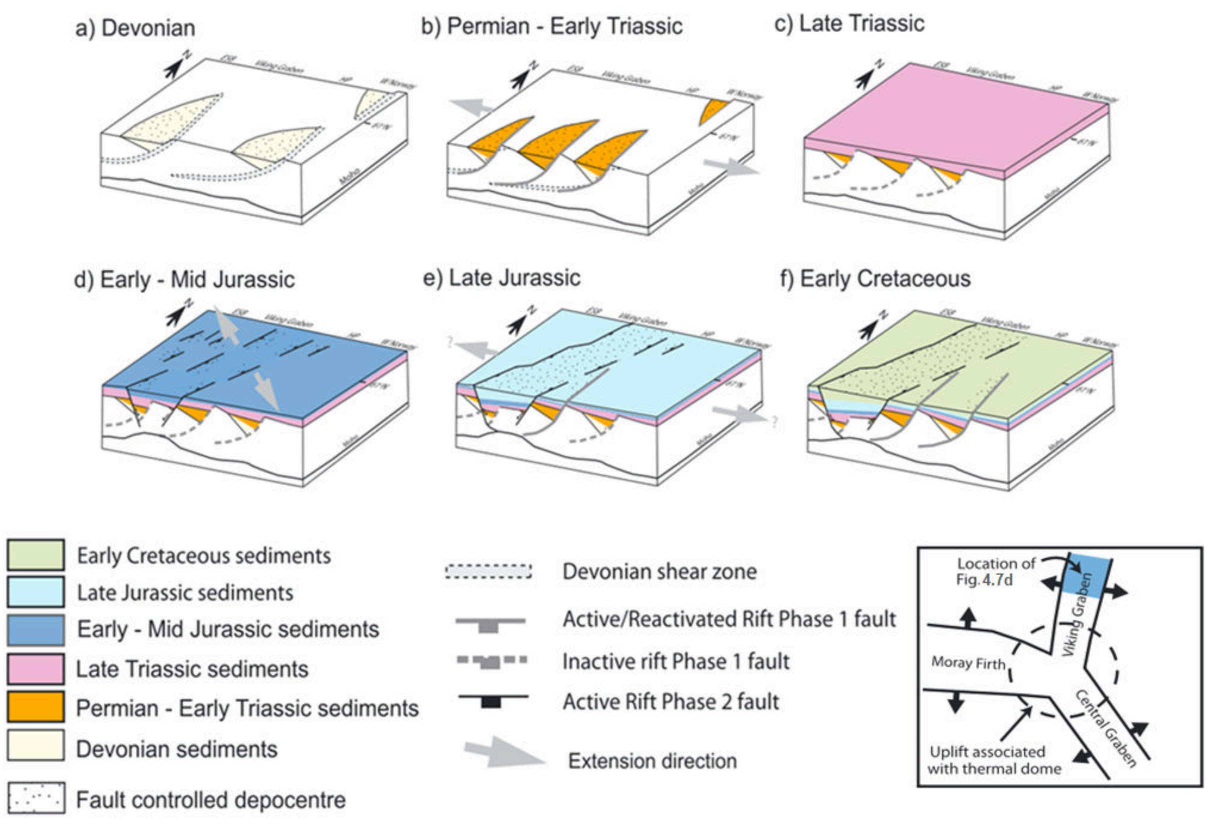


Figure 4.10: Schematic block diagrams illustrating the crustal-scale evolution of the northern North Sea; no scale implied (Bell et al., 2014).

Chapter 5
TECTONO-STRATIGRAPHIC EVOLUTION

5.1 PALEOZOIC

During the Paleozoic era, several tectonic events took place when major continents rifted apart and others collided. No pre-Paleozoic continent remained as a distinct entity throughout this era. The major Paleozoic continents that are represented in Europe are Laurentia, Baltica, Avalonia and Gondwana, with smaller continental fragments of the Armorican Terrane Assemblage, including Bohemia and Armorica. Reconstructions based on biogeography, paleomagnetism and facies distributions indicate that, in later Paleozoic time, there were no wide oceans separating the major continents. During the Silurian and Early Devonian time, many oceans became narrower so that only the less mobile animals and plants remained distinct.

5.1.1 Paleogeography

The early Paleozoic and pre-Paleozoic geology of the northern North Sea is sparsely documented, and is thus understood in far less detail than the successions of Devonian and younger ages. The modern geographical positions and terrane boundaries of many of the Lower Paleozoic units are shown in the Figure 5.1. To the north, the Iapetus Ocean between Laurentia and Gondwana was steadily widening. Baltica was separated from Siberia by the Ægir Ocean and was inverted in relation to its present orientation. However, from the mid-Cambrian onwards, Baltica rotated quickly counterclockwise, probably because of dextral strike-slip within the Ran Ocean, which was located between Baltica and Gondwana (Torsvik et al., 2013).

The Iapetus Ocean between Laurentia, Baltica and the Avalonian sector of Gondwana was at its widest very early in the Ordovician, after which spreading changed to subduction there and the ocean started to close. That change may have been linked to the separation of Avalonia from Gondwana, since Avalonia rifted from Gondwana at the same time during earliest Ordovician (probably Tremadocian), leaving an opening and then steadily widening of the developed Rheic Ocean between the two continents (Cocks and Fortey, 2009).

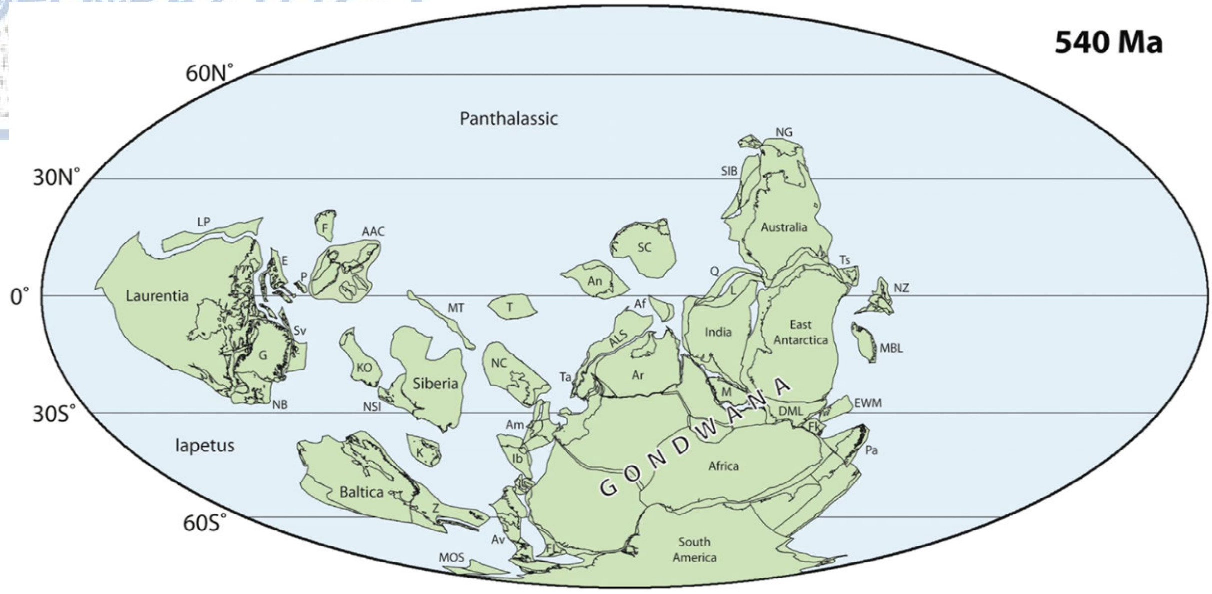


Figure 5.1: Lower Paleozoic terranes at 540 Ma (Early Cambrian, Fortunean) (from Torsvik et al., 2013). AAC, Arctic Alaska-Chukotka; Af, Afghan terranes; ALS, Alborz, Lut and Sanand; Am, Armorica; An, Annamia; Ar, Arabia; Av, Avalonia; DML, Dronning Maud Land; E, Ellesmere terranes; EWM, Ellsworth Whitworth Mountains; F, Farewell; Fk, Falklands; FL, Florida; G, Greenland; Ib, Iberia; K, Kara; KO, Kolymar-Omolon; L, Lhasa; LP, Laurentian Parautochthon; M, Madagascar; MBL, Marie Byrd Land; MOS, Mixteca-Oaxaquia and Sierra Madre; MT, Mongolian terranes; NB, North Britain and NW Ireland; NC, North China; NG, New Guinea; NSI, New Siberian Islands: NZ, New Zealand; P, Pearya; Pa, Patagonia; Q, Qiantang; SC, South China; SIB, Sibumasu; Sv, Svalbard; T, Tarim; Ta, Taurides; Ts, Tasmania; Z, Novaya Zemlya.

There was substantial tectonic activity, as well as, subduction in the Iapetus Ocean during most of the Ordovician, evidenced by the island arcs seen on or near both the western (Laurentian) and eastern (Avalonian and Baltic) margins, as well as further offshore (Harper et al., 1996). East of Laurentia, the 120º rotation of Baltica finished prior to Late Ordovician, and the Tornquist Ocean between Baltica and Avalonia steadily narrowed (Fig. 5.2). The two continents merged obliquely in a relatively soft docking at about the Ordovician-Silurian boundary (443 Ma) (Torsvik and Rehnström, 2003), and thus Avalonia was only an independant terrane during the Ordovician.

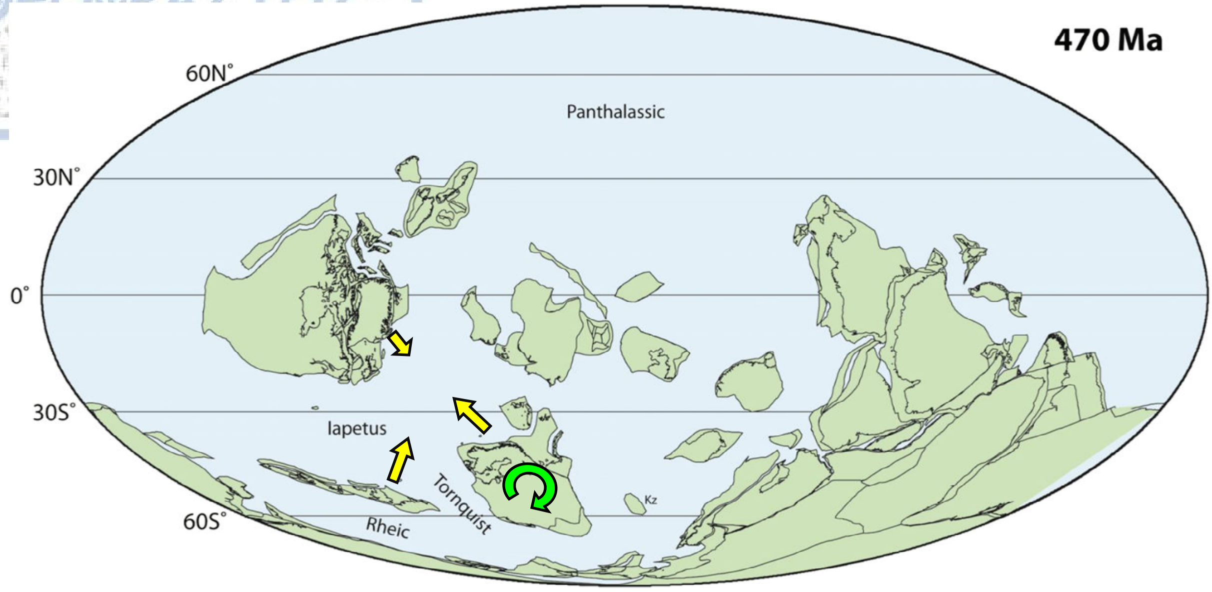


Figure 5.2: Lower Paleozoic terranes at 460 Ma (Late Ordovician, Sandbian) (from Torsvik et al., 2013). Kz, Kazakh terranes.

Avalonia and Baltica had merged by about the start of the Silurian (Torsvik and Rehnstr*ö*m, 2003). However, the major event in this relatively short system was the Caledonide Orogeny, in which the combined Avalonia-Baltica continent collided with Laurentia in a complex sequence of tectonic events which have been described and reviewed in many papers over the last decades (e.g. van Staal et al., 2009). The Caledonide collision zone extends today from the eastern North American seaboard at Cape Cod, Massachusetts, through New England and the Maritime Provinces and Newfoundland within Canada, diagonally across Ireland, approximately following the Scotland-England boundary, and then veers northwards under the North Sea (Fig. 5.3).

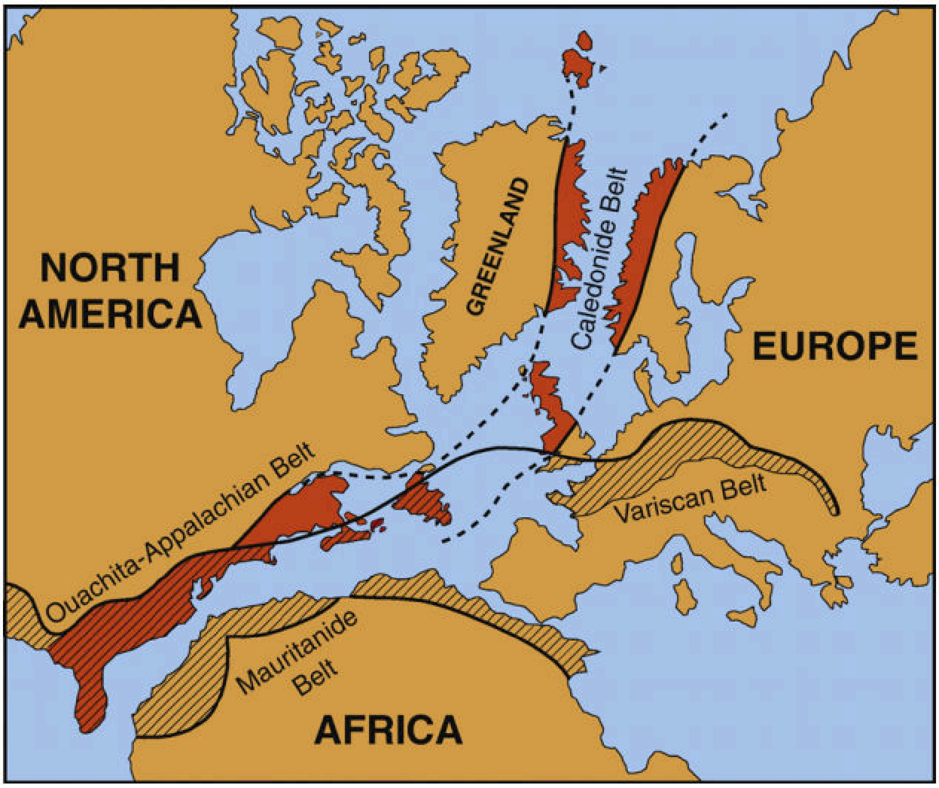


Figure 5.3: Continuity of the Ouachita-Appalachian belt of North America with the Caledonian and Variscan belts of Europe and the reactivated Mauritanide belt of West Africa in a Pangaea fit of the North Atlantic (Nance et al., 2009).

Prior to their Silurian collision, Laurentia was nearly stationary at the equator whereas Baltica had a rapid northward-directed latitudinal velocity component of up to 8-10 cm/yr. Whole-scale paleo-westward subduction of Baltic continental crust gave rise to extreme crustal thickening in the Caledonian Belt, exemplified by the preserved high-pressure terranes in western Norway (Andersen et al., 1991; Dewey et al., 1993; Eide and Torsvik, 1996). Sinistral transpressive deformation prevailed (Hutton, 1987), probably due to oblique NW-SE collision, and Scandian thrust-related orogenesis continued into Devonian times in northern areas of Norway (Fig. 5.4). The Scandian event was followed by Emsian extensional collapse at least in the southwestern parts of Norway, but from central Scotland to New York compressional events continued in the form of the Emsian-Eifelian Acadian Orogeny (McKerrow, 1988). The extensional collapse in western Norway is recorded by uplift-cooling ages from the Western Gneiss Region (lower plate), that peak between 390 and 400 Ma. The high-temperature processes of the Caledonian Orogeny and early orogenic collapse can be dated by a variety of geochronological methods (e.g. Fossen and Dunlap, 1998; Bingen et al., 2001; Fossen and Dunlap, 2006; Walsh et al., 2007; Bingen and Solli, 2009; Smit et al., 2010).

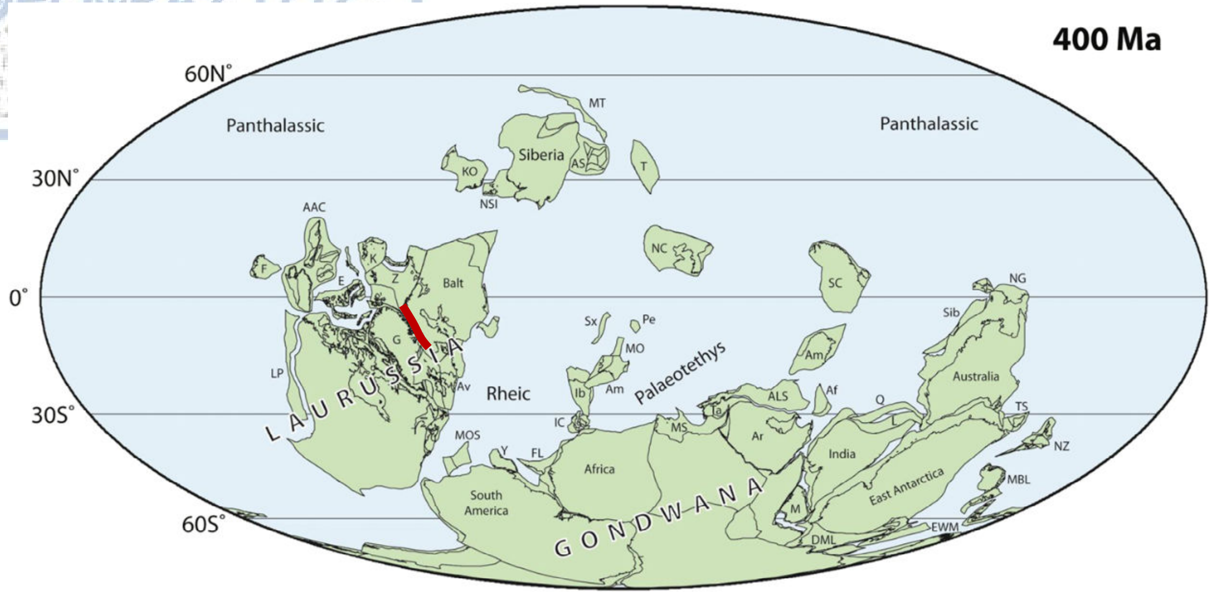


Figure 5.4: Upper Paleozoic terranes at 400 Ma (Early Devonian: Emsian) (from Torsvik et al., 2013). AAC, Arctic Alaska-Chukotka; Af, Afghan terranes; ALS, Alborz, Lut and Sanand; Am, Armorica; An, Annamia; Ar, Arabia; Av, Avalonia; Balt, Baltica; DML, Droning Maud Land; E, Ellesmere terranes; EWM, Ellsworth Whitworth Mountains; F, Farewell; FL, Florida, G, Greenland, Ib, Iberia; It, southern Italy and Sardinia; K, Kara; KO, Kolymar-Omolon; L, Lhasa; LP, Laurentian Parautochthon; M, Madagascar; MBL, Marie Byrd Land; MO, Moldanubia; MOS, Mixteca-Oaxaquia and Sierra Madre; MS, Mediterranean shelf part of NE Africa; MT, Mongolian terranes; NC, North China; NG, New Guinea; NSI, New Siberian Islands: NZ, New Zealand; Pe, Perunica; Q, Qiantang; SC, South China; SIB, Sibumasu; Sx, Saxothuringia; T, Tarim; Ta, Taurides; TS, Tasmania; Y, Yucatan; Z, Novaya Zemlya.

At the end of the Permian, the superterranes Gondwana (which included South America, Africa, peninsular India, Antarctica and Australia, among other areas) and Laurussia (which included North America, northern Europe and other areas merged along the Caledonian sutures) and others such as Siberia, had amalgamated into the Pangaea supercontinent that dramatically changed the distribution of land and sea areas.

In the northern North Sea, extensive hydrocarbon exploration has resulted in a thorough knowledge of the post-Caledonian tectonic evolution of the offshore region. The large sedimentary basins of the northern North Sea formed during a two-stage rift history, with an initial, wide Permian-Triassic rifting followed by a Middle-Late Jurassic rift phase that was focused mainly in the Viking Graben (e.g. Badley et al., 1988; Gabrielsen et al., 1990; Steel and Ryseth, 1990; Færseth, 1996; Bell et al., 2014).

5.1.2 Structural setting

The tectonic framework of the crust of the north-west Europe developed as a result of the accretion of the ancient continental fragments and newer magmatic arcs onto the Laurentian-North Atlantic craton during Caledonian to Variscan tectonic events. The accretion direction was south-east to north-west, using the present-day geographical co-ordinates. In Europe, Caledonian continental collision between Laurentia and Baltica ceased during Late Silurian to Early Devonian, but continued in the Appalachians (Fig. 5.3) until the Middle to Late Devonian. A large Devonian basin developed in the northern North Sea, possibly formed by gravitational collapse of the thickened crust (McClay et al., 1986). It is believed that Devonian strata is present beneath much of the East Shetland Platform (Holloway et al., 1991; Platt, 1995). This deep pull-apart basin formed a 'proto-Viking Graben' (Coward, 1993) and probably caused crustal thinning in that area.

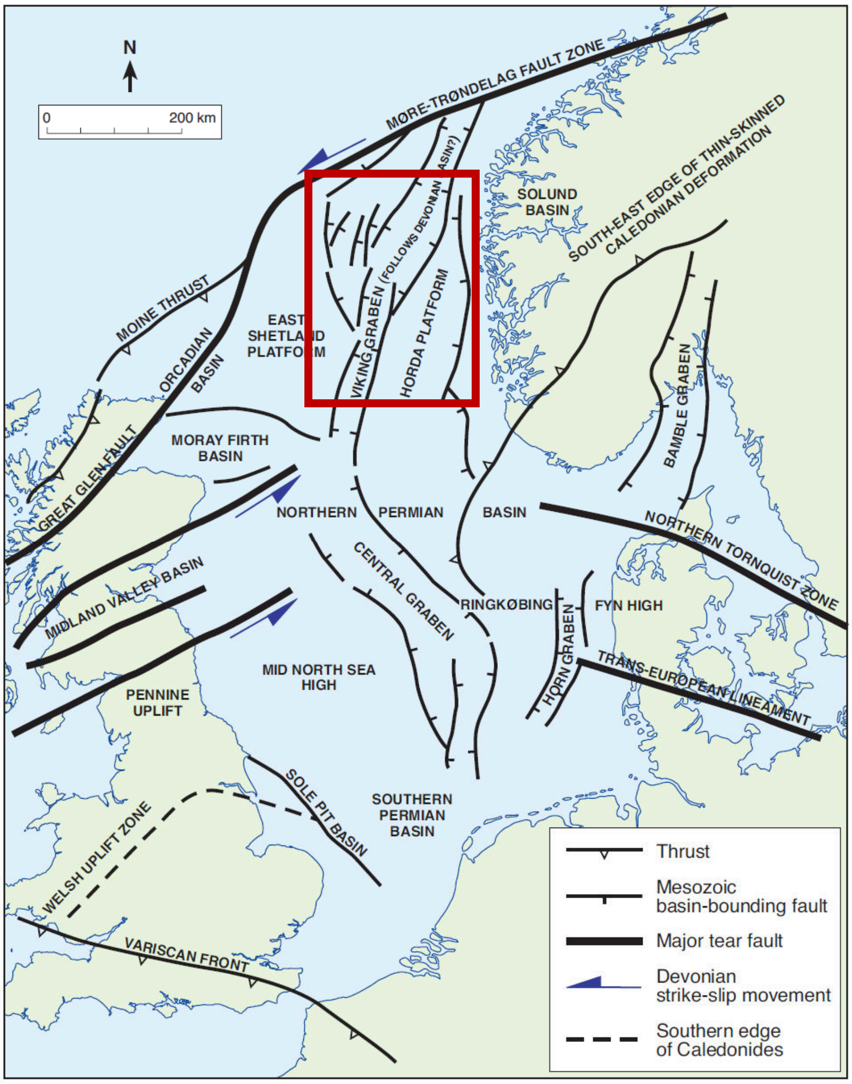


Figure 5.5: Generalised tectonic framework of north-west Europe (modified from Coward, 1990).

Sinistral strike-slip movements along the Great Glen to Møre-Trøndelag fault zone and the Midland Valley system during the Devonian (Fig. 5.5) may have produced pull-apart basins, which were subsequently reactivated during Mesozoic extension to form the Viking Graben. During Early Carboniferous, there was further reactivation of the Great Glen proto-Viking Graben system as reversal of the sense of displacement on faults of Devonian and Early Carboniferous age caused tectonic inversion across north-western Europe (Coward et al., 1989; Coward, 1993; Roberts et al., 1999). Large inversion-related fold structures were formed on the East Shetland Platform at this time, and right-lateral displacement occurred along the line of the Great Glen Fault and in the Midland Valley of Scotland.

Early Permian basaltic volcanism followed Westphalian inversion in northern England, the Midland Valley of Scotland, and north-west Germany (Francis, 1987). This volcanism pre-dated much of the Permian extension, suggesting that the region was underlain by hot asthenosphere. Volcanism was accompanied by uplift and erosion of Upper Paleozoic strata before thermal subsidence formed the Rotliegend and Zechstein basins. Permian tectonic activity had its origins in older events. At the end of the Carboniferous, the Variscan Orogeny, caused by the creation of the Pangea megacontinent, was approaching the end of its phase of mountain building. The plate movements responsible for the newly formed, approximately easterly trending Variscan Mountains of central Europe were already subjecting these mountains to transtensional stresses that were to bring about their partial destruction (Ziegler et al., 1990a). These stresses were active right across the North Sea area to the Caledonian shields of Scandinavia and Scotland (Fig. 5.6). Major structural units converged in the west, while in the east the Tornquist-Teysseyre Line provided a north-westerly trending zone of weakness and potential strike-slip movement. Differential movements of the bounding masses led to transtensional crustal extension and Early Rotliegend volcanism, and subsequently to transpression causing crustal warping, local inversion and erosion.

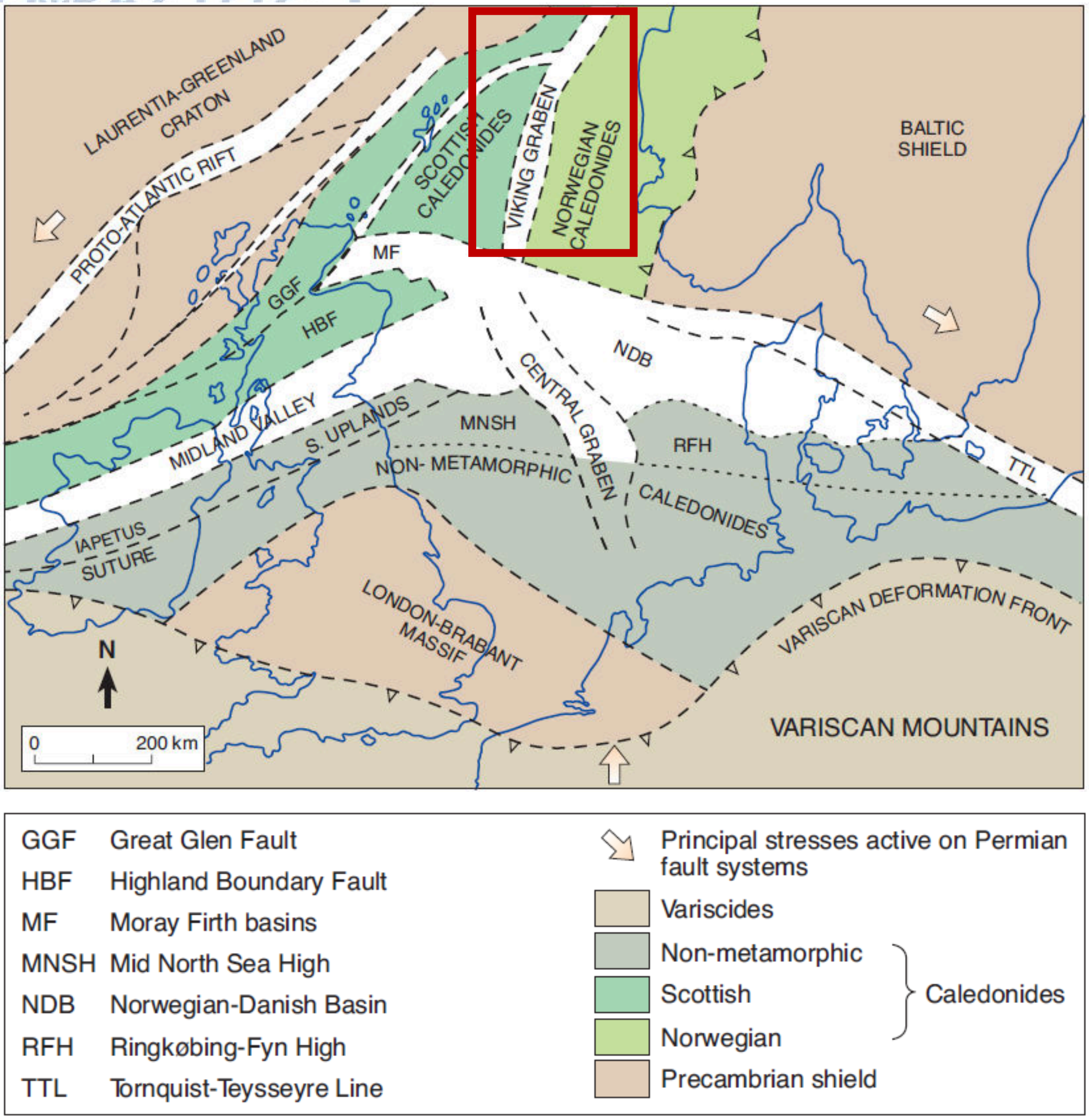


Figure 5.6: Regional tectonic framework for Permian times (Evans et al., 2013).

The northward-drifting Godwana plate collided with the southern edge of the slower, but also northward-moving Laurussia (Laurentia-Greenland and Baltic shields), compressing the interventing sedimentary sequences to produce the Variscan Mountains in Late Carboniferous to Early Permian times. The continued northward drift of Godwana may have driven a wedge into the re-entrant between the Laurentia-Greenland and Baltic shields, thereby initiating separation of the old Iapetus suture along the line of the present Viking Graben, and re-activation of the strike-slip Tornquist-Teysseyre Line and other lines of weakness.

In the northern North Sea, Upper Permian salt is largely absent, and there is no major detachment between basement and cover rocks. In the East Shetland Basin, for example, deep seismic reflection profiles suggest domino-style rotation of large crustal fault blocks (Fig. 5.7)

(Klemperer and White, 1989). Uplift of the footwall blocks by extensional faults led in many cases to pronounced erosion and fault-scarp degradation (Underhill et al., 1997; McLeod and Underhill, 1999). Indeed, much of the oil remaining in the Middle Jurassic fields of the East Shetland Basin may lie within such degradation complexes (Underhill, 1999). It should also be noted that many of the major faults probably grew through linkage of originally isolated segments, rather than by simple radial propagation. Pronounced changes in fault strike, displacement minima and transverse hanging-wall highs are commonly inferred to represent paleo-segment boundaries that subsequently became breached and incorporated into an extensive fault zone (e.g. Peacock and Sanderson, 1991; McLeod et al., 2000). A consequence of fault growth by segment linkage is that transfer zones/relay ramps at segment boundaries are transient features (Jackson et al., 2002).

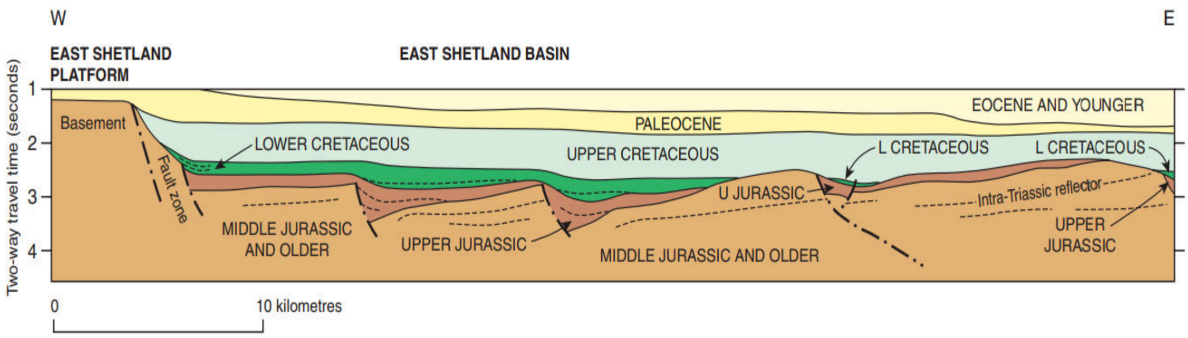


Figure 5.7: Generalised cross-section across the northern North Sea; (after Andrews et al., 1990; Gatliff et al., 1994 and Johnson et al., 1993).

5.1.3 Basin evolution and depositional environments

Pre-Devonian basement rocks below the northern North Sea include diverse suites of low- to high-grade metamorphic facies, igneous rocks and metasedimentary rocks. Geophysical mapping and well data across the northern North Sea provide a fairly accurate picture of the depth and configuration of the basement, which has a dominantly north to north-westerly structural trend across a 150 km-wide zone (Frost et al., 1981; Hospers and Ediriweera, 1988, 1991). Three structural levels are identified between Norway and the East Shetland Platform: on platforms, shelves and major structural highs the top-basement depth is less than 2 to 3 km; in basins it has a maximum depth of 7 to 9 km; and in the Viking Graben it reaches 8 to 10 km.

The existence in the North Sea region of a triple junction resulting from the Early Paleozoic suturing of the Laurentia, Baltica and Eastern Avalonia plates is well established (Fig. 5.8) (Livermore et al., 1985; Glennie, 1990; Soper et al., 1992b; Pickering and Smith, 1995; Torsvik, 1998), although the precise location of the junction is not evident (Pharaoh, 1999).

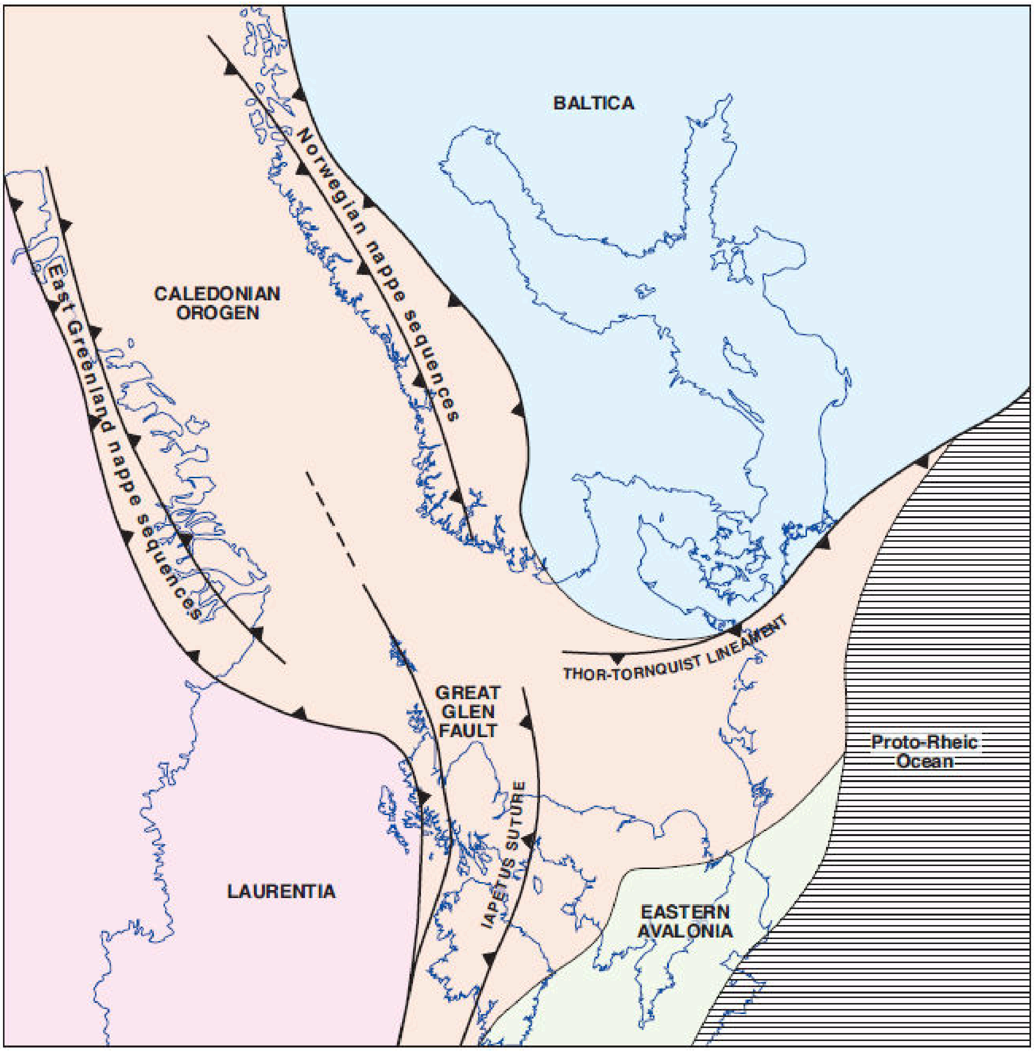


Figure 5.8: Schematic reconstruction of Early Paleozoic plate dispositions in the North Sea region (Evans et al., 2003).

The extended polyphase metamorphic deformation and heating of the whole region gives no known potential for any pre-Devonian rocks as hydrocarbon sources. In terms of reservoir potential, preserved sedimentary rocks are consistently tightly cemented, but highly fractured basement rocks have some potential as conduits for hydrocarbon migration or as reservoirs. The Precambrian basement of the North Atlantic and north-west Europe (Fig. 5.9) comprises crystalline rocks derived from at least three tectonic domains that were accreted during Caledonian collision.

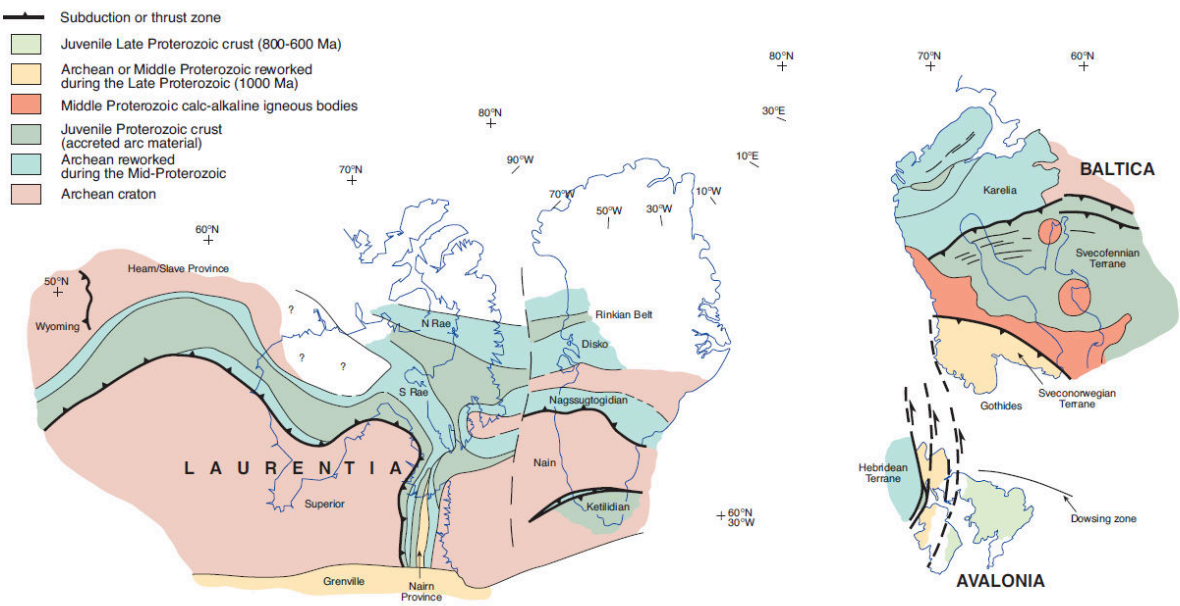


Figure 5.9: Precambrian basement distribution (Evans et al., 2013).

Devonian

During Silurian and Early Devonian times the Iapetus Ocean underwent progressive closure as the continental elements of Baltica, Laurentia and Eastern Avalonia successively collided (Woodcock and Strachan, 2000; Bluck, 2001). This was a complex process marked by a series of Caledonian orogenic events. The closure created the new craton configuration known as the 'Old Red Sandstone Continent' on which were deposited distinctive continental redbeds. Paleomagnetic data show that during Devonian times this continent occupied a low-latitude position between 15º and 30º S where the climate was warm to hot, and generally arid to semi-arid (Tarling, 1985; Witzke and Heckel, 1988).

In about mid-Silurian times the compressional regime altered, and major north-easterly trending structures within the Midland Valley of Scotland became extensional; it was here in small local basins that the first continental Old Red Sandstone sediments were deposited during Silurian (Marshall, 1991). Continued extension led to the deposition of a thicker succession of alluvial, volcaniclastic and lacustrine sediments of Early Devonian age within the more extensive Strathmore Basin. During Early Devonian, a further deformation event took place (Soper et al., 1987). This again changed the regional stress pattern, and led to inversion of the Midland Valley succession; it is also initiated a gravity-driven collapse of the northerly orientated Caledonian compressional structures to the north of the Highland Boundary Fault (Fig. 5.10).

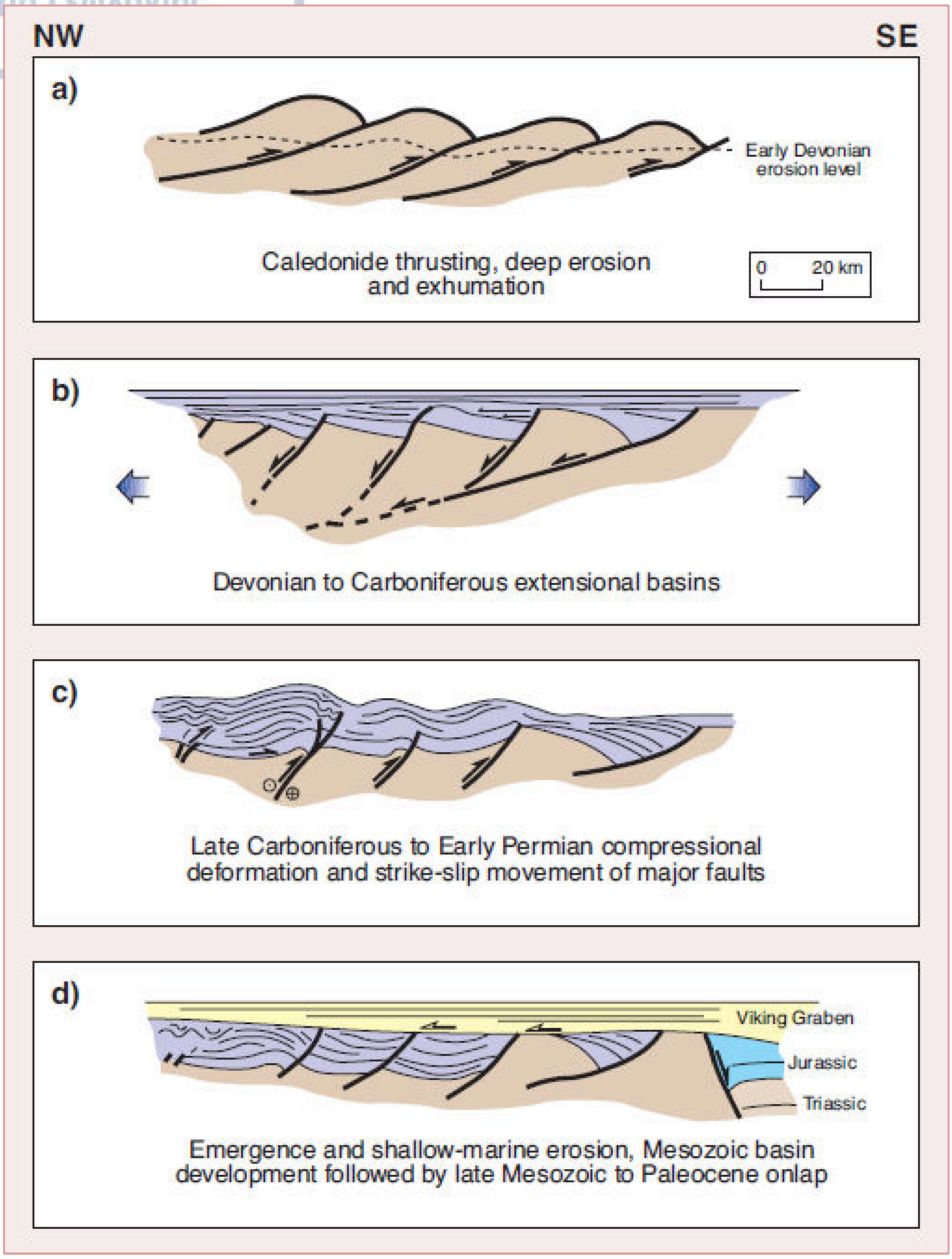


Figure 5.10: Structural evolution of the East Shetland Platform (Evans et al., 2003).

This generated a separate northern series of half-graben sub-basins which were controlled by extensional reactivation along the Caledonian thrusts (McClay et al., 1986; Norton et al., 1987; Séguret at al., 1989). It was in these half graben basins that the characteristic alluvial, aeolian and lacustrine Orcadian Basin sediments were deposited. During latest Middle Devonian and Late Devonian times, the basins became post-rift in character and evolved to a more open drainage system. This changed the sediment supply to extra-basinal as the area now came under the influence of a larger river system with a continent-sized drainage area (Stuart et al., 2001). From this time on, the dominant sedimentary processes became fluvial, and the basins were inundated with coarse-grained clastic sediment.

Carboniferous

Over much of north-west Europe, the onset of Carboniferous time was marked by a change from the dominantly continental red-bed deposition of the Devonian period to more-diversified marine, fluvial, deltaic and continental sedimentation. This change was a direct result of a major, southerly derived, marine transgression over the Old Red Sandstone Continent at the beginning of the Carboniferous (Anderton et al., 1979), and the continued northward continental drift of Laurussia from an arid to a more-humid, tropical latitude (Ziegler, 1990a). However, the boundary between Devonian and Carboniferous is not clearly defined, as arid to semi-arid continental deposition continued well into the Early Carboniferous, and marine sedimentation did not significantly affect the area until the late Visean.

Unlike the southern North Sea where Upper Carboniferous coals provide the main source for the gas-fields, the Carboniferous of the northern North Sea has hitherto proven to be of limited economic importance, primarily due to the apparent lack of coal-bearing strata. There are only a few documented cases where Carboniferous sandstones contribute to part of a reservoir.

Permian

The Permian rocks of the central and northern North Sea consist of a lower sequence termed the Rotliegend Group, that largely comprises sandstones with local basal volcanics, and an upper sequence of carbonates and evaporites with local clastic rocks that form the Zechstein Group (Fig. 5.11).

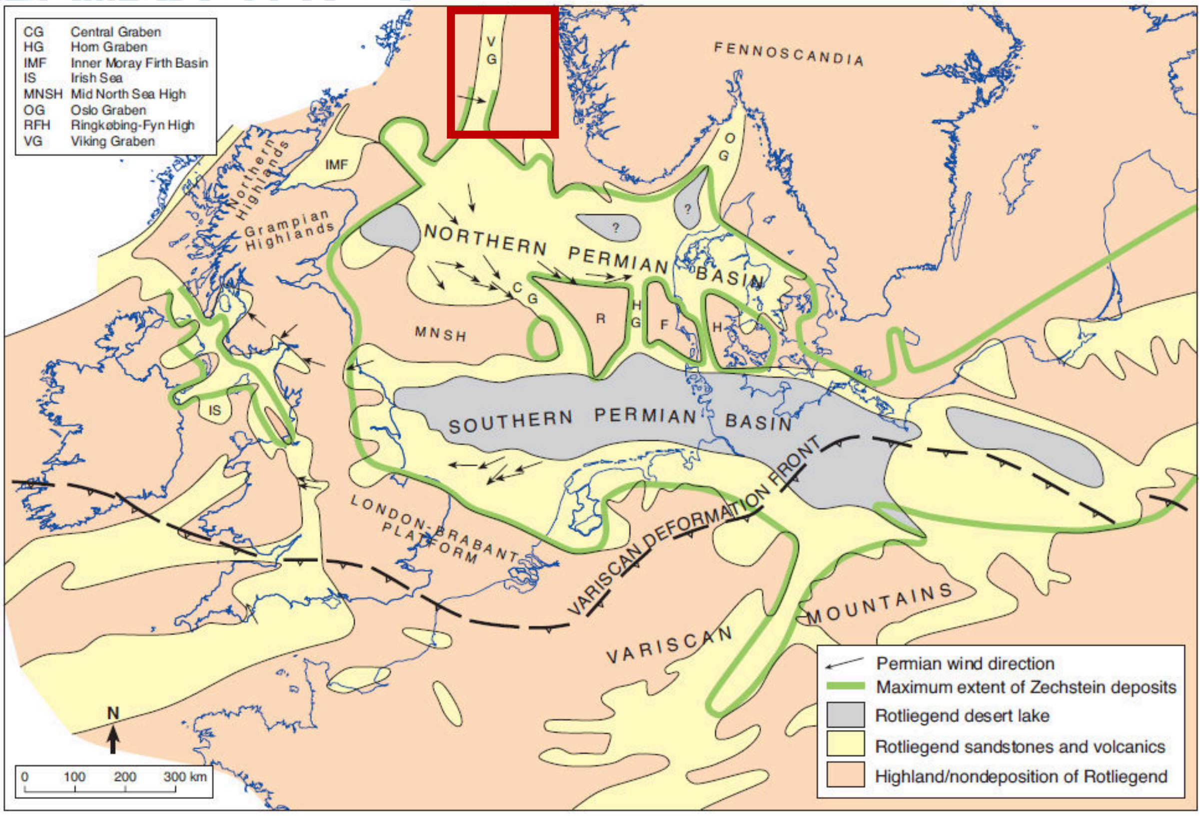


Figure 5.11: Sketch map of Permian sedimentary basins in north-west Europe (Evans et al., 2003).

Figure 5.11 shows the maximum extent of Permian Rotliegend and Zechstein sequences in the regional context of north-west Europe, together with selected wind directions deduced from observations that the Rotliegend Group deposits were transgressed by the Zechstein Sea, resulting in deposition of carbonates and evaporites; access to northern oceanic waters was probably via the Viking Graben and perhaps smaller rifts to its west. In northern areas, pre-Permian sequences were eroded down to Lower Carboniferous, Devonian and Caledonian strata (Sørensen and Martinsen, 1987; Cameron, 1993a).

5.2 MESOZOIC

The Mesozoic era was characterised by major extensional events that affected the North Sea. It has been proposed that an E-W oriented axis of extension, parallel to the minimum horizontal principal stress axis, existed throughout the Triassic, and that the axis shifted towards, NW-SE, either during Bajocian-Bathonian (Færseth et al., 1997) or in latest Jurassic times (Doré and Gage, 1989; Ziegler, 1990; Gabrielsen et al., 1999). Deep basins developed along the rift zones of the North Sea and between East Greenland and Norway, and were filled with sediments derived from mainland Scandinavia and Greenland. The marginal areas bordering the rift zones suffered less subsidence, as did the epicontinental Barents Sea.

5.2.1 Paleogeography

Pangea, the super-continent formed at the end of the Paleozoic era, existed for about 100 million years, until rifting commenced during Late Triassic and Early Jurassic times and the super-continent began to break up. By the end of the Jurassic period, rifting had succeeded in splitting North America from Europe and Africa. The Mid-Atlantic Ridge formed, and the North Atlantic Ocean started to grow (Fig. 5.12).

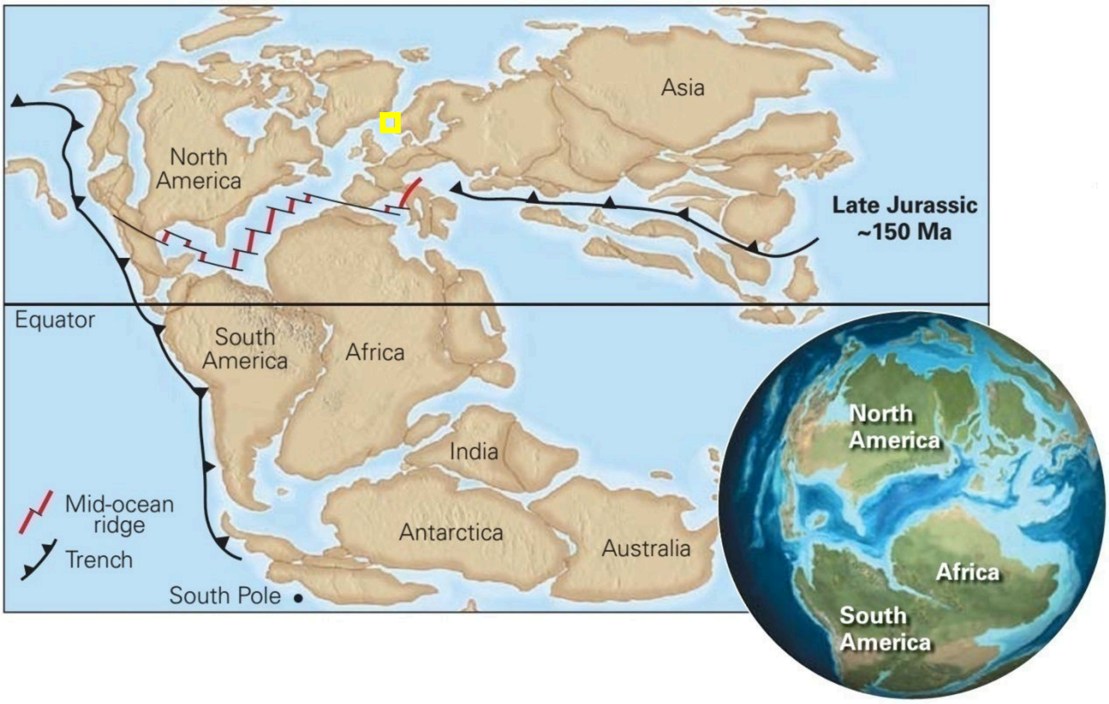


Figure 5.12: Pangea began to break up during Triassic, and by Jurassic time, a narrow North Atlantic Ocean existed (Marshak, 2016).

Since the end of the Caledonian Orogeny, the Central and Northern North Sea Basin has occupied an intraplate setting. Early Jurassic strata within the North Sea Basin accumulated during a phase of post-rift subsidence following Permian-Triassic extension (e.g. Ziegler, 1990; Faerseth, 1996). During Middle Jurassic times, the Central North Sea area experienced transient thermal doming, erosion and volcanism, possibly associated with a mantle plume (Underhill and Partington, 1993) (Fig. 5.13). The resulting regional unconformity is commonly termed the 'Mid Cimmerian Unconformity' although in the Central North Sea it covers a much wider timespan (Husmo et al., 2003). Stratigraphical relationships indicate that the uplift was centered upon the North Sea rift triple junction (Fig. 5.13). Although the initial formation of a simple triplete rift junction may have been the result of doming and deflation, subsequent extension during Middle and Late Jurassic led to the development of a series of intra-rift fault sets (Davies et al., 2001). However, the detailed structural evolution of the region has been a topic of many debates. Rattey and Hayward (1993) and Fraser (1993) proposed that rifting was initially most intense at the extremities of the present graben system and as time elapsed it propagated back towards the centre of the domal uplift. Underhill (1991) and Glennie and Underhill (1998) suggested that the onset of major rifting probably occurred in mid-Oxfordian to early Kimmeridgian times. However, a number of pulses of Late Jurassic extension have been recognised (e.g. Davies et al., 1999, 2001; Errat et al., 1999).

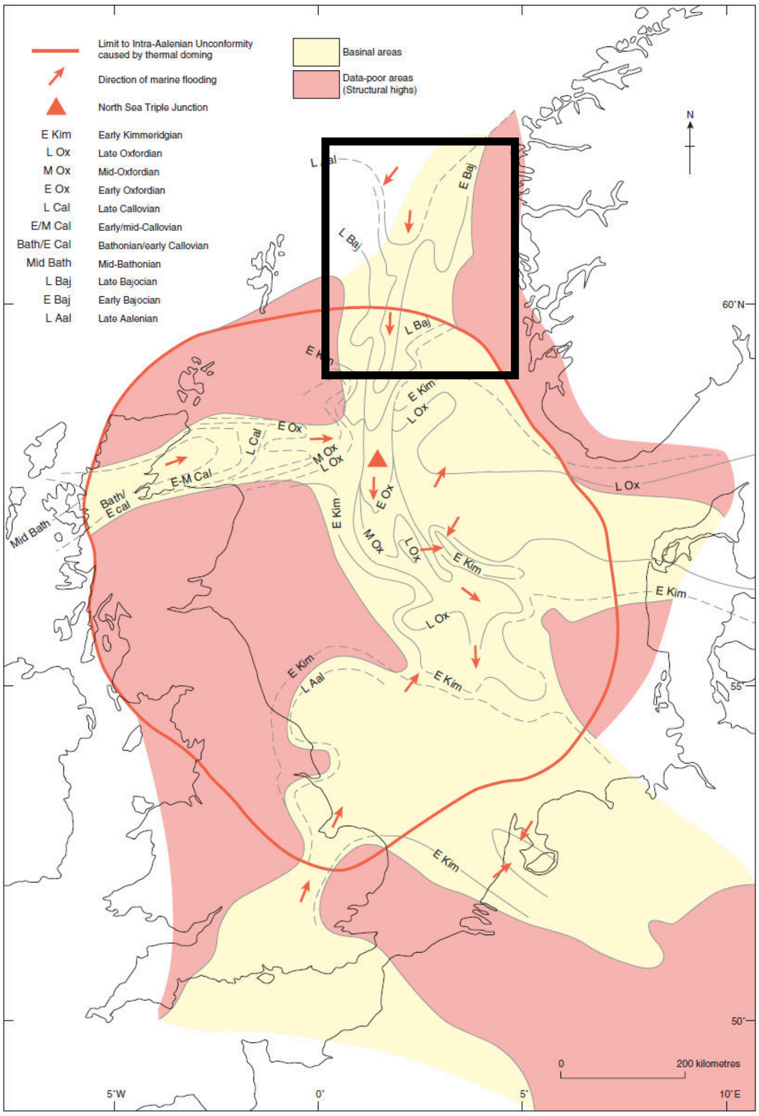


Figure 5.13: Approximate extent of the 'Mid-Cimmerian Unconformity' due to transient domal uplift and the pattern of subsequent marine onlap onto the unconformity (after Underhill and Partington, 1993; Underhill, 1998).

The Central Graben trends north-west to south-east, approximately parallel to the displacement direction recognized in the Viking Graben. The Moray Firth basins trend between north-west to south-east and north-east to south-west. Roberts et al. (1990a) put forward a vector-triangle model in terms of three simultaneously spreading rift systems (Fig. 5.14). Sediments are locally absent in the 'triple junction' itself. The so-called 'Mid-Cimmerian' (Aalenian) subaerial unconformity exists as a basin-wide erosion surface, cutting down into Liassic and earlier sequences. It has been used as evidence for a Middle Jurassic pre-rift thermal dome. Underhill and Partington (1993) have used flooding surfaces to highlight the presence of the dome in the Middle Jurassic and its subsequent foundering. Rifting began at the end of the Bajocian and continued until the Callovian-Oxfordian at a relatively slow rate. Major faulting is recorded on each of the three rift arms during this period, seemingly dying out towards the 'triple junction'. Open marine conditions were rapidly established as the rift arms subsided, and the new basin was flooded.

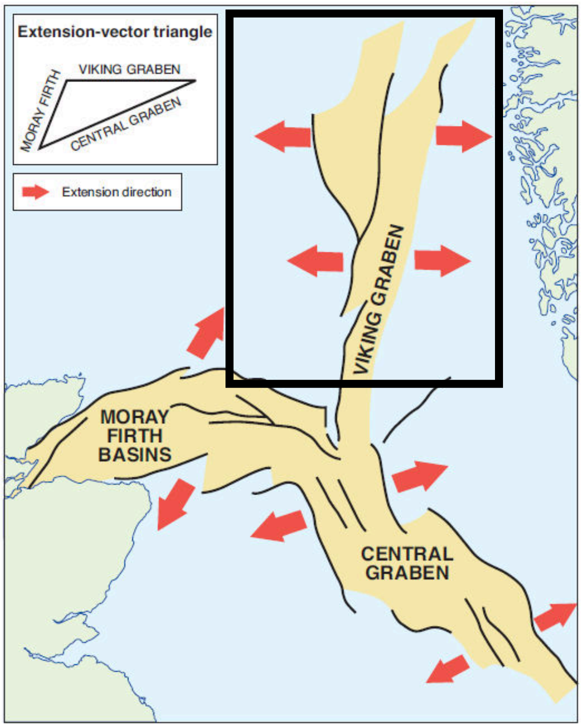


Figure 5.14: An 'extension-vector-triangle' model of the North Sea rift (Evans et al., 2003).

5.2.2 Structural setting

The northern North Sea paleo-rift system, including the Viking and Sogn graben, is an approximately 150-200 km wide zone of extended upper crust with preserved strata from pre-Triassic to Tertiary. It is bounded by the Shetland Platform to the west and Norwegian mainland to the east. The North Sea rift system, post-dating the Caledonian orogenic extensional collapse, was affected by two lithospheric extension events in Permian-earliest Triassic time (in the literature often referred to as the Permo-Triassic event) and late Middle Jurassic to earliest Cretaceous time (here referred to as Late Jurassic), respectively. Triassic rifting produced deep half-grabens in the eastern North Sea, and generated the north-north-easterly trending faults of the Unst Basin to the north-east of Shetland (Fig. 5.15). On regional seismic data from the relatively deep Triassic basin had formed in the centre or farther east (Faerseth, 1996).

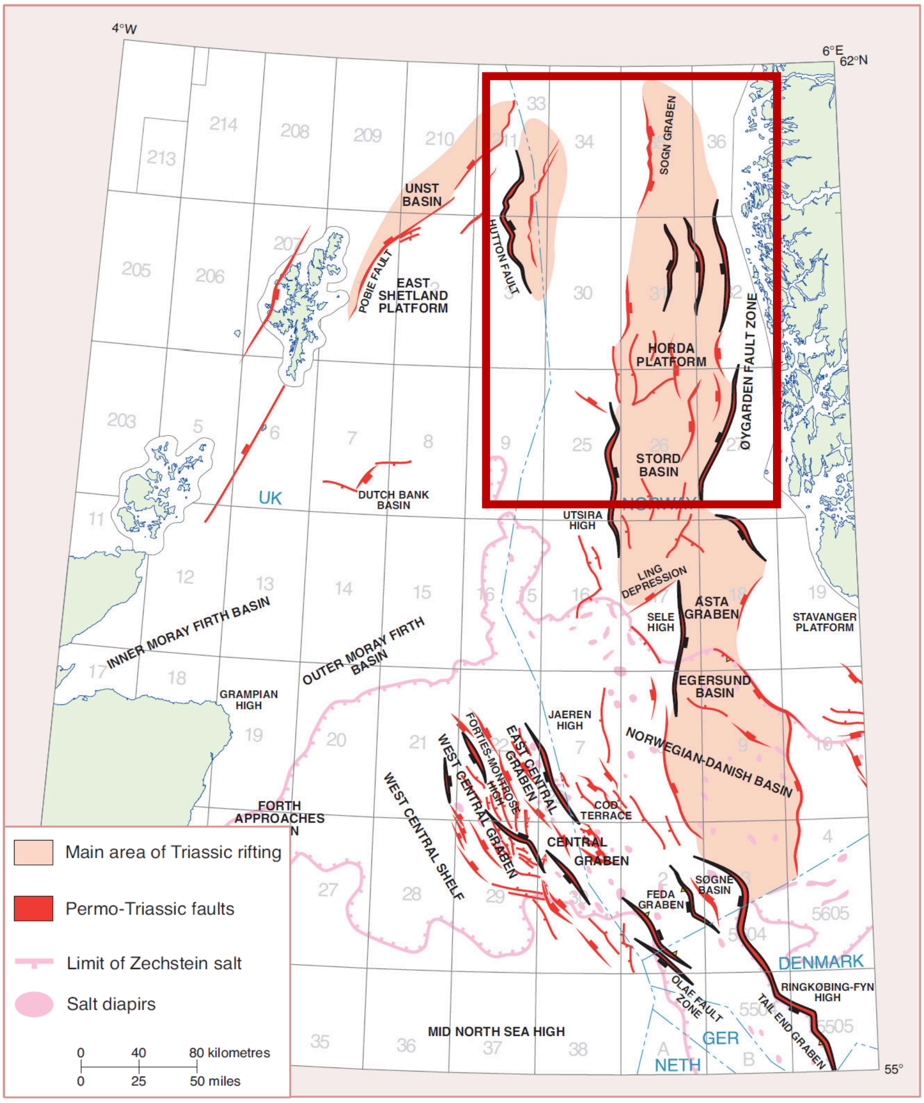


Figure 5.15: Triassic to Early Cretaceous rifting patterns (Evans et al., 2003).

Triassic extension is characterised in the northern North Sea by wide, north-south- oriented, tilted fault blocks. The Triassic extension direction and its possible variations throughout the study area are uncertain. In the northern North Sea, the Permian structural pattern was modified by the superimposition of a graben system that controlled later Mesozoic sedimentation. Beach (1986) suggested that the dominant extension direction in the northern North Sea was north-west to south-east. Within the central part of the Viking Graben, this phase of rifting is strongly overprinted by Late Jurassic extension, but both east and west of this zone Triassic fault-blocks can be readily identified (Fig. 5.16).

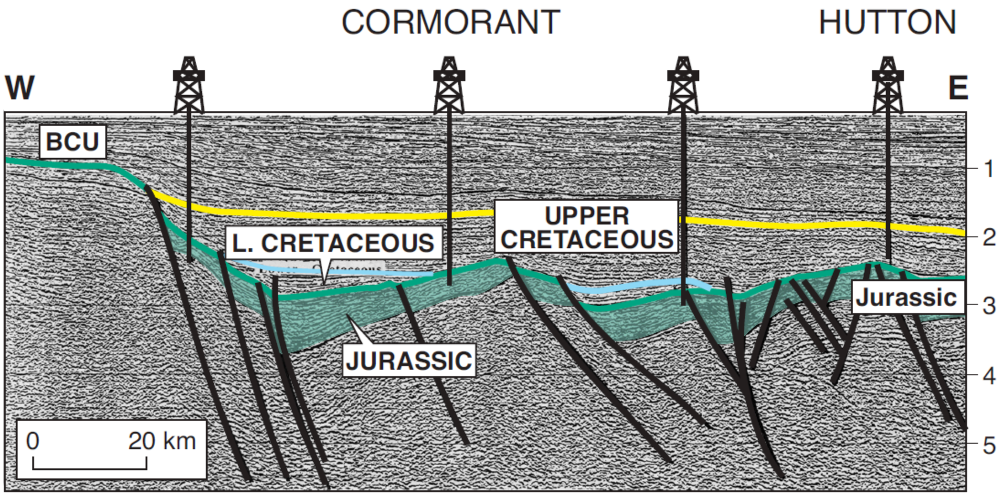


Figure 5.16: Late Jurassic fault-block rotation in the East Shetland basin (modified from Bartholomew et al., 1993).

There seems to have been very little Early Jurassic rifting in the central and in the northern North Sea. The occurrence of Middle Jurassic volcanic rocks in the central North Sea suggests the presence of a mantle hot spot during Middle Jurassic (Underhill and Partington, 1993), and associated uplift allowed erosion down to Lower Jurassic or Triassic strata. Evidence for regional uplift affecting the North Sea during Toarcian to early Aalenian times comes from stratigraphic data and regional well-correlations that have been used to define the form of the Middle Jurassic (Mid-Cimmerian) unconformity (Underhill and Partington, 1993). Erosion of the uplifted area yielded Bajocian to Bathonian sands that formed the important Brent Group reservoirs of the northern North Sea.

The major rifting event in the North Sea took place during the Late Jurassic, leading to the development of the Viking Graben, Central Graben and Moray Firth basins triple-rift system. However, there is evidence that rifting may have began during Middle Jurassic times in the northern North Sea, perhaps during Aalenian to early Bathonian deposition of the Brent Group (Roberts et al., 1999), or during the deposition of the latest Bajocian to mid-Callovian J30 sequence defined by Rattey and Hayward (1993). Nevertheless, Rattey and Hayward (1993) demonstrated that the mid-Oxfordian to early Kimmeridgian was the time of the major pulse of faulting, and that rifting continued until Early Cretaceous. There were multiple pulses of faulting separated by intervening stages of relative tectonic quiescence; this pattern was a major influence on the nature and architecture of the sediments in the basin (Ravnås et al., 2000).

The rate of expansion appears to have varied spatially across the graben system, resulting both in local offset of the main rift axis, and in variations in the topography formed by the rifting. The faulting created a considerable topography locally, with pronounced footwall highs that became significant landmasses. There were eroded to provide a supply of sediment sufficient to fill adjacent basins. Elsewhere, such as along the central axis of the Viking Graben, lesser footwall uplift led to adjacent basins being sediment starved. Figure 5.17 suggests the relationship between Jurassic and Permo-Triassic fault blocks and associated master faults at the end of Cretaceous times. The figure also indicates that the position of the Viking Graben moves westward across the northern North Sea from north to south. In detail, the Viking Graben and its eastern margin show the interference of east- and west- dipping faults of Permo-Triassic and Jurassic origin, respectively (Fig. 5.17b). The Brage Horst is a narrow, high relief accommodation zone that separates a Permo-Triassic graben to the east from a Jurassic half-graben to the west.

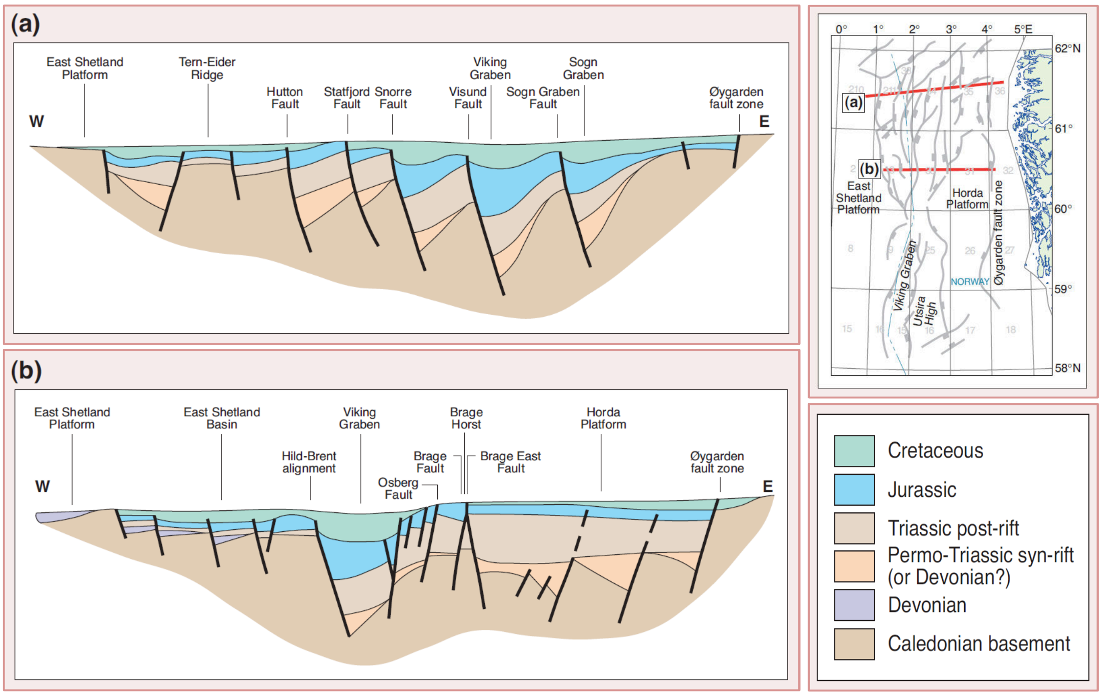


Figure 5.17: Sketched profiles across the northern North Sea (Evans et al., 2003).

It has been suggested that an east-west extension direction explains the pattern of faulting in the Viking Graben during Late Jurassic (Roberts et al., 1990a). However, 3D structural modelling of fault displacement in both the Brent and Brae provinces has showed that the displacement direction can be constrained to 120º ± 3º, and that the major field-bounding normal faults are made up of intersecting cuspate sections where the axes of the cusps trend at 120º (Fig. 5.18). Any extensional movement oblique to this trend on the main fault produces anomalous hanging-wall basins or uplifts and hence can be recognized from 3D seismic data. Extension of 15% is considered to be a reasonable estimate for the stretching in the East Shetland Basin (Roberts et al., 1993). On the Horda Platform, the Late Jurassic stretching was only 5%, whereas in the axis of the Viking Graben stretching reached 30-40%. Furthermore, in the Viking Graben west to north-westerly trending normal faults associated with Volgian and Early Cretaceous extension are superimposed upon the north-easterly trending Late Jurassic normal faults; either new north-westerly trending faults were formed, or older north-trending structures were reactivated with normal fault movement. Older north to north-easterly trending structures were reactivated as strike-slip faults.

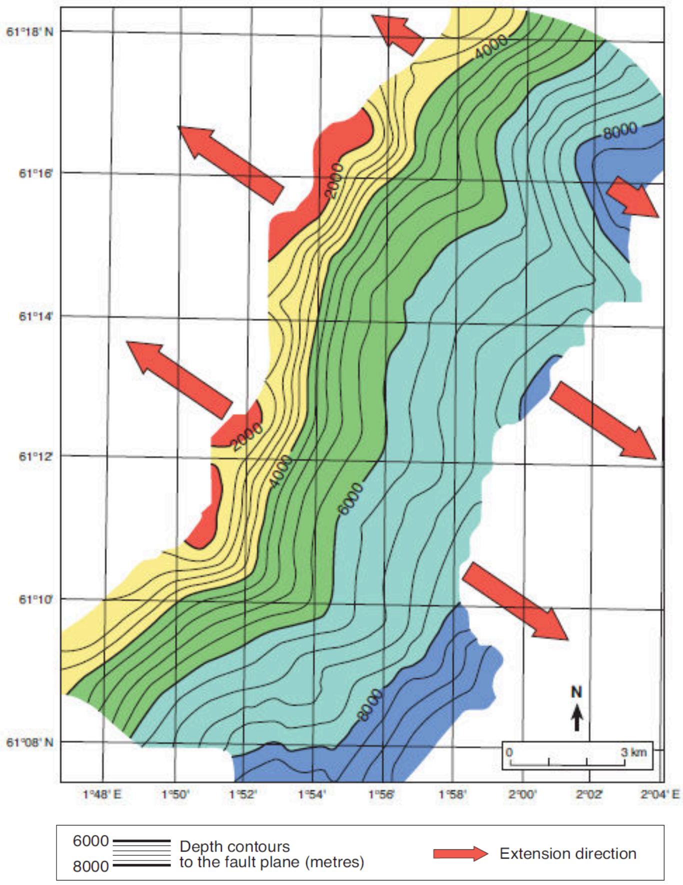


Figure 5.18: The eastern bounding fault of the Statfjord Field (Evans et al., 2003).

The Cretaceous to Cenozoic post-rift period was dominated by regional thermal subsidence, with superimposed pulses of uplift along the western and eastern flanks of the basin. On the western margin of the northern North Sea, deposition of large submarine fans in the basin during Paleogene resulted from the tectonic uplift and eastward tilting of the Scottish Mainland, the East Shetland Platform, and the Inner Moray Firth Basin. Integration of sonic-velocity, vitrinite-reflectance and fission-track data suggests that there was uplift in the order of 1 km in the Inner Moray Firth Basin (Thomson and Underhill, 1993). On the eastern margin, uplift and erosion of the eastern flank of the Stord Basin and the adjoining Norwegian mainland, which was not accompanied by significant faulting, also resulted in the development of westerly prograding wedges. Sequence-stratigraphic analysis of the Cenozoic section by Ghazi (1992) has indicated that movements took place during late Paleocene, Miocene-Pliocene and finally during late Pliocene to early Pleistocene. In the northern North Sea, only very localized inverted structures have been reported.

5.2.3 Basin evolution and depositional environments

At the beginning of the Mesozoic era there was a return to arid, continental climate conditions and both sandstone- and mudstone-dominated red-bed successions were laid down. Mesozoic basins developed during a period of crustal attenuation, where normal crust was extensively modified to a variably thinned crust. Mesozoic basins cross some of the major Caledonian tectonic elements and may have been built on a Devonian basin architecture. The northern North Sea formed the northern corner of the NW European block which deformed during Mesozoic within the boundaries defined by the Tornquist, Biscay and Rockall-Faeroes fault systems.

Triassic

The start of the Triassic period is dated at 251.4 Ma (Jin-Yugan et al., 1997), and its end is considered to be at about 199 Ma (Pálfy et al., 2000). The Triassic rocks are widely distributed (Fig. 5.19). Rifting continued into earliest Triassic time and the Triassic to Middle Jurassic succession reflects a pattern of repeated outbuilding of clastic wedges from the Norwegian and East Shetland hinterlands within a generally evolving post-rift basin. There was still considerable sediment supply from the Variscan mountains to the south and there is also evidence of an uplift of Scandinavia. A broadly similar geometry of the megasequences in both continental Triassic and marine Jurassic successions was related to subsidence rate variations. Differential subsidence across faults throughout Triassic time has also been reported. Triassic is notable for its lithologically monotonous red-bed intervals and for its common lack of fossiliferous sequences. In addition, there are only few regional seismic markers in the Triassic section that can be mapped confidently. This lack of good quality, widely distributed biostratigraphic control and correlatable log and seismic markers has hampered the understanding of the Triassic sequence. However, with the more recent release of wells drilled to deeper targets, an increase in the publication of biostratigraphic data and improvements in seismic quality, it is now possible to attempt a more detailed regional synthesis.

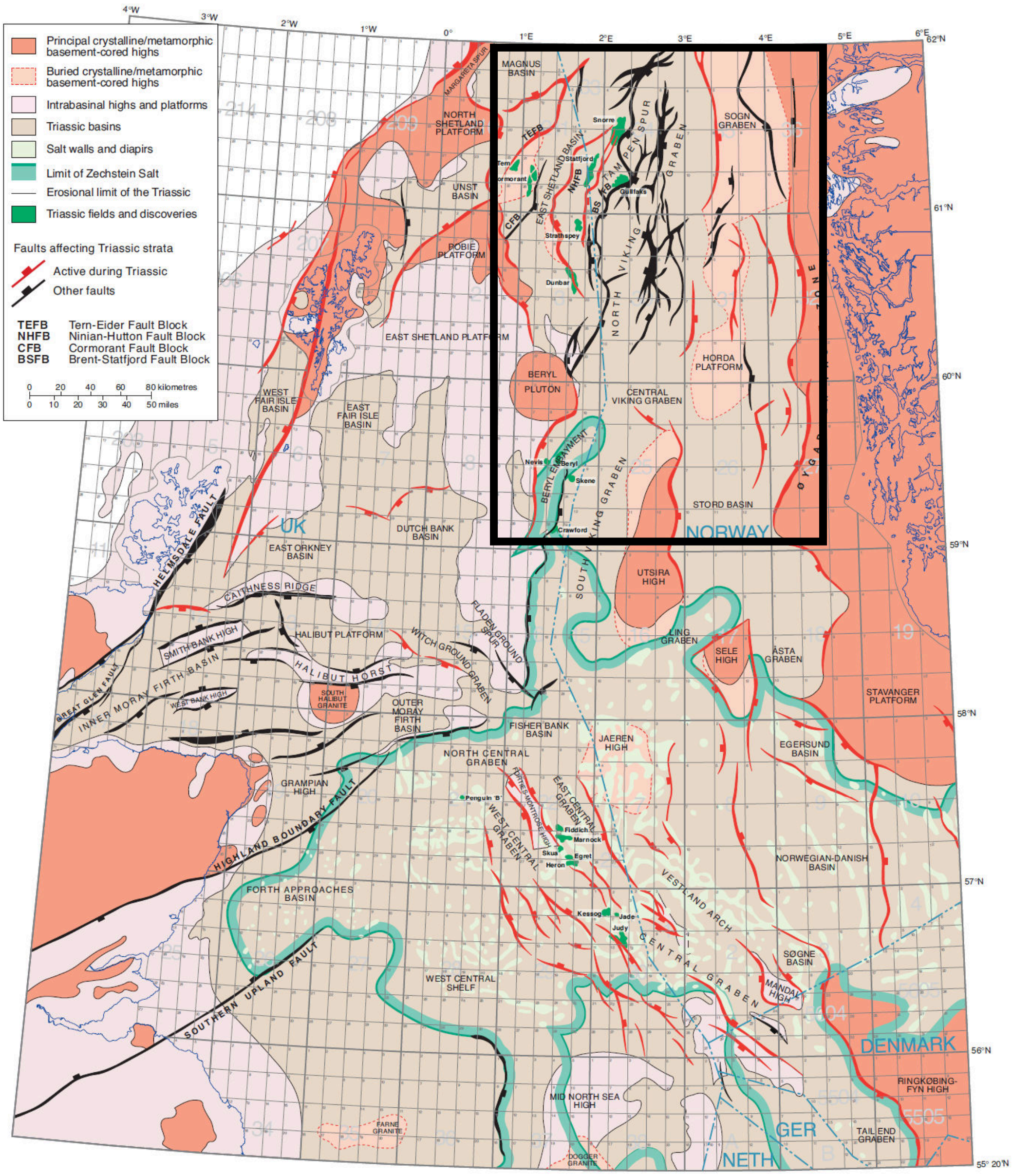


Figure 5.19: Triassic tectonic elements (Evans et al., 2003).

In the northern North Sea, well penetrations to the base of the Triassic are also rare, although here there is no Zechstein salt, so the base of the Triassic is commonly unconformable upon Permian and Devonian continental deposits and is hard to identify. The upper boundary of Triassic strata is also commonly unclear. Triassic sequences of the northern North Sea have fewer interval unconformities and less thickness variations than those in the central North Sea, and their stratigraphic development is easier to link to regional tectonic controls. In the northernmost North Sea, some wells have encountered Triassic rocks conformably overlying thin Zechstein carbonates (Lervik et al., 1989), and in few cases Triassic is commonly conformably overlain by Lower Jurassic sequences, whereas elsewhere, Middle Jurassic to Early Cretaceous erosion has created a significant unconformity.

Triassic strata were deposited in arid to semi-arid intra-continental basins determined by both local and regional tectonics. Base-level changes, induced by fluctuating sea levels, together with long-term climate changes due to continental drift also had an overall effect on sedimentation. However, evidence of climate/eustatic controls on sedimentation is confined to the northernmost North Sea where some marine influences are identified. Ormaasen et al. (1980) and Hag et al. (1987a) proposed a gradual sea-level rise during Triassic to Early Jurassic, culminating in the Sinemurian transgression. The area also migrated from paleo-latitudes of 20º-30º N to 40º-50º N between Late Permian and Early Jurassic times (Doré, 1992; van Der Swan and Spaak, 1992), resulting in a gradual cooling of the climate, and a trend of overall increasing humidity (Fig. 5.20). Torsvik et al. (2000) interpreted the relative northward movement of Europe and North America during the Triassic at around 11-12 degrees of latitude.

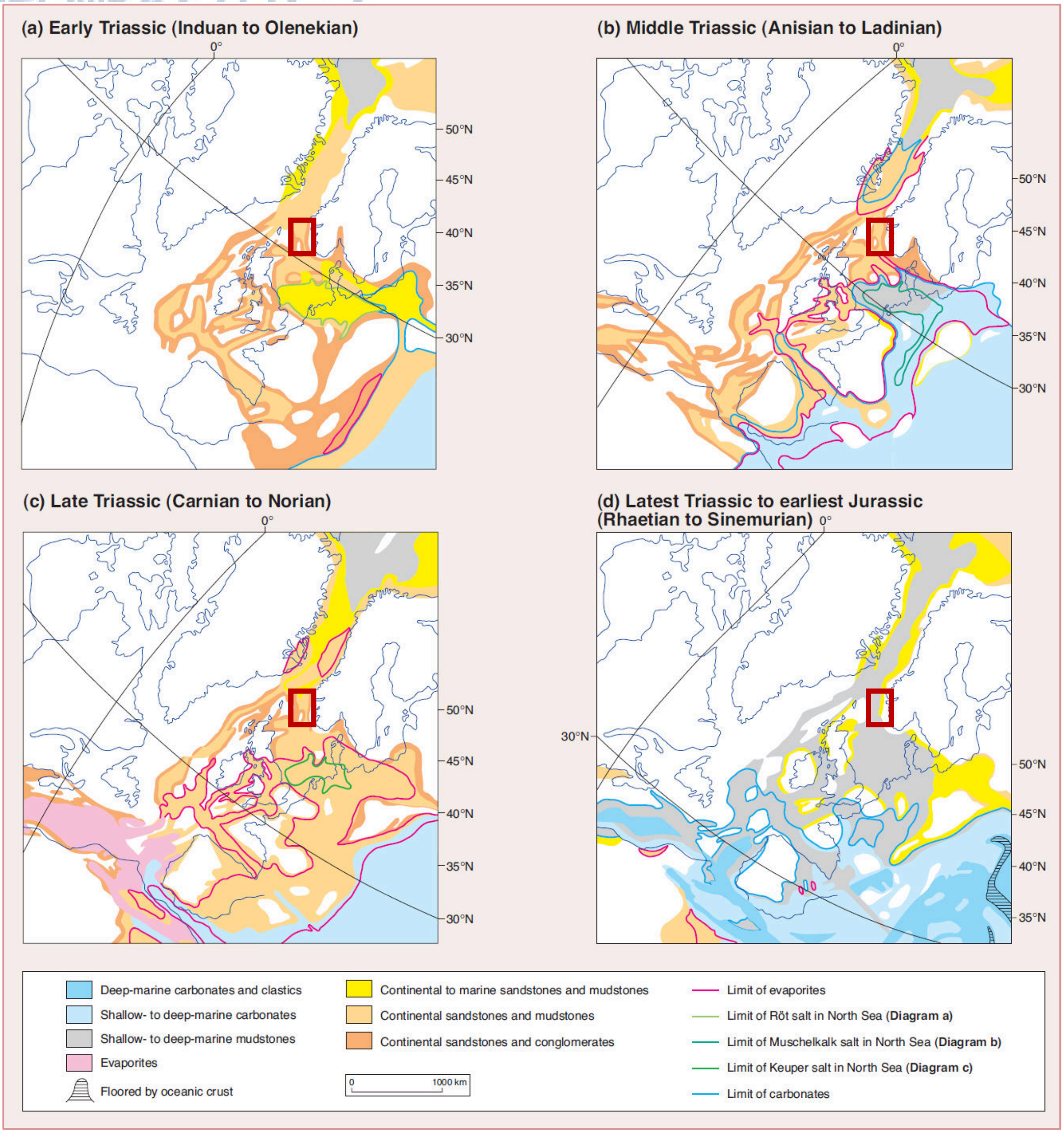


Figure 5.20: North Atlantic depositional environments and principal lithologies (Evans et al., 2003).

During Late Triassic, the Arctic rift system appears to have been largely inactive and the North Atlantic Rift propagated northwards to the Celtic Sea (Shannon, 1995). Late Triassic tectonism is also inferred to the north-west of Britain (Morton, 1992) and in the northern North Sea (Steel and Ryseth, 1990; Lee and Hwang, 1993). Latest Triassic tectonism was contemporaneous with a general sea-level rise, leading to the Jurassic marine link between the North Atlantic Arctic rift systems via the Færoe-Rockall Rift, thus joining the Boreal and Tethyan realms (Ziegler, 1988; Doré, 1992). Within this framework in the northern North Sea, continental clastic sedimentation continued right up to the end of the Triassic (Rhaetian).

Sabkha environments fringed the evaporite basins and caliche (i.e. carbonate precipitation in soil profiles) is typical. Towards the end of the Triassic, the climate became less arid with more normal fluvial sedimentation and gradually also marine sedimentation when the Statfjord Formation was deposited.

Jurassic

The transition from Triassic to Jurassic coincides approximately with a change from continental to shallow marine depositional environments. The climate also gradually became more humid during Jurassic as northwest Europe was pushed northward out of the arid belt at about 30º N. Within this context in the northern North Sea, fluvial and partly marine sandstones of Lower Jurassic age (Lunde and Statfjord formations) are important reservoir rocks in the Viking Graben. The Statfjord Formation is succeeded by the Dunlin Group, which is a dark marine shale but normally without enough organic content to become a significant source rock. Subsequently, the Brent Group sandstones were deposited, comprising a prograding delta sequence which forms the main reservoir rock in the northern North Sea. These sandstone deposits were deposited in a delta that drained the central part of the North Sea towards the marine embayment to the north, between the Shetland and Horda platforms. The sequences were sourced from an uplifted area in the south associated with Middle Jurassic (Bajocian-Bathonian) volcanic activity. The volcanic centre was located south of the Viking Graben and east of Scotland (Moray Firth). On the other side of the uplifted area, the sediments were transported southwards, exemplified in good coastal sections along the Yorkshire coast (UK).

During Aalenian and Bajocian, drainage was oriented southwards (Fig. 5.21a). This was a time period that followed the 'Mid-Cimmerian' tectonic phase that led to the uplift of the Central North Sea dome (Rattey and Hayward, 1993; Underhill and Partington, 1993). According to Herngreen et al. (2003), the deformation front shifted gradually southwards to the northern Netherlands, where open-marine sedimentation ceased during the Bajocian (van Adrichem Boogaert and Kouwe, 1993). The widespread brackish conditions observed during this period (Fig. 5.21a) suggest that the restricted shallow-marine incursions were proceeding from the southernmost Tethyan Sea, while the central part of the Central Graben recorded thermal subsidence and deposition of the Brent Group. The closure of the southern marine corridor is recorded by the widespread supratidal deposits around Bathonian J32 time. The renewal of brackish to open-marine conditions during Callovian (Fig. 5.21b) indicates the reopening of a new marine corridor, following the initiation of the Late Jurassic rifting. Transgression was rapid and from the north, along the Viking Graben and Central Graben (Fig. 5.21b).

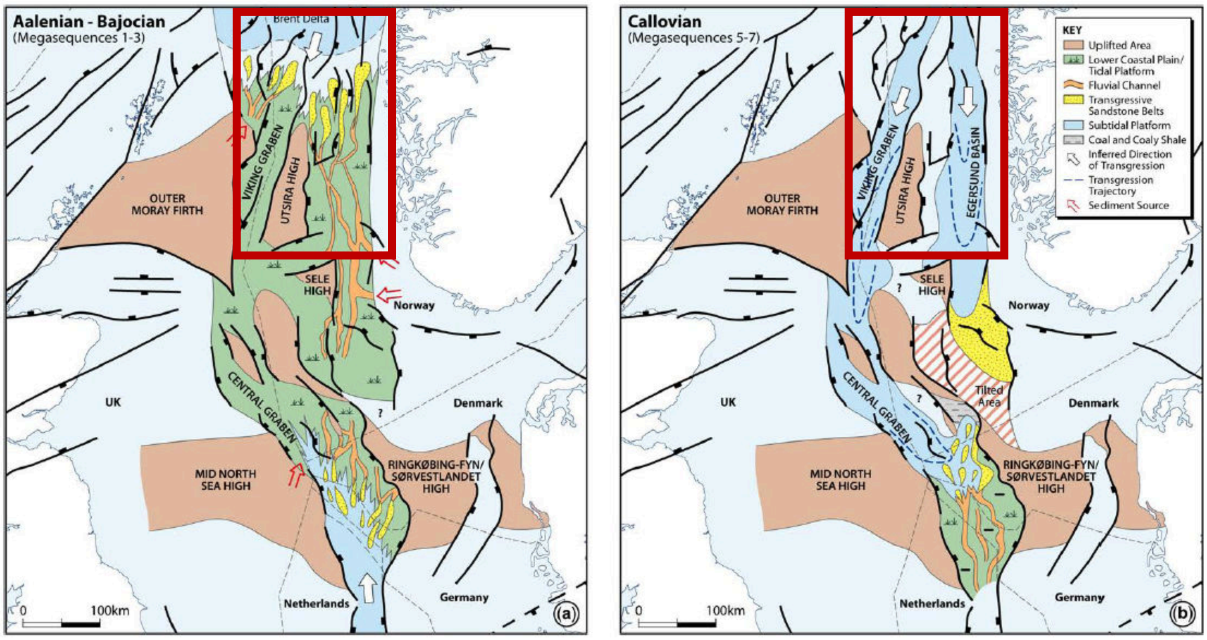


Figure 5.21: Reconstructed regional paleogeography during (a) Aalenian to Bajocian and (b) Callovian times (Mellere et al., 2016).

The Jurassic period (~201-145 Ma) was long considered a warm 'greenhouse' period; more recently, cool and even 'icehouse' episodes have been postulated. However, the mechanisms governing transition between so-called warm and cool modes are poorly known. The North Sea Dome uplift would have fundamentally modified paleocean current patterns. The general Early Jurassic ocean circulation of the NW Tethys and adjacent shelf is thought to have been characterized by a gyre acting down to water depths of several hundred metres, perhaps modified by monsoonal processes. Middle Jurassic reservoirs commonly take the form of delta systems that prograded radially up the proto-graben arms from the North Sea rift triple junction, though some deltaic sediments also prograded east from the Shetland Platform to form part of the Brent Delta (Fig. 5.22).

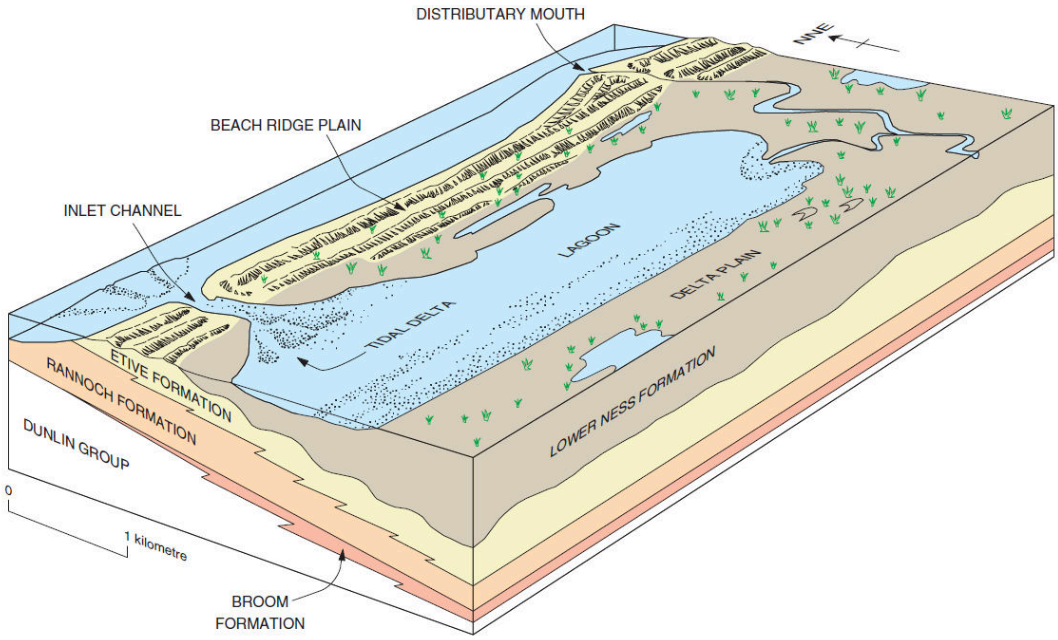


Figure 5.22: Depositional model for the Rannoch, Etive and Lower Ness formations (part of the Brent Group) (after Budding and Inglin, 1981).

The truncation at the regional unconformity below Middle Jurassic strata stretches over an area from Scotland to Denmark, and central England to 59º N in the North Sea (Ziegler, 1990b; Underhill and Partington, 1993). This domal area outline was centred on what is now the triple-junction area of graben system, and was some 1000 km in diameter. The existence of a doming event and its significance as a sediment source was suggested at an early stage in North Sea exploration (Hallam and Sellwood, 1976; Eynon, 1981). The dome acted as a source for the clastic material supplied during Bajocian and Bathonian to the north (Brent Group delta, northern North Sea), to the east (Denmark), to the south (Ravenscar Group Yorkshire) and to the west (West Province and Inner Hebrides). The land barrier created by the dome also 'interrupted' the open-marine sea-ways that had linked the Arctic and Tethys seas during Early Jurassic.

Figure 5.23 shows the connection between the equatorial Tethys Ocean and the Boreal Sea via the Laurasian Seaway; the latter included the Viking Corridor which was several hundred kilometres wide. Furthermore, during Late Jurassic, volcanism was particularly reduced and the areas within and surrounding the rift systems subsided in response to lower geothermal gradients. At the same time, normal faulting along the Viking Graben led to the rotation of basement blocks and their overlying sediments. The shoulders of the tilted fault blocks were exposed to erosion, removing Lower-Middle Jurassic and locally even Upper

Triassic strata. The Late Jurassic (Oxfordian) transgression covered the Viking Graben with a thick drape of clayey sediments of the Heather Formation, while coarser clastics (sand) were deposited as turbidites and in deltas along the basin margins. Some of the deltas appear to have been controlled by the same structures that have determined the location of the fjords in western Norway. The uppermost Jurassic Kimmeridge Clay Formation is transgressive and often forms a several hundred metres thick rich source rock which on the Norwegian side is called the Draupne Formation. The rift topography produced numerous, locally overdeepened, basins with poor bottom water circulation. Only a relatively small proportion of the organic production was oxidised while the sedimentation rate was fairly high. The organic rich shales of the Upper Jurassic are thus the prime source rock in the North Sea, and provided the main petroleum source in both the Statfjord and Ekofisk areas. The thickness of the Upper Jurassic sediments along the rift axis may reach 3000 m. The deposition of organic-rich shales continued into the Early Cretaceous in some of the basins. The edges of the rotated blocks suffered erosion and a few were not buried until the Late Cretaceous. The majority of the faults die out before the Cretaceous but a few continue up into younger beds. The rifting resulted in rotated fault blocks containing sandstone reservoirs of Lower and Middle Jurassic age (sandstones of the Brent Group and Statfjord Formation). Small fan deltas developed along the rift and also deepwater sandstones including debris flows. Some of these are good reservoir rocks occuring within the Upper Jurassic source rocks.

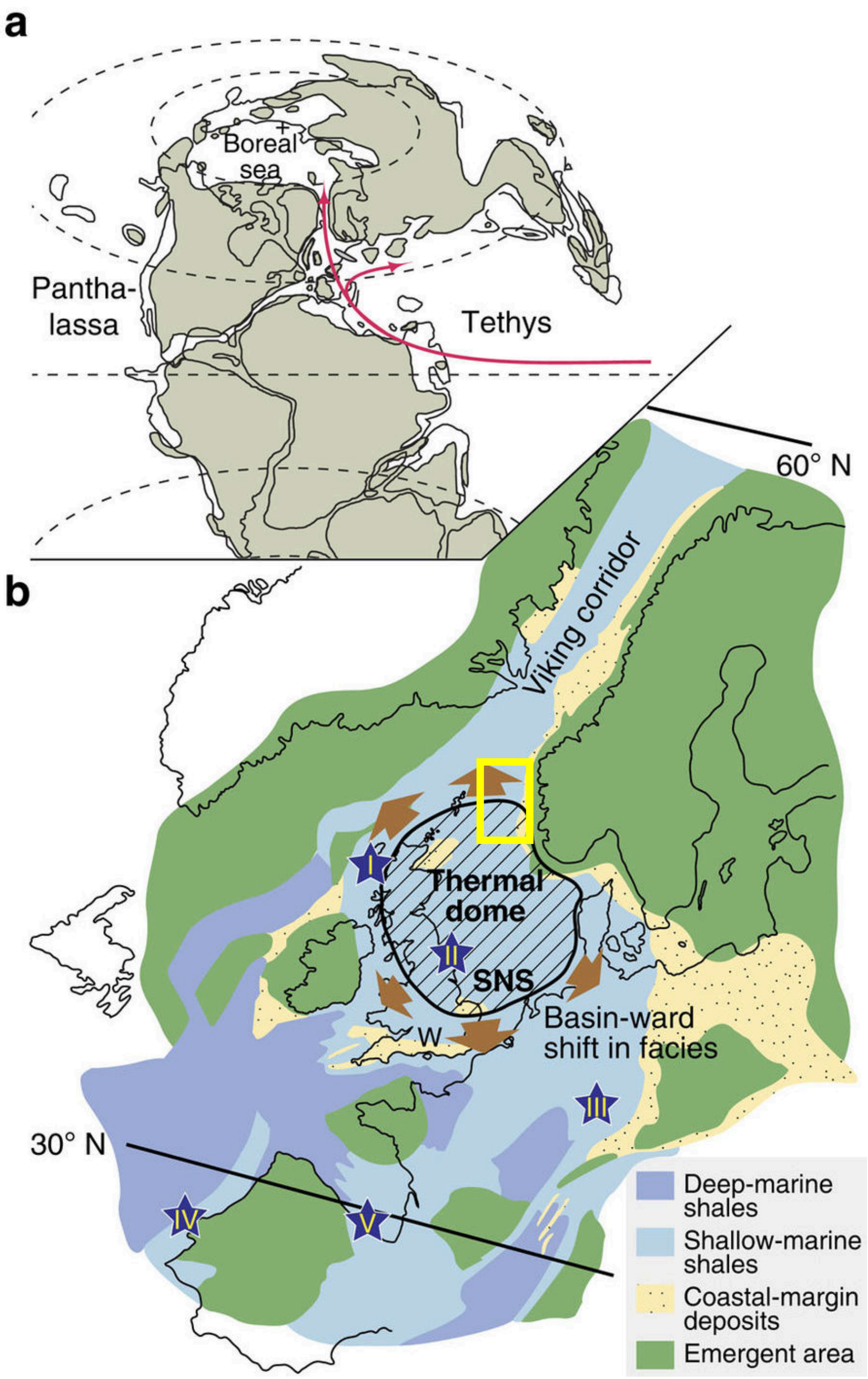


Figure 5.23: Late Early Jurassic paleogeography (Korte et al., 2015). (a) Red arrows mark generalized palaeocurrents. Detail of Laurasian Seaway palaeogeography with the region affected by North Sea Dome as determined by the generalized outer limit of the Toarcian subcrop; (b) Brown arrows represent the siliciclastic sediment supply/transport in relation to domal uplift. Sample locations are numbered and identified by stars. Hebrides Basin (I; Scotland), Cleveland Basin (II; England), Swabo-Franconian Basin (III; Germany) and Lusitanian (IV; Portugal)/Basque-Cantabrian basins (V; Spain). SNS, Southern North Sea Basin, W, Wessex Basin.

Cretaceous

The last phase of rifting in the North Sea during Late Jurassic was followed by a major transgression, however the uplifted rift structures remained dry and were islands for most of the Early Cretaceous as well. There is a major unconformity between the Cretaceous and the Jurassic except in the deep parts of the rifts where there may have been continuous sedimentation (Figs. 4.6 and 4.7). The Base Cretaceous Unconformity is very well marked on most seismic sections from the North Sea. Fault activity diminished during Cretaceous, and the Cretaceous subsidence was due primarily to crustal cooling after the Jurassic rifting. The transition from syn- to post-rift configuration was strongly diachronous, suggesting that the thermal state of the system was not homogeneous at the onset of the post-rift stage.

Three stages can be identified in the post-rift Cretaceous development of the northern North Sea:

1) The incipient post-rift stage (Ryazanian-latest Albian) was characterised by different degrees of subsidence. The major structural features inherited from the syn-rift basin (e.g. crests of rotated fault blocks, relay ramps and sub-platforms) had a strong influence on the basin configuration and hence the sediment distribution.
2) In the middle stage (Cenomanian-late Turonian) the internal basin relief became gradually drowned by sediments. This is typical for basins where sediment supply outpaces or balances subsidence, as was the case in the northern North Sea. Thus, the influence of the syn-rift basin topography became subordinate to the subsidence pattern determined by the crustal thinning profile, which in turn relied on thermal contraction and isostatic/elastic response to sediment loading.
3) The mature post-rift stage (early Coniacian-early Paleocene) was characterised by the evolution into a wide, saucer-shaped basin where the syn-rift features were finally erased. Since thermal equilibrium was reached at this stage, subsidence ceased, and the pattern of basin filling became, to a larger degree, dependent on extra-basinal processes.

During Late Cretaceous, the sea attained its transgressive maximum and clastic sedimentation almost ceased across large areas of northwest Europe. Parts of Scandinavia were probably also covered by the Cretaceous sea. Sedimentation was dominated by planktonic carbonate algae (coccolithoporids) which formed a lime mud, the main component of Chalk, though it also included some foraminifera and bryozoa. The main development of the Chalk was in the

Campanian and Maastrichtian, but sedimentation continued up into the Danian of the Paleocene, for the most part through re-sedimentation of earlier Chalk deposits which had been uplifted along the central highs. In the Viking Graben, the carbonate content diminishes northwards and we do not have pure limestone (Chalk) facies like that in the southern and central part of the North Sea. Instead, shales predominate, though often with a significant carbonate content.

5.3 CENOZOIC

The evolution of the North Sea basin region throughout the Cenozoic occurred against a tectonic regime resulting from the fragmentation of the Eurasian-North American plate, and Alpine orogenesis (Cloetingh et al., 2005; Knox et al., 2010). The break-up of the northern hemisphere plate, along the North Atlantic mid-ocean ridge spreading centre, gave rise to tensional or extensional features, whereas Alpine mountain building, arising from continental collision between the Eurasian and African plates, produced compressional features. Although the North Atlantic margins had been regarded as 'passive' (Ziegler, 1978, 1987, 1994; Dewey, 2000; Anell et al., 2009; Knox et al., 2010), active tectonics led to widespread reactivation of older structures, particularly those of Variscan origin, with the Norwegian Atlantic coastal area undergoing substantial vertical movements during the Cenozoic (Cloetingh et al., 1990). The interplay between these two processes resulted in structural and depositional palaeogeographical changes through the period (Cloetingh et al., 2005).

5.3.1 Paleogeography

Skogseid et al. (2000) argued for 140 km of extension across the conjugate Greenland-Norwegian margin during Maastrichtian to Paleocene interval, based on the apparent thinning of the original crust as determined from deep-seismic data. Many authors considered this to be an extreme overestimate because seismic sections through the Norwegian margin show relatively little faulting of Paleocene sediments (Swiecicki et al., 1998). Furthermore, the margin was generally a zone of uplift during Maastrichtian and Paleogene times, with tectonic inversion structures being generated (Fig. 5.24).

During late Paleocene to Eocene, there was also uplift of north-west Europe associated with the North Atlantic hot spot (Iceland plume). The uplift supplied a new influx of sediments into the North Sea, contributing to further subsidence due to sediment loading. At least two phases of volcanic activity can be recognized in the North Atlantic province. The volcanic events probably coincided with pulses of extension. Ocean spreading began immediately after the extrusion of the younger volcanic, leading to continental separation between Greenland and Europe. Continental break-up and initiation of the Norwegian Sea began about 55 Ma, at the Paleocene-Eocene transition (Eldholm et al., 2002; Tsikalas et al., 2012). During the early phase of conti-nental separation, oceanic crust was formed by sea-floor spreading south of the Senja fracture zone when the north- to north-westward motion of Greenland away from Svalbard took place along a regional transform fault without the formation of a deep basin.

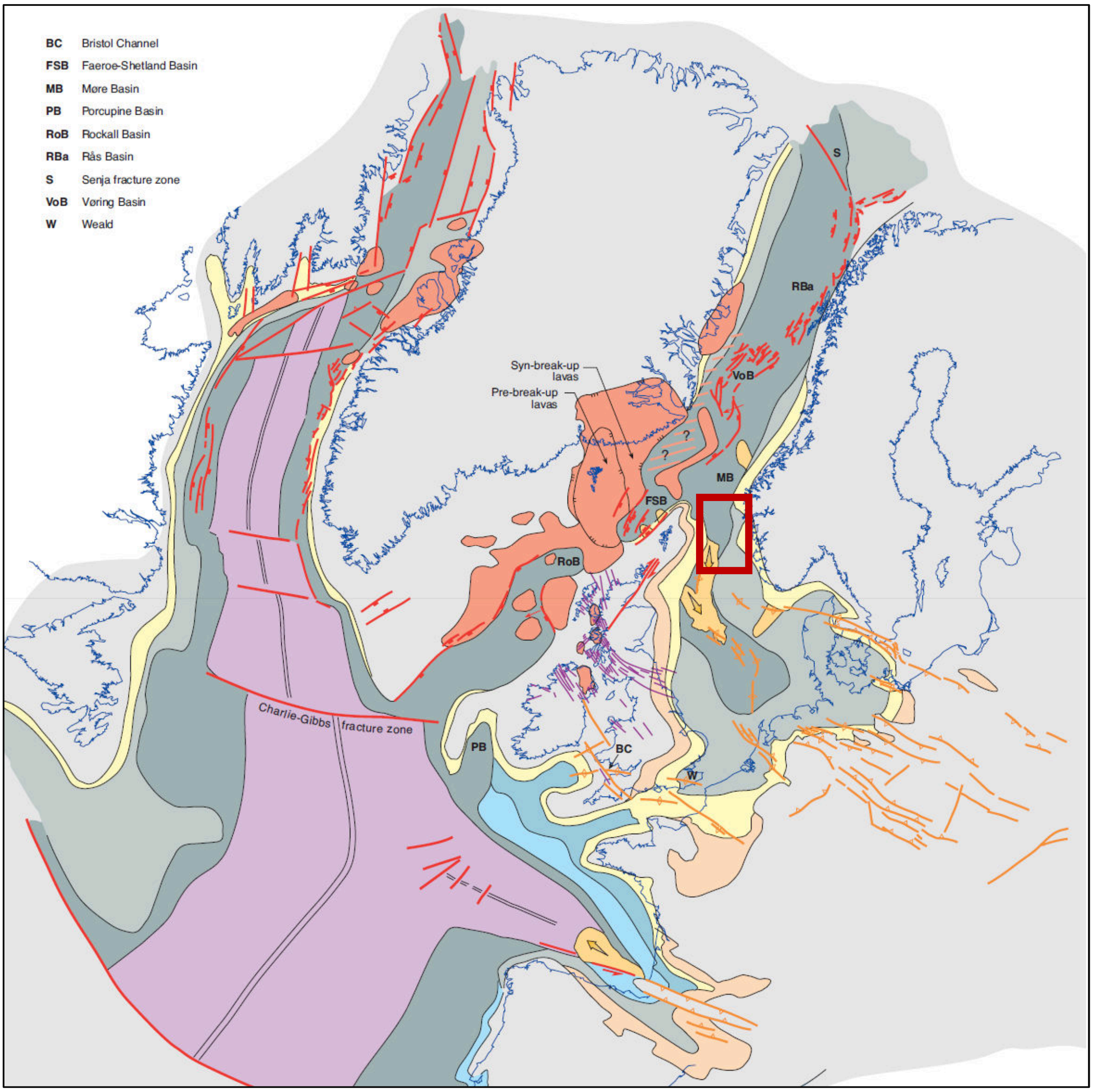


Figure 5.24: Palinspastic map for the Paleocene showing the distribution of active structures, sediment facies and volcanic rocks associated with the North Atlantic mantle plume (Evans et al., 2003).

Following continental breakup of the NE Atlantic subsequent passive margin development along the Norwegian continental margin during early Tertiary, the North Sea basin development was influenced by the dual controls of the closing of the Tethys Ocean to the south-east and the opening of the North Atlantic Ocean to the north and west (Fig. 5.25). During this time, uplift west of mainland Norway is observed and may be related to renewed shear during Oligocene to Miocene, with initial tectonic uplifts magnified by subsequent glacial erosion and isostatic readjustments (Riis and Feldskaar, 1992). Figure 5.26 shows the tectonic setting during Oligocene to Pleistocene times.

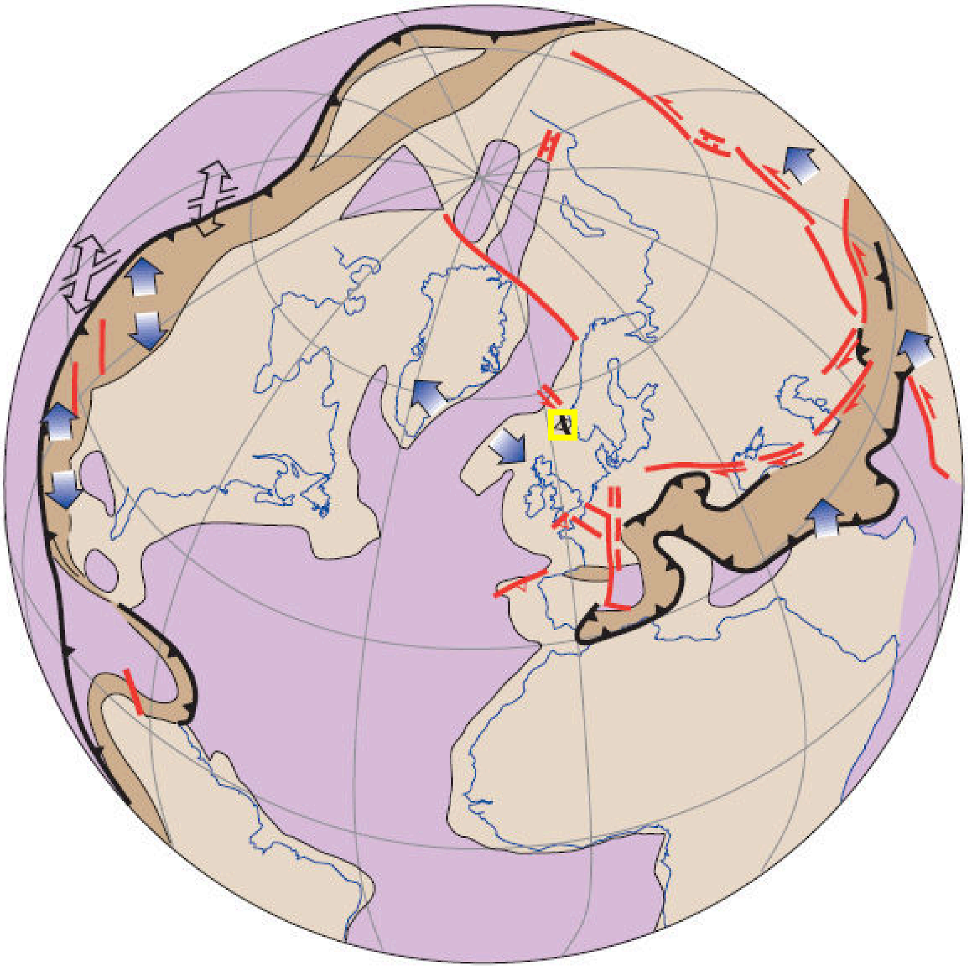


Figure 5.25: Global view of Oligocene tectonics (Evans et al., 2003).

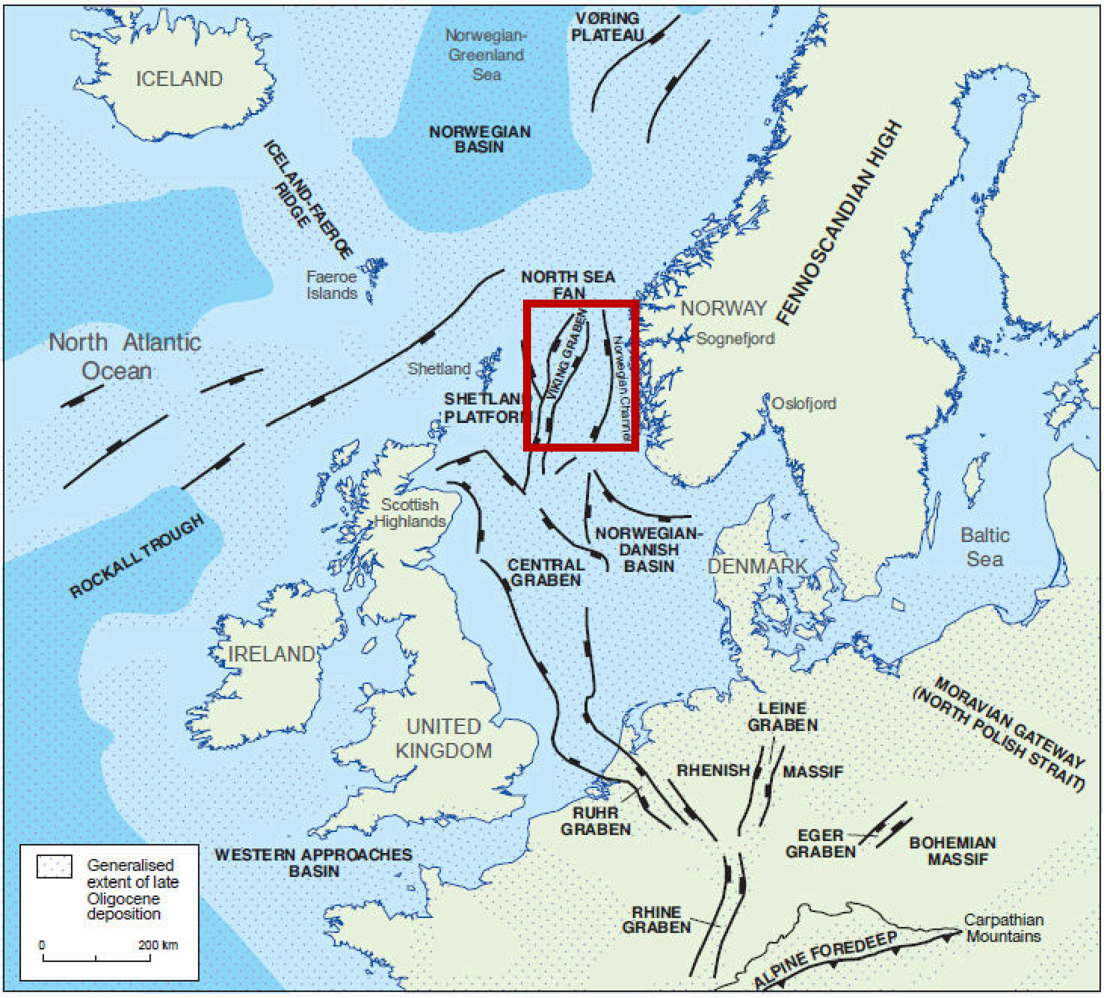


Figure 5.26: Location map illustrating structural elements active during Oligocene to Pleistocene maps and generalised depositional areas (stippled) during the late Oligocene (Evans et al., 2003). Based on maps by Ziegler (1982, 1988) and Udintsev Kosminskaya (1982); Areas with present-day water depths of greater than approximately 2500 m are shown as darker blue.

5.3.2 Structural setting

The early Cenozoic rifting, break-up and onset of seafloor spreading in the NE Atlantic gave rise to differential vertical movements that also have affected the North Sea area. The sedimentary architecture and breaks are related to tectonic uplift of surrounding clastic source areas, thus the offshore sedimentary record provides the best age constraints on the Cenozoic exhumation of the adjacent onshore areas.

Major depocentres sourced from the uplifted Shetland Platform and areas along the incipient plate boundary in the NE Atlantic formed during Late Paleocene-Early Eocene times. A local source area also existed in western Norway. Tectonic subsidence accelerated in Paleocene time throughout the basin, with uplifted areas to the east and west sourcing prograding wedges, which resulted in large depocentres close to the basin margins. Subsidence rates outpaced sedimentation rates along the basin axis, and water depths in excess of 600 m are indicated.

Five key events are distinguished and summarized:

1) Danian/Thanetian: major hinterland rejuvenation related to doming around a mantle hot spot centred under East Greenland.
2) Early Paleocene: volcanic activity, caused by east-west extension, led to the British and Faeroe-Greenland igneous province, with impact in the North Sea exemplified by the Andrew Tuff of the Witch Ground Graben.
3) Late Paleocene: volcanic activity, associated with the onset of sea-floor spreading in the Norway-Greenland Sea, led to eruption and deposition of widespread tuff marker beds (the Balder Formation tuff of the northern North Sea).
4) Restriction of the northern North Sea, due to the thermal doming, leading to the development of an anoxic basin in the North Sea during the late Paleocene and early Eocene.
5) Minor inversion during early Eocene caused by the final rupture of the North Atlantic. This was followed by passive subsidence, leading to a clear marine connection of the North Sea with the Atlantic.

Knowledge of the present-day stress field in the northern North Sea has become increasingly important in drilling and production operations because in-situ rock stress affects borehole stability, the rate of drill penetration, and the layout of deviated or horizontal wells. Determining the orientation and intensity of in-situ stresses also helps to optimize reservoir productivity and to better evaluate the sealing potential of faults. In the North Sea, as in many other regions of the world, the horizontal stress field exceeds the vertical stress and it is controlled by regional plate-tectonic movements.

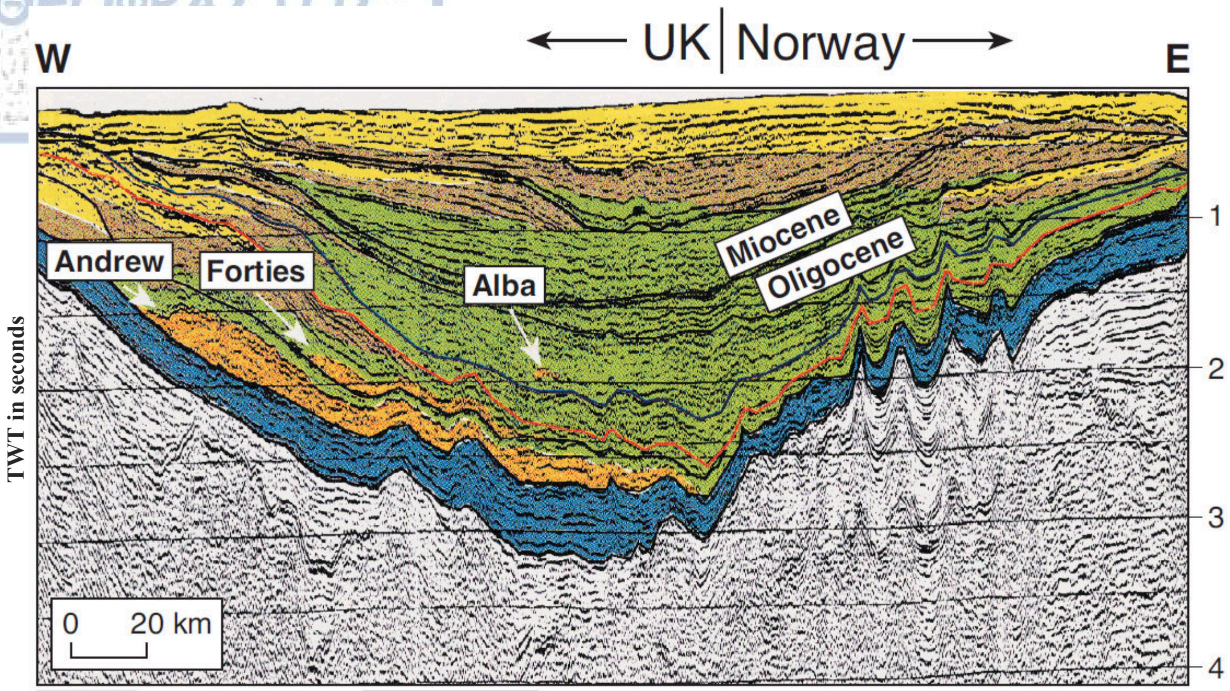


Figure 5.27: Squeezed seismic section through the northern North Sea (Evans et al., 2003).

Figure 5.27 illustrates geometries of stratigraphic sequences and unconformities identified in the Cenozoic section (coloured interval) that show uplift of the basin margins, Fennoscandia and the Scotland-East Shetland Platform, during Cenozoic time (Den Hartog Jager et al., 1993). Furthermore, tectonic activity at Paleocene time was related to the development of the Iceland Plume, which caused regional uplift (Fig. 5.24). Adjacent to the North Sea, the Scottish Highlands and the east Shetland Platform were uplifted, but there was less uplift of the Norwegian landmass. Further stresses along the line of the future NE Atlantic Ocean led to major volcanic activity, which is represented by tuffs. Finally, the regional seismic profile in Figure 5.28 shows that the Paleocene interval typically thins from west to east and is most deeply buried in the centre of the basin above the Viking Graben.

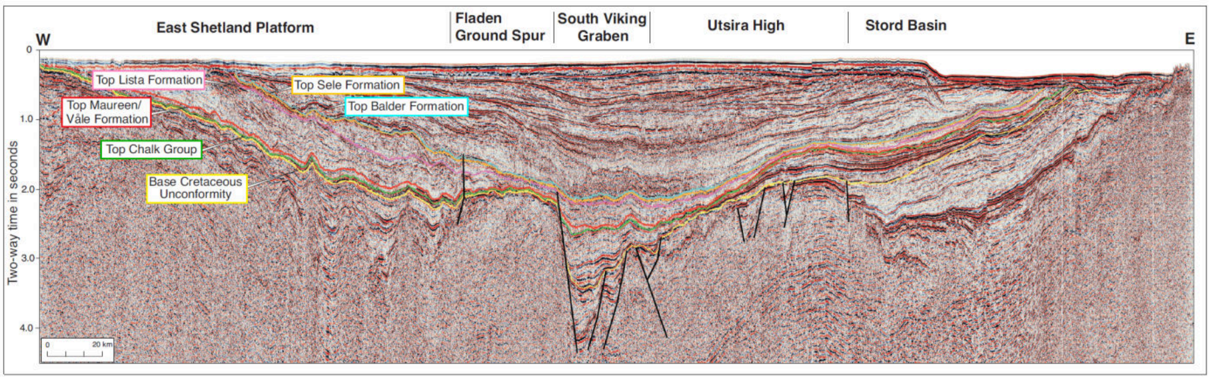


Figure 5.28: Regional seismic profile of the Viking Graben (Evans et al., 2003).

Towards the end of the Eocene, the regional stress regime in the North Sea changed to more east-west extension (Le Pichon et al., 1988; Kooi et al., 1989). In the northern North Sea, the Eocene-Oligocene boundary probably represents one of the most important breaks within the Cenozoic. Rundberg (1989) suggested that the distinct changes in lithostratigraphy, mineralogy and biostratigraphy observed at this boundary are thought to be controlled by the large drop in global temperature at the end of Eocene time (Kennett, 1982; Ruddiman, 2000; Zachos et al., 2001). Furthermore, during Oligocene-Early Miocene the northern North Sea progressively shallowed, and by the end of the period fairly shallow-marine conditions were established in the northernmost North Sea. The sediments are mainly fine-grained in nature and contain an abundance of diatoms and sponge spicules. The climatic conditions were still relatively warm and resulted in intense, locally lateritic weathering on the continents (Buchardt, 1978; Rundberg, 1989).

Detailed seismic interpretation has revealed that the Eocene, Oligocene and lower Miocene shale-prone sequences within the basin center are commonly deformed by abundant small faults (Fig. 5.29). The polygonal nature of these faults has become evident with the use of 3D-seismic surveys from which images of surfaces can be generated. The faults are broadly arranged into two tiers, one in the Eocene, and the other in Oligocene to middle Miocene strata; these tiers are separated by a lower Oligocene, undeformed layer (Cartwright, 1994). The polygonal-fault networks are believed to have been developed during early burial by the bulk volumetric contraction of muds during dewatering (Cartwright and Lonergan, 1996; Lonergan and Cartwright, 1999) and may be exploited by migrating fluids. From an exploration viewpoint, small complex anticlines developed between fault zones with opposing dips have been confused with submarine-fan mounds.

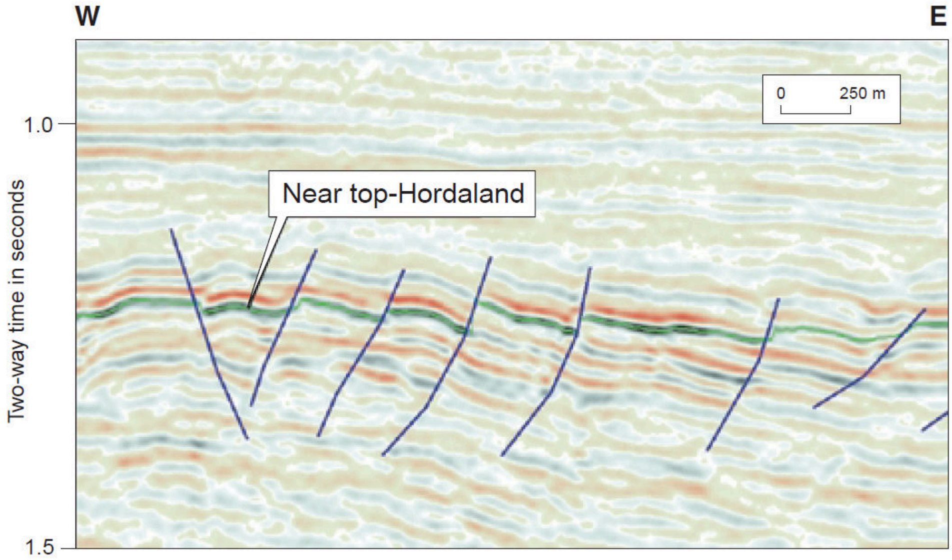


Figure 5.29: Polygonal faults at the near top-Hordaland Group (middle Miocene) level (Evans et al., 2003).

5.3.3 Basin evolution and depositional environments

Most of the Cenozoic was dominated by a thermal subsidence which was responding to Late Jurassic rifting, in addition to some new generated faults during the Cenozoic times. Local norms of sedimentation altered hugely during the early Paleogene times due to the invasion of enormous coarse clastic detritus volumes, deposited as turbidites and debris flows. The detritus mentioned was discarried from the inner northern Scotland and also from the Orkney-Shetland Platform where thermal uplift took place responding to the evolution of the Iceland Plume. The latter has caused regional uplift and gradual enclosing and isolation of the North Sea basin from the Atlantic Ocean (Fig. 5.30).

Paleogene

Rifting of the Greenland-European plate during early Paleocene caused thermal uplift of Scotland and the East Shetland Platform, with rejuvenation of older Mesozoic hinterlands and basin margins. This is the major control on the supply of coarse siliclastic detritus during Paleogene. It changed the relatively deep, sediment-starved basins of the late Cretaceous into major clastic depocenters, dominated by a complex interplay and mosaic of deltaic and submarine-fan systems. Alpine orogenesis had a less dramatic effect on prospectivity, with local inversion mostly along former basin-margin faults.

Sedimentation was controlled by a complex interplay between tectonic activity, eustasy and hinterland characteristics. Each operates at both a regional and a local scale, leading to a complex depositional pattern across the basin. The volume and grain size of the clastic detritus increased gradually to a peak in the late Paleocene (mid-Thanetian). Large volumes of material were fed into the North Sea and Faeroe-Shetland Basins as major submarine-fan depocenters. Provenance data for Paleocene sands demonstrate that the impact of tectonic activity was not uniform along the basin margins and hinterlands. Differential uplift led to the development of geographically and temporally separate depocenters (Morton et al., 1993). Relatively small volumes of sand were derived from western Norway, due to the predominantly argillaceous and metamorphic nature of that hinterland. This explains the relatively poor prospectivity of the Tertiary over large parts of the Norwegian sector.

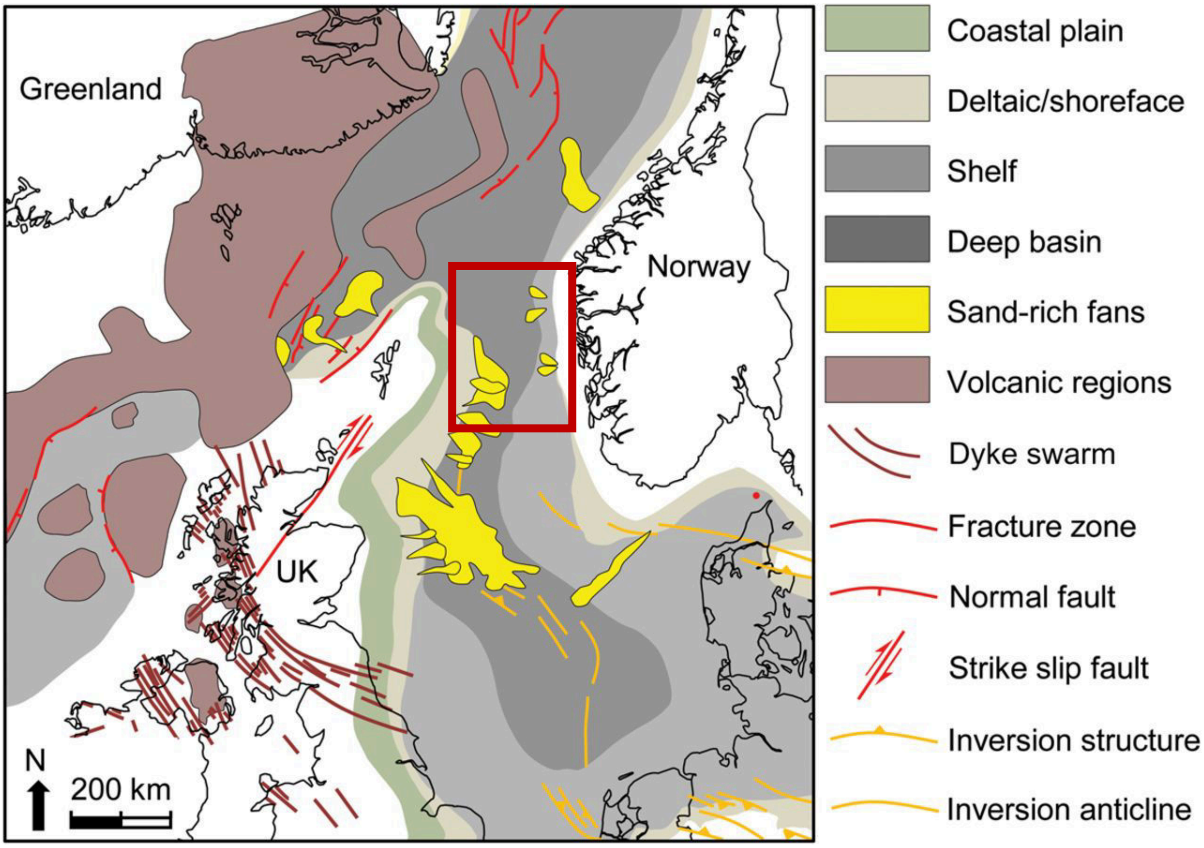


Figure 5.30: Regional basinal context of the Tertiary deep-marine reservoirs illustrated by the Paleocene paleogeographical setting (modified after Coward et al., 2003).

The combination of seismic, sedimentological and stratigraphic data indicates that early stages of deposition (Paleocene) are distinguished by great basin depth, steep margins and high sedimentation rates. This led to instability of delta and shelf slopes, enabling direct liberation of large volumes of sediment to the basin. The combination of delta front failure, relative stability of the margins and rapid basin subsidence led to bypass of the shelf and the direct supply of sand to the basin. Deltaic systems constructed during highstand conditions were subsequently eroded and bypassed during lowstand conditions, which transferred this large sediment yield to the basin floor (Fig. 5.30) (Den Hartog Jager et al., 1993; Jennette et al., 2000). In contrast, late Paleocene to Eocene progradation resulted from relatively shallow basin depths. By this time, basin slopes and sedimentation rates were reduced. The relatively stable slopes inhibited direct transfer of sediment to the basin. This led in turn to smaller, more localized, basin-floor systems, which are often more sand-prone than their Paleocene counterparts. During early Tertiary, major changes in paleogeography and sedimentation patterns took place. Specifically, the shift of rift focus from the Viking Graben to the North Atlantic region resulted in a marked uplift of the East Shetland Platform which sourced eastwards-pinching, sand-rich turbiditic fan systems developed at different times, such as the Ty, Heimdal, Hermod, Balder, Grid and Skade formations (Fig. 5.31).

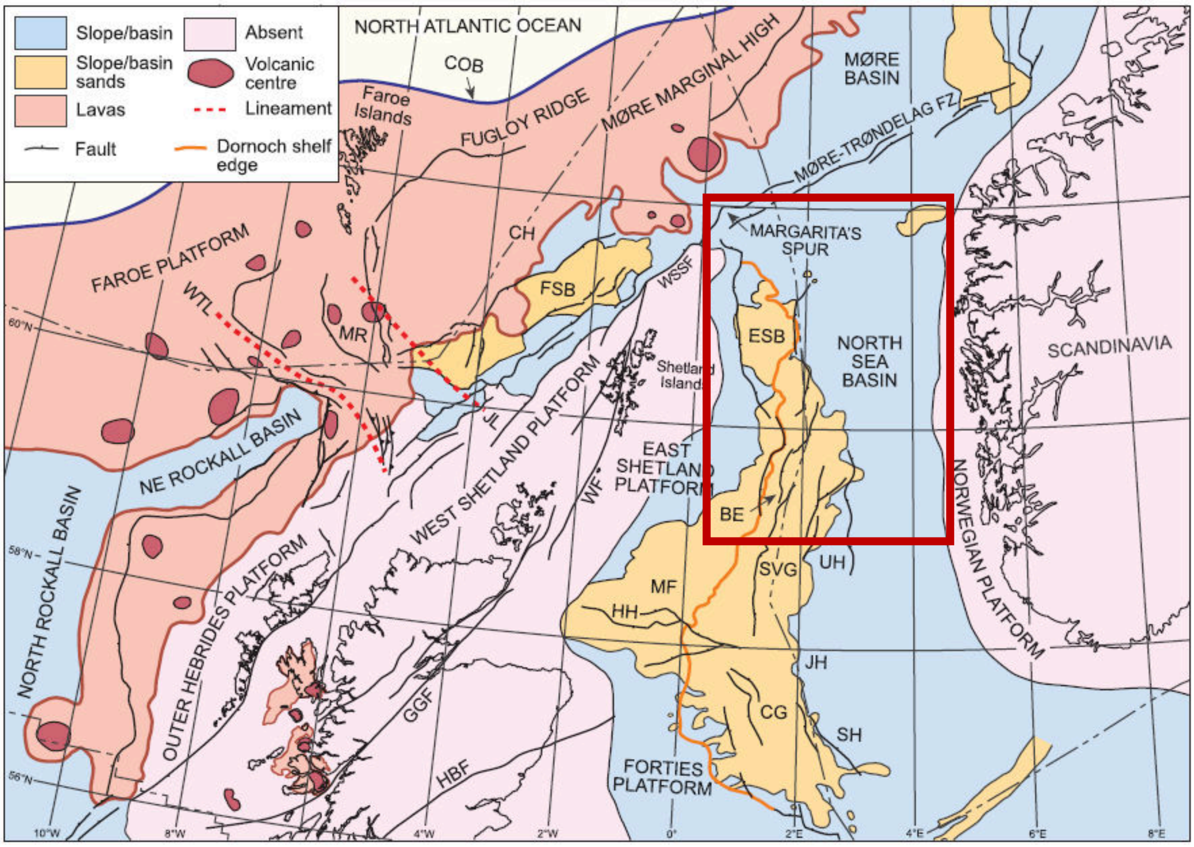


Figure 5.31: North Sea and NE Atlantic margin basins showing present-day distribution of Paleocene-Lower Eocene sediments and volcanics (Mudge, 2014). BE, Beryl Embayment; CG, Central Graben; MF, Moray Firth; ESB, East Shetland Basin; HH, Halibut Horst; JH, Jæren High; SH, Sørvestlandet High; SVG, South Viking Graben; UH, Utsira High; GGF, Great Glen Fault; HBF, Highland Boundary Fault; WF, Walls Fault; CH, Corona High; FSB, Faroe-Shetland Basin; JL, Judd Lineament; MR, Munkagrunnur Ridge; WSSF, West Shetland Spine Fault; WTL, Wyville-Thomson Lineament; COB, continent-ocean boundary.

The Eocene strata includes a number of important hydrocarbon accumulations but remains relatively unexplored. The general pattern of sedimentation in the Eocene was one of marginal- to shallow-marine sedimentations in the center of the basin above the Viking and Central Grabens. Sea level became lower during Eocene times, and the water temperature cooled (Fig. 5.32).

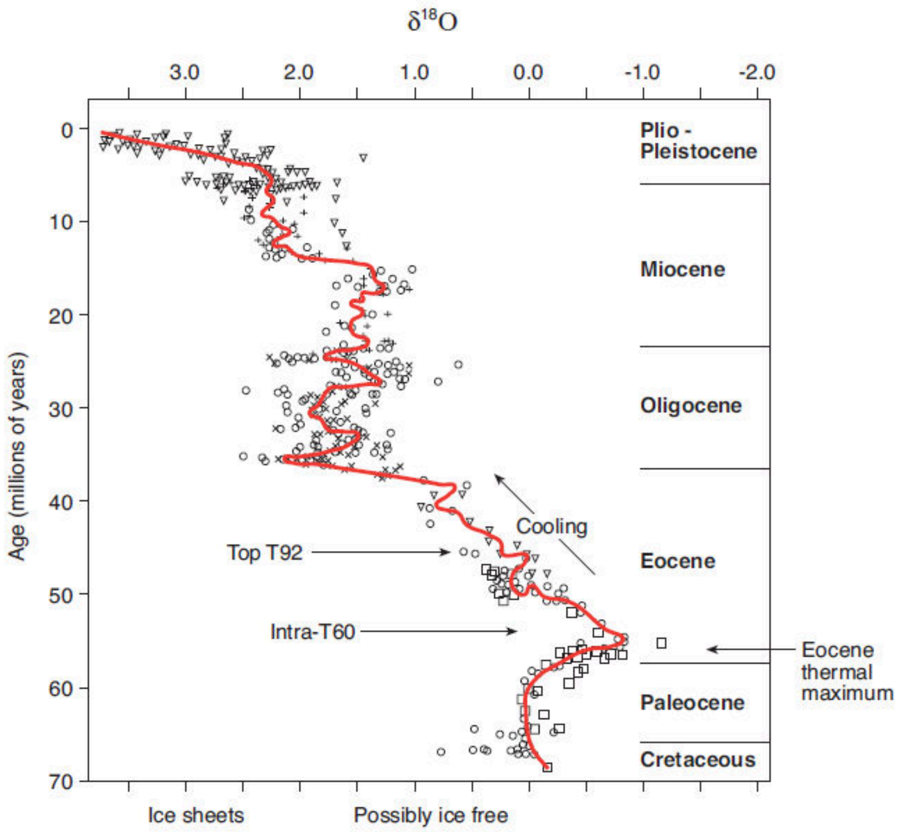


Figure 5.32: Oxygen-isotope ratios for the Cenozoic (Evans et al., 2003).

The oxygen-isotope record for the Eocene records a progressive cooling of marine waters as well as an ice-volume increase towards the end of the epoch. Prominent ash layers of earliest Eocene age are found throughout the entire North Sea and also farther north. Onshore in Denmark the volcanoclastic sediments are known as “moler”. The extensive volcanism was related to the opening of the North Atlantic and both the Eocene and Oligocene mudstones are dominated by smectitic clays formed from volcanic ash. These smectitic mudstones are characterised by low seismic velocities also compared to the overlying Neogene sediments. Ash layers rich in volcanic glass (hyaloclastites or tuff) may, however, form hard layers due to diagenesis. They will then be characterised by high seismic velocities, particularly after burial to more than 2 km depth and quartz cementation, giving rise to strong seismic marker horizons (top Balder Formation). The top-Balder surface is widespread and is easily recognized lithologically and biostratigraphically, as well as on wireline logs and seismic profiles. During Eocene times, progradation from the East Shetland Platform was dominant and major depocentres developed in the Viking Graben area, with deep water along the basin axis. The Paleocene and Eocene submarine fans were built up with turbidite sands carried out into the central part of the North Sea with the Utsira High limiting their eastward extent. Parts of Fennoscandia were probably covered by sea during Middle-Late Eocene times. The maximum thickness of the Eocene succession is in the Viking Graben where it is over 800 m thick, although only slightly thicker than in the Central Graben. At the Eocene-Oligocene transition, southern Norway became uplifted. This uplift, in combination with prograding units from both the east and west, gave rise to a shallow threshold in the northern North Sea, separating deeper waters to the south and north.

Following successful rifting of the North Atlantic, the Eocene and Oligocene are characterized by reduced rates of clastic input along the newly developed passive margin. Sedimentation rates were reduced, the hinterlands gradually denuded, and a more uniform pattern of deposition established across both the North Sea and the Faeroe-Shetland Basins. Relative sea-level changes became the primary control on sedimentation patterns. Sediment dispersal patterns and input points were controlled by basin bathymetry, which was strongly influenced by the geometry of the underlying Jurassic failed rift. Differential uplift of the hinterland affected the overall pattern of basin fill, with temporally and spatially distinct phases of sediment input.

Neogene

The uplift and shallowing continued into Miocene time when a widespread hiatus formed in the northern North Sea, as revealed by biostratigraphic data. Miocene outbuilding from the north into the southeastern North Sea was massive. Coastal progradation of the Utsira Formation in the northern North Sea reflects Late Miocene-Early Pliocene uplift and erosion of mainland Norway. This relatively thick sandstone is a good aquifer and is used for injection of CO_2 in the Sleipner Field in the Central North Sea. It was still relatively warm in the Early Pliocene, compared to the Late Pliocene when mountain glaciation started to develop.

The Miocene in the northern North Sea is represented by the Utsira Formation. The Utsira Formation was deposited during late Middle Miocene (~20 Ma) to Early Pliocene (~14 Ma) (Eidvin et al., 2002). The formation belongs to the Nordland Group and is present in the

Viking Graben, area from ca. 58º N to 62º N (Gregersen and Michelsen, 1997). The Utsira Formation consists of marine sandstones with source area mainly to the west, and its maximum thickness exceeds 300 m (Fig. 5.33b). The sands of the Utsira Formation display a complex architecture and the elongated sand body extends ~450 km in a north-south direction and 90 km in an east-west direction. The northern and southern parts are mainly composed of large mounded sand systems. In the middle part, the deposits are thinner, and in the northernmost part (Tampen Spur area) they consist of thin beds of glauconitic sands.

Post-Eocene uplift of the East Shetland Platform produced four sandy systems in the northern North Sea area (Rundberg and Eidvin, 2005): an Early-Late Oligocene set of mainly gravity-flow sands; Early Miocene mainly turbidite sands (Skade Formation); Middle Miocene shelf sands and Late Miocene-Early Pliocene shallower shelf sands (Utsira Formation). The latter were formed approximately between 12 and 4 Ma, probably by high-energy marine currents in a relatively shallow and elongate seaway between the deeper Møre Basin to the north and the central and southern North Sea to the south (e.g. Galloway, 2002; Rundberg and Eidvin, 2005; Gregersen and Johannessen, 2007). The palaeogeography of the Late Miocene was, therefore, of a semi-enclosed North Sea (Rundberg and Eidvin, 2005). Except for a condensed Upper Pliocene unit in the southern Viking Graben (Head et al., 2004; Eidvin et al., 2013), the Utsira Formation immediately underlies the Quaternary sediments of the North Sea.

The Utsira sequence extends far beyond the lithostratigraphic limits of the Utsira Formation. It is an unusually sand-rich stratigraphic unit, averaging 35% sand regionally over the North Sea Basin, and 70% sand within the study area (Liu and Galloway, 1997). Descriptions of cuttings and the common subdued gamma-log response indicate that much of the Utsira ‘‘sand’’ is actually clean sandy silt. During Miocene time, the North Sea formed a highly elongated, N-S trending pericratonic basin (Fig. 5.33a) (Ziegler, 1990). It was constricted at its north end to form a relatively narrow strait, called the Viking Strait, between the west Norwegian High and the Shetland High.

There are predictable consequences of the Miocene North Sea Basin setting and geometry. First, the basin lied, as it does still, within the high-latitude North Atlantic winter storm belt. Frequent, intense North Atlantic storms would have set up geostrophic flows along the N-S oriented basin, as well as creating enhanced wave energy with resultant long-shore sediment transport and winnowing, much as occurs along modern North Atlantic shelves (Swift et al., 1986). Secondly, the elongate shape, large area, and constricted connection of the North Sea to the open North Atlantic form an ideal geometry to amplify tidal and other marine currents that must have passed through the Viking Strait (Martinsen et al., 1999). The impact of enhanced Neogene marine circulation is documented by the abrupt return to the southern North Sea of oxygenated bottom waters and calcareous benthic foraminifera, which had been absent since the Early Eocene (Michelsen et al., 1998; Louwye et al., 2000). This paleontologic event records resurgent inflow and mixing of Atlantic waters throughout the seaway. Initial Utsira deposition followed upon the first evidence of glaciation in Greenland (Fronval and Jansen, 1996) and concurrent reorganization of North Atlantic circulation and accelerated exchange between the sub-Arctic ocean with worldwide ocean masses (Wright and Miller, 1993).

(a) (b)

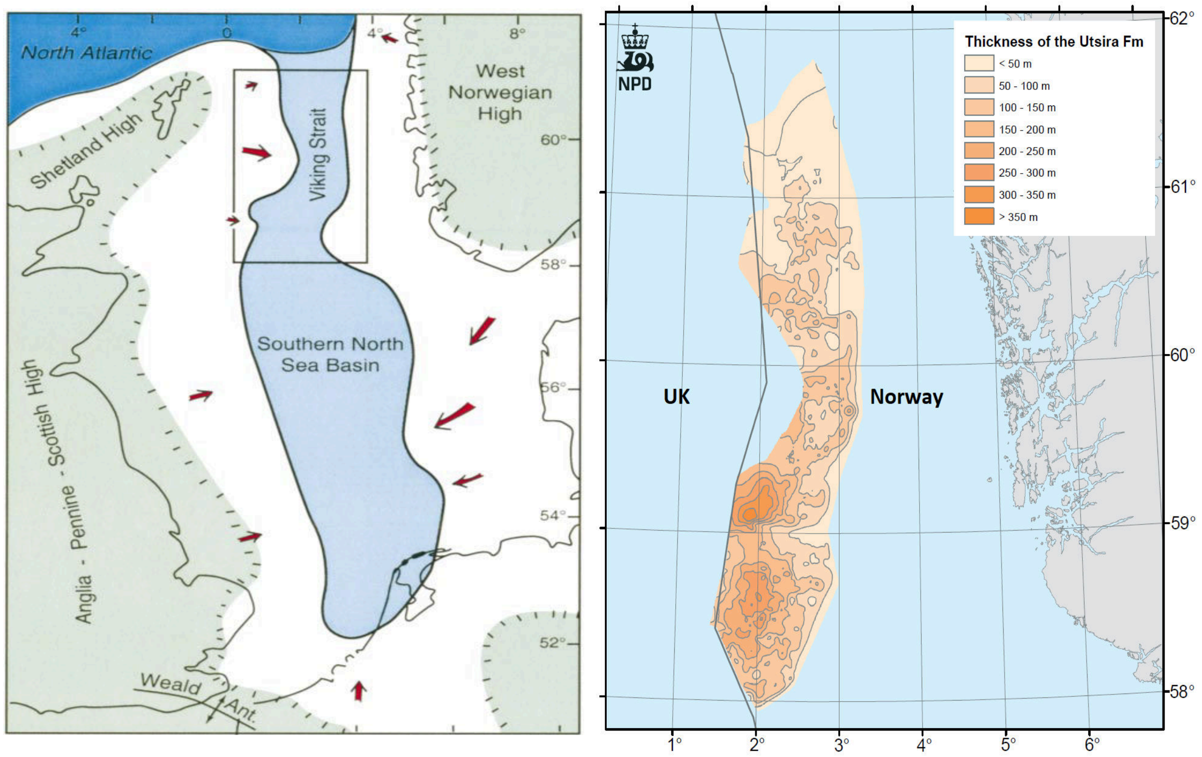


Figure 5.33: (a) Regional Miocene paleogeography of the North Sea area. Arrows indicate inferred avenues of sediment supply. Compiled from Ziegler (1990) and Sørensen et al. (1997); (b) Thickness and extent of the Utsira Formation (from NPD website www.npd.no).

Late Tertiary is characterized by an inversion phase that took place during Late Miocene, resulting in a regional unconformity (e.g. Eidvin et al., 2014) and a change from deep-marine to shelfal conditions. From a petroleum system perspective, such a compressional event had an impact not only on trap generation, but also most likely on hydrocarbon migration patterns by fault reactivation and differential uplift. Following the mid- to late-Miocene uplift of the basin margins, subsidence of the basin took place during Pliocene. This subsidence, together with continued input from European delta systems to the south-east, resulted in the deposition of a large thickness of argillaceous sediments. The re-establishment of the connection to the Norwegian-Greenland Sea led to the appearance of icebergs; consequently the prodeltaic deposits include glaciomarine dropstones (Eidvin et al., 2000). The late Pliocene and early Pleistocene were times of uplift of the old landmasses surrounding the North Atlantic, including Norway and Scotland (Doré et al., 1999). This increased sedimentation in the northern North Sea, while the southern North Sea was being infilled by a major delta complex extending northwards from the Netherlands (Cameron et al., 1992).

The Late Pliocene basin configuration was dominated by the progradation of thick clastic wedges in response to uplift and glacial erosion of eastern source areas (Fig. 4.7). Considerable Late Pliocene uplift of the eastern basin flank is documented by the strong angular relationship and tilting of the complete Cenozoic succession below the Pleistocene unconformity. The Plio-Pleistocene sediments are partly glacial and partly marine in nature representing reworked glacial sediments, and are typically poorly sorted. Such sediments compact readily and periods of glacial advances may contribute to the compaction.

Quaternary

The global climate continued to cool into the Pleistocene, leading to the development of a Scandinavian ice cap. Throughout the remaining time of the Pleistocene, periglacial, glacial and glaciomarine conditions altered with periods of elevated temperature climate in the North Sea. The repeated advance and retreat of Scandinavian and Scottish ice sheets led both to erosion and to depositions of a range of ice-related sediments (Holmes, 1997). In the Norwegian Channel, which was an important glacial pathway to the North Sea Fan (King et al., 1996; Sejrup et al., 1996), there was strong glacial truncation of the underlying prograding sediments (Fig. 5.34).

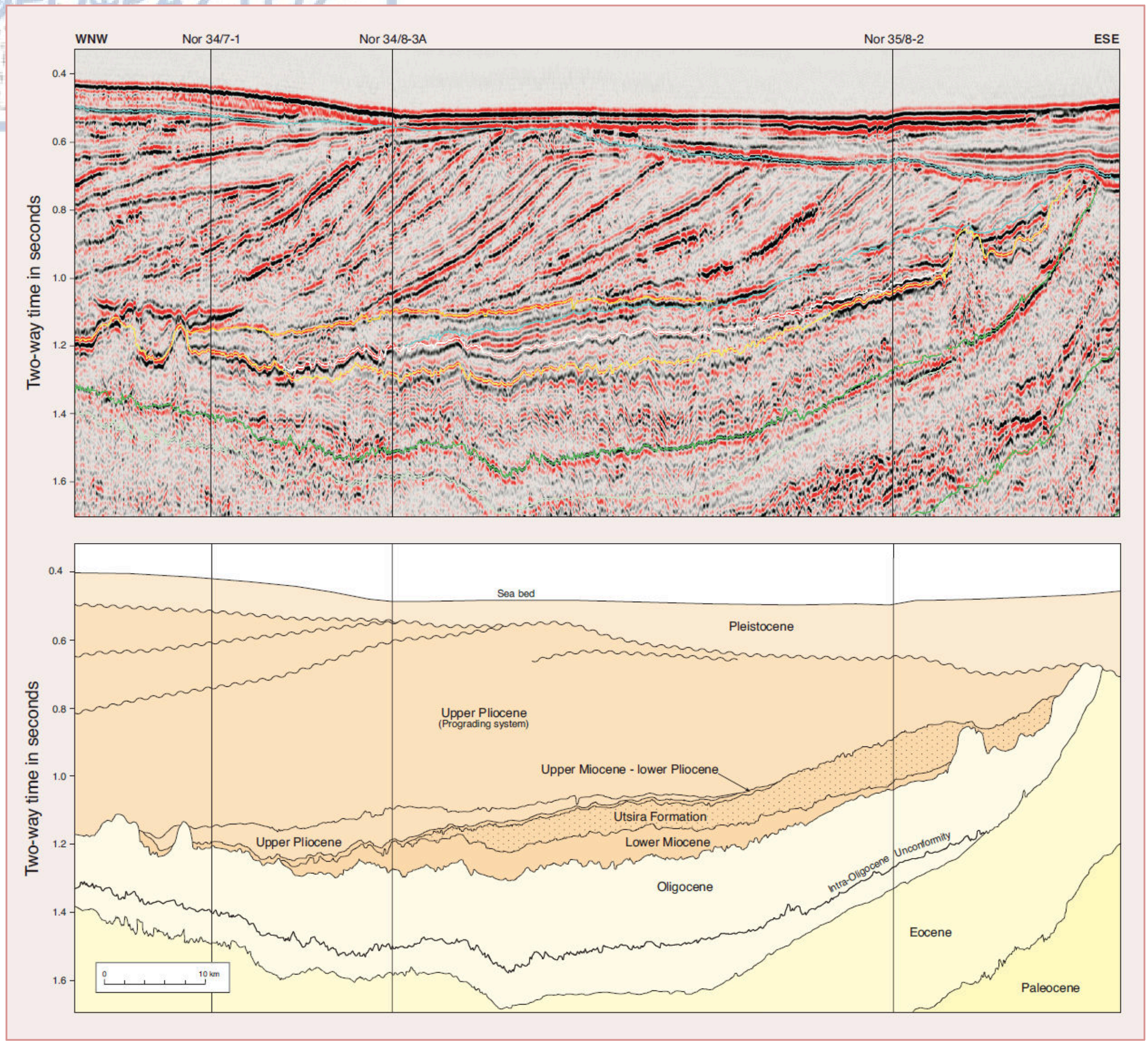


Figure 5.34: Seismic section and interpretation of the stratigraphy from the Norwegian sector of the northern North Sea (Evans et al., 2003).

At most places on the shelf the Holocene (the last 10,000 years) is represented by only a thin layer of silty sediment, mainly reworked from Quaternary or older sediments exposed on topographic highs or along the margins of the North Sea. Very little “new” sediment has been supplied from land during the Holocene. This is because the fjords of the Norwegian mainland act as very efficient sediment traps, collecting the sediment from the rivers. Because fjords are deep but have shallow thresholds, not much clastic sediment reaches the shelf. On the seafloor, there are in many areas frequent depressions which are typically a few tens of metres across and several metres deep. These are called pockmarks and have formed by fluid, generally gas, seeping from deeper layers to emerge at the seafloor. The Cenozoic sedimentation was relatively rapid and the clayey sediments had little time to compact sufficiently to reduce the water content. Some beds, therefore, display plastic folding and diapir structures due to the under-compacted clays, especially in the Eocene. Polygonal faults are also common in these mudstones. They form a network which is from several hundred metres to 1 km across.

The North Sea has been subsiding slowly throughout the Quaternary and contains hundreds of metres of sedimentary fill along its main N-S axis (Gatliff et al., 1994; Riis, 1996). Ice appears to have built up to reach the western coast of Scandinavia from about 2.75 Ma (Jansen and Sjøholm, 1991; Eidvin et al., 2000; Ottesen et al., 2009). The Quaternary basin of the North Sea is largely sediment-filled and is elongate in an approximately N-S direction. The basin is narrowest at about 60º N where the East Shetland Platform extends for 100-150 km east of the Shetland Islands. From this narrowing, the basin widens towards the north into the deep Norwegian Sea. The northern North Sea Basin is filled by more than 1000 m of sediments at the present shelf edge at 62º N (Fig. 5.35). The eastern flank of the basin is cut by the glacially eroded Norwegian Channel (Sejrup et al., 2003).

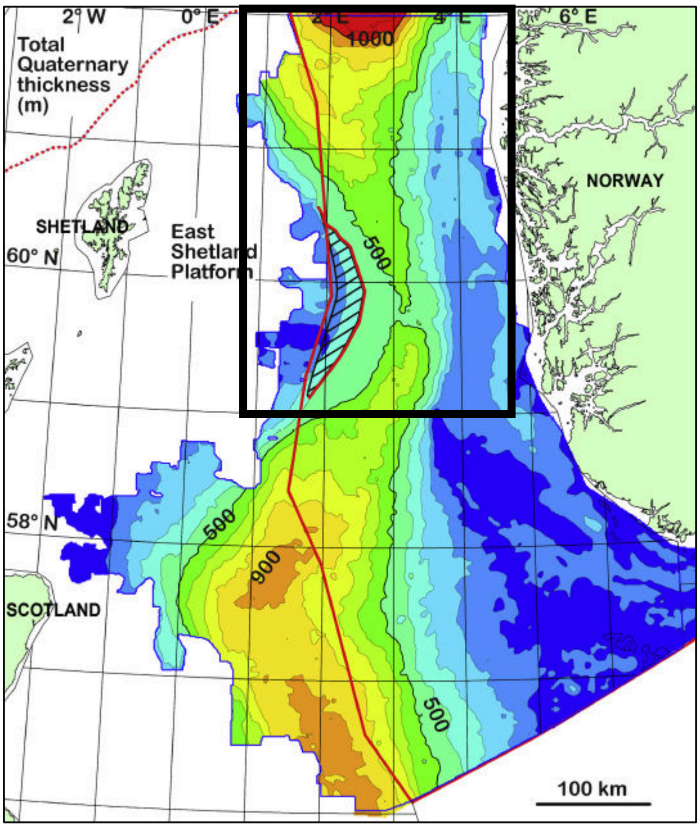


Figure 5.35: Thickness map of the Quaternary sediments in the North Sea Basin (Ottesen et al., 2014). Contour interval is 100 m. A Pleistocene delta mapped along the western side of the basin is marked by black hachuring. Delta front is marked by thick red line. The boundary line between Norway and UK is shown in red. Red stippled line marks the present shelf edge.

Chapter 6
MAIN PETROLEUM SYSTEMS

6.1 PETROLEUM SYSTEM DEFINITION

A petroleum system is a geologic system that encompasses the hydrocarbon source rocks and all related oil and gas and which includes all of the geologic elements and processes that are essential if a hydrocarbon accumulation is to exist (Magoon and Dow, 1994). There are five essential parts for the existence of a hydrocarbon system:

1) Source rock: deeply-buried rock where hydrocarbons are generated.
2) Reservoir rock: porous and permeable rock where hydrocarbons are stored.
3) Trap: an overall geological structure in which hydrocarbons gather and are retained.
4) Cap rock: acting as impermeable seal for the retained hydrocarbons.
5) Migration: the process of relocation of the generated hydrocarbons from the source rock to the reservoir rock over time.

The basic prospectivity elements for hydrocarbon accumulations to be present and trapped are related with the existence of the above-mentioned essential parts, in combination with the appropriate pressure and temperature conditions to ensure their generation. Generation of oil, usually, takes place at depths of 3-6 km below the surface of the earth, in the source rocks, and temperatures must range between 80-140°C. Gas generation, on the other hand, needs higher temperatures, ranging between 120-180°C (Kassinis et al., 2015). Upon burial, organic matter in sedimentary rock undergoes numerous compositional changes that are dictated initially by microbial agencies and later mainly by thermal stress. This continuum of processes is termed thermal maturation and is divided into three consecutive stages (Fig. 6.1a) (R_o, vitrinite reflectance, indicative the thermal maturation level): (i) Diagenesis ($R_o < 0.5\%$), (ii) Catagenesis ($0.5\% < R_o < 2.0\%$) and (iii) Metagenesis ($2.0\% < R_o < 4.0\%$).

Oil and gas are generated by the thermal degradation of kerogen in the source beds. With increasing burial, the temperature in these rocks rises and, above a certain threshold temperature, the chemically labile portion of the kerogen begins to transform into petroleum compounds (McKenzie and Quigley, 1988). Kerogen, the major global precursor of petroleum, consists of selectively preserved organic materials in variable proportions. Kerogen formation is complete by the end of diagenesis. The mode of kerogen formation exerts a strong influence on its structure and bulk composition, and hence on oil- and gas-generating characteristics, during catagenesis. Throughout metagenesis, source rock kerogens are strongly depleted in hydrogen and generated gases consist of methane (dry gas) and sometimes hydrogen sulfide or nitrogen. Nevertheless, original oil potential can sometimes be recognized (Horsfield et al., 1994).

Source rocks of hydrocarbons are organic rocks. Organic rocks are derived from the fossilization of living organic matter (plants and/or animals). Based on their origin, three main types exist (Fig. 6.1b): Type I: Coals, Anthracite, Peat; Type II: Bitumen, Tar; Type III: Kerogen. The organic matter buried in sediments is in a form known as kerogen and source rocks are classified by the types of kerogen that they contain, which in turn determines the type of hydrocarbons that will be generated. Type I source rocks are formed from algae deposited under non-oxidizing conditions in deep lakes, while Type II source rocks are formed from marine planktonic and bacterial remains known as liptinitic kerogens, that are preserved under anoxic conditions in marine environments. Both Type I and Type II are oil generating source rocks. Type III source rocks are formed by decomposition under oxic or sub-oxic conditions, known as humic kerogens and they tend to generate mostly gas.

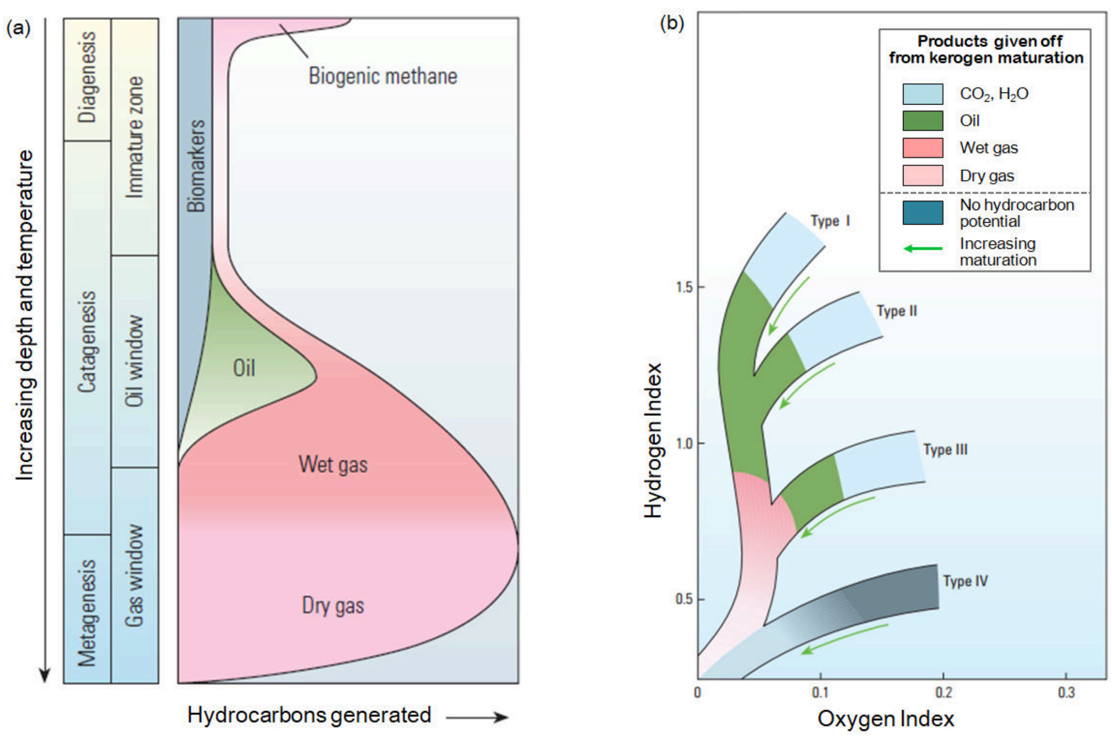


Figure 6.1: (a) Transformation of kerogen (and generated products) with depth of burial; (b) Van Krevelen diagram showing the maturation pathways of kerogen upon burial and associated increase in temperature (modified from McCarthy et al., 2011).

The hydrogen index is a measure of the hydrocarbon generation potential remaining in the kerogen, as opposed to that of the whole rock, and is an indicator of kerogen type. A hydrogen index above 300 mg/g TOC, at the maturation level equivalent to vitrinite reflectance of approximately 0.60%, would indicate that the main pyrolysis product comprises oil and, therefore, that the main maturation product would be also oil. Hydrogen index values less than about 150 mg/g TOC are indicative of gas-prone source potential only; with no significant oil source potential. Hydrogen index values in the intermediate range 150 to 300 mg/g TOC are indicative of potential for both oil and gas. The hydrogen index is analogous to the atomic H/C ratio derived from elemental analysis. Hydrogen index values decrease with maturity, initially by the evolution of water and at higher levels by the expulsion of hydrocarbons.

6.2 PETROLEUM SYSTEMS IN THE NORTHERN NORTH SEA

6.2.1 General characteristics

The main source rocks in the northern North Sea are believed to be Jurassic organic-rich shales (Rønnevik et al., 1983). Shales of Jurassic age are thermally immature on the Horda Platform, whereas in the graben area oil maturity is reached at approximately 3.5 km. The Jurassic in the central part of the graben is at present in the gas window (deeper than 5 km) (Rønnevik et al., 1983). Potential source rocks are found in several formations within the Jurassic. Both the Upper Jurassic (Kimmeridge Clay/Draupne and Heather formations), and the Lower Jurassic (Drake and Burton/Amundsen formations) have the characteristics of potentially rich source rocks for both oil and gas. Based on organic richness and kerogen type, the Kimmeridge Clay/Draupne Formation is by far the 'richest' source rock in the area. Maturity for oil generation was reached during the Late Cretaceous (early maturity at about 71 Ma, peak oil maturity at about 54 Ma) and the northern North Sea has been mature for significant gas generation since about 14 Ma (Fraser et al., 2002). In terms of migration efficiency, the Lower Jurassic and intra-Brent shales may be more effective source rocks due to close juxtaposition with carrier/reservoir beds.

Paleozoic source rocks are predicted to have virtually no economic potential in the study area. In the Mesozoic and Cenozoic section, major source horizons have been developed only during Jurassic (Fig. 6.2). Shales of the Humber Group, which is subdivided into the

Kimmeridge Clay and Heather Formations, and Dunlin Group, and coals of the Brent Group and Statfjord Formation are apparent as potential source horizons. Figure 6.2 also demonstrates the average potential of each horizon, and the local enhancement of source quality is shown in a lighter tone. Total organic carbon (TOC) content is expressed in weight percent, and the hydrogen index (HI) values are representative of immature rocks. The oil and gas fields located in the North Sea are a result of the elements and processes which, combined in time and space, allowed commercial quantities of petroleum to pool (Magoon and Dow, 1994). Figure 6.3 summarizes the relevant source rocks and reservoirs present in the South Viking Graben that are also relevant for the northern North Sea area.

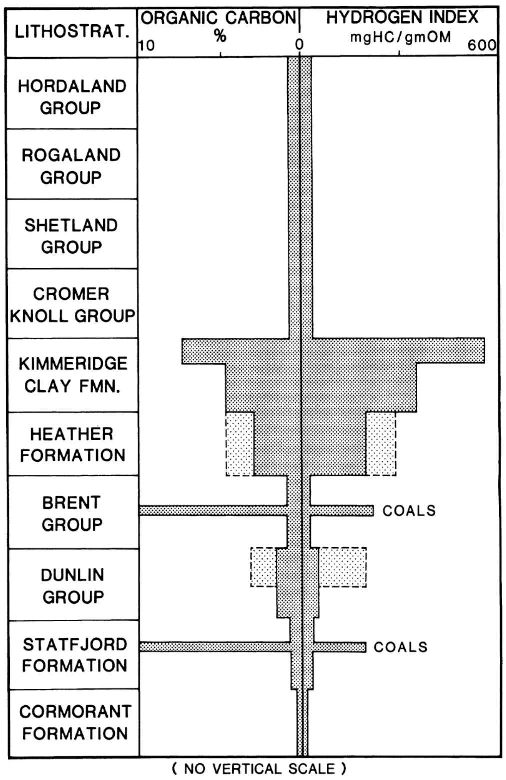


Figure 6.2: Northern North Sea, source potential of Mesozoic and Cenozoic strata (Thomas et al., 1984).

The petroleum found in reservoirs in the North Sea generally has API gravity values around 36-38º, which classifies the petroleum as light. Gas: oil ratio (GOR) values usually range between 20 m^3 m^{-3} and 110 m^3 m^{-3} (Kubala et al., 2003). Sulphur contents are low to moderate, ranging from 0.02% to 0.93%. The average pristane/phytane (Pr/Ph) ratio is about 1.3, indicating Type II kerogen, and a marine siliciclastic source-rock facies. The nickel/vanadium (N/V) ratio is usually around 1 or less, and the $\delta^{13}C$ value varies between -28‰ and -30‰ (Barwise, 1990). The onset of petroleum generation from Jurassic source rocks in the major depocentres was in the late Upper Cretaceous, and generation continued into the Tertiary. Petroleum from the Norwegian North Sea varies in thermal maturity from early mature to late mature, but the majority of oils have a maturity corresponding with the middle part of the oil window (Pedersen, 2002). Oils derived from the Upper Jurassic shales of the North Sea are typically rich in the compound bisnorhopane (Peters and Moldovan, 1993) and are low in gammacerance and carotane (Grantham et al., 1980; Bailey et al., 1990).

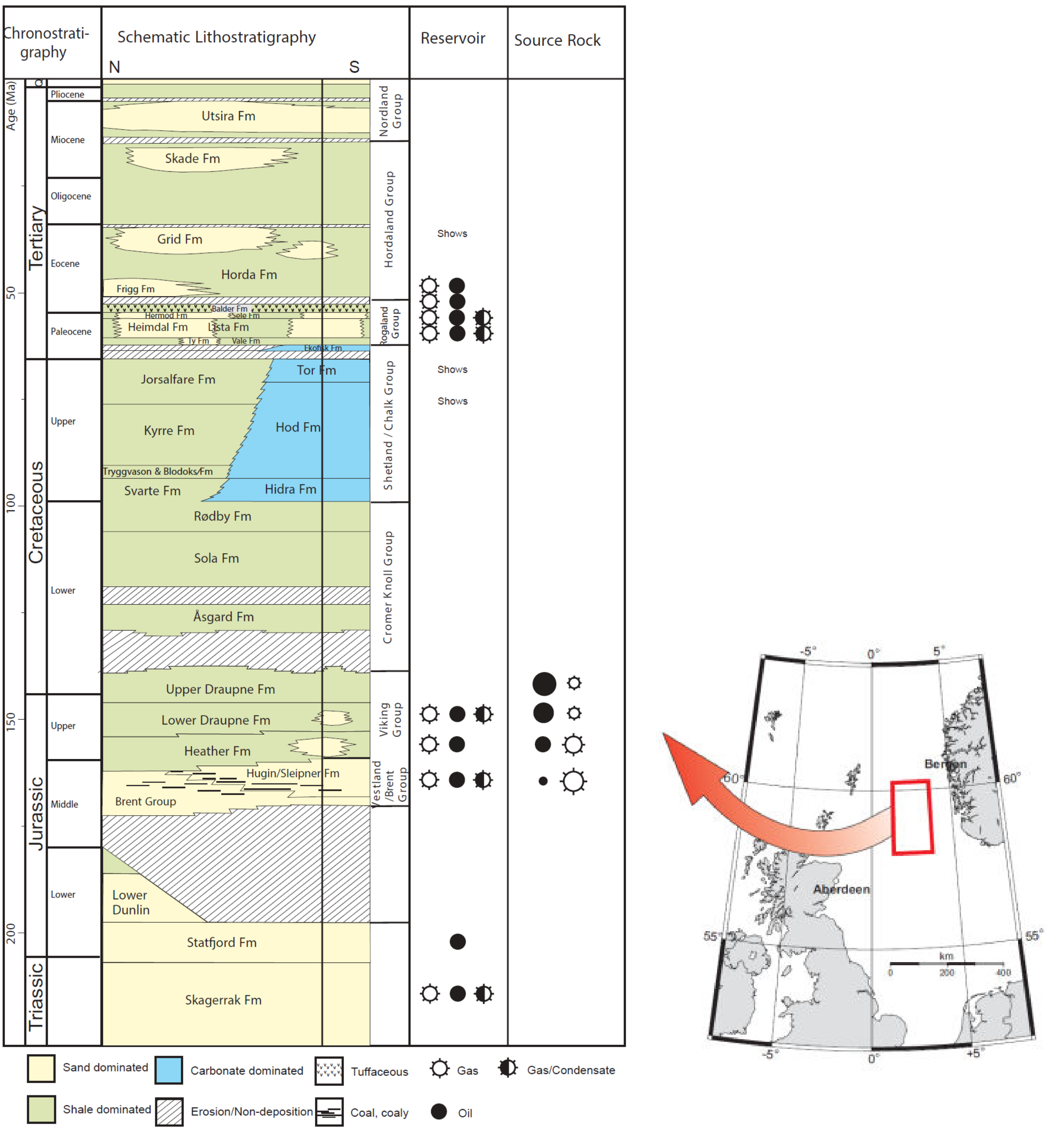


Figure 6.3: Generalised stratigraphic column for the South Viking Graben. Stratigraphic intervals containing source or reservoir rocks are indicated. Principal hydrocarbon type in the reservoirs and principal hydrocarbon products generated from source rocks are indicated by symbols. The symbol size for the source rock products indicates the dominating product. (modified from Justwan, 2006).

6.2.2 Carboniferous

Unlike the southern North Sea where Upper Carboniferous coals provide the main source for the discovered gas-fields, the Carboniferous of the central and northern North Sea has hitherto proven to be of limited economic importance, primarily due to the apparent lack of coal-bearing strata. The Carboniferous Coal Measures, which are thick and economically important as natural-gas source rocks in the southern North Sea, are relatively thin and poor in organic matter in the Central Graben and are largely absent in the Viking Graben.

6.2.3 Lower Jurassic

In the East-Shetland Basin and the Viking Graben, the Dunlin Group is organically lean (Goff, 1983). However, the Drake Formation may locally contain effective source rocks in the Oseberg area (Thomas et al., 1985). Mudstones within the lower and middle parts of the Dunlin Group have organic carbon contents around 1%, predominantly made up of inertinite, while mudstones within the Drake Formation have organic carbon contents of around 2% but contain only minor amounts of sapropelic kerogen.

The thickness, distribution, paleogeography and kerogen-type distribution of the Dunlin Group (Field, 1985) suggest that organic facies are related to sedimentary facies. The marginal-marine lithologies are dominated by terrestrially derived type III/type IV kerogens of vitrinitic and intertinitic composition with an average organic carbon content of around 1.5% and only poor gas-source potential. Shales and siltstones deposited in deeper water, open marine parts of the basin centre have higher organic carbon contents with large up to 3% (Brosse and Huc, 1986), with pyrolysis hydrogen indices up to around 200 mg/g TOC. The latter also contain mixed kerogens of vitrinitic and amorphous sapropelic types (type III/type II), and may have some oil- and gas-source potential in the Norwegian part of the Viking and Sogn grabens. The basin-margin shales have only minor gas source potential. The basin-centre shales have gas and oil source potential in the Møre Basin, the North Viking and Sogn grabens, and possibly in the undrilled Stord Basin.

6.2.4 Middle Jurassic

The Ness Formation is inhomogeneous and comprises interbedded sandstones, mudstones and coals. It is a coastal plain deposit with widespread lagoonal and fluvial developments (Miles, 1990). This formation is part of the Brent Group and the coal within this group is believed to be important source for gas generation. According to the study of Schroeder and Sylta (1993), coals within the Brent Group contain terrestrial organic matter and they are believed to generate only gas. In addition, the richest source rocks in the Viking Graben are the oil-prone Draupne (Kimmeridge Clay) Formation and the gas-prone Brent Group coals and coaly mudstones (Goff, 1983). Gas accumulations are likely to be sourced from the Draupne Formation, and additionally from coal-bearing intervals within the Brent Group which become gas mature during the Oligocene (at about 27 Ma) (Kubala et al., 2003).

The coal-bearing sequences exhibit TOC up to 45% (Oudin, 1976) and high hydrogen index values in the range of 200-250 mg/g TOC (Durand and Paratte, 1983; Ungerer et al., 1984). Oudin (1976) reports that the heavy, alkane-deficient oil of well 3/15-2 (UK sector) exhibits good correlation with extracts of Middle Jurassic carbonaceous beds based on mass-spectometry and gas-chromatography techniques. The upper boundary is the change to the more massive and cleaner sandstones of the overlying Tarbert Formation (Fig. 6.4). The formation is interpreted to represent delta plain or coastal plain deposition. The amount of silt and mudstones in the formation may act as a local seal. The Ness Formation shows large thickness variations ranging from 26 m up to about 140 m.

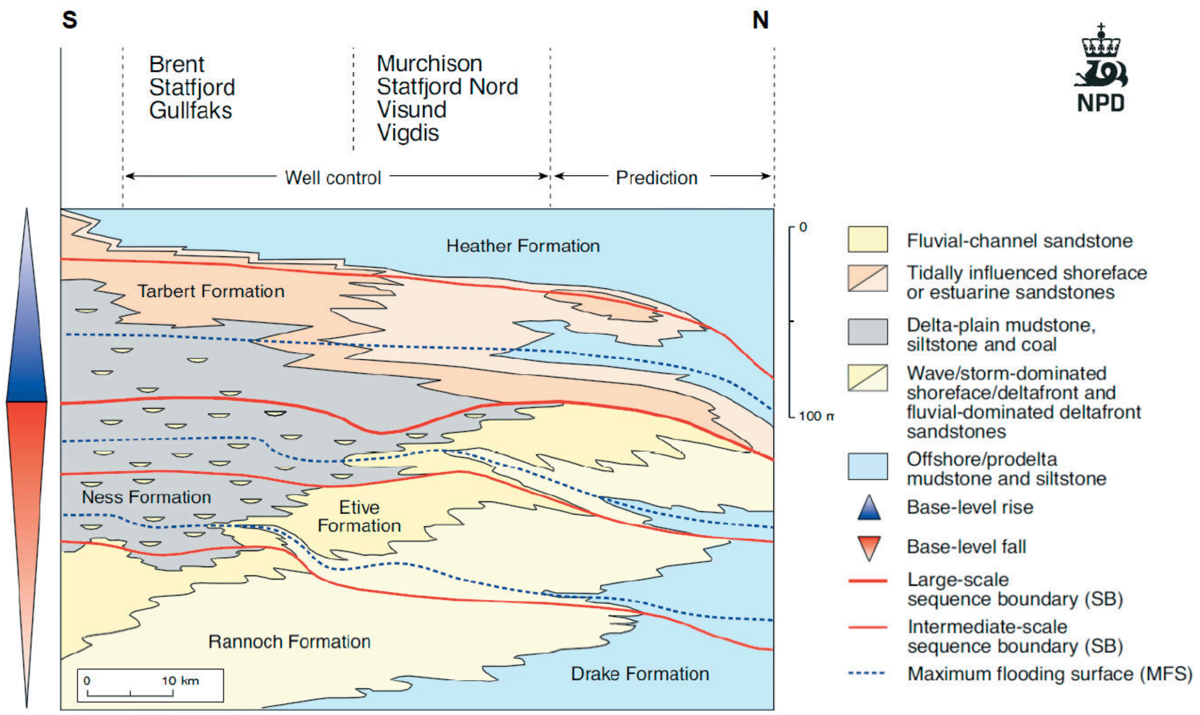


Figure 6.4: Relative position of producing fields on the Brent Group delta (from NPD website www.npd.no).

6.2.5 Uppermost Middle to lower Upper Jurassic

The Heather Formation is Bathonian to latest Oxfordian in age (Fig. 6.3) and is therefore partly of Middle Jurassic age. The formation is distributed widely across the Central and Northern North Sea and consists of up to 700 m of marine mudstone with sporadic thin stringers or concretions of limestone and localised bodies of mass-flow sandstone (e.g. Bruce, Freshney and Ling sandstone members), shallow marine spiculitic sandstone (e.g. Alness Spiculite Member) and paralic mudstone (e.g. Gorse Member); local syn-rift depocentres accommodate more than 1000 m in the Viking Graben. Although it is commonly perceived as representing shelf facies, the Heather Formation also includes mass-flow sandstones of slope or basin association. By earliest Callovian times, marine mudstone deposition (Heather Formation) covered much of the northern North Sea. Later, deposition spread farther south into the southern Viking Graben and the Inner Moray Firth Basin. Some turbiditic sands of latest Callovian age were deposited in the southern Beryl Embayment and northern Viking Graben, forerunners of the processes that were going to dominate during Late Jurassic.

The Heather Formation comprises dark grey, commonly silty mudstones with abundant interbedded carbonate bands; the mudstones tend to be more calcareous than the overlying Kimmeridge Clay Formation. The boundary between the Kimmeridge Clay and the Heather formations is based on lithology or on wireline-log characteristics, and is not necessarily sharp or isochronous. The logs in Figure 6.5 illustrate the petrophysical properties of the Upper Jurassic source rocks from the UK-sector well 211/16-3. Note the high gamma-ray, low density, high neutron-porosity, high resistivity and low sonic-velocity values over the organic-shale interval. It is possible to calibrate the logs using geochemical data so that source intervals can be identified in wells where no analytical data are available. Long sonic-transit times and low densities are typically related to high organic-carbon contents. High neutron response is related to the content of organic material and also to the relatively high hydrogen content of type II kerogen up to early to middle maturity.

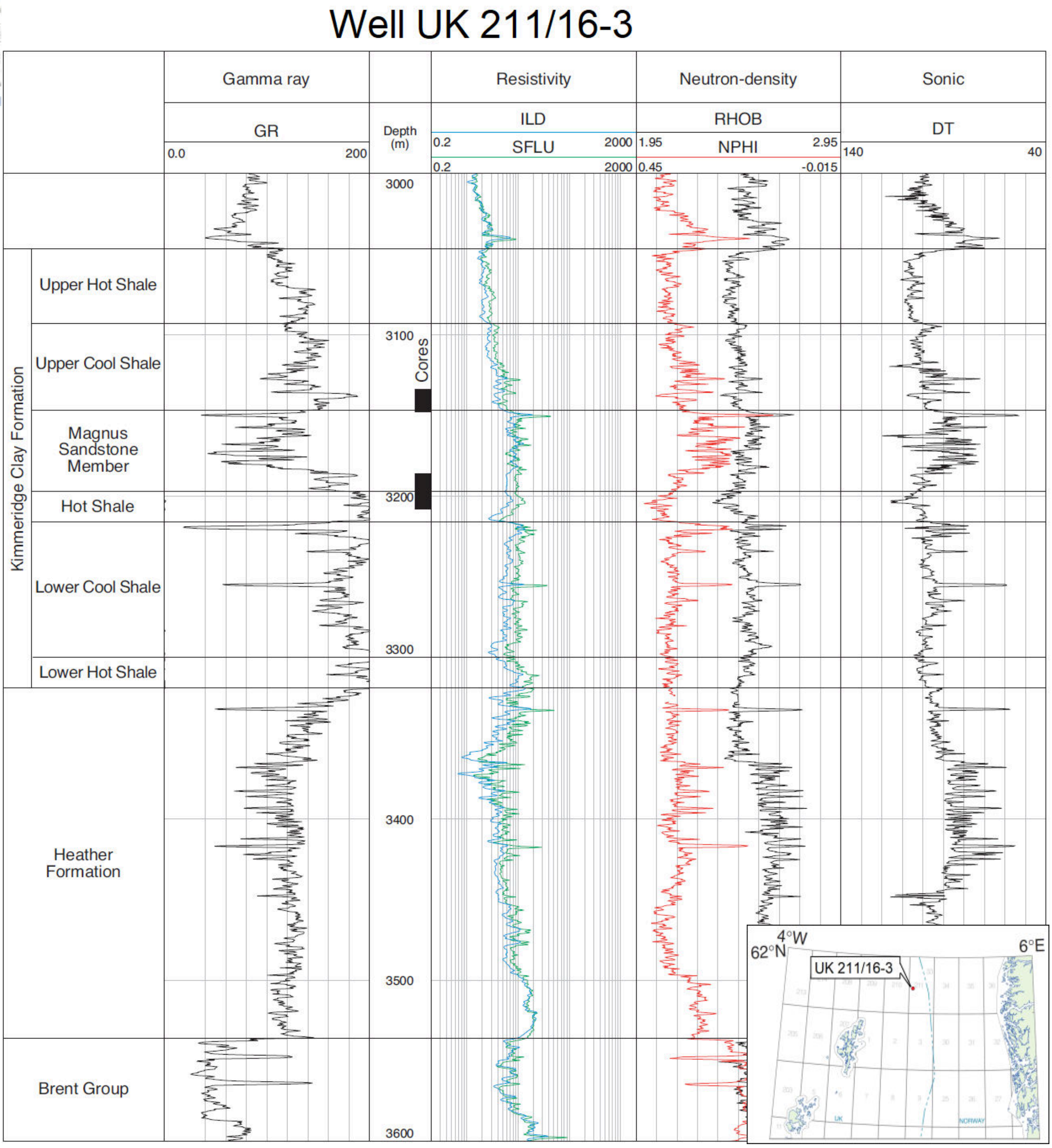


Figure 6.5: Wireline-log curves from UK-sector well 211/16-3 (Evans et al., 2003).

TOC contents of mudstones within the Heather Formation are typically lower than in the Kimmeridge Clay Formation, at around 2-2.5% (Goff, 1983; Field, 1985; Brosse and Huc, 1986). Pyrolysis hydrogen indices are similarly lower, associated with a greater proportion of terrestrially derived, humic kerogen of vitrinitic and intertinitic composition. Organic carbon contents exceed 4% in a limited number areas and exceed 7% only locally within the southern part of the Southern Viking Graben. Pyrolysis hydrogen indices are above 200 mg/g TOC in some areas but rarely exceed 300 mg/g TOC. They are commonly in the range 100-200 mg/g

TOC but may be less than 100 mg/g TOC, mainly along the axial regions of the North Viking and Central Grabens where the Heather unit is at a late- to post-mature stage for oil generation. In the East Shetland Basin, sub-basins with restricted circulation developed during the late Callovian to early Kimmeridgian, resulting in the deposition of mudstones with hydrogen indices of up to 300 mg/g TOC (Field, 1985). On the Horda Platform, some mudstones of the Heather Formation can be organically rich with significant source potential, as indicated by organic carbon contents of around 4% and pyrolysis hydrogen indices of around 300-400 mg/g TOC (Fig. 6.6). This source-rock interval shows only a slightly enhanced gamma-ray response compared to overlying and underlying organically leaner mudstones, but is readily recognised from the combination of porosity-log and resistivity response.

Oils derived from the Kimmeridge Clay and Heather formations were differentiated by Gormley et al. (1994). Oils derived from the Kimmeridge Clay Formation are characterised by pristine/phytane ratios in the range 1.0 to 1.5 and carbon isotope ratios in the range -28 to -31‰, whereas oils and condensates derived from the Heather Formation are characterised by higher ratios in the range 2.15 to 4.0, and heavier carbon-isotope ratios in the range -25 to -28‰. The source-rock interval within the Heather Formation attains middle maturity for oil generation in areas where a generally thicker and organically richer source-rock interval within the Kimmeridge Clay Formation is marginally mature or immature. Furthermore, the Heather Formation is widely distributed and forms a control on migration into both Middle and Upper Jurassic sandstones. On the Horda Platform and at the flanks of the adjacent North Viking Graben, reservoirs within the Middle Jurassic contain hydrocarbons with characteristics indicative of Heather Formation source rocks. Reservoirs within the Upper Jurassic are in contact with both the Kimmeridge Clay and Heather formations, and hydrocarbons trapped at this level may reflect a mixture from both sources (Gormley et al., 1994).

6.2.6 Upper Jurassic to Lower Cretaceous

Source rock facies

Late Jurassic represents a crucial period during which the most important North Sea source rock, the Kimmeridge Clay/Draupne Formation, was deposited (Fig. 6.3). The Kimmeridge Clay Formation is the main hydrocarbon source rock unit in the North Sea area but the Heather Formation can be as important in certain restricted areas and possibly of greater potential in the northern extreme of the Viking Graben and in the Sogn Graben. The thickness of the Kimmeridge Clay Formation varies from less than 50 m over platform areas to greater than 1250 m in grabenal depocentres (Bernard and Bastow 1992), but the Heather Formation is thicker and the combined thickness reach maximum values of about 1000 m in the Viking Graben and over 2000 m in the Central Graben. Kerogen contents in the northern North Sea for the Kimmeridge Clay Formation vary from purely sapropelic, usually type II, to mixtures of types III and IV (Thomas et al., 1985). The widespread Kimmeridge Clay Formation is Kimmeridgian to late Ryazanian in age. It comprises highly organic-rich, marine mudstone with local bodies of mass-flow sandstone (e.g. Burns, Claymore, Magnus and Ribble sandstone members). These sediments were deposited in a restricted marine embayment of the Boreal seaway in the north, resulting from crustal stretching and formation of the three main North Sea grabens (Cornford and Brookes, 1989; Cooper et al., 1995; Erratt et al., 2010). Sediment accumulation followed the widespread subsidence that occurred during the Late Jurassic to Early Cretaceous rifting episodes. Concomitant global sea-level rise led to the Late Jurassic marine transgression event, resulting in the Oxfordian Heather Formation, comprising of organic-lean mudstones deposited under oxic bottom water conditions. With the closing of the Boral-Tethyan connection, high sedimentation rates, elevated organic matter productivity (probably controlled by nutrient supply) and increased water depths all promoted stratified anoxic bottom waters. With greatly improved organic matter preservation, this resulted in the deposition of the thick, organic-rich Kimmeridge Clay Formation (Cornford and Brookes, 1989; Tyson, 2004).

According to Fraser et al. (2002), the Kimmeridge Clay Formation in the northern North Sea typically has TOC contents around 6% locally reaching values in excess of 10% and can be as low as 2%. Pyrolysis hydrogen indices vary considerably depending upon kerogen composition. Type II amorphous kerogens may have pyrolysis hydrogen indices of up to about 600 mg/g TOC (Fig. 6.6). Mixed type II/type III kerogens may have pyrolysis hydrogen indices in the general range 200 to 400 mg/g TOC. Organically lean, thermally immature mudstones within the Kimmeridge Clay Formation typically have TOC contents of around 2% and generally have limited source potential, mainly for gas. Pyrolysis hydrogen indices are typically around 150 mg/g TOC, indicative of type III kerogens of vitrinitic and intertinitic composition. Figure 6.6 represents a simple summary of data from several hundred analysed wells.

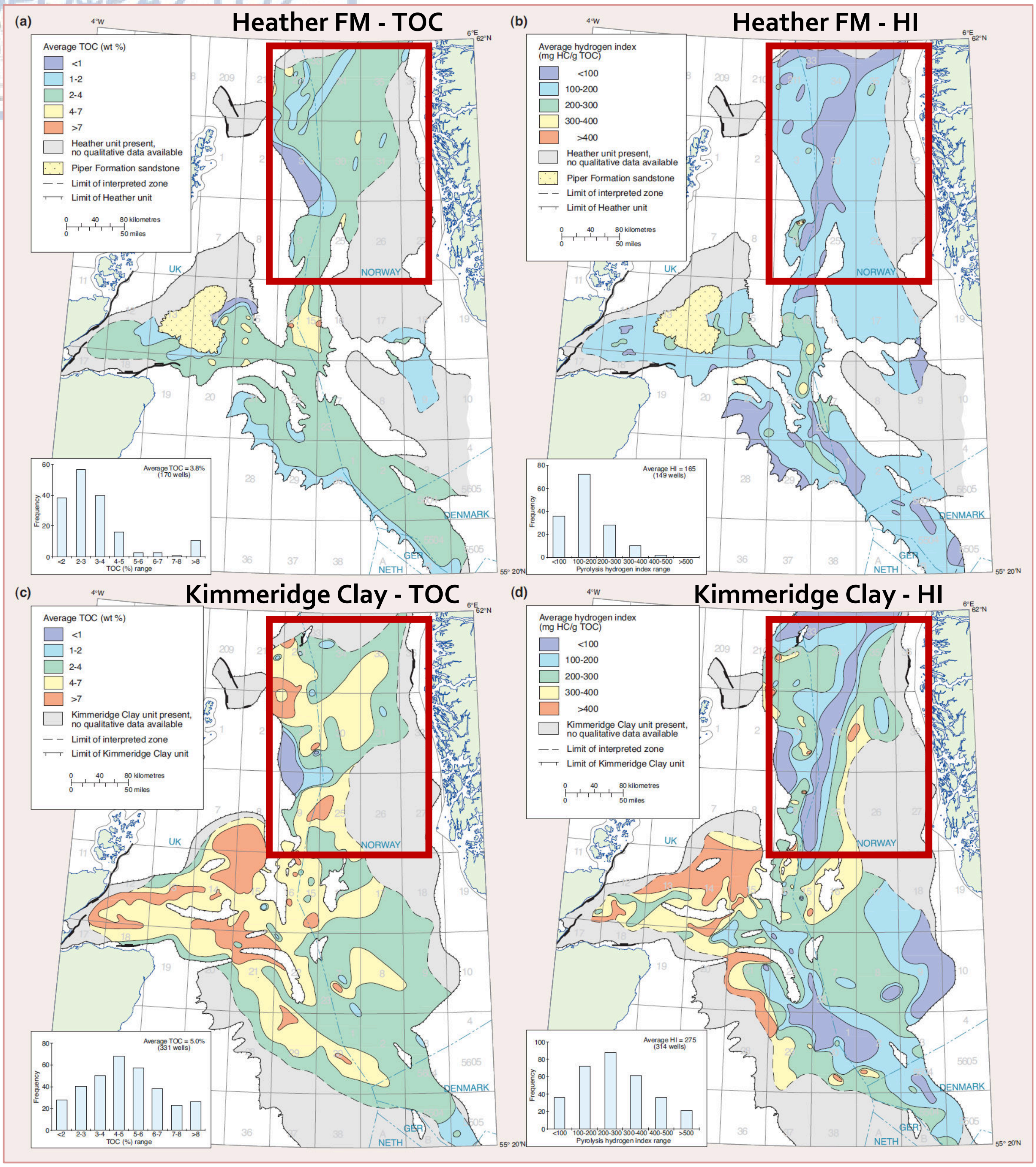


Figure 6.6: TOC and hydrogen index (HI) maps of the Kimmeridge Clay and Heather formations (Evans et al., 2003).

A variably high gamma signature, due to high uranium content, is characteristic of this formation and has led to the term 'hot shale' being applied to uranium-rich units of source rock within the formation. The uranium was probably adsorbed onto the enclosed organic matter during deposition on a stagnant sea floor (Bjørlykke et al., 1975). The organic component of the Kimmeridge Clay Formation is derived from both land and marine environments and there is general agreement that the organic-rich sediments within the formation were deposited under anoxic conditions, where a lack of bottom feeding organisms and aerobic bacteria resulted in preservation of oil-prone material. Within the graben areas, deposition of the source rock probably occurred below wave base and beneath about 200 m or more of water (Cornford, 1998). The maturity of the Upper Jurassic mainly reflects the amount and timing of Neogene to recent sedimentation (Fig. 6.7) (Cornford, 1998).

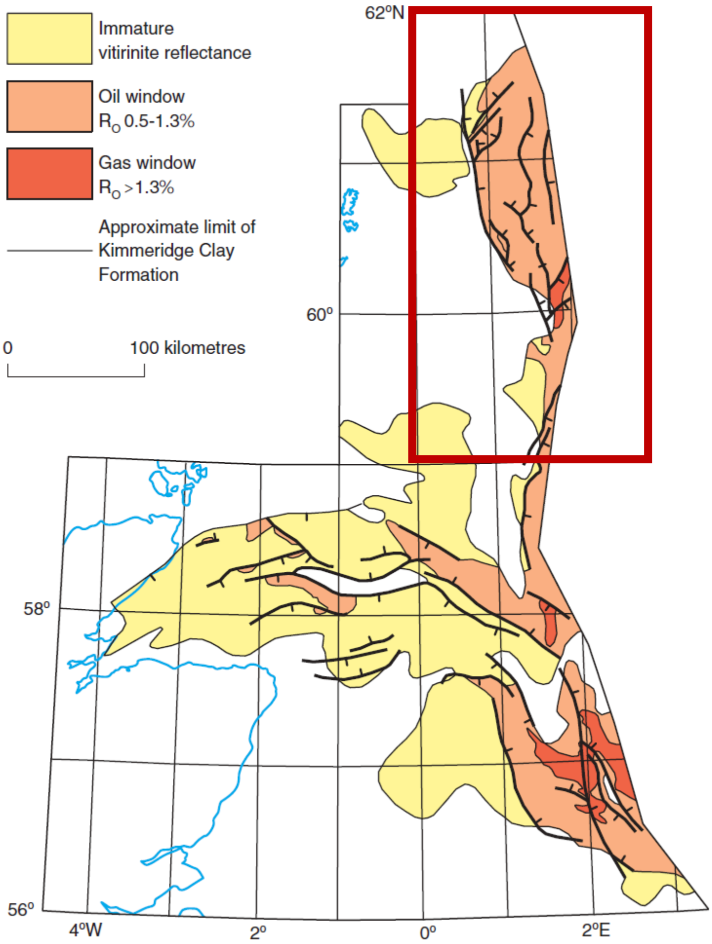


Figure 6.7: Approximate thermal maturity at top Kimmeridge Clay Formation (after Goff, 1983; Field, 1985; Cayley, 1987).

The importance of the Draupne Formation as a source rock becomes clear when looking at the estimated hydrocarbon yield potential (S2) of ~80 litres of oil being generated from 1m³ of source rock (Throndson and Karlsson, 1986b). Generally, hydrocarbons have migrated up dip from deeply buried source rocks and into adjacent traps. The composition of the kerogen, together with the thermal maturity of the source, are factors in determining the composition of derived hydrocarbons now entrapped in adjacent fields (Fisher and Miles, 1983), though expulsion efficiencies are perhaps the main control on the gross gas/oil ratio of the total expelled product (Cornford, 1998). As shown in Figure 6.8 the petroleum system responsible for nearly all the discovered resources is derived from an Upper Jurassic source rock.

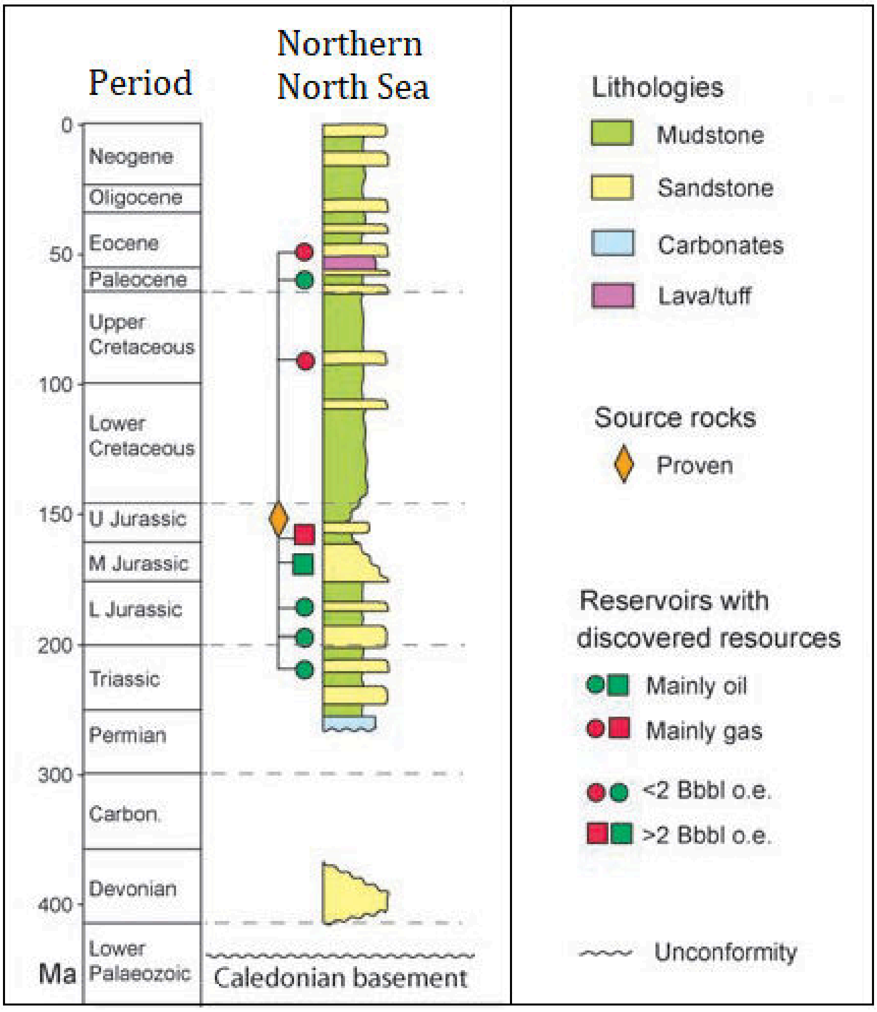


Figure 6.8: Stratigraphy of the northern North Sea, indicating the source rocks, reservoirs and resources. (modified from Harland et al., 1997; Evans et al., 2003; Henriksen, 2005; and Ramberg et al., 2006).

Maturity

The Kimmeridge and Heather formations can be found at depths of 3000-3500 m in the northern Viking Graben. In addition, the coaly beds in the Brent Group sandstones and the Early Jurassic shallow-marine shales are also good source rocks (under 4000 m). The best reservoirs are the Late Jurassic Brent Group deltaic sandstones, and the deep-marine sandstones interbedding the organic-rich Heather Formation (between 3300-4500 m). The seal rocks of the study area are the Jurassic deep marine shales. As a result, the largest accumulations are observed in the Brent Group deltaic sandstones sealed by the Jurassic

Heather Formation shales. Figure 6.9 shows a general event chart of the petroleum system across the northern Viking Graben area.

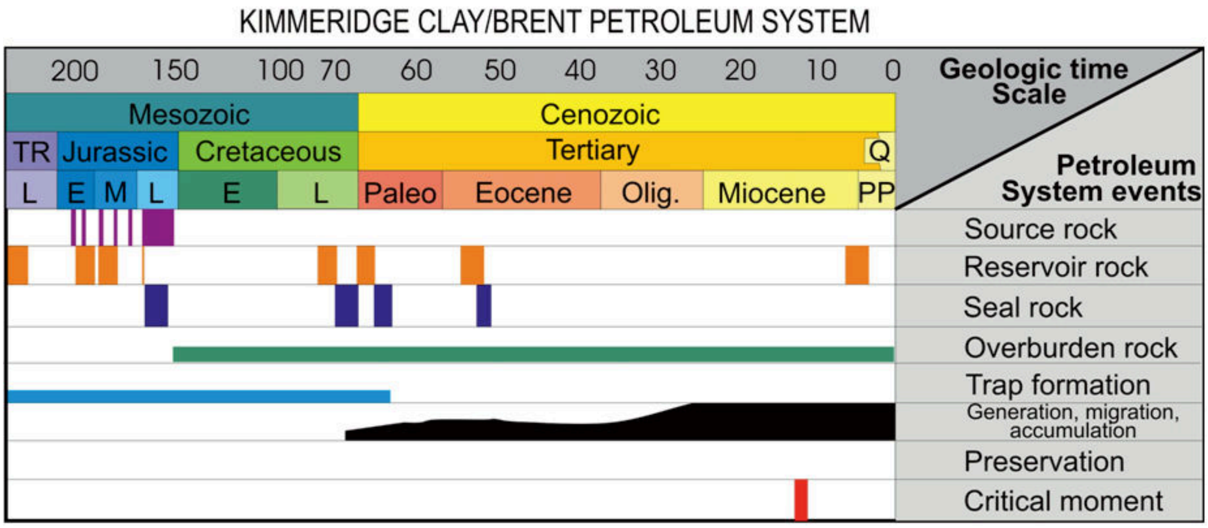


Figure 6.9: Event chart of the Kimmeridge Clay/Brent Group petroleum system. Jurassic: coaly sediments (Hettangian-Bajocian) and anoxic marine shales (Bathonian-Berriasian) and T3, J, C2, Pc, E, M source formations reservoir (Schlakker et al., 2012).

In general throughout the northern North Sea area, a temperature of 100º C corresponds to a vitrinite reflectance (R_o) of about 0.5% and rocks at this level or shallower are considered thermally immature for hydrocarbon generation. The map in Figure 6.10 is based upon a large number of data sources but the procedures followed in the compilation of regional maturity maps are compatible. Vitrinite reflectance values posted at well locations were contoured using depth-structure maps to guide contouring, particularly in areas of sparse well control. Mapped horizons rarely coincide with sample depth intervals for which measured vitrinite reflectance values are available, and values for the mapped horizons are obtained by interpolation between available data points on depth plots of vitrinite reflectance in each well.

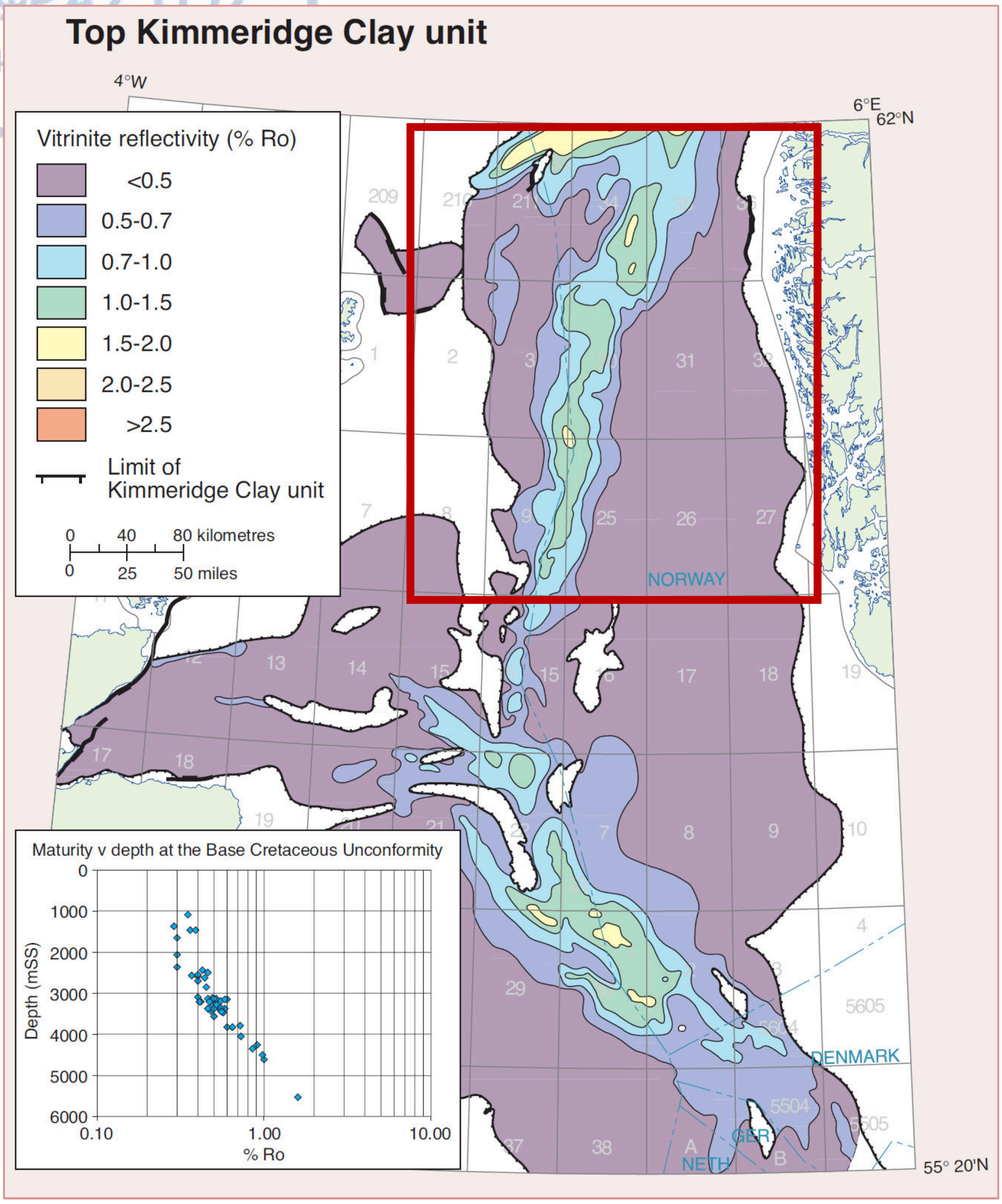


Figure 6.10: Vitrinite reflectance map of the Kimmeridge Clay Formation (Evans et al., 2003).

The Callovian to Oxfordian age Heather Formation is usually gas-prone over large areas of the North Sea, but it shows large variations in TOC, kerogen type, and thickness (Goff, 1983; Field, 1985; Thomas et al., 1985). According to Justwan et al. (2005), the Heather Formation is more organic rich and oil-prone in the central part of the Viking Graben than in the southern or northern areas. The Heather Formation is overlain by the upper Oxfordian to Berriasian Draupne Formation, which is the equivalent of the Kimmeridge Clay of the UK sector of the North Sea (Vollset and Dore, 1984). The Draupne Formation has significant lateral and vertical variations in organic richness and quality. Earlier studies (Cornford et al., 1986) stated that the amount and quality of kerogen decreases toward the graben flanks. Later studies (Justwan and Dahl, 2005; Justwan et al., 2005) indicated a more complex pattern, highlighting the significance of the dilution effects of mass flows. The measured TOC data (from cuttings) and calculated TOC log in the Draupne Formation section in well 25/5-2 are shown in Figure 6.11a, using the sonic and resistivity logs using the method of Passey et al. (1990).

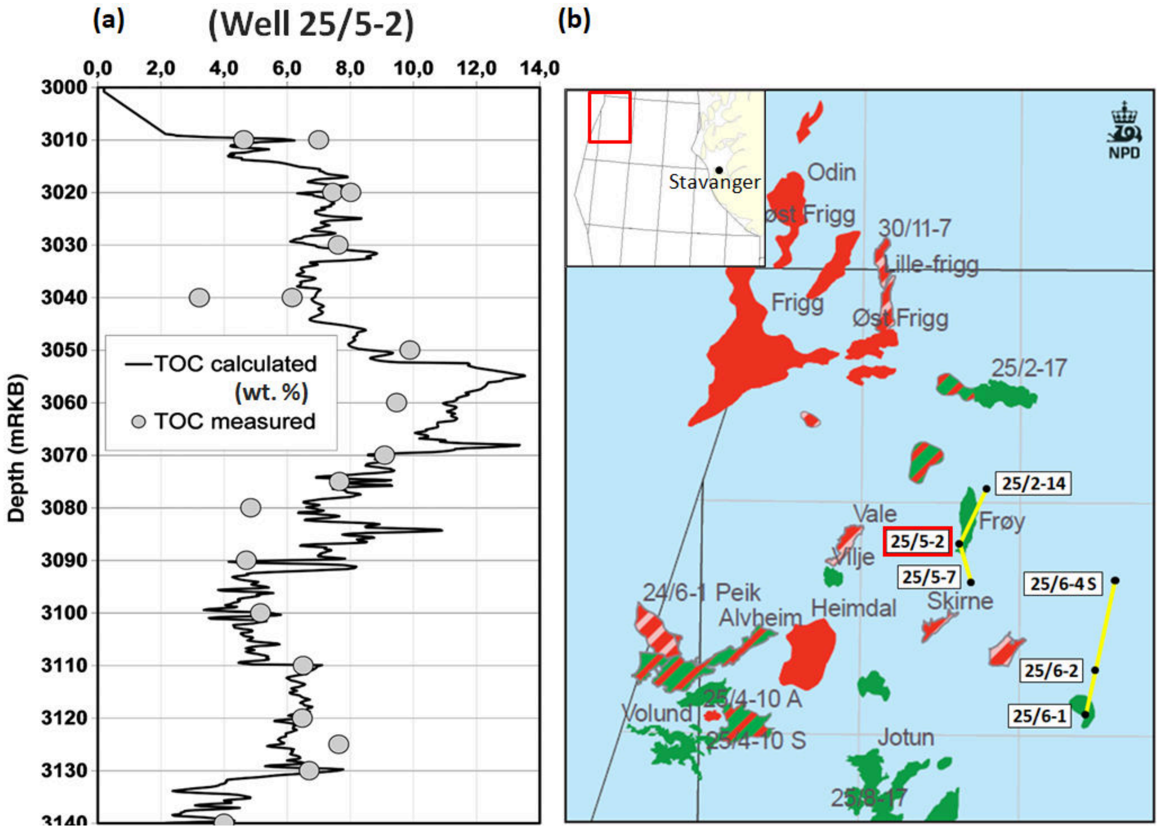


Figure 6.11: (a) Measured TOC data (cuttings) and calculated TOC log in well 25/5-2 obtained from the use of sonic and resistivity logs using the method of Passey et al. (1990). This section focuses only on the Draupne Formation (3008-3131 m RKB) (Badics et al., 2015); (b) Location map of the seismic composite transects showing in Figures 6.12 and 6.13.

Well-log and reflection seismic responses

A general characteristic of the top and base of the Draupne Formation is a marked increase in the gamma-ray (GR) log, particularly at its base. This is best observed on wells 25/6-1, 25/6-2, and 25/5-7. However, this is not always so clear and in such cases needs verification from cuttings, core, and any log data available. Figure 6.12 shows the Draupne Formation section in wells 25/6-1, -2, and 25/6-4 on the Utsira High, where it is most condensed, resulting in a high GR response. The highest GR peak reaches 300-350 API exactly, where the base Volgian or middle Volgian stage appears in the wells (2253 m in well 25/6-1, 2300 m in well

25/6-2, and 2775 m in well 25/6-4). The absolute maximum of approximately 450 API is observed in well 25/6-4. This corresponds to the base of the upper Draupne Formation, as described by Kubala et al. (2003) and Justwan et al. (2005).

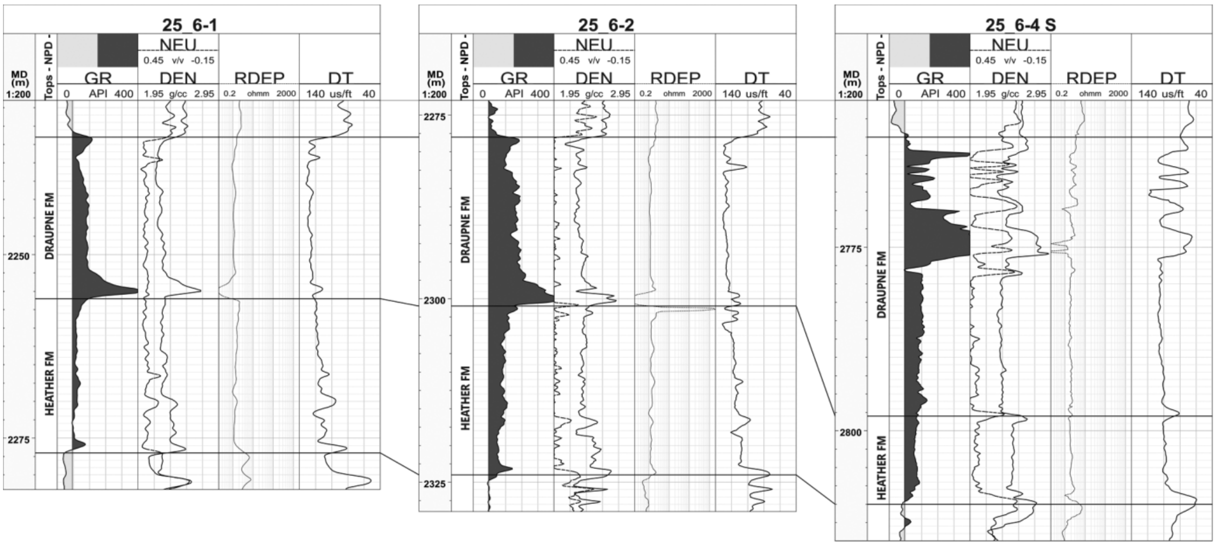


Figure 6.12: Petrophysical well correlations showing Draupne and Heather formations in wells 25/6-1, 25/6-2 and 25/6-4, from southwest to southeast (Badics et al., 2015). Well correlation-panel location in Figure 6.11.

On the other hand, Figure 6.13 illustrates wells 25/5-7, 25/5-2, and 25/2-14 in the Frøy Field area, where the Draupne Formation is much thicker.

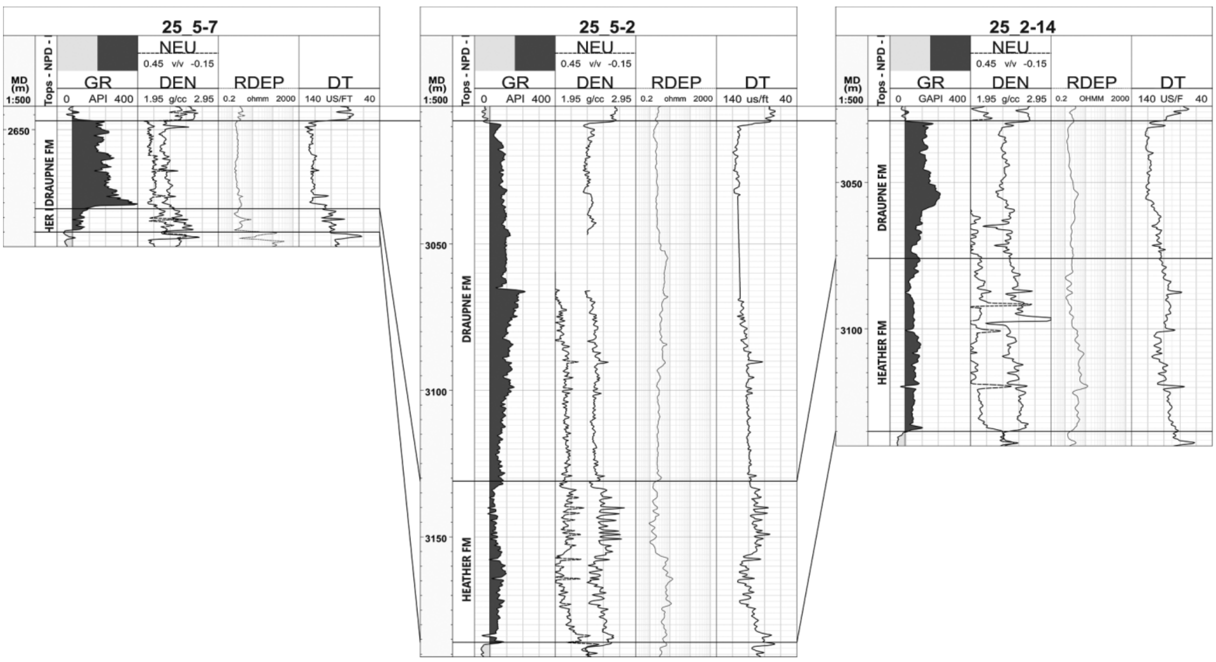


Figure 6.13: Petrophysical well correlations showing Draupne and Heather formations in wells 25//5-7, 25/5-2 and 25/2-14, from southwest to southeast (Badics et al., 2015). Well correlation-panel location in Figure 6.11.

The Base Cretaceous Unconformity (BCU) represents the Top Draupne reflector in basinal settings and a composite erosional surface over basement highs in areas in which the Draupne and Heather formations are eroded (Fig. 6.14b). The Top Draupne reflector exhibits a very prominent decrease in acoustic impedance (negative amplitude) and a continuous reflection character in the area (Fig. 6.14c). In the Southern Viking Graben, the upper Draupne Formation is often found to rest directly on the Heather Formation on highs in the area (Justwan and Dahl, 2005; Justwan et al., 2005). The weak amplitude areas on the intra- and base Draupne reflections showed where these reflections have low amplitudes, and they are therefore difficult to interpret. The base Draupne Formation horizon was particularly difficult to map on the western, deeper part of the area, and the thickness uncertainty is therefore largest here. The wells in the west show a more steady increase and decrease in radioactivity throughout the entire Draupne Formation section.

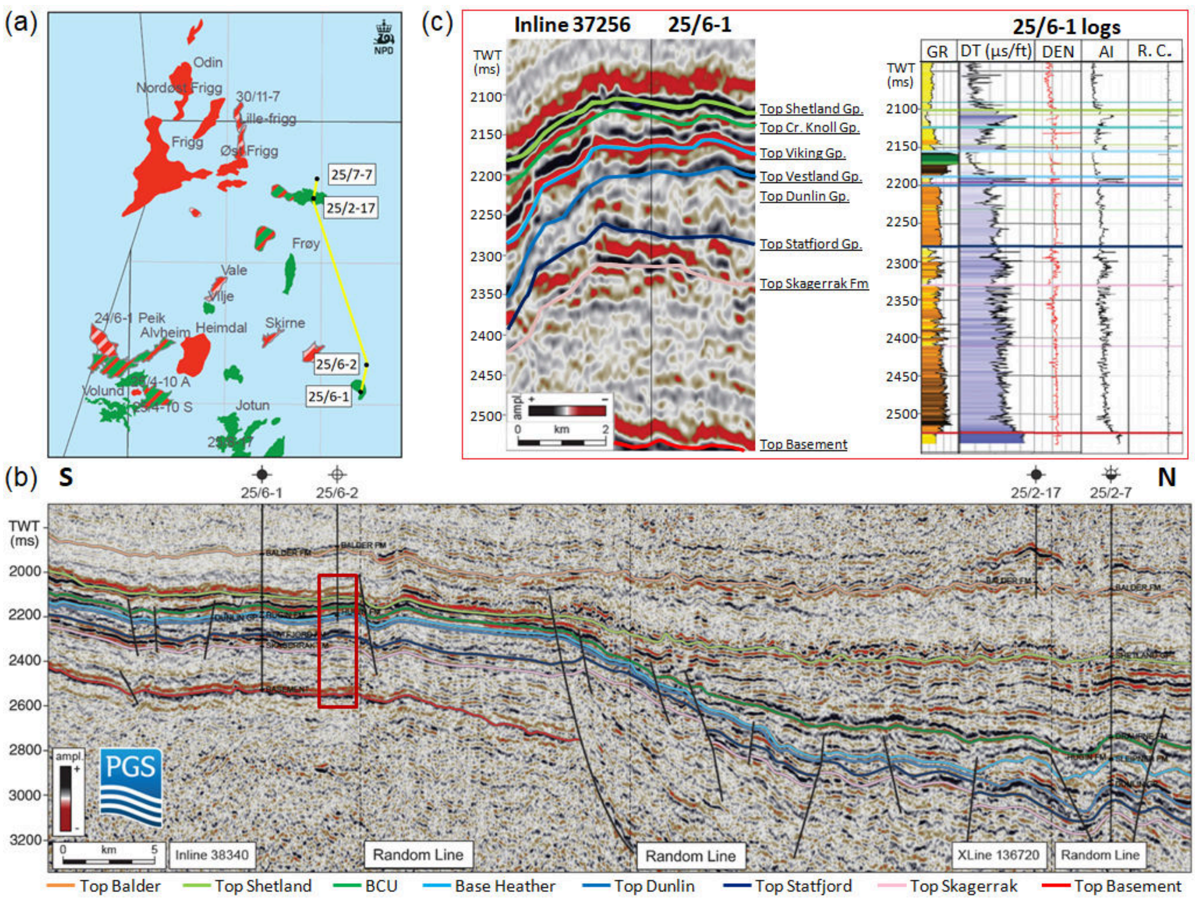


Figure 6.14: (a) Location map of the seismic composite transect; (b) Regional south-north 2D composite seismic section two-way traveltime (TWT) showing the main interpreted horizons; (c) Seismic-to-well tie in well 25/6-1: seismic on the left; GR, sonic (DT), compressional velocity (V_P), density (DEN), and acoustic impedance (AI) logs on the right. The seismic data are from the PGS North Sea MegaSurvey. The positive amplitudes are shown in black, and the negatives are in red colors (Badics et al., 2015).

The fact that the entire thickness of the Draupne Formation does not only consist of depositional facies of a type II source rock may imply that the assumed total potential of hydrocarbons predicted from the Draupne Formation were probably too high in some areas. However, a more stable facies in the Draupne Formation was identified and seems to be relevant for petroleum formation. This, in turn, enhances the petroleum formation prospectivity for the Draupne Formation in areas, in which this source rock is assumed to be over-mature or exhausted based on conventional concepts. Figure 6.15 illustrates the present day transformation ratio for the Draupne Formation. A type II source with 80% oil potential at base Cretaceous level has been assumed for this model. The deep sections of the Viking Graben have reached total conversion in most places (red colours) whereas the transformation ratio of the lateral extent of the recognised type II/III organic matter is significantly lower in various areas.

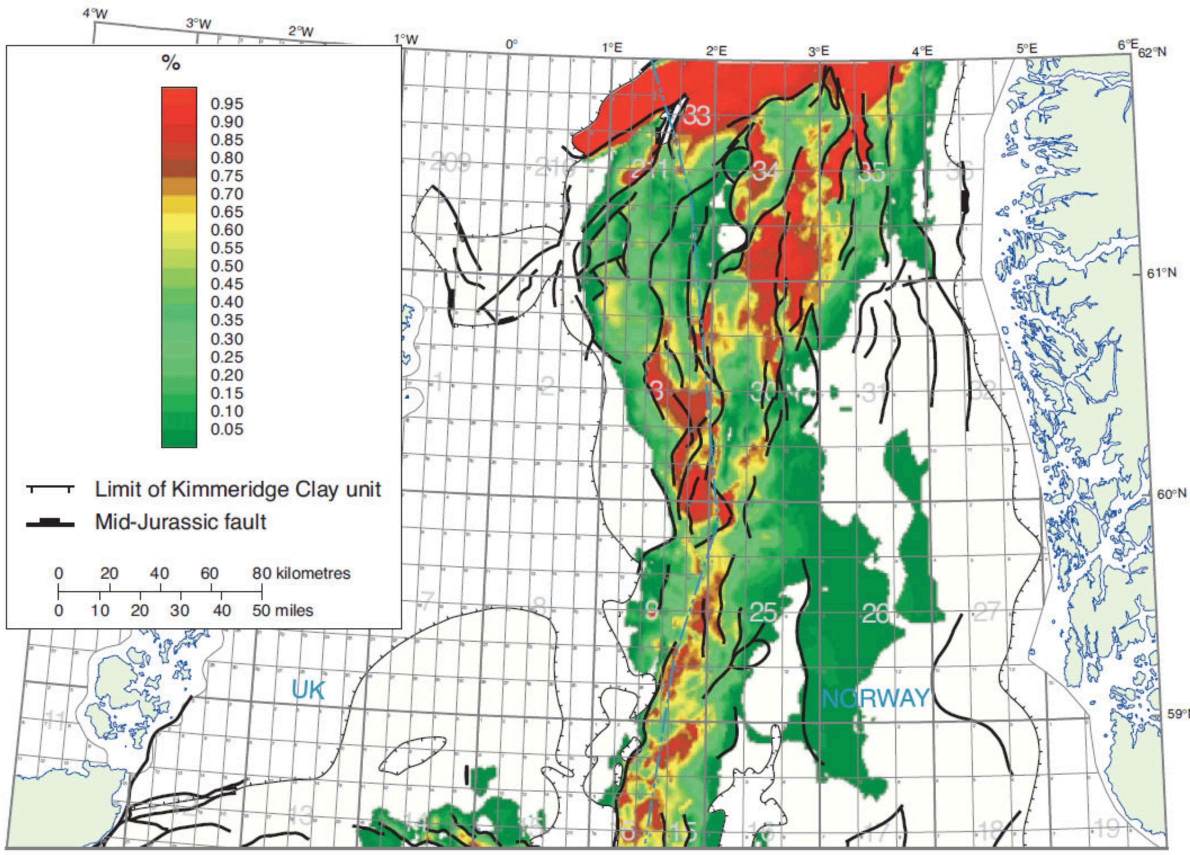


Figure 6.15: Modelled Kimmeridge Clay transformation at the present day (Evans et al., 2003).

6.2.7 Cretaceous and Cenozoic

During early Cretaceous, the clastic influx to the North Sea decreased as a consequence of rising sea levels. No good hydrocarbon accumulations are reported from that time in the Viking Graben. The observed values of TOC less than 1%, dominated by inertinite, and hydrogen index values less than 50 mg/g TOC indicate that only poor to fair source potential is present in these systems. Locally minor gas- and oil-prone kerogen is developed, but the source potential of this section in minor in comparison to the underlying Jurassic part.

In the northern North Sea, Tertiary sediments are unlikely to be effective source rocks because of their low degree of maturity. It has been shown that the top Cretaceous is buried below 3000 m only in the Central Graben (Day et al., 1981; Gowers and Saebøe, 1985; Ziegler, 1988). A similar situation exists in the Møre Basin, located farther north of the northern North Sea (Hamar and Hjelle, 1984). Paleocene shales are in any case generally lean and gas- and condensate-prone. North of 62° N within the Møre Basin, the Tertiary may be a potential source for gas, where burial is sufficient (Cohen and Dunn, 1987).

Chapter 7

MAIN GEOLOGIC PLAYS

7.1 PLAY DEFINITION

Play is a geographically and stratigraphically delimited area where a specific set of geological factors is present so that hydrocarbons should be able to be proven in producible volumes. Such geological factors are reservoir rock, presence of a mature source rock and of migration routes, seal, trap and the requirement that the trap was formed before the migration of petroleum ceased. These factors are seldom all present simultaneously. If one or more are missing, no accumulations of oil and gas will be found in the area. Uncertainty always prevails about the presence of hydrocarbons, and wells must be drilled to establish it. A prospect is a potential trap and a successful prospect turns into an oil/gas field when drilled or disappears when it is unsuccessful. All discoveries and prospects in the same play are characterised by the play's specific set of geological factors. Mapped and unmapped prospects, discoveries and fields can be found within a single play (Fig. 7.1).

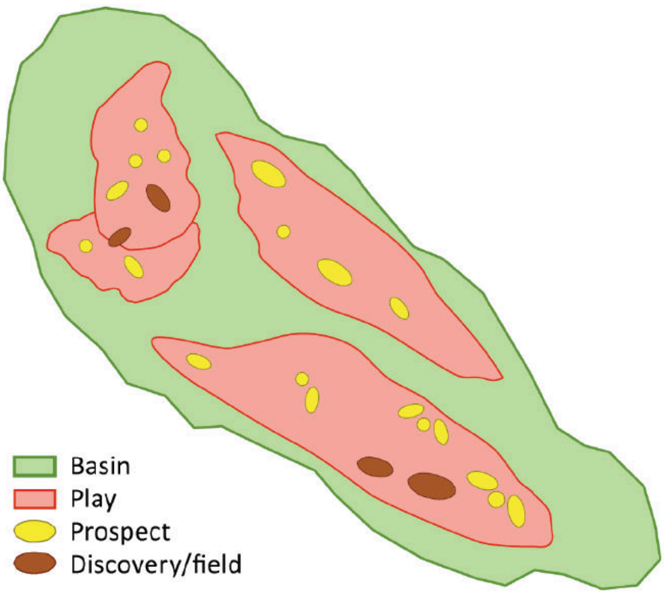


Figure 7.1: The relationship between basin, play, discovery and prospect (from NPD website www.npd.no).

A play may be considered proven if hydrocarbon accumulations (pools or fields) are known to have resulted from the operation of the geological factors that define the play. These geological requirements are thus known to be present in the area under investigation, and the play may be said to be 'working'. In unproven plays, there is some doubt as to whether the geological factors actually do combine to produce a hydrocarbon accumulation. One of the objectives of play assessment is to estimate the probability of the play working; this is known as 'play chance'. Play chance combines model risk and conditional play risk into one factor.

In the next sub-chapters, the key elements that define the main geologic plays in the northern North Sea, namely reservoir rocks, mature source rock evidenced by hydrocarbon migration and charge, seal, and trap are presented and discussed in detail.

7.2 RESERVOIR ROCKS

Rock physical properties, like velocity and bulk density, change as a function of various diagenetic compaction processes in sedimentary rocks. Reservoir characterization, basin modeling and seismic interpretation require data about rock properties. This may be obtained from well-log data, experimental compaction and petrographic analysis of core samples. The reservoir properties are a function of the depositional conditions, both on account of primary sorting and because diagenetic changes are usually determined by the primary mineralogical composition and sorting. The sandstones of the Brent Group are generally immature with a high content of feldspar and mica indicating a basement source and a relatively short transport into the prograding Brent delta. This implies that all sandstone bodies where flushed intensively by freshwater shortly after deposition. Nearly every sample of Brent Group sandstone, therefore, contains abundant evidence of feldspar leaching and pore-filling authigenic kaolinite. Carbonate-cemented beds are often associated with marine environments with aragonitic fossils which have dissolved and formed cement.

The reservoirs are commonly found within sandstones of the Rhaetian-Sinemurian Statfjord Formation, in the Aalenian-Bathonian Brent Group, and locally in the Pliensbachian-Toarcian Cook Formation of the Dunlin Group. In addition, Upper Jurassic (Bathonian-Kimmeridgian) sandstones provide good reservoirs, perhaps particularly in the platform areas, where fault block rotation is moderate (e.g. Troll Field), and in mixed structural-stratigraphic traps along fault-block crests. Post-rift marine sands (Cretaceous and Cenozoic) add to the prospectivity of the northern North Sea. Indeed, the Cenozoic marine sands of the Frigg Formation type were the major target of early exploration activity.

7.2.1 Triassic

A common feature of the Triassic reservoirs of the northern North Sea is that they generally occur in tilted fault blocks with varying levels of Early to Middle Jurassic and Late Jurassic to Early Cretaceous erosion and varying degrees of Cretaceous onlap (Goldsmith et al., 2003). The majority of fields with Triassic hydrocarbon accumulations in the northern North Sea have most of their hydrocarbons in overlying Lower and Middle Jurassic reservoirs with the exception of the Snorre Field. The distal, cleaner and mature nature of the sands ultimately results in very good porosity ranging from 19-29% and permeabilities ranging from 300-500 mD (Goldsmith et al., 2003).

7.2.2 Lower-Middle Jurassic

Lower and Middle Jurassic reservoir sandstones are nearly all arkoses or subarkoses. The Middle Jurassic Brent Group forms one of the most important stratigraphic units in the North Sea. It consists mainly of sandstones with interbedded siltstones, shales and interbedded coals (Table 7.1). The main constituent is quartz (ca. 50%), which together with kaolinite, albite and ilite comprises more than 95%. These sandstones are commonly cemented by quartz overgrowths. Authigenenic kaolinite is common pore-filling mineral at a burial depth of 2.5 to 3.5 km, and illite is found in increasing amounts below 3.5 km burial depth. Calcite-cemented sandstones are also common, particularly in the lower-shoreface facies; this strongly reduces the vertical connectivity for migrating fluids in the reservoirs (Walderhaug and Bjørkum, 1992).

GROUP	Formation	Lithology	Depositional environment
BRENT	Tarbert	Sandstone	Upper shoreface
	Ness	Sandstone, siltstone & shale	Lower delta plain
	Etive	Sandstone	Upper shoreface
	Rannoch	Sandstone	Lower and middle shoreface
	Broom	Sandstone	Fan-delta

Table 7.1: Lithostratigraphy of the Brent Group.

The Brent Group reservoirs have been characterized as having excellent porosity and permeability. These sandstones were deposited in coastal-plain and shallow-marine to near shore environments (Vollset and Dore, 1984) and have a high degree of lateral continuity.

Even when faults are abundant, the high net-to-gross ration (generally 50 to 70%) of the Brent Group commonly leads to sandstone-to-sandstone juxtaposition and non-sealing faults. Lower and Middle Jurassic reservoirs dominate in the North Viking Graben (Fig. 7.2).

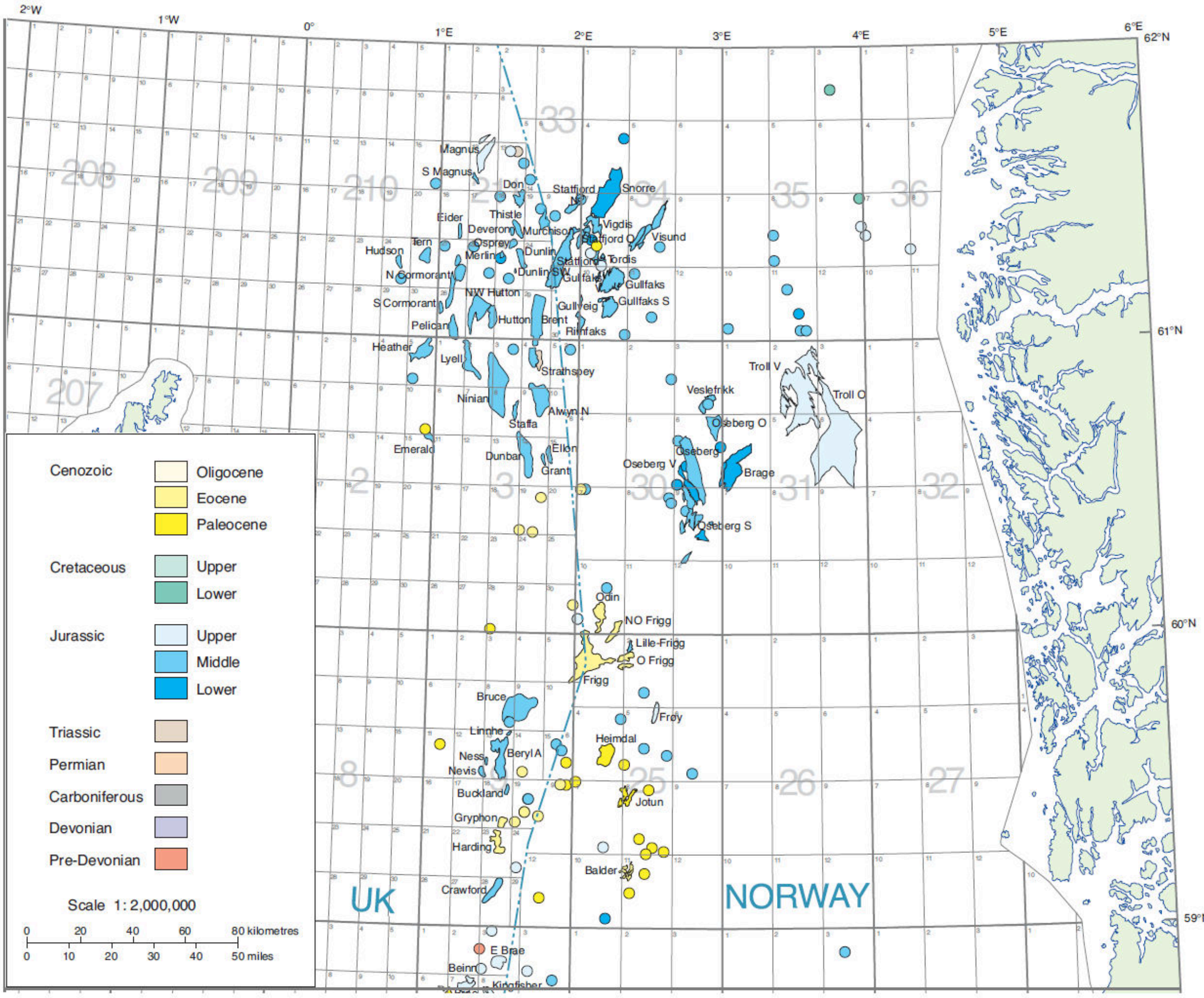


Figure 7.2: The distribution of discoveries and fields, classified by principal reservoir (Evans et al., 2003).

Middle Jurassic sequences commonly comprise a mixture of sediment types from a variety of depositional facies assemblages. The best reservoir quality is found in barrier-bar sandstones of the Etive and Hugin formations, and in the Gilbert-type delta deposits of the Oseberg Formation. Other shallow-marine to tidal facies are encountered in the Tarbert, Rannoch, Broom, Emerald and Fulmar formations. As depth increases, reservoir quality generally decreases due to compaction. Wireline logs of the cored section from well 33/9a-31 (Norwegian sector) have been chosen to illustrate the main reservoirs and their key petrophysical parameters (Fig. 7.3).

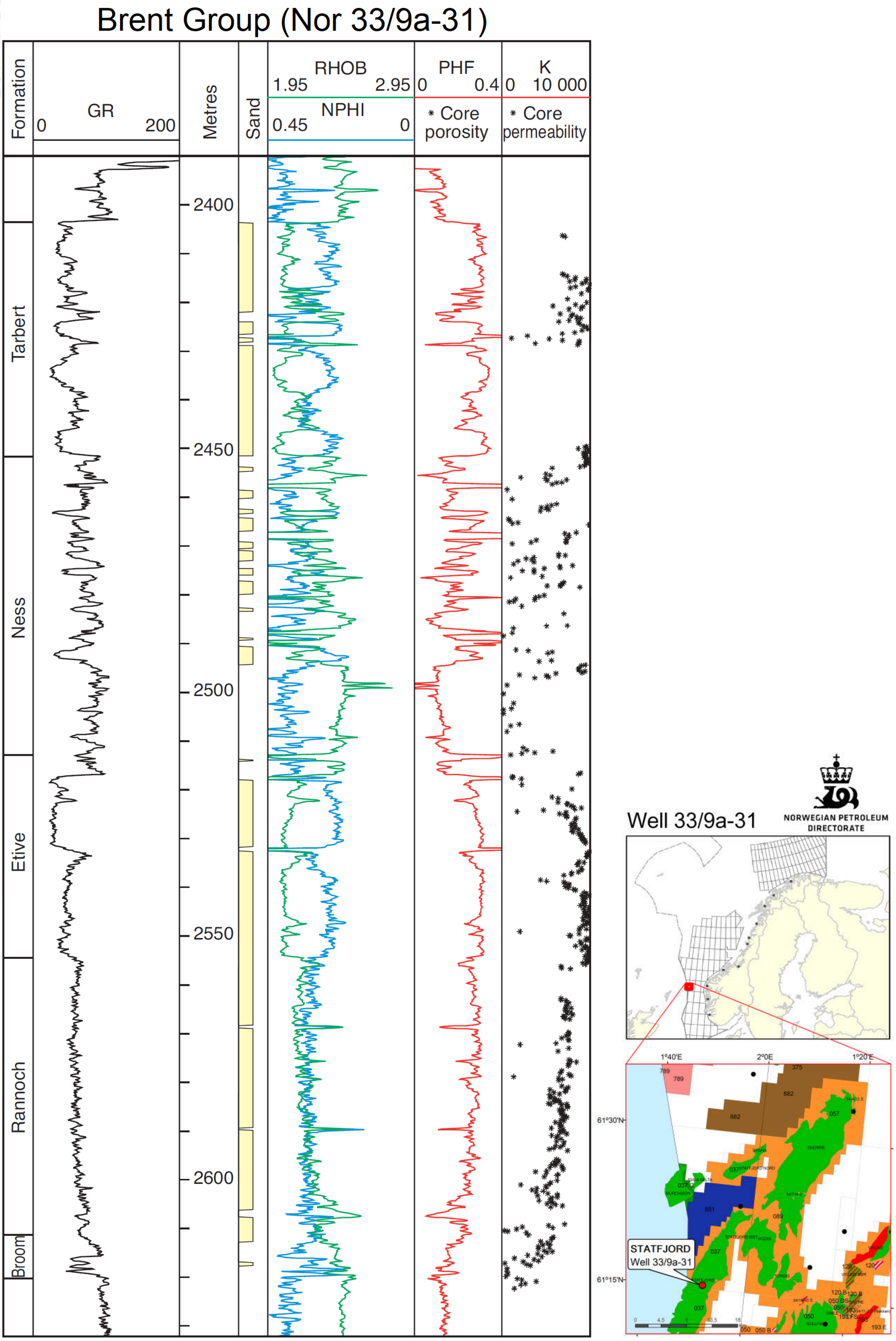


Figure 7.3: Reservoir characteristics of the Brent Group (Evans et al., 2003).

The Hugin Formation is found in the southern Viking Graben in the northwestern part of the Sørvestlandet High, where it overlies the deltaic coal-bearing Sleipner Formation. The upper boundary is the shales of the Viking Group. Generally the thickness decreases to the east and north. The thickness distribution of the Hugin Formation (Fig. 7.4) is partly controlled by salt tectonics. The depositional environment is interpreted in terms of a near-shore, shallow marine environment with some continental fluvio-deltaic influence. Burial depth of the formation over the Sleipner West Field is approximately 3400 m and reported average porosities and permeabilities are in the range between 16-20% and 0.1-4000 mD, respectively.

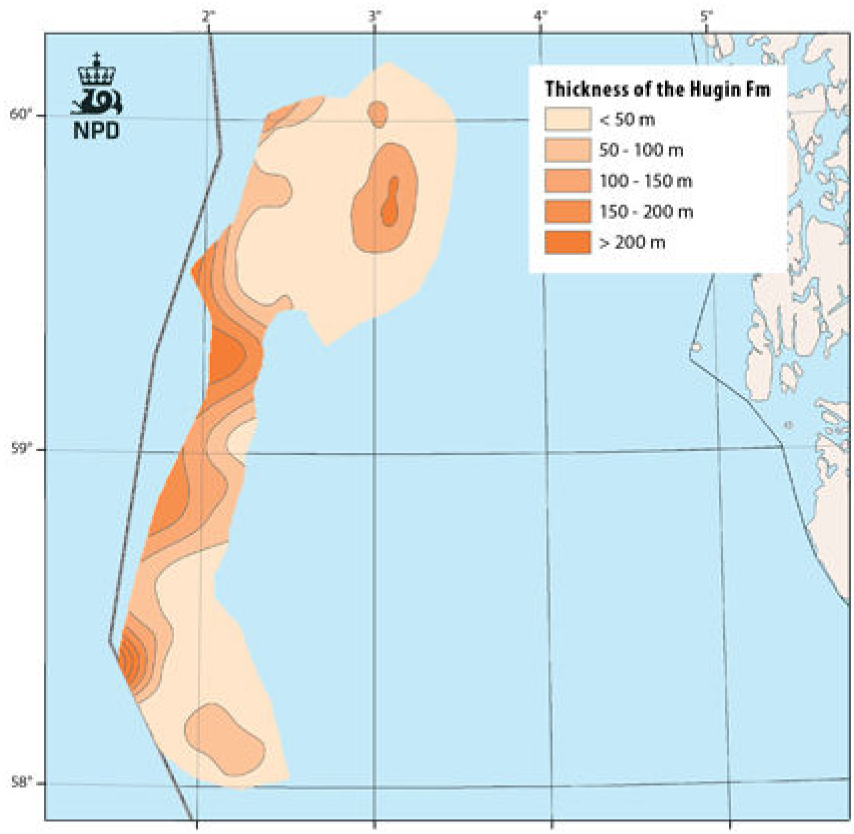


Figure 7.4: Thickness of the Hugin Formation (from NPD website www.npd.no).

The Oseberg Formation is interpreted as proximal, marine-dominated fan delta deposit bracketed by alluvial deposits. It is 20-60 m thick and laterally continuous throughout the main structure of the Oseberg Field, with few or no changes in lithology. The Oseberg Formation is composed primarily of coarse- to medium-grained, poorly sorted, immature lithic sandstones with permeabilities ranging from 1 to 10 D and porosities between 15% and 25%.

Despite the variations in primary composition and facies of Brent Group sandstones the main diagenetic processes are considered to be similar for all formations (Bjørlykke et al., 1992). Dissolution of feldspar, the precipitation of kaolinite, and carbonate cementation occurred at shallow depth related to fresh water flow, while albitization of K-feldspar, quartz precipitation and the formation of authigenic illite occurred during burial diagenesis (Bjørlykke, 1983; Bjørlykke et al., 1992; Giles et al., 1992). In the Brent Group, quartz cementation increases significantly at depths exceeding 3 km (Bjørlykke et al., 1992). Studies of quartz cementation in sandstones from the Norwegian continental shelf (Walderhaug, 1994b; Bjørlykke, 1996; Oelkers et al., 2000) show that quartz cementation is a temperature controlled process sourced by dissolution along stylolites and is rather insensitive to changes in effective stress.

7.2.3 Upper Jurassic

Upper Jurassic hydrocarbon-bearing reservoirs are of two main types: shallow-marine/coastal-shoreface sandstones and deep marine-fan sandstones (Fraser et al., 2002). In the northern North Sea, Upper Jurassic shallow-marine reservoirs are rare, although localized, shallow marine sandstones occur along the Tampen Spur in the Snorre-Statfjord fields area as a result of footwall uplift and erosion during the early phase of rifting in the North Viking Graben (Solli, 1995).

Shallow-marine sandstones

All shallow marine depositional systems are affected to some degree by several depositional processes, divided into two main categories: first, a seaward prograding system with a large sediment supply (e.g. deltas, strandplains, and tidal flats), and secondly, a retrograding system associated with relative sea-level rise (e.g. estuaries, strandplains, and lagoons) (Siddiqui et al., 2017). A ternary diagram is used to define these processes in relation to wave, tidal and fluvial influence, and the relative importance of depositional environment in controlling depositional architecture (Fig. 7.5).

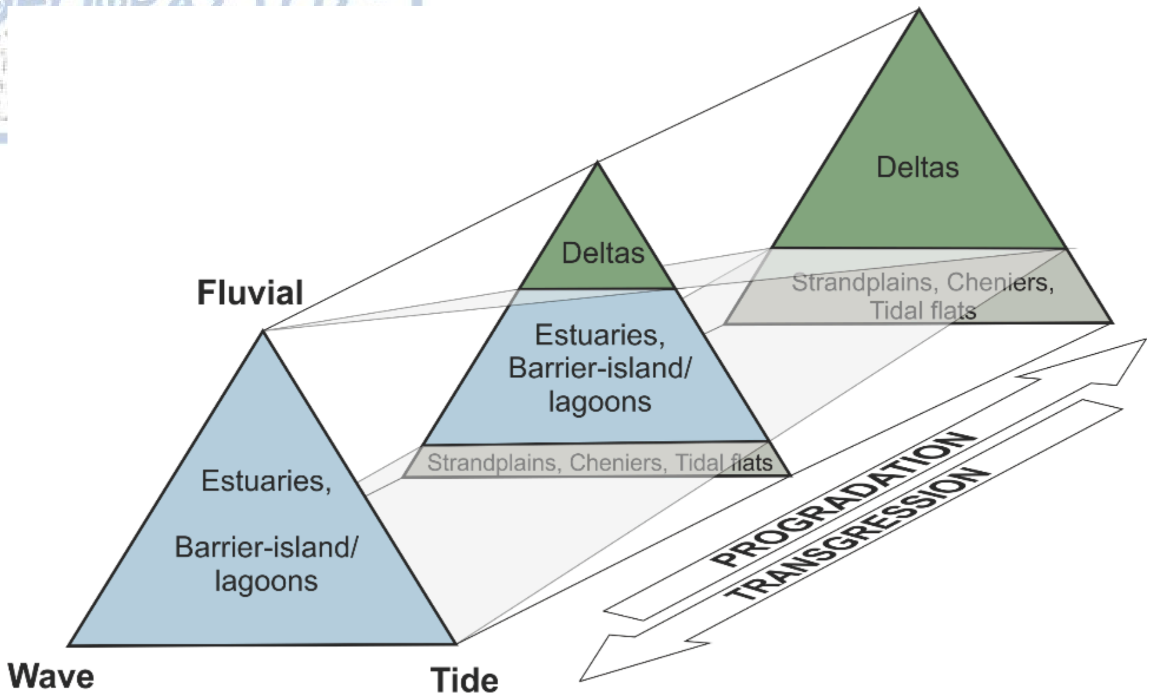


Figure 7.5: Diagram showing how coastal environments evolve through transgression and progradation. Through progradation, systems develop into deltaic and tidal environments, whereas during transgression, estuaries are dominant (adapted after Reading and Collinson, 1996).

A special occurrence of these reservoirs is found in the Troll Field, a super-giant gas accumulation with a prominent oil rim (Høye et al., 1994). The gas and oil reservoirs in the Troll East and Troll West structures consist primarily of shallow marine sandstones belonging to the Sognefjord Formation of Late Jurassic age. Part of the reservoir is also in the Fensfjord Formation below the Sognefjord Formation. The field consists of three relatively large rotated fault blocks. The fault block to the east constitutes Troll East. The reservoir depth at Troll East is about 1330 metres (Fig. 7.6). Pressure communication between Troll East and Troll West has been proven. Previously, the oil column in Troll East was mapped to be 0-4 m thick. A well drilled in 2007 proved an oil column of 6-9 m in the Fensfjord Formation in the northern segment of Troll East.

The Upper Jurassic (Bathonian to Kimmeridgian) reservoirs of the Troll Field occur in a 400 m thick sequence belonging to five formations and comprising siltstones, sandstones and sands with porosities up to 34%. Their depositional environments ranged from open marine in the west to shoreface and restricted marginal marine in the east (Hellem et al., 1986).

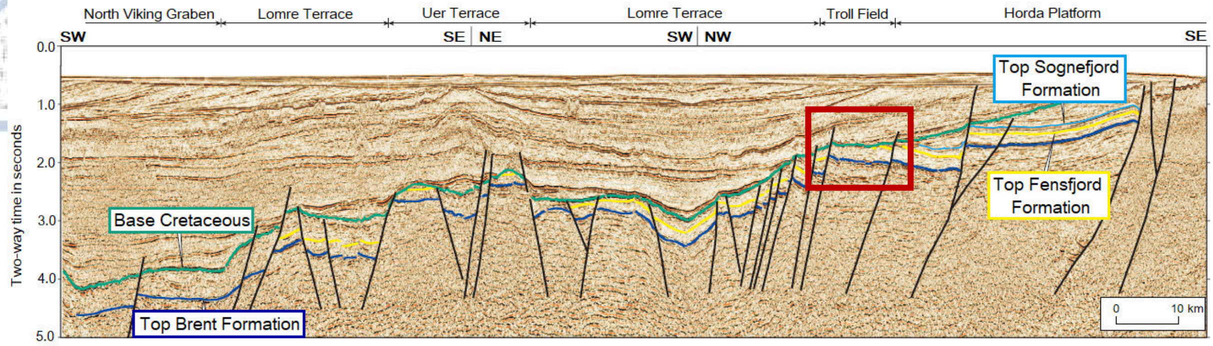


Figure 7.6: A composite north-east to south-east seismic section from the Lomre Terrace across the Uer Terrace to the Troll Field on the Horda Platform (Evans et al., 2003).

Deep-water sandstones

Deep-water sandstones form volumetrically smaller and stratigraphically more complex accumulations. Trapping configuration shows a greater degree of depositional control than with the shallow-marine sandstones, partly due to more-rapid facies changes within individual submarine-fan systems, but mainly because of the contrasting dimensions of the sand-prone depositional systems relative to field and prospect size. Submarine fans have diameters of 1-5 km compared to the 15-20 km width, and several tens of kilometers length, of shoreface zones. Structural control on deep-water sedimentation and reservoir distribution was invariably of major significance, resulting in up to 1500 m of high-quality but laterally restricted sandstone bodies which are partially encased in organic-rich muds and juxtaposed up-dip against major, and commonly sealing, fault systems. This is a near-perfect situation for hydrocarbon short-distance migration and entrapment. A combination of structural and stratigraphic trapping controls is involved in virtually all Upper Jurassic deep-water hydrocarbon accumulations, notably in the Viking Graben fields.

The Magnus Field is located 160 km northeast of the Shetland Isles in license blocks 211/12a and 211/7a of the UK sector of the northern North Sea. The oil accumulation occurs within sandstones of an Upper Jurassic submarine fan sequence situated in an easterly dipping fault block. The field is located to the north of several giant oil reservoirs in the East Shetland basin, including the Statfjord, Brent, and Ninian fields (Fig. 7.7). The reservoir sections from both wells (211/7-1 and 211/12-5) were evaluated using wireline data transformed to generate continuous mineralogical and fluid compositional data (Barclay and Worden, 1998; Worden and Matray, 1998).

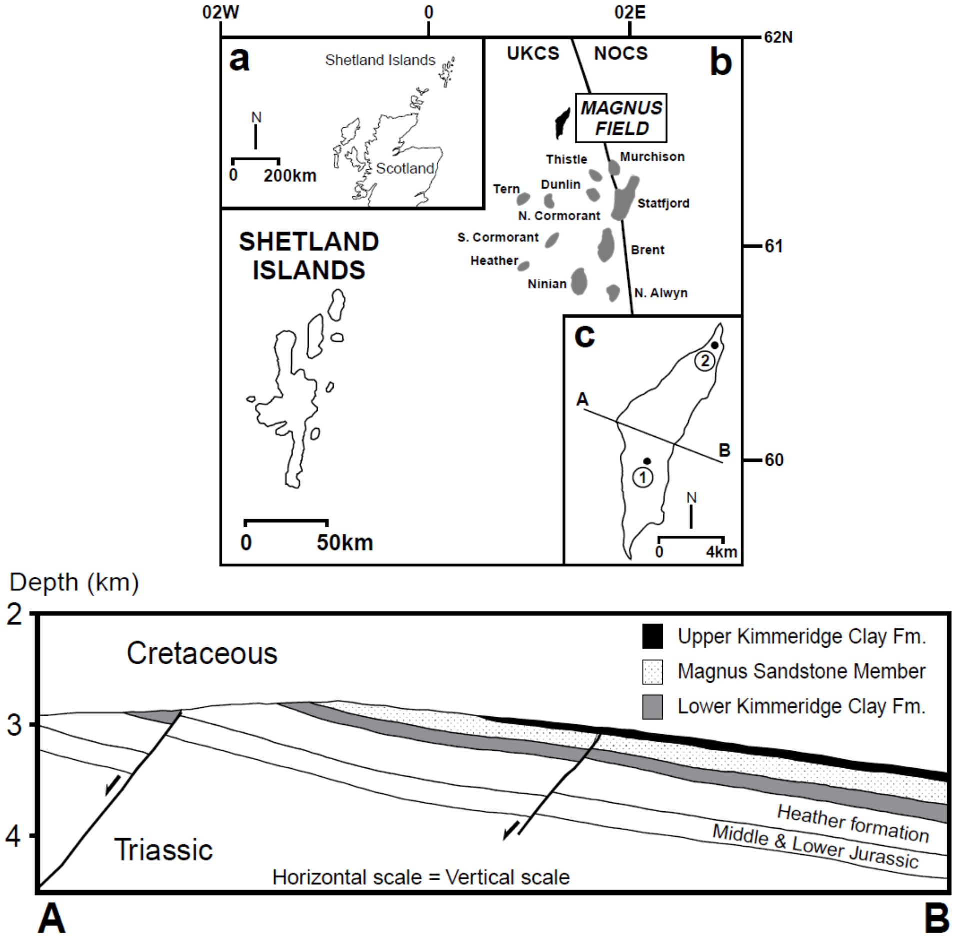


Figure 7.7: (a, b) Location maps of the Magnus oil field with the two sampled wells (dots 1 and 2) indicated on (c), which also shows the location of cross section A-B. Dot 1: well 211/12-5 and dot 2: well 211/7-1 (Barclay et al., 2000).

The Magnus Field has an Upper Jurassic (Kimmeridgian) reservoir comprising a 200 m submarine-fan sandstone-mudstone sequence with porosities of 18-24% and permeability of 100-1000 mD, deposited by high-density turbidity currents, with relatively thin interbedded mudstones (De'Ath and Schuyleyman, 1981; Shepherd, 1991). Cores from the Upper Jurassic reservoir sequence show sedimentary associations and structures consistent with a submarine fan environment of deposition. For example, thick massive ungraded sandstone beds are interbedded with marine ammonite bearing mudstones. Bioturbation and cross bedding structures are rarely observed. Partial or occasionally complete classical Bouma-turbidite sequences are commonly recorded in core.

For the purposes of reservoir description in the Magnus Field, the Kimmeridge Clay Formation has been subdivided into three units. The Magnus Sandstone Member is the sandstone dominant reservoir interval and sustains most of the production from the field. The underlying Lower Kimmeridge Clay Formation is mudstone dominated but with specific intervals of thin sandstones contributing some oil production. The Upper Kimmeridge Clay Formation is the highest unit and this mudstone interval acts as an overall seal except the crestal area of the reservoir where it is eroded. The trapping mechanism consists of a combination of stratigraphic pinch-out and reservoir truncation by unconformity (Fig. 7.8). To the north and to the south of the field, the reservoir is limited by the depositional extent of the Magnus submarine fan sandstones. Reservoir seal is provided both laterally and vertically here by Kimmeridge Clay mudstones. At the crest of the fault block the Upper Kimmeridge Clay mudstones are missing due to erosion and the vertical seal is provided by Cretaceous mudstones.

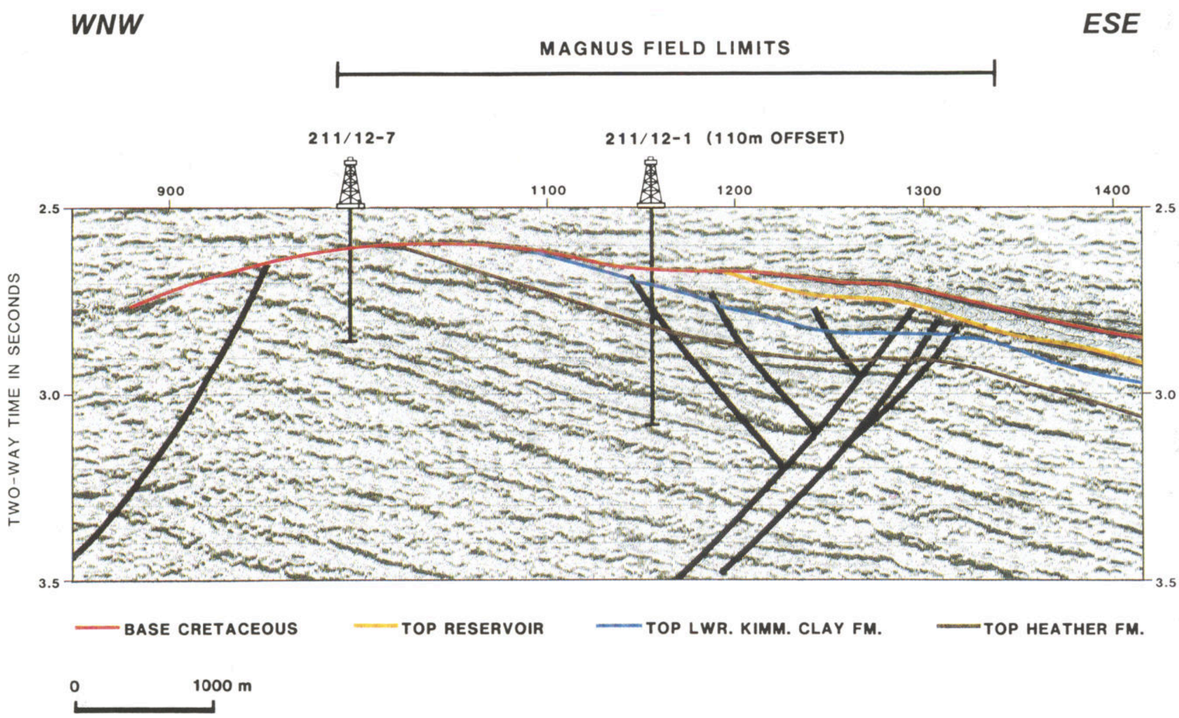


Figure 7.8: Seismic section through Magnus Field acquired as part of the 1983 3D survey shot by GECO and processed by Western Geophysical (Shepherd, 1991).

The Tiffany and Toni fields lie at the western margin of the South Viking Graben in the Northern North Sea in UK Block 16/17 (Fig. 7.9). The reservoirs are composed of coarse clastic sediments of the Upper Jurassic Brae Formation, which were deposited by turbidity currents and debris flows in a submarine fan setting. The Brae Formation accumulated adjacent to the graben margin fault scarp and abuts pre-Jurassic rocks of the Fladen Ground Spur to the west. The Kimmeridge Clay Formation provides both the source of hydrocarbons and the seal for the reservoir.

Although generated by essentially the same processes, each of the fans that constitute the reservoirs in Block 16/17 exhibits a distinct character in terms of facies assemblage. The variation can be broadly attributed to distance from the source area, volume of sediment input and structural evolution. In the Tiffany Field, the Brae Formation reservoir is dominated by conglomeratic and sandstone facies with argillaceous intervals restricted to the distal/interfan locations. The Toni Field is similarly characterized by a massive conglomeratic centre, but with a greater volume of sandstones and shale on the flanks of the structure compared with the Tiffany Field. The Bathonian to Middle Callovian volcanic and paralic successions, which overlie eroded Triassic sediments in Block 16/17, are essentially pre-rift deposits that accumulated in response to regional thermal relaxation of the crust following collapse of the triple point junction dome. The late Callovian, however, was characterized by a significant increase in clastic input from the Fladen Ground Spur, suggesting that rifting may have been initiated at this time. The late Callovian-aged shallow marine and estuarine sandstones which make up these early syn-rift deposits form a secondary reservoir in Toni Field (Fig. 7.9).

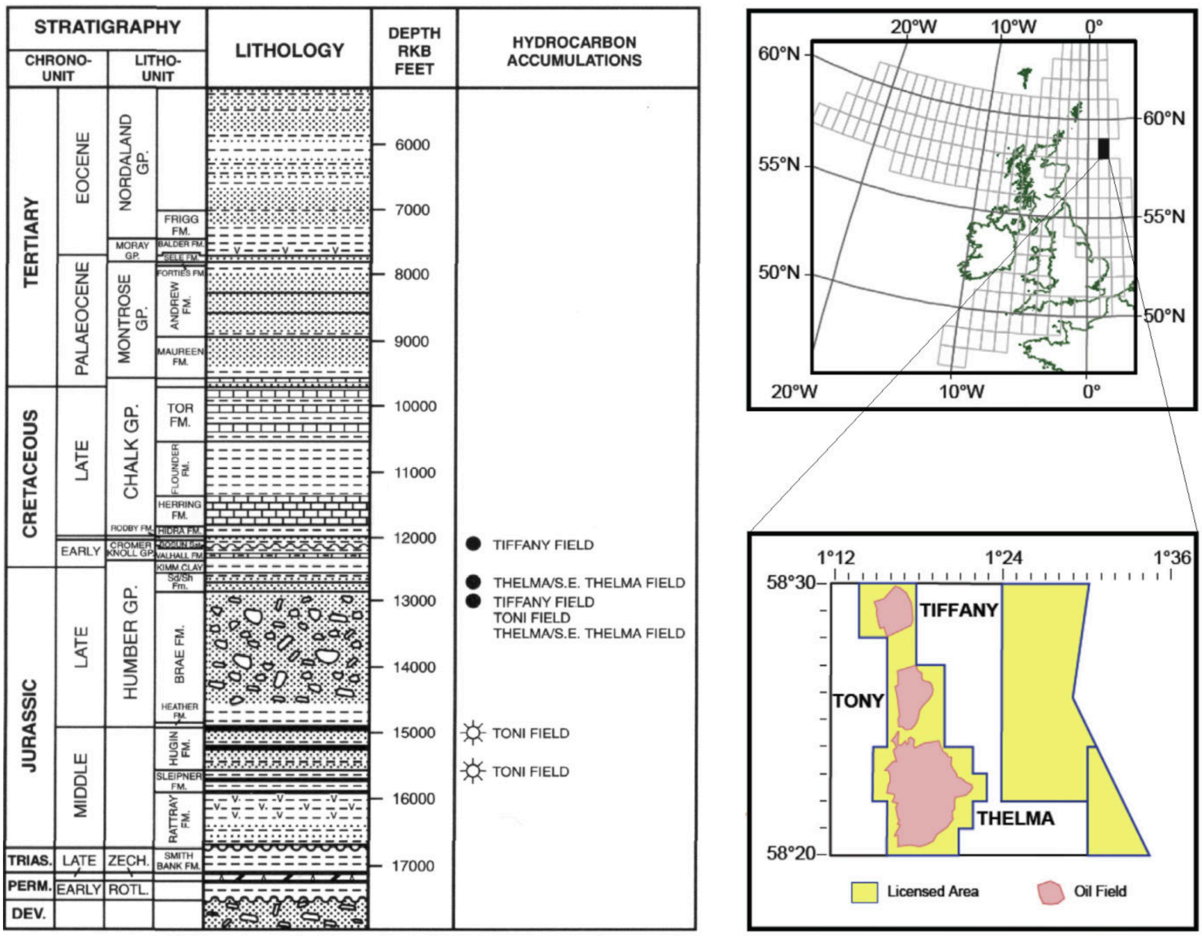


Figure 7.9: (left) Generalised stratigraphy of the T-Block (Tiffany and Toni) fields (Kerlogue et al., 1995); (right) Regional location map of Tiffany and Toni fields (Gluyas et al., 2003).

Average core porosity within the sandstones and conglomerates of the Tiffany Field reservoir is about 10% and average horizontal air permeability is in the region of 75 mD. Permeability is seen to decrease noticeably with depth and shows little or no relationship to porosity. This decrease with depth is thought to be related mainly to lithological variation rather than diagenetic effects. The development of secondary porosity, primarily through the dissolution of feldspars, is related to source rock maturation and hydrocarbon migration. Secondary porosity occurs throughout the section but is particularly enhanced in the crestal part of the field. The Toni reservoir contains similar facies to Tiffany, which were deposited through various sub-aqueous mass transport and gravity flow processes. The depositional environment is envisaged to be more complex than Tiffany with a higher degree of tectonic activity associated with sedimentation. A summary of the basic reservoir properties is given in Table 7.2.

Fields	**Tiffany**	**Toni**
Trap	Structural/stratigraphic	Structural/stratigraphic
Formation	Brae	Brae
Average net:gross ratio	79%	45%
Average permeability	75 mD	150 mD
Average porosity	10.0%	11.1%
Hydrocarbon saturation	78%	57.9%
Fluid type	Oil	Oil

Table 7.2: Tiffany and Toni fields basic reservoir properties (Kerlogue et al., 1995).

7.2.4 Cretaceous

The Cretaceous deposits in the northern North Sea have for many years been a minor play for exploration in Norway, with the Agat discovery as the only significant Lower Cretaceous discovery in the Norwegian North Sea. The discovery lies within the tilted fault-block terrace off Måløy, in block 35/3 (Fig. 7.10). The discovery was made by Saga Petroleum in 1980 and the estimated gas-in-place is $65x10^9$ Sm^3. The area was later relinquished. The reservoir interval is the sandy Agat Formation, previously interpreted as submarine fan deposits of late Albian age (Gulbrandsen, 1987), and reinterpreted in terms of upper slope sand lobes. Lower Cretaceous turbiditic sandstones in a 200 m thick sequence contain gas pools in the Agat discovery; net-to-gross ratios are low (0.1 to 0.3) and individual sandstone beds are thin (5-15 m), while porosities are up to 20% (Gulbrandsen, 1987).

The hemipelagic deposition of the Early Cretaceous was interrupted by sandy mass-flow events (Bugge et al., 2001). Sandstones of the Agat Formation occur in several wells in Block 35/3. These sandstone beds are typically 10-30 cm thick and are interbedded with thin mudstone beds, but can be amalgamated to thicknesses of many tens of metres (Bugge et al., 2001). The sandstone beds have a fine- to medium and occasional coarse grain-size, are in general massive to normally graded with water escape structures and are interpreted as turbidites. Nystuen (1999) presented a similar interpretation to Bugge et al. (2001). However, Shanmugam et al. (1995) presented an alternative interpretation of the Agat sandstone intervals as sandy debris flows.

Well 35/3-7S proved gas in the Agat Formation in the Lower Cretaceous. Preliminary estimates indicate that the size of the discovery in well 35/3-7S, together with previously proven gas discoveries in the licence (wells 35/3-2 and 35/3-4, collectively called Agat, proven in 1980), is between three and eight billion standard cubic metres of recoverable gas. Viewed together with the well 35/3-2 discovery, the discovery in well 35/3-7S is characterised as interesting. The collective Agat discovery is still currently under evaluation for potential future development.

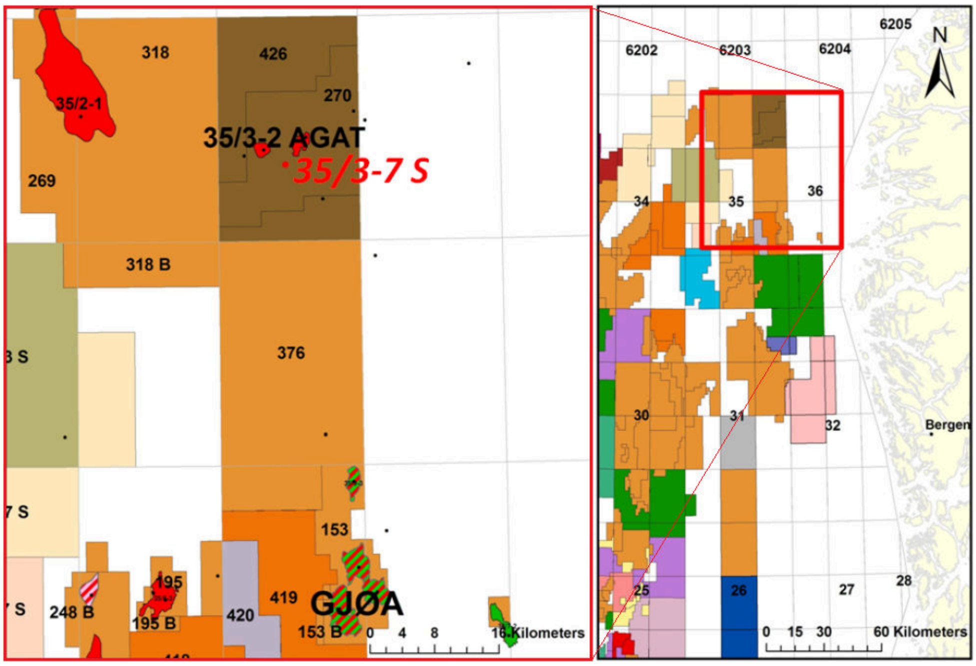


Figure 7.10: North Sea index map showing the Agat collective discovery (from NPD website www.npd.no).

The prospectivity of Cretaceous deposits in the northern Norwegian North Sea, particularly in the Agat area, has been evaluated and economic importance is proven. The reservoirs of the Agat discovery are overlapping fan lobes, fan channels and/or slump debrites. Deposition of Cretaceous reservoirs in the North Sea is strongly influenced by the basin topography created by Jurassic rifting, that gave rise to development of slope and fault aprons (Fig. 7.11).

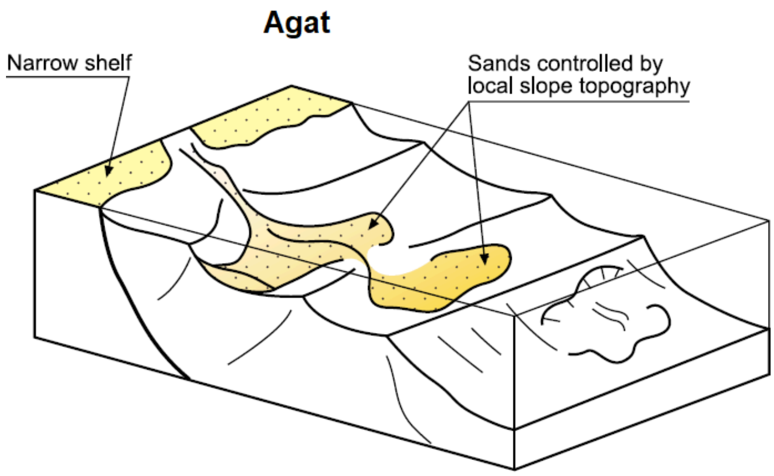


Figure 7.11: Deep-water depositional system illustrating the shape of sands as a result of the controlling processes. Not to scale (Martinsen et al., 2005).

Several seismic anomalies/mounds have been identified south of the Agat area and have been evaluated in more detail. The seismic line in Figure 7.12 shows the tie from between the best sandstone interval in well 35/3-5 and two interpreted seismic anomalies/mounds. Well 35/3-5 is located ca 13 km south of the Agat discovery. The primary target of the well was sandstones of Early Cretaceous age, which had been found hydrocarbon bearing in wells 35/3-2 and 35/3-4. The well was considered a wildcat due to the uncertain correlation between sand bodies in the area. The secondary objective was to penetrate sandstones of Early –Middle Jurassic age, which had been found hydrocarbon bearing in well 35/3-2. An Intra-Albian unconformity in interpreted at the base of these mounded features. The Agat Formation was encountered from 3219 m to 3620 m. A thin intra-Heather sandstone was penetrated from 3865 m to 3874 m. A minor show was noted at the top of the Agat Formation. Minor oil shows with associated formation gas peaks were recorded in sandstones at 3547 m and 3568 m. Minor shows were recorded in siltstones below 3685 m, but these were not associated with gas peaks. Organic geochemical analyses confirmed migrant hydrocarbons at 3223 m in the top of the Agat Formation. Source rocks were immature down to about 3000 m. Oil window maturity is postulated below ~3900 m. Below ~3300 m in the well, total organic carbon was found in the range 1.7% to 3% in picked mud stone samples. Shale in a thin interval at 3286 m to 3295 m was evaluated as a good/rich potential as a source rock for gas and oil while claystone/siltstone from 3847 m to 4063 had fair/good potential as a source rock for gas and some paraffinic oil. The well was plugged and abandoned as a dry hole with weak shows.

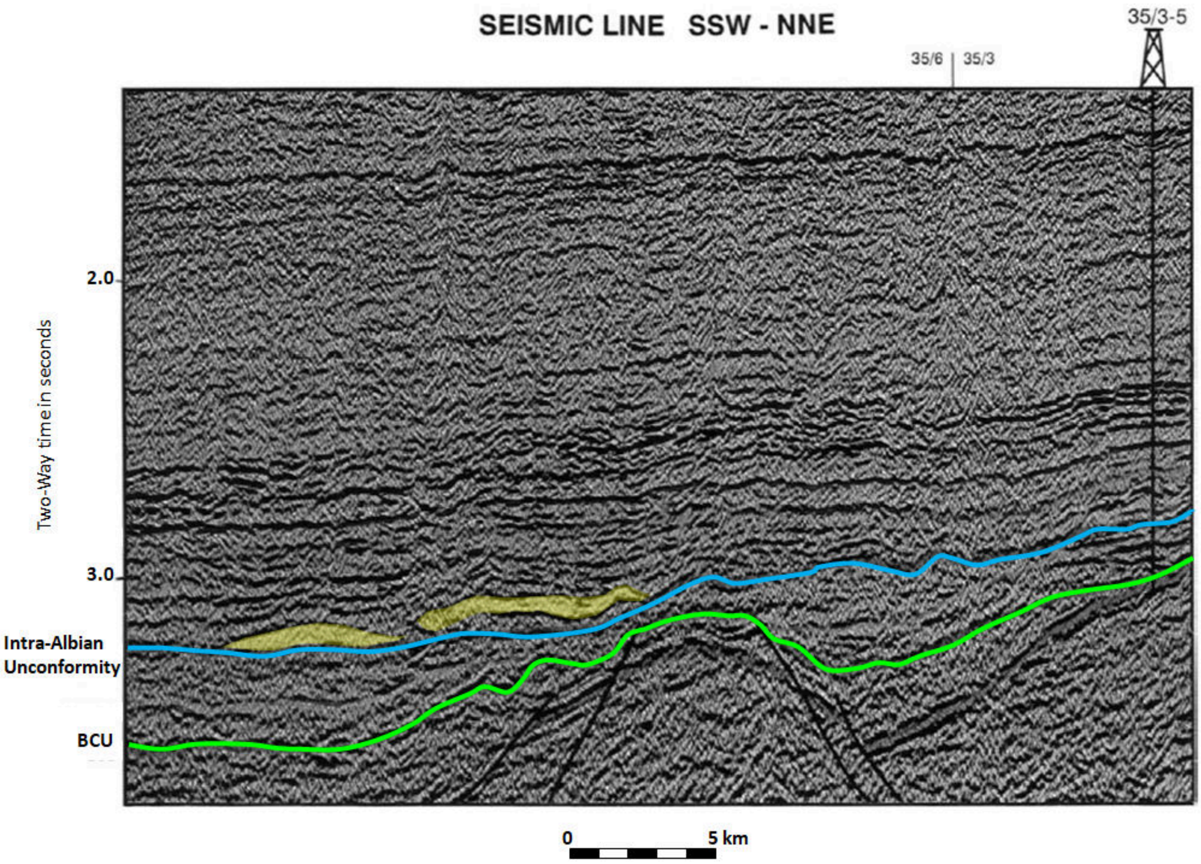


Figure 7.12: A NNE-SSW squashed seismic line allowing the tie from the Agat well 35/3-5, south to two interpreted seismic anomalies/mounds (yellow raster) lying on an Intra-Albian unconformity. Note potential reservoir sand at same level in well 35/3-5 (modified from Skibeli et al., 1995).

Well-log evaluation from the appraisal well 35/3-4 of the Agat discovery (Fig. 7.13) indicates 13 m net thickness in the interval 3445 m to 3471 m, with an average porosity of 19% and an average water saturation of 52%. Organic geochemical analyses showed poor, immature to marginally mature with a limited potential for gas/condensate down to ~3200 m. Between 3200 m to ~3650 m, zones of medium to dark grey shales have useful TOC (up to ca 3%), but are effectively immature and have a negligible potential for gas (hydrogen index from 50 mg/g to 150 mg/g TOC). Abundant medium to dark grey and dark olive grey shales occur in zones from 3650 m to TD. Although they are generally poor source rocks scattered fair and good to very good interbeds are also present, notably in the Heather Formation and below 4000 m (base of Cook Formation). The best interval was found in the interval 3695 m to 3725 m in the Heather Formation (TOC from 3.1% to 3.8% and hydrogen index from 260 mg/g to 360 mg/g).

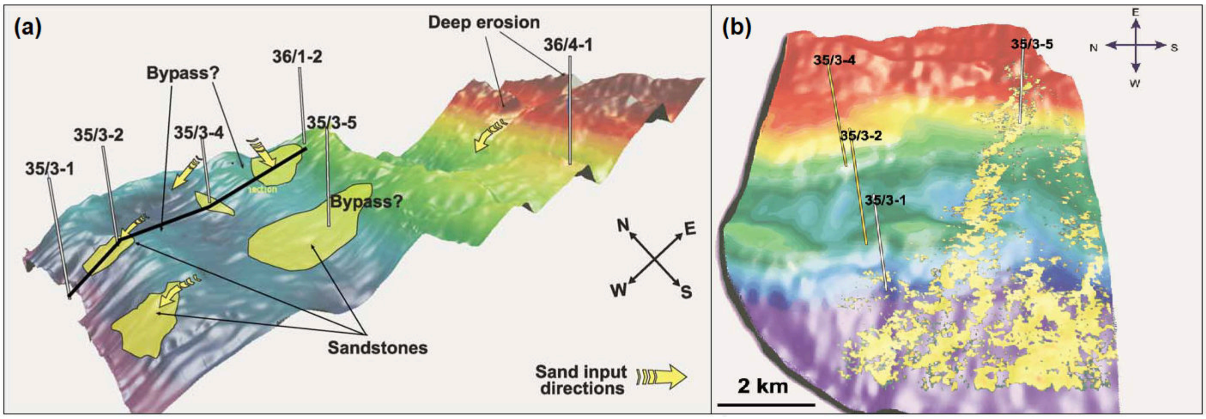


Figure 7.13: (a) Lower Cretaceous sandstone bodies draped on a top basement map on the Måløy Terrace. Note the correlation between the position of the sandstones and the basement lows. (b) Base Cretaceous Unconformity (BCU) time map overlain by amplitude map of the Agat Formation sandstones penetrated by well 35/3-5. Note the updip (to the east) elongate bodies which fan out towards the west (Jackson et al., 2005).

The petrography and biostratigraphy in well 35/3-5 appears to differ significantly from the other Agat wells. This could suggest that well 35/3-5 belongs to a separate depositional system, a difference which may have been tectonically controlled. The Albian sediments encountered in wells 35/3-2 and 35/3-4 were interpreted to have been derived from the northeast whereas in well 35/3-5 these sediments were derived from the southeast. These directions (fairways) were probably structurally controlled. The potential reservoir leads identified from the basin-floor anomalies (Fig. 7.13) belong clearly to the fairway containing the proven sands in well 35/3-5.

7.2.5 Paleocene

Paleocene sandstones typically form excellent reservoirs, and have good regional connectivity. The fields have average porosities ranging from 17% to 33% and permeabilities from 16 mD to 10 Darcies. These high quality reservoir properties are due to the mineralogical and textural maturity of the sandstones, and to the fact that depth-related diagenesis is relatively minor (Johnson and Fisher, 1998). Cementation is relatively low and the only common phases are minor clay, quartz and patchy carbonate (Aplin et al., 1993).

Almost all Paleocene traps formed early and were hydrocarbon-charged before significant cementation had taken place.

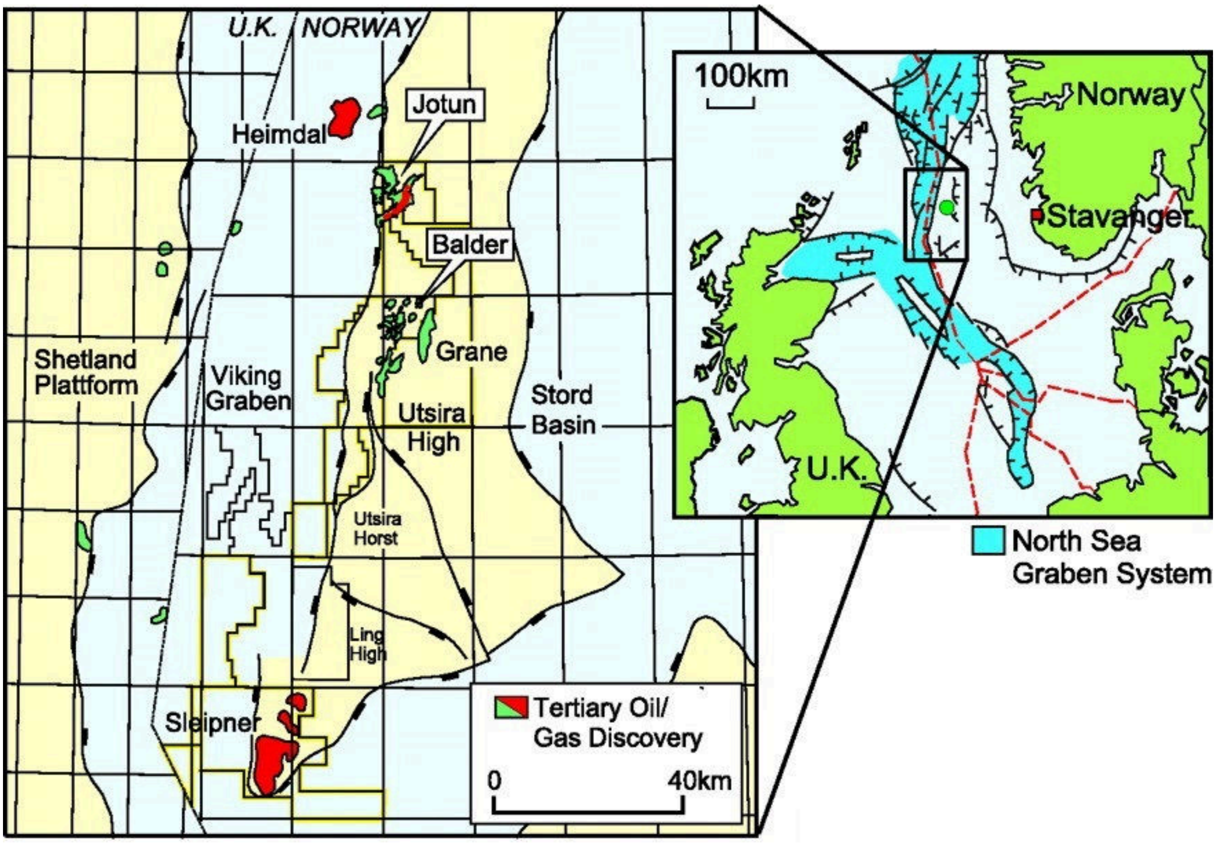


Figure 7.14: Jotun and Balder fields are located on the western margin of the Utsira High, near the eastern limit of sand deposition (Bergslien, 2002).

The Jotun Field is an example of a Paleocene reservoir field, and lies in Norwegian Blocks 25/7 and 25/8 in an average water depth of 126 m. The Jotun Field is located on the Utsira High between the Balder and Heimdal fields (Fig. 7.14) approximately 200 km west of Stavanger, mainland Norway. The field covers an area of 30.5 km^2, and recoverable reserves are estimated to be approximately 200 million barrels of oil (32 million m^3) and 1.8 billion m^3 of gas. Specific gravity of crude is 38 degrees API. Reservoir pressure is 200 bar and reservoir temperature 82° C. The field comprises two, four-way dip-closed structures and one stratigraphically trapped structure (Fig. 7.15).

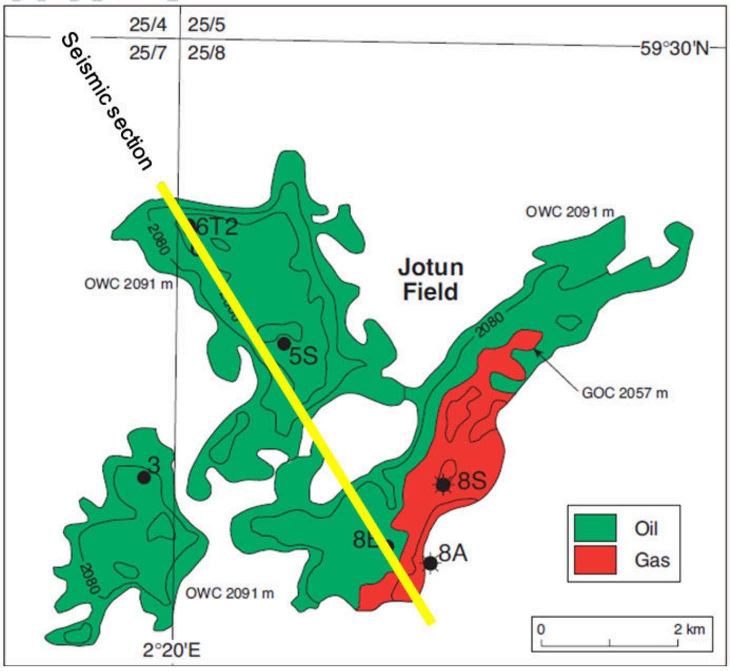


Figure 7.15: Location map of Jotun Field (Evans et al., 2003).

The Jotun Field contains the Heimdal Formation sandstones that pinch-out onto the terraces of the Utsira high to the east (Fig. 7.16). The cross-section in Figure 7.17 illustrates the structural setting of the Jotun Field and the 3D-seismic profile from a far-offset-stack seismic cube shows the amplitude enhancement of the oil-bearing sandstones.

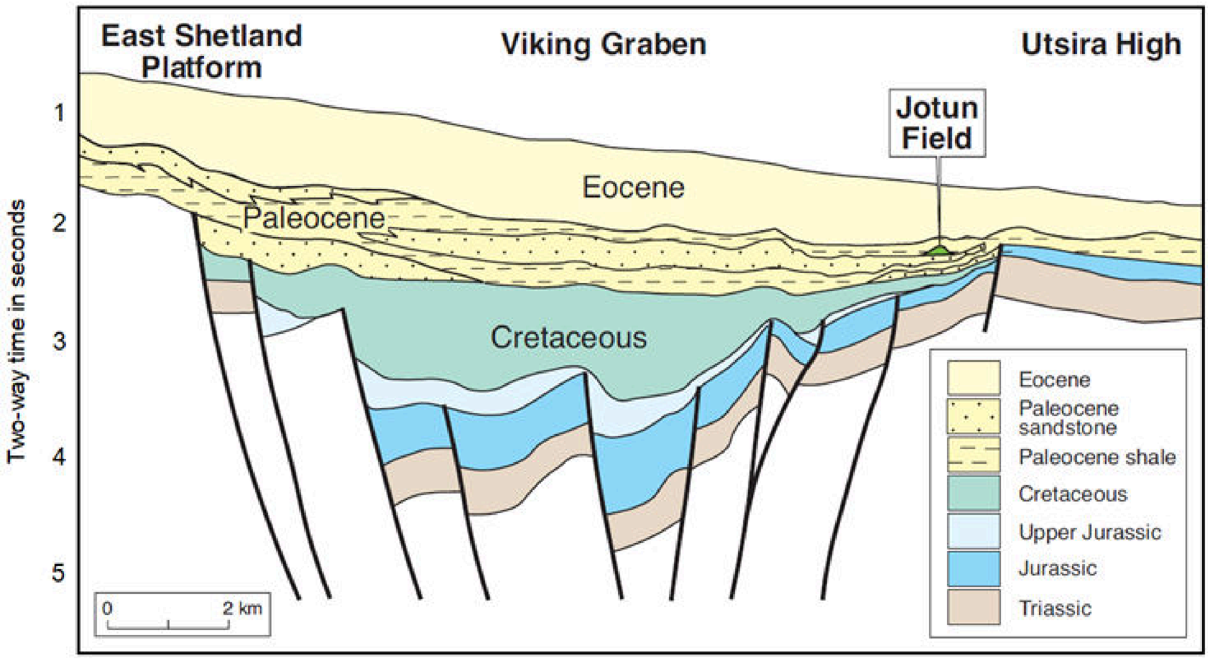


Figure 7.16: Cross-section illustrating the structural setting of the Jotun Field (Evans et al., 2003).

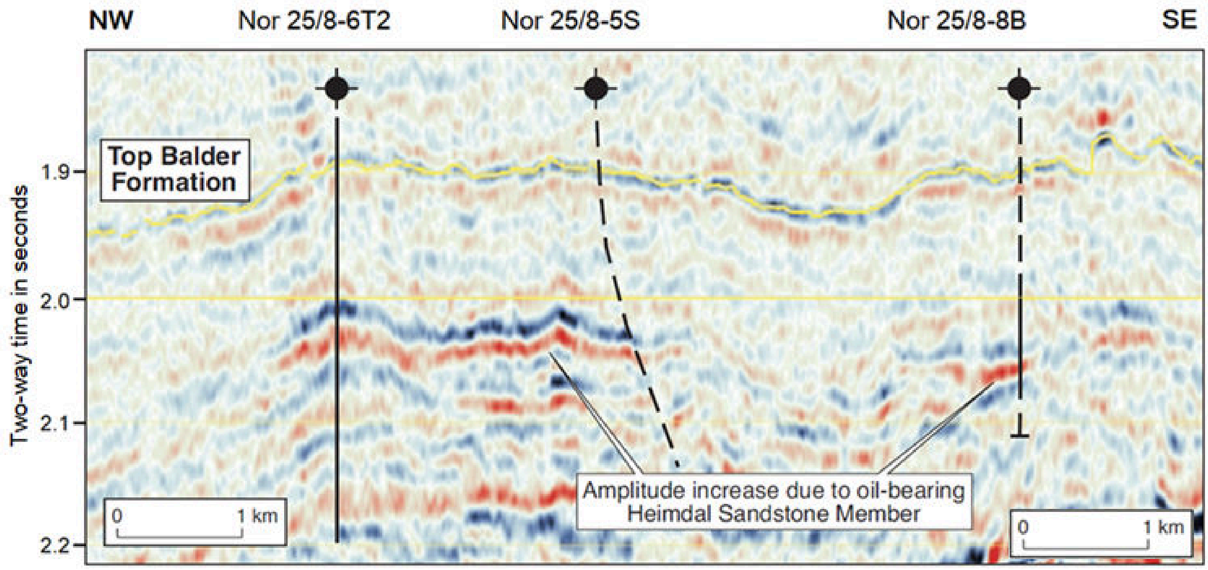


Figure 7.17: 3D-seismic profile from a far-offset-stack seismic cube. This type of processing enhances the amplitude of the oil-bearing sandstones (Evans et al., 2003).

Geologically, the Jotun Field contains both differential compaction traps (Elli and Elli South four-way dip closure prospects) and a stratigraphic pinch-out trap (Tau West prospect) (Fig. 7.18a). The field produces from the distal parts of the Paleocene Heimdal Formation sand-rich submarine-fan system. Transport distance from the sediment source area on the East Shetland Platform was 50-100 km. The easternmost structure has a small gas cap. The oil-water-contact (OWC) has been located at 2091 m below the seabed. To the west, the reservoir quality is good, while the shale content increases towards the east. The oil column thickness in exploration wells range from 18 to 46 m.

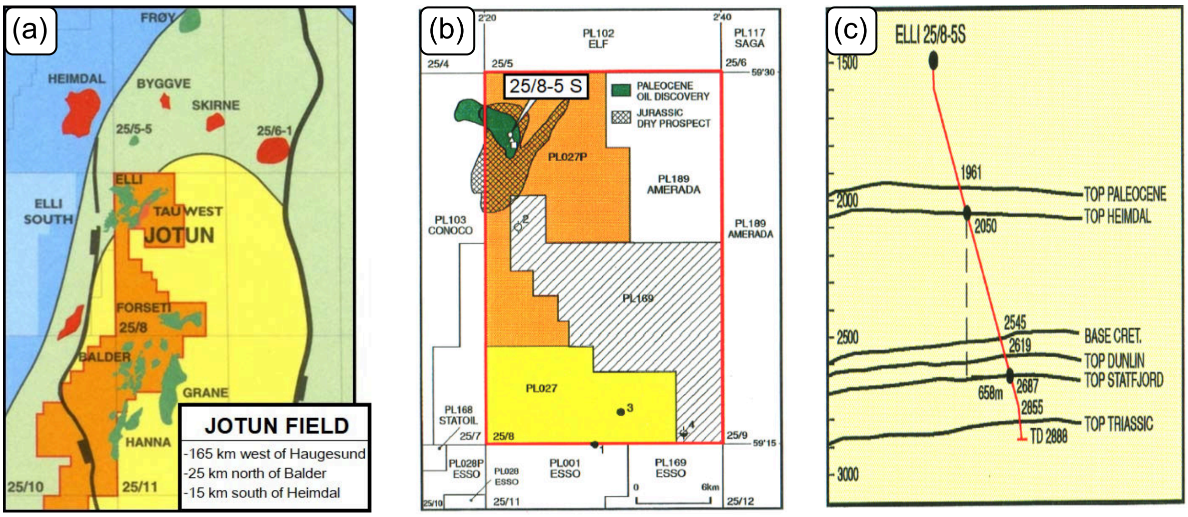


Figure 7.18: (a) Location of Jotun Field; (b) Location of exploration well 25/8-5 S; (c) Well-tops (top formations penetrated by well 25/8-5 S (from NPD website www.npd.no).

The main objective of well 25/8-5 S (Fig. 7.18b) was to test the presence of hydrocarbons in both the Lower Jurassic Statfjord Formation and in the Paleocene Heimdal Formation in the Elli Prospect (Fig. 7.18c). The well was to be drilled as a directional well in order to penetrate the two targets. Top Heimdal Formation was penetrated at 2112.6 m (2050 m TVD SS) at an inclination of 33 degrees and an azimuth of 171 degrees and was found to contain oil. The oil-water-contact (OWC) was estimated at 2158 m (2087 m TVD SS). The well was successfully tested in the Heimdal Formation (interval: 2118-2149 m) and flowed 1073 Sm^3/day of 37 degrees API oil through a 128/64 inch choke. The GOR was 38 Sm^3/Sm^3. No sand or water was produced. The recovered Heimdal Formation core consisted of fine-medium grained sandstone. The core showed dewatering structures and the depositional units have sharp erosional bases. The depositional environment has been interpreted as high density turbidity flow (Fig. 7.19).

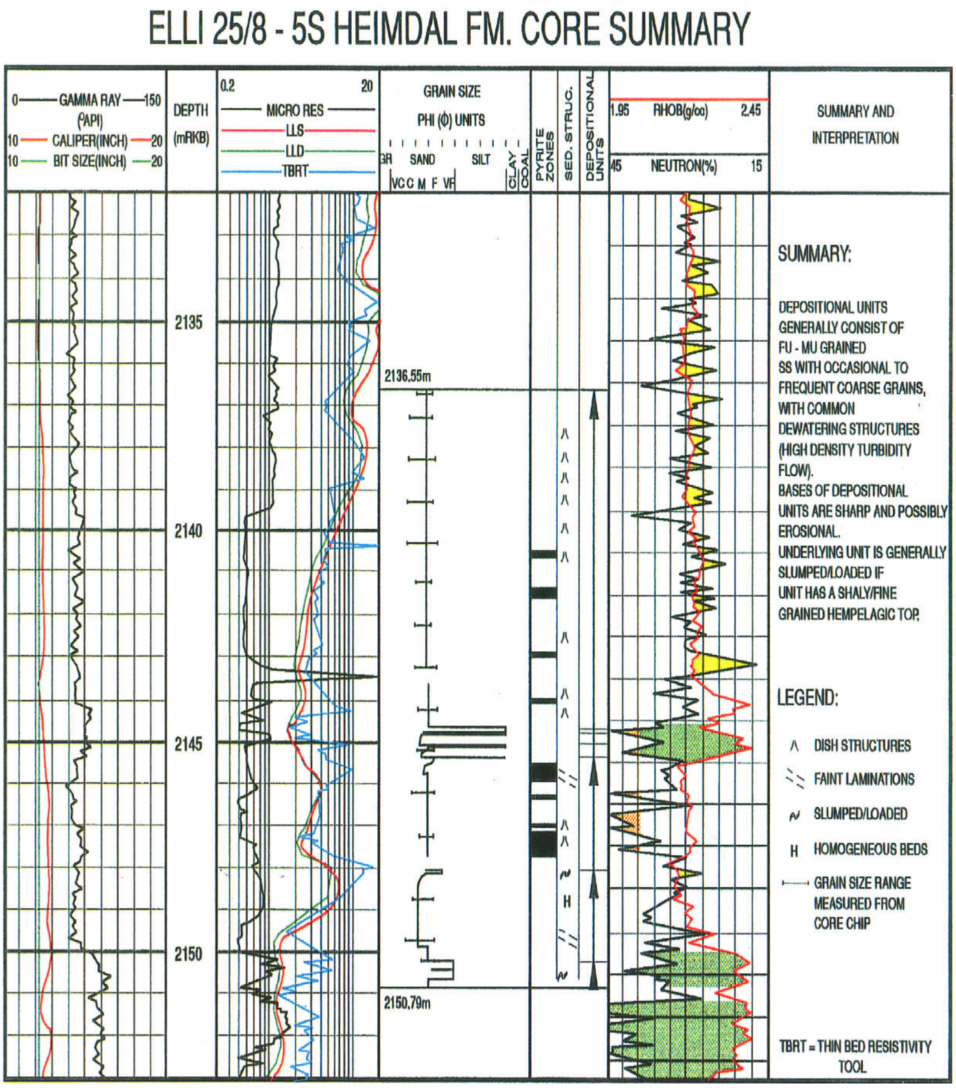


Figure 7.19: Well-log interpretation and core summary of the discovery well 25/8-5 S (from NPD website www.npd.no).

The density log porosity was calculated using the density porosity, while the shale volume from the gamma ray, density, neutron and thorium logs. Water saturation was calculated using the LWD deep resistivity log in a standard Archie equation. The density log porosity was calibrated to the overburden corrected core porosity. The porosity fits are excellent, and give high confidence in the density porosity. The porosity values vary from 25 to 32% and the permeability values from 0.5 to 3 Darcies.

7.2.6 Eocene

The principal Eocene reservoirs are interpreted as deep-marine sandstones deposited in the basin centre. They include not only classical turbidites, generally interpreted as having been deposited during lowstands, but also debris flows and slumps that could equally have been deposited during highstands. Reservoir quality is good in most Eocene fields since the sandstones are relatively unconsolidated, and thus diagenesis does not play any role in deteriorating the Eocene reservoir quality. Most Eocene reservoir sandstones were charged with hydrocarbons prior to any significant cementation. The principal control on porosity and permeability characteristics is primarily depositional lithology. Eocene reservoir sandstones differ from those of the Paleocene in detrital mineralogy, as the large delta-fed Paleocene fans are typically more clay rich. Eocene reservoirs are generally cleaner with a low detrital clay component, reflecting their provenance from extensive reworking on the shelf prior to resedimentation into basinal areas (Bowman, 1998). Eocene reservoir sandstones thus display similar porosities to Paleocene reservoir sandstones (25 to 35%), but with considerably higher permeabilities (100 to > 1000 mD).

Lower Eocene submarine-fan sandstones contain gas in the Odin and Northeast Frigg fields; reservoir properties are excellent with net/gross of 0.9 and porosities of 30%. For example the poorly consolidates sandstones in the Frigg Field have an average porosity of 29% and a permeability of greater than 1 Darcy (Brewster and Jeangeot, 1987). The Odin Field is located in the Norwegian sector of the North Sea, approximately 22 km northeast of the Frigg Field and approximately 250 km northwest of Stavanger, mainland Norway (Fig. 7.20). The Odin Field is a part of the reservoir system of Eocene age which includes the Frigg and Northeast Frigg fields. The three fields lie at different subsea depths with the gas-oil-contact (GOC) at 2021 m subsea for the Odin field. The reservoir contains a dry gas similar to the Frigg Field gas. Using seismic information and reservoir data obtained from the exploratory wells, it is estimated that recoverable reserves are 22 x 10^9 Sm^3 of hydrocarbons. There is no direct connection in the gas zone between Odin and Frigg fields, however, the reservoir sand connects the Odin Field with the Frigg Field in the underlying water zone.

The Odin Field sandstones are mostly interpreted as representing mass flow transport and deposition in channels or fans sourced from shallow marine environments of the East Shetland Platform. Some sandstones are considered to have been emplaced by injection from lower levels. The sandstones are well to moderately sorted, clean and poorly cemented, although tightly cemented sandstones occur locally. Grains are medium rounded to sub angular. Sandstone intrusions are frequently found associated with the upper boundary of sandstones bodies, often with an abundance of angular and tabular mudstone clasts.

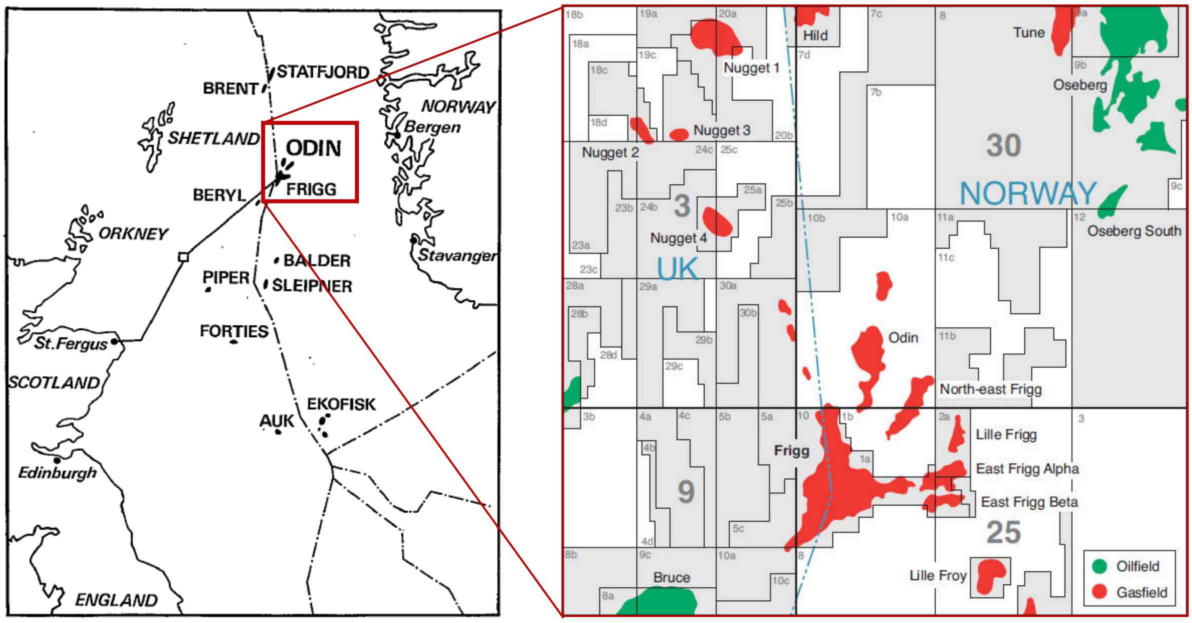


Figure 7.20: Location maps of the Odin and Frigg fields. Licensed areas are shown in grey (Evans et al., 2003).

The seismic character of the Odin sandstone Member varies from mounded to lenticular or trough shaped channel infills. Sometimes the top of the sandstones of the Odin Member is associated with a marked change in acoustic impedance and an increased amplitude. In other cases the top of the Odin sandstone Member is difficult to recognize, and its presence is inferred from a thickening of the Balder Formation interval (Fig. 7.21).

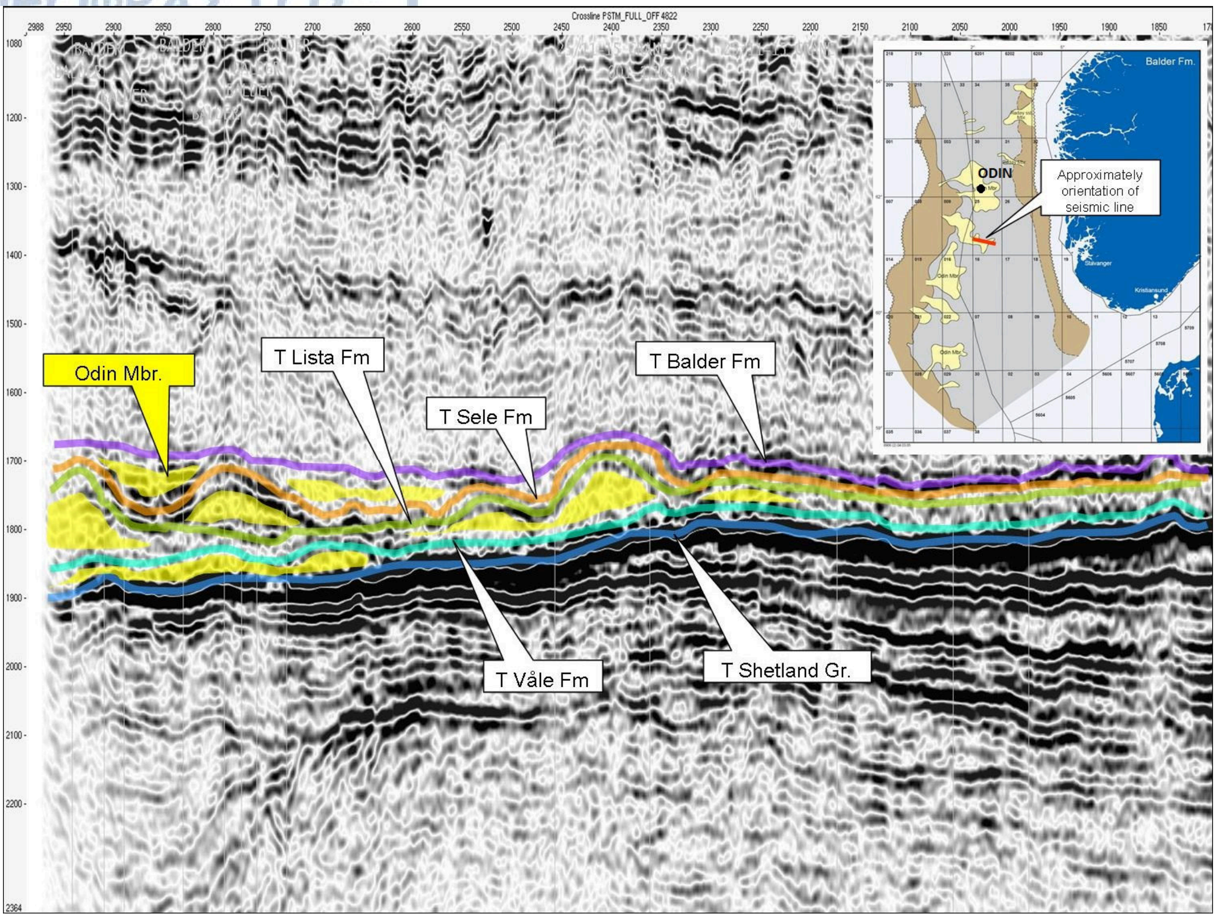


Figure 7.21: W-E seismic cross section through the area between the northern Balder and Grane fields in blocks 25/10 and 25/11. Inferred presence of the Odin sandstone Member is highlighted (from NORLEX website www.nhm2.uio.no).

The basal contact of the Odin sandstone Member is seen as the boundary between the shales of the Sele or Balder Formation and the lower parts of the Odin sandstone Member. The boundary is placed where there is an upwards transition from higher gamma-ray readings and higher velocity in the shales to lower gamma-ray readings and higher velocity in the sandstones. The Odin sandstone Member is overlain by the Balder Formation with variable amounts of tuff. The transition from the Balder Formation is usually seen as a downwards decrease from low/intermediate gamma-ray readings to lower gamma-ray readings together with an increase in velocity readings (Fig. 7.22).

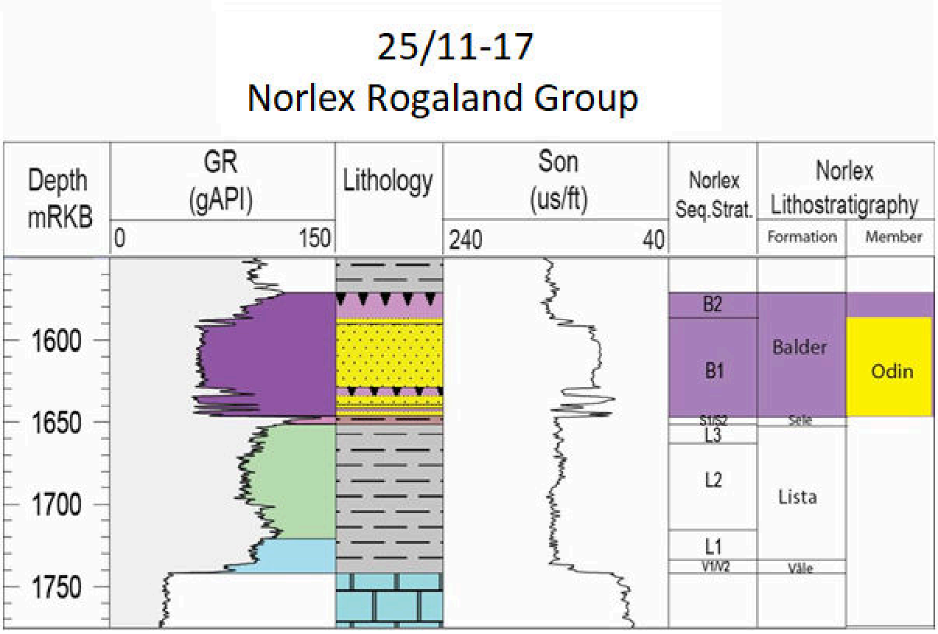


Figure 7.22: Well 25/11-17 composite log in Rogaland Group. Stratigraphic position of the Odin sandstone Member is outlined in the stratigraphic column to the right (from NORLEX website www.nhm2.uio.no).

7.3 HYDROCARBON MIGRATION AND CHARGE

7.3.1 Petroleum system modelling considerations

Kerogen decomposes to bitumen and gas as a result of the increase in temperature experienced during burial. This process of maturation gives rise to the generation of oil and gas, initially within the kerogen. In order to discharge the generated oil (or gas), the hydrocarbon phase must first escape from the oil-wet kerogen particle or network (Barker, 1980). Once the hydrocarbon is discharged from the kerogen, it must escape through the fine-grained source rock via local intergranular or fracture permeability. This is the process termed 'drainage'. For drainage to occur, the source rock must be capable of generating enough hydrocarbon to 'saturate' the porosity of the source rock, with any excess being available for expulsion. The most impressive direct evidence for source-rock saturation on expulsion derives from the increase and then decrease in wireline-log resistivity over the oil-expulsion window as seen in the Kimmeridge Clay Formation on the Viking Graben (Durand, 1983; Goff, 1984). Secondary migration includes hydrocarbon-phase movement within longer distance through regionally extensive conduits (permeable beds, faults, etc). Since Gauthier and Lake (1993) have demonstrated the faults cutting the Brent Group sandstones in the northern Viking Graben to be fractal in terms of geometry (throw, length, density), secondary migration efficiency will be a function of the relationship between carrier-bed thickness and fault spatial density at seismic and subseismic scales. Moving away from the dominantly dip-slip faulting of the northern Viking Graben, it is a general observation that faults with a major lateral component tend to be poorly sealing, conversely acting as good vertical-migration conduits. The main proven source rocks of the northern North Sea, the Upper Jurassic Draupne and Heather formations (Barnard and Cooper, 1981; Thomas et al., 1985, Kubala et al., 2003) show large vertical and lateral variations in TOC, kerogen type, and thickness, making the accurate calculation of the generated petroleum volume and thereafter the modelling of migration pathway patterns challenging through geological time. The discussion below focuses on the time intervals that have an important role in the petroleum system modelling considerations of the northern North Sea.

Late-Paleocene

Jurassic source rocks in the North Viking Graben depocentre attained temperatures of about 120º C and have generated significant amounts of oil. On the flanks of the North Viking Graben and in the East Shetland Basin, the Jurassic section was mainly immature for oil generation.

Late-Eocene

Jurassic source rocks in the North Viking Graben had attained temperatures of over 140º C and were at peak oil-maturation level; most of the oil generated from source rocks within this area migrated eastwards with the prevailing dip towards the Oseberg area. Jurassic shales on the eastern flank of the graben remained immature, while on the western flank, oil-mature Late Jurassic source rocks fed the area around the Brent Field. The Jurassic in the East Shetland Basin had become oil generative (Fig. 7.23c).

Middle Miocene

Middle Jurassic rocks (Brent Group coals) in the North Viking Graben depocentre had attained temperatures of about 160º C and were gas generative; gas migrated vertically and particularly laterally eastwards under the Upper Jurassic source-rock seal towards the Oseberg Field area. The Upper Jurassic source rocks in the North Viking Graben were oil and gas generative, and oil migrated vertically and laterally eastwards (Fig. 7.23b). Jurassic source rocks in the East Shetland Basin became fully oil generative, and oil migrated into half-graben highs (Ninian region) and up the western boundary-fault zone (Emerald region).

Present day

Formation temperatures are generally similar to those prevailing in Miocene times; any increases due to additional burial have been counteracted by decreasing sea-bed temperatures. Maturation has slowed, but migration of both oil and gas continues at similar rates, and in similar directions, to those established during Middle Miocene. There is only limited hydrocarbon migration from largely depleted source rocks (Fig. 7.23a).

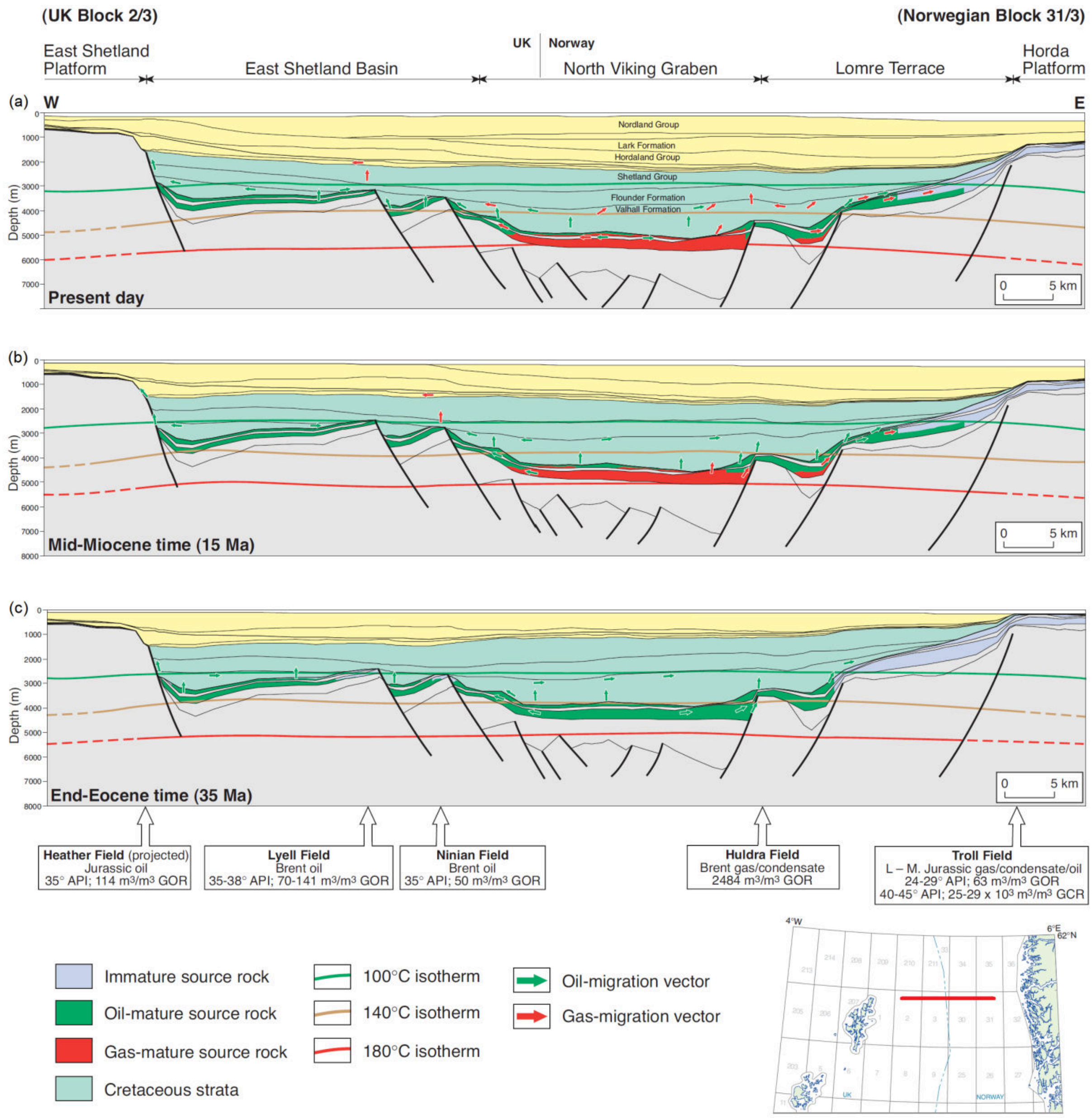


Figure 7.23: (a, b, c) 2D models of source-rock maturation, petroleum generation and migration in the East Shetland Basin and Viking Graben (Evans et al., 2003).

7.3.2 Expulsion mechanisms

Oil-to-source rock correlations, using isotope and biomarker data, consistently point toward the organic-rich facies of the Upper Jurassic (Draupne Formation and, in places, the Heather Formation) as dominant source rocks for oils in the northern North Sea (e.g. Schou et al., 1985). When a saturation-dependent approach to expulsion is used (Skjervøy and Sylta, 1993) the model results are consistent with the observations. The saturation-dependent model suggests that the Draupne Formation is the principal effective source rock by virtue of its high organic richness and that most liquid generation products tend to be retained in other source rocks (Heather, Brent and Dunlin) due to the dispersion and lower concentration of organic matter. According to calculations, the initial generation potential of the Draupne Formation accounted for only 15-20% of the total generation potential from organic matter dispersed in the Dunlin Group through the Draupne Formation succession. However, expulsion modelling shows that the Draupne Formation accounts for 50-100% of the expelled oil. Figure 7.24 shows an example of volumetric output proportions from four different locations in the northern North Sea and illustrates how the volumetric output can vary as a function of variations in source rock characteristics and geological history.

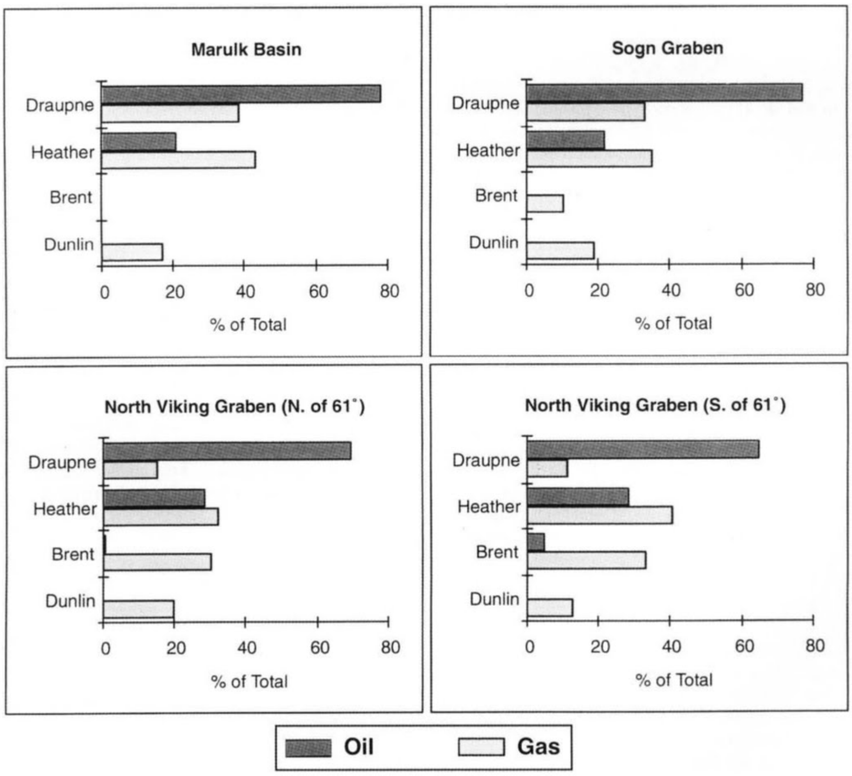


Figure 7.24: Bar charts showing semi-quantitative contributions of expelled oil and generated gas from the four source rock horizons in four different northern North Sea locations. The percentages are based on in situ yield numbers in kg/m^2 (Ofstad et al., 1998).

7.3.3 Secondary migration

During secondary migration the main driving forces are buoyancy (the difference in density of the hydrocarbon phase compared to that of the formation water) and pressure gradients due to compaction and hydrodynamic flow (Hindle, 1997). Migration is resisted by capillary pressure, a function of pore-throat radii, interfacial tension and pore-throat wettability (Showalter, 1979). At a permeability barrier or seal, hydrocarbons migrate laterally or accumulate until the buoyancy pressure exceeds the capillary entry pressure of the seal (Dembiki and Anderson, 1989; Thomas and Clouse, 1995).

In the northern North Sea, faults play a key role in controlling both hydrocarbon migration pathways and the distribution and magnitude of hydrocarbon accumulations. Faults modify migration routes and trap hydrocarbons by offsetting carrier units or, where carrier unit are juxtaposed across faults, by providing zones of fault rocks with high capillary threshold pressures (Childs et al., 2002). Vertical migration of hydrocarbons has occurred along the major graben-bounding faults in the northern North Sea. Where sandstones with the Mesozoic section terminate against faults, some leakage of hydrocarbons into the plane of the fault may have occurred, however, the bulk of the hydrocarbon would have been directed to follow structural contours along the plane of the fault towards structural culminations (Kubala et al., 2003). The main conduits for the migration of hydrocarbons within the Mesozoic section are sandstones of Middle or Late Jurassic age in the Brent Group of the Viking Graben (Miles, 1990). When the structure closest to the source rocks was filled completely to spill-point, the fluids migrated to the next structure (Fig. 7.25). Three main modes of migration from source to reservoir were identified by Curtin and Ballestad (1986): (1) intercalation of source and reservoir, (2) juxtaposition of source and reservoir across faults, and (3) vertical migration through micro-fracture systems. This classification has been expanded by Cornford et al. (1986) and Cornford (1998) as follows: (i) short distance migration, (ii) migration in rotated fault blocks, (iii) migration through faults and micro-fractures, (iv) up-flank migration from the graben, and (v) unconformity and multiple conduit migration.

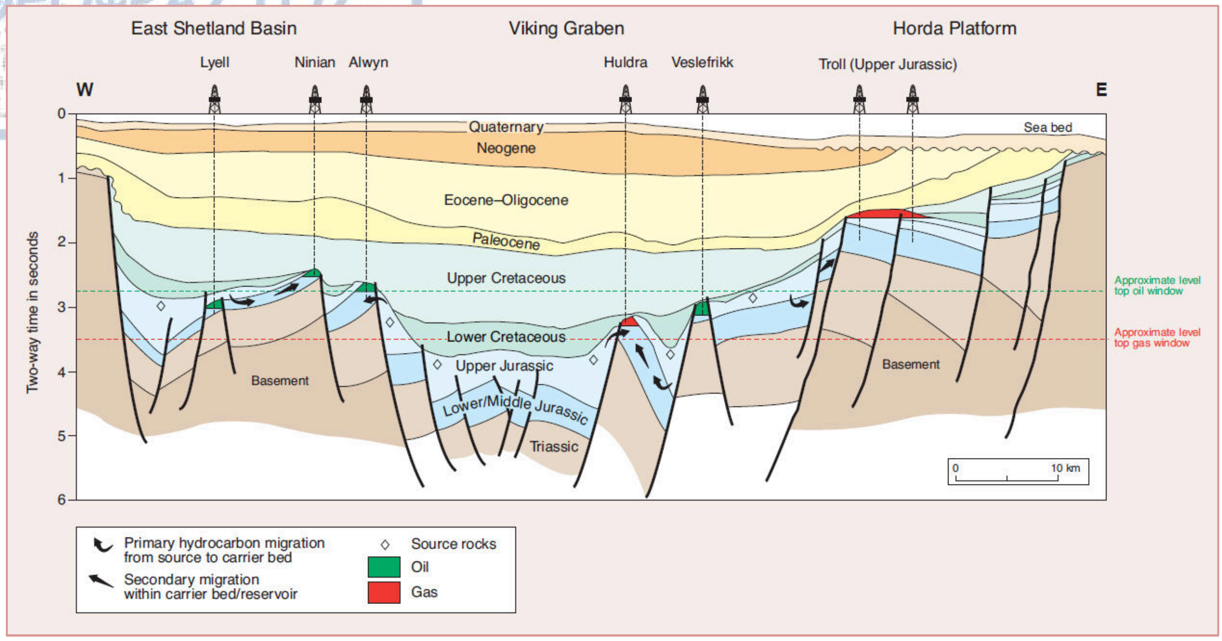


Figure 7.25: Geoseismic profile illustrating the petroleum system in the northern North Sea (Evans et al., 2003).

Sandstones of Paleocene age were important for the migration of hydrocarbons generated within the Kimmeridge Clay Formation, but which have been able to migrate vertically out of the Jurassic section. Migration may have occurred through a considerable thickness of mainly low-permeability Cretaceous strata, or by bypassing the regional Cretaceous caprock through faults. Correlation studies, particularly by detailed analyses of molecular biomarkers using gas-chromatography mass spectrometry and also by carbon-isotope analyses, have shown that, despite the variation in physical and bulk-chemical properties of oils and oil-shows in Paleocene reservoirs, they are derived from the same source-rock intervals within the Kimmeridge Clay Formation as are the bulk of oils in Jurassic reservoirs (Cooper and Barnard, 1984; Northam, 1985; Schou et al., 1985; Cornford, 1990). Migration directions would have been controlled by the dip and permeability distribution of the carrier, and by the buoyancy of the hydrocarbon phase. Lateral migration directions within Paleocene sand complexes have been strongly influenced by subtle late Cenozoic tectonism (Larter et al., 2000).

7.3.4 Tertiary migration

Tertiary migration (also called dismigration) includes leakage, seepage, dissipation, and alteration of hydrocarbons as they reach shallower depths. Tertiary migration observations may be useful as direct hydrocarbon indicators in a poorly understood basin. The physical processes that drive tertiary migration are the same as those that operate during secondary migration. Buoyancy drives hydrocarbons to the surface. This may be helped or hindered by overpressure gradients or hydrodynamics. Perhaps the only major difference that can be used to separate tertiary migration from secondary migration is the rate of petroleum supply. Trap failure, through capillary leakage, hydraulic fracture, or tectonism, supplies hydrocarbons into a new carrier system much more rapidly than does a maturing source rock. The direction of tertiary migration can be vertical, horizontal, or some combination of both. Detection and characterization of oil and gas shows within the Tertiary stratigraphic section permit mapping of migration entry points from the Jurassic source rocks and help delineate secondary and tertiary migration pathways within the Paleocene-Eocene play.

The question of how faults affect the migration of fluid in petroleum reservoirs of the northern North Sea is complicated, as some faults contribute dramatically to formation permeability (Dholakia et al., 1998) and allow hydrocarbon migration between different reservoir units (Finkbeiner et al., 2001), yet others provide effective barriers separating distinct reservoir compartments (Hunt, 1990). The sealing potential of a fault can be related to the juxtaposed lithologies across the fault and the presence or absence of seals resulting from the structure and content of the fault zone (Weber et al., 1978; Downey, 1984; Allan, 1989; Nybakken, 1991; Knipe, 1992; Berg and Avery, 1995; Fristad et al., 1997). However, the process by which a previously sealing fault begins to leak is unclear. Fault reactivation and hydrocarbon leakage in the area of Visund Field (Fig. 7.26) appears to be caused by three factors: (1) locally elevated pore pressure due to buoyant hydrocarbons in reservoirs abutting the faults, (2) fault orientations that are nearly optimally oriented for frictional slip in the present day stress field, and (3) a relatively recent perturbation of the compressional stress caused by postglacial rebound

The relationship between overpressure and fault leakage appears to be present throughout the northern North Sea. Hermanrud et al. (1997) have deduced from seismic chimneys and hydrocarbon shows in caprocks that most overpressured hydrocarbon bearing structures in the northern North Sea are currently leaking. The timing of the compression in the northern North Sea has implications for the timing of hydrocarbon leakage and migration. Long-term compression in the North Sea has been inferred from inversion structures observed offshore Norway (Rohrman et al., 1995; Vagnes et al., 1998), and bordering other parts of the northeast Atlantic Margin (Doré and Lundin, 1996). These studies generally indicate that compression may have started with ridge-push during Late Cretaceous-early Cenozoic time and extended into the Neogene. However, Grollimund (2000) has shown that glacial loading may have reduced the compressive stresses and stopped active faulting in the northern North Sea while the glacial ice sheet was present. A number of investigators have suggested that the current compressional stress observed in this region may be related to, or enhanced by lithospheric flexure associated with the subsequent deglaciation in the Pleistocene (Stephansson, 1988; Klemann and Wolf, 1998; Grollimund and Zoback, 2000). If this interpretation is correct, the existence of the current compressional stress in this area is a geologically recent (~10,000-15,000 years old) phenomenon. In Figure 7.26, it is likely that few faults ('A central' and 'A north' faults) were oriented favorably for slip in the past and by inference leaked at several times during Weichselian interglacials and after the final melt of the Weichselian age ice sheet. Several studies have found some evidence for Quaternary fault activity in the northern North Sea based on analysis of seismic data (e.g. Boe et al., 1992). However, it is very difficult to find conclusive evidence from seismic data because the accumulative fault offset associated with Quaternary faulting is expected to be no more than 1-2 m.

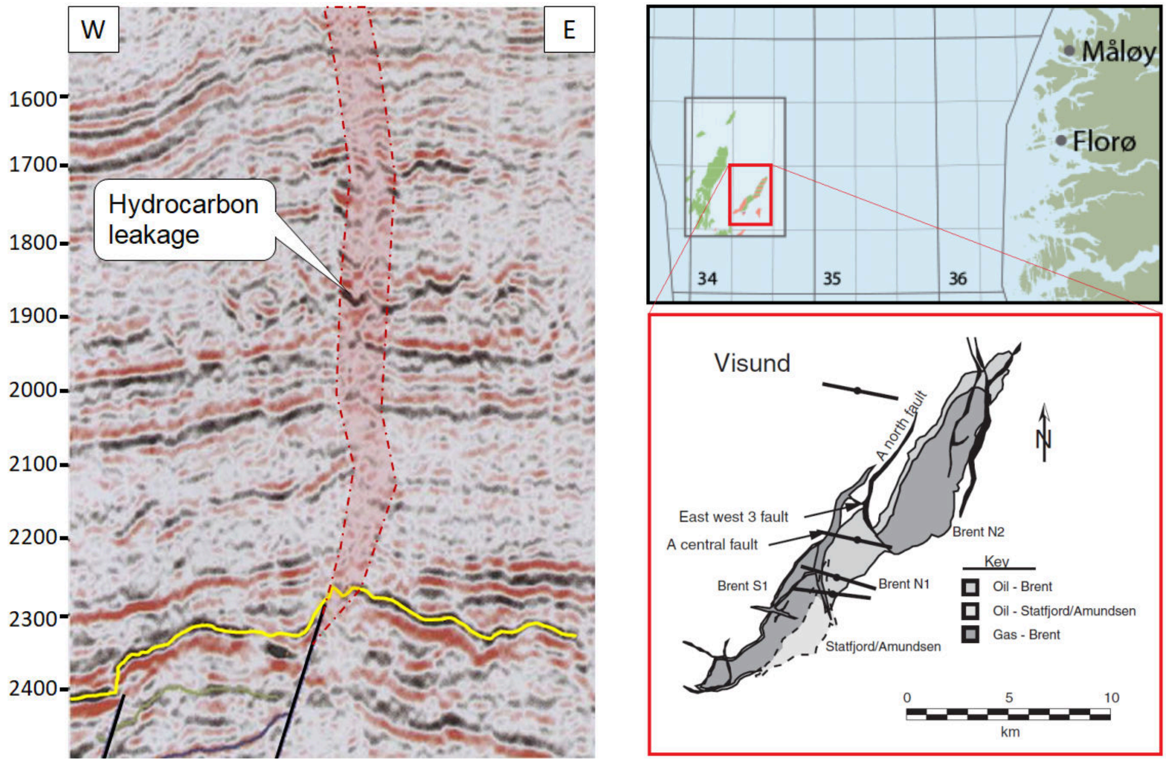


Figure 7.26: East-west seismic section showing leakage along a reservoir-bounding fault inferred from reduced seismic amplitudes. Scale is two-way-time in milliseconds. Red dashed line shows the hydrocarbon leakage pathway (left) (modified from Wiprut and Zobak, 2002); structural and location maps of the Visund Field showing the major faults and the reservoir extent (right) (Grollimund and Zoback, 2003).

Several analyses have been conducted, suggesting that any hydrocarbon reservoir that is located in the vicinity of a former ice sheet margin may have been exposed to episodes of fault leakage, if the reservoir faults were preferably oriented. However, the detailed assessment of fault leakage in a hydrocarbon prospect should be based on a dedicated fault leakage study, which should include analysis of the local in-situ stress and pore pressure conditions.

Pockmarks

Large pockmark fields represent a window into the subsurface plumbing systems. They have been targeted for extensive geological and geophysical explorations offshore Norway in order to investigate the gas origin and if they are currently active or not. Active pockmarks and mud volcanoes represent oasis of unique chemosynthetic life (Olu et al., 1997; Sibuet and Olu, 1998; Menot et al., 2010; Ritt et al., 2011). However, numerous questions remain unanswered in particular for the pockmarks at northern latitudes. For example, is the seepage entirely related to gas hydrate dissociation? Or could the leakage from underlying gas and oil reservoirs represent the source of gas? Was the gas release catastrophic or did the fluid migration occur at slow mode?

There are three main settings where pockmarks are commonly present: (1) in offshore hydrocarbon provinces where fluids leaking from reservoirs reach the seafloor, (2) in gas hydrate regions as the result of ongoing or paleo-dissociation of clathrates, and (3) in estuarine and delta regions where the constantly deposited organic-rich sediments or drowned wetlands trigger the production of shallow gas. Comparative studies show that the fields with the highest density of pockmarks are usually located at shallow depth associated with deltaic and estuarine settings (e.g. Kelley et al., 1994; Rogers et al., 2006; Brothers et al., 2012; Riboulot et al., 2013). At these localities the presence of microbial methane is mostly recorded as opposed to thermogenic methane that is common at greater water depths especially in hydrocarbon-rich provinces (e.g. Nickel et al., 2013; Smith et al., 2014)

The seabed of the northern North Sea is a gently inclined plateau; water depths gradually increasing from the south to the far north, at the edge of the continental shelf. The sediments where most pockmarks are found are all post-glacial and are similar in most respects. The density of pockmarks varies from area to area both within the North Sea and within the individual pockmarked areas in the North Sea. In the Norwegian Trench the density varies from 0 to about 60 per km^2 (counting only those that are more than 10 m across); the most densely pockmarked area of substantial size lies over the Troll gas field.

The giant Troll oil and gas field is located in the northern North Sea, about 50 km west of Norway, in the 300 m deep Norwegian Channel (Fig. 7.27A). The field extends over more than 700 km^2, and is situated on the Horda Platform between the northern Viking Graben to the west and the Øygarden Fault Zone to the east. The reservoir consists of faulted Jurassic sandstones of the Viking Group about 1.5 km below the sea floor. An extensive multibeam survey in the area above the Troll field revealed the presence of a huge pockmark field in the Norwegian North Sea where large carbonate blocks have been identified and sampled. These results were part of a large industry-funded project aiming at investigating gas migration around the Troll A platform. More than 7000 pockmarks have been identified and most likely many more could be mapped with a more extensive bathymetry study. More detailed ROV (Remote Operated Vehicle) multibeam bathymetry surveys (MBE) have provided excellent images of the pockmarks morphology. The pockmarks targeted for more comprehensive studies (Septagram, Peanut, Arch B-E) (Fig. 7.27C) have similar dimensions. The 0.5 m grid showed that the pockmarks are up to 100 m wide and 15 m deep and that the satellite pockmarks make the complexes bigger (about 300 m in diameter).

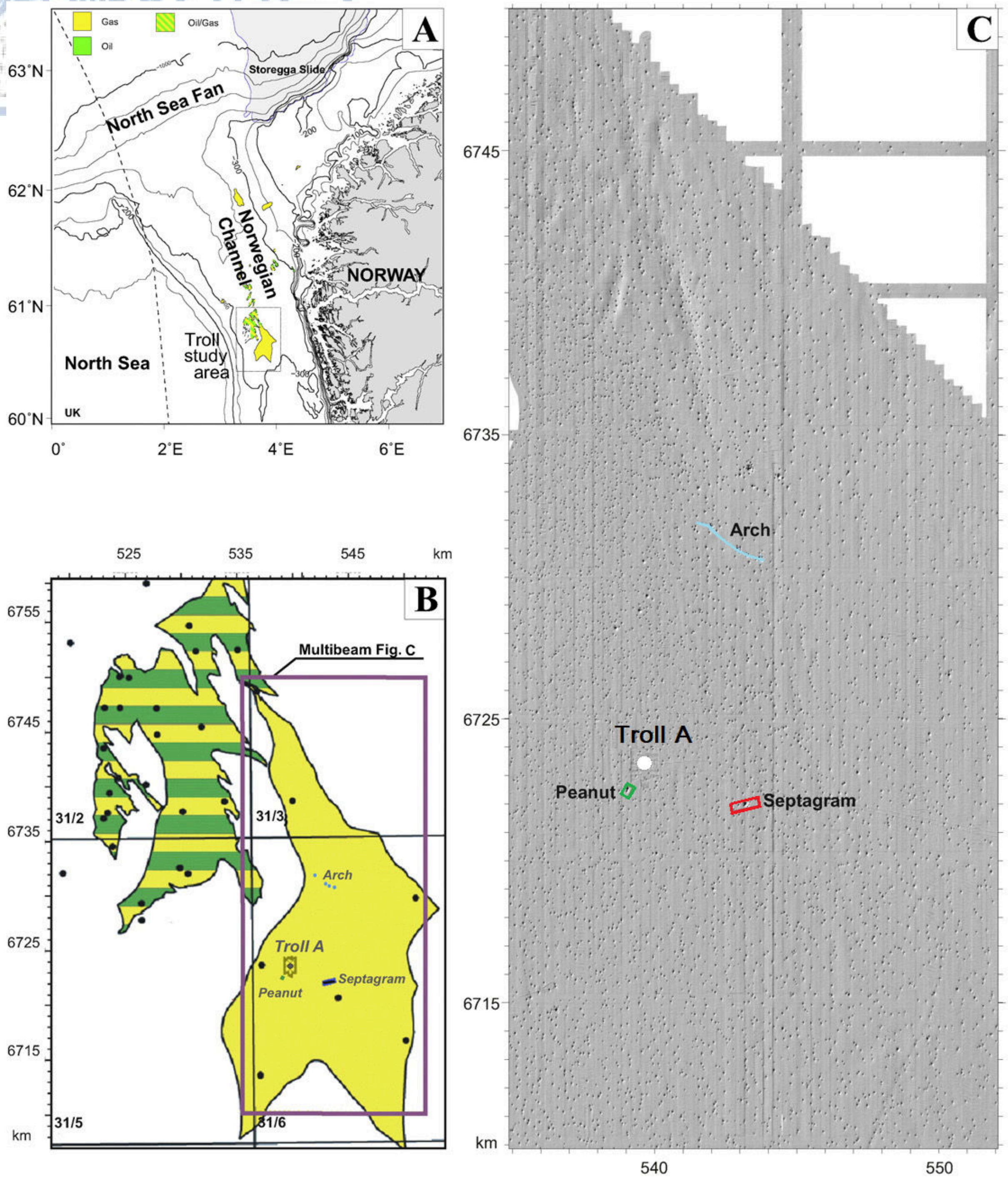


Figure 7.27: (A) Inset map of Norwegian channel and North Sea, framed the Troll study area. (B) Detail of the Troll East gas field (yellow) covered with an extensive multibeam survey (purple line). (C) Troll field multibeam data. Note the large number of pockmarks (about 7500 in total). UTM Zone 31, WGS84 datum. Indicated are the Troll A platform and the location of the three main ROV (Remote Operated Vehicle) pockmark study areas: in red (Septagram), green (Peanut), and blue (Arch) (Mazzini, 2015).

The hydrocarbons trapped in the Troll reservoir provide important information regarding the gas composition migrating from the Viking Graben (Horstad and Larter, 1997). It is therefore suggested that a thermogenic methane with composition similar to the one present in the Troll reservoir (i.e. $\delta^{13}C$=of -44.5‰; Thomas et al., 1985) migrated in the entire region of the Norwegian Channel and was mixed with shallower microbial methane. This would explain the depletion values recorded in the Troll Field carbonates. The presence of thousands of pockmarks over a large area, suggests formation during a major gas release event. Therefore, given that the Troll Field $\delta^{13}C$ carbonate values are fairly clustered, it is hypothesized that the mix of deeper and older thermogenic gas with the younger and shallower microbial gas, occurred prior to the main gas pulse that triggered the formation of the pockmarks. A possible analogy to this scenario is provided by the Peon discovery shallow gas reservoir located on the Tampen Spur to the North of Troll Field. Despite its shallow depth (165 mbsf), Peon is estimated to hold 15 to 30 billion standard cubic meters of mostly microbial gas ($\delta^{13}C$ ~of approximately -72‰). Similar to the Troll Field pockmarks, this gas is likely to be the result of deeper thermogenic and shallower microbial gas that is now trapped in a thin 18.7 m unit in a 37.8 m think formation of porous sands (NPD, 2005).

Additional evidence of paleo-seepage is provided by water analyses extracted from cores sampled inside and outside the pockmarks. The results show no difference between pockmark and background pore water sulfate concentrations, indicating that the pockmarks are currently not active fluid flow conduits. Seafloor observations showed no evidence of bubbles, fluids seepage, microbial colonies or other typical chemosymbiotic alive assemblages present at active seepage sites. Although active pockmarks are reported elsewhere in the North Sea and in the Nyegga area to the north (mid-Norwegian margin), the evidence collected reveal that there is no activity in the Troll Field area and that the retrieved carbonates are the result of a paleo-methane seepage. It is concluded that methane seepage formed this extensive pockmark gas field following gas hydrate dissociation (Mazzini et al., 2015).

7.4 SEAL

In contrast to the southern North Sea, where the Zechstein evaporites serve as a regional permeability barrier for all manner of hydrocarbon accumulations, in the central and northern North Sea, the diversity of hydrocarbon accumulations is matched by the wide variety of seals and traps. Oil and gas accumulations in pre-rift reservoirs commonly are found in tilted fault blocks where seals are formed by various fine-grained post-rift sedimentary sequences that drape the Late Jurassic structures. In the Middle Jurassic Brent Group reservoirs of the Viking Graben, traps are sealed vertically by unconformably overlying Jurassic and Cretaceous shales. Lateral seals result from the juxtaposition of shales and reservoir sandstones at fault contacts. In many syn-rift submarine-fan and turbidite reservoirs, the seal is temporally equivalent to Kimmeridge Clay Formation. In many cases Upper Jurassic shales provide both the source of the hydrocarbons and the seal for the reservoirs. Fields with post-rift reservoirs require fine-grained facies in the Tertiary sequences for seals. Wherever post-rift reservoirs are Paleocene and Eocene sandstones deposited in submarine channel and fan systems, facies relationships exert primary control on oil entrapment.

An example of thickness variations is given in Figure 7.28 where the thickness of Draupne Formation decreases from 123 m (in well 25/5-2) closer to the Viking Graben axis to approximately 30 m on the flanks of the Heimdal Terrace, and then it further decreases to 20-25 m or less over the Utsira High (in well 25/6-1 and 25/6-2). Based on the very clear seismic response of the Top Draupne reflection, and the interpretation of the Base Draupne horizon, the Draupne Formation can be up to 150-400 m thick in deep grabens, for example, in the area between wells 25/2-5 and 25/2- 4, whereas close to the crest of the Utsira High, in well 25/5-3 (Fig. 7.28a), the entire Draupne Formation has been eroded. The Heather Formation is slightly thicker, typically between 8 and 160 m in the wells. It is present in the entire area in all wells shown in Figure 7.28b, except well 25/4-1 on the Heimdal horst, where it was probably never deposited. It is up to 500 m thick in the undrilled deep parts of the grabens in the northwestern part of the area.

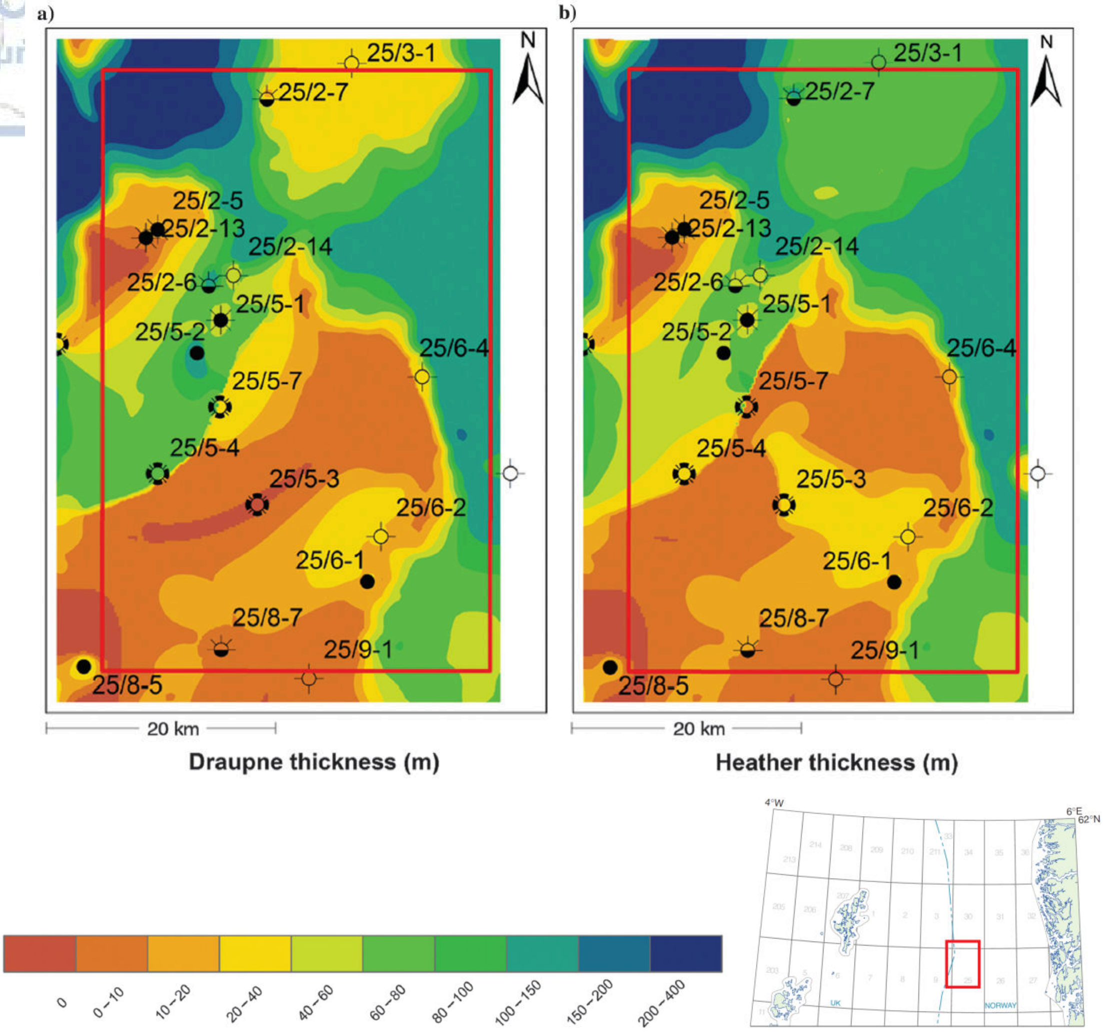


Figure 7.28: (a) Draupne Formation thickness map (m) and (b) Heather thickness map (m), indicative for appropriate effectiveness. Wells with Jurassic penetrations are shown. The red rectangles show the study area (Badics et al., 2015).

Two isopach maps of two sets of potential seals in the northern North Sea have been created (Angeli et al., 2013). Figure 7.29 illustrates the potential seal thickness distribution over a large portion of the northern North Sea. There is clear evidence of areas with so small thickness that they should not be considered as effective cap-rocks. These areas for the Mesozoic shales for example, are located along the marginal platform high that is located west of the basins forming the platform (Horda Platform, Stord Basin). The thickness increases progressively to the west and south-west, following the directions of the grabens. The quality of Cenozoic shale succession (Nordland, Rogaland, and Hordaland groups) as a secondary seal has already been proven with the success of the storage at Sleipner Field in the Utsira Formation sandstone, where shales from the Nordland Group form an excellent seal. Most of it has a ductile behaviour due to their shallow burial depth which would make their sealing properties less altered by fault movements. The transition from mechanical to chemical compaction occurs almost most of the time within these groups meaning that the bottom part of the seal would behave in a brittle way.

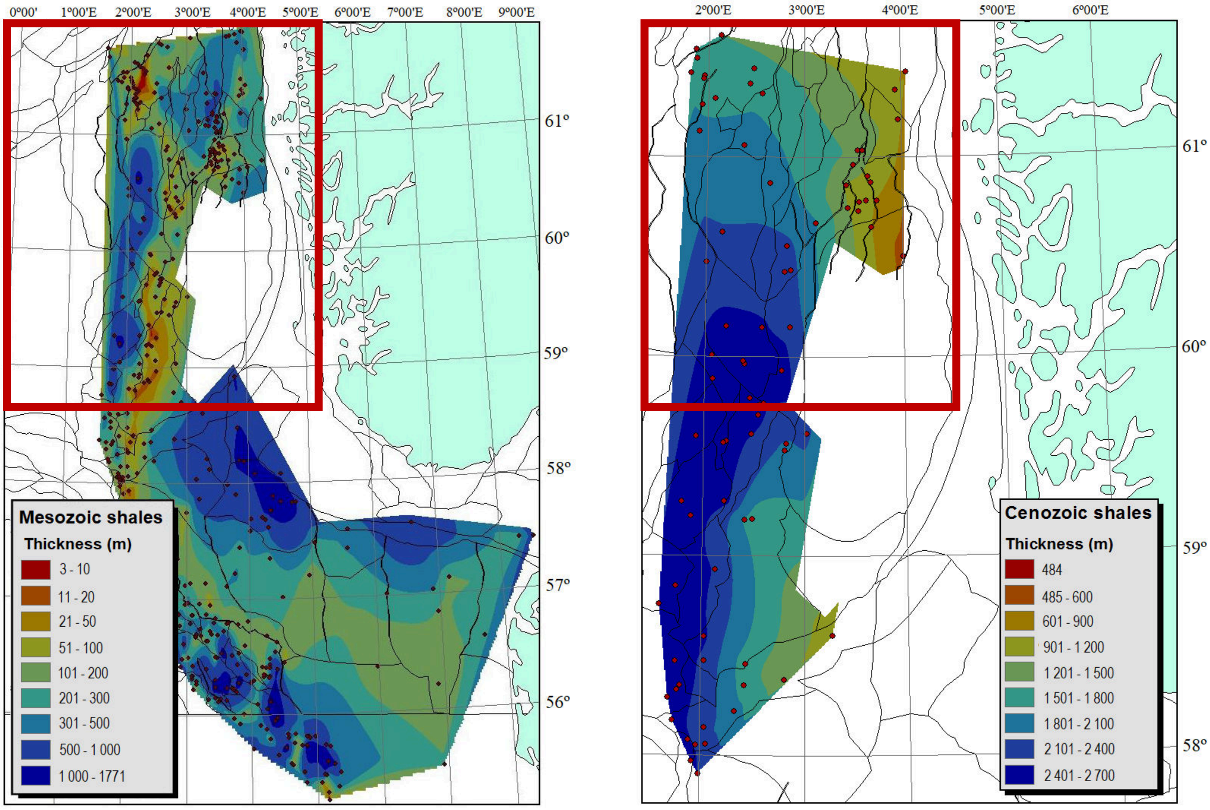


Figure 7.29: (a) Isopach of the primary seal, the Lower Cretaceous-Upper Jurassic shale formations (left hand side) (b) Isopach of the secondary seal, the Cenozoic shales groups (Nordland, Hordaland, Rogaland) (right hand side) (Angeli et al., 2013).

7.5 TRAP

7.5.1 Structural, stratigraphic and combined traps

In the northern North Sea, trap definition is the most important local parameter. Other local risks include top-seal, reservoir erosion and variations in top-seal, and reservoir facies. Exploration in the Norwegian North Sea has focused on structural traps. Recently, however, stratigraphic traps have received more attention, particularly with the advent of sequence stratigraphy as an interpretive tool for prediction of sedimentary facies and stratigraphic traps (Vail and Wornardth, 1991). The majority of the hydrocarbon traps found in the northern North Sea have an important structural component produced during phases of deformation or subsidence from Triassic to Cenozoic times. In the northern North Sea, there are very few traps related solely to pre-Late Jurassic rifting.

Oil and gas fields associated with the pre-rift, Middle Jurassic tilted fault blocks are some of the most productive in the North Sea. Syndepositional rifting exerted a major control on the development of Upper Jurassic traps in the northern North Sea. The syn-rift producing fields display a wide variety of trapping mechanisms, including tilted fault blocks, four-way dip closures, hanging-wall closures and combined structural stratigraphic closures (Johnson and Fisher, 1998). During the Late Jurassic, many of the fault blocks in the province were uplifted and eroded during the rifting. The erosion was most severe on the crests of the fault blocks, and on some the entire part of the Brent Group was eroded, as at the Gullfaks Field. In this field, the oil-bearing reservoir beneath the Base Cretaceous Unconformity (BCU) is progressively older towards the east, and the oil is trapped on numerous stratigraphic-structural compartments with several different oil-water contacts (Fig. 7.30).

Drilling results from the majority of northern North Sea fields with structural traps demonstrate that faults form pressure barriers and seals in addition to forming the hydrocarbon traps. During the exploration in the northern North Sea the significance of the faults which do not completely offset reservoir formations has not always been appreciated. These faults, often of relatively small throw, have now proved their importance with respect to disrupting hydrocarbon migration routes, providing lateral seals and variations in hydrocarbon contacts as well as causing unanticipated compartmentalization during hydrocarbon production from the fields.

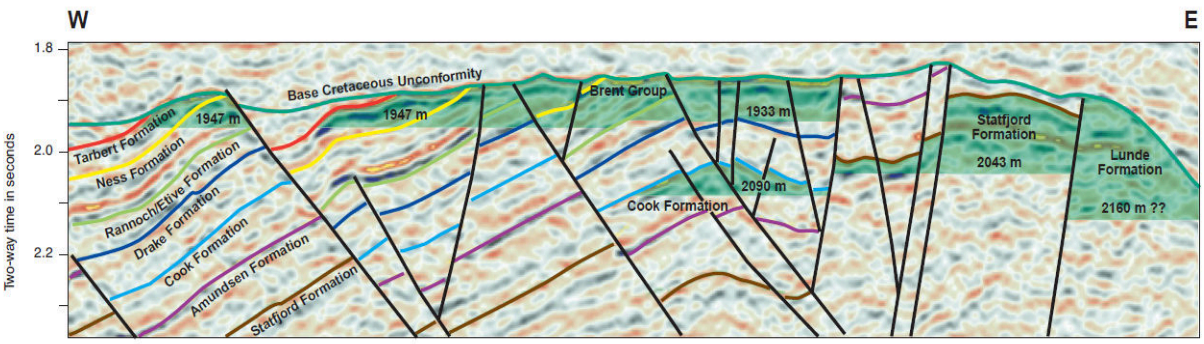


Figure 7.30: Initial distribution in the Brent Group reservoirs at the Gullfaks Field (Evans et al., 2003).

Many Lower Cretaceous depocentres within the UK Central and Northern North Sea have not yet been tested by drilling and may still yield discoveries in stratigraphic traps. The Agat

Field in Norwegian waters, comprising Aptian to Albian mass-flow sands on the margin of the North Viking Graben, indicates that conditions for Lower Cretaceous reservoir charging do exist in the northern North Sea (Copestake et al., 2003), but until further exploration takes place it remains uncertain whether significant additional reserves will be found.

Paleocene sands were deposited in a nearshore shallow marine environment. In particular, there is good potential for the development of stratigraphic traps along the margins of the East Shetland Platform and Fladen Group Spur where good quality reservoir sands are present and possibilities exist for sand pinchouts and drape over the platform edge. In such stratigraphic traps it is important to gain an understanding of the patterns of sedimentation which occur in the Paleocene and also the geometry of the sand bodies present. The cyclical episodes of sand and shale deposition are fundamental part of the Paleocene play. Laterally extensive Paleocene sandstone fairways, overlain by Paleocene and Eocene sealing shales and mudstones, act as regional conduits for hydrocarbons generated in Upper Jurassic rocks. These hydrocarbons are then structurally and stratigraphically trapped in Paleocene reservoirs.

The combined structural/stratigraphic trap is considered to be the most important hydrocarbon-trapping mechanism for Eocene reservoir sandstones. Depositional factors influence sand-body thickness, geometry and orientation. In general, Eocene hydrocarbon accumulations occur within the highest reservoir unit below the main Horda Formation claystone regional seal. This implies that intraformational seals are not always reliable as top-seals. Intense polygonal faulting and/or clay diapirism has the effect of compromising regional top-seal integrity, and commonly degrades the quality of seismic data, especially in deeper graben areas. The Frigg Field comprises a number of hydrocarbon-charged closures formed by a combination of fault seal and differential compaction across the fan.

7.5.2 Rift-related trap classification

The hydrocarbon finds in the northern North Sea can be classified into traps by reservoir age; pre-rift is pre-Jurassic and Lower-Middle Jurassic: syn-rift is Upper Jurassic. All of the pre-rift and some of the syn-rift finds are traps in footwall blocks. They form a series with respect to the amount of conformable versus unconformable cap rock. In many, the up-dip seal is due to stratigraphic truncation of the reservoir below an unconformable cap-rock and the hydrocarbon pool does not extend to the bounding fault. The amount of erosion on the fault-blocks and the footwall uplift which occurred seem to be related to the magnitude of fault-throw. Most of the other syn-rift finds are hangingwall traps with entirely conformable cap-rocks.

The Lower-Middle Jurassic hydrocarbon traps are a family of traps with similar reservoirs and structural appearances. The fault blocks range considerably in areal size (Statfjord to Thistle fields) and also in structural complexity (Ninian to Gullfaks fields). With respect to the degree of erosion of the faults blocks, there is a continuous series from fields with none (Murchison and Thistle fields) to fields with major truncation (Gullfaks Field) (Fig. 7.31). The pre-Jurassic hydrocarbon traps are simply a continuation of this series, where erosion has cut even deeper.

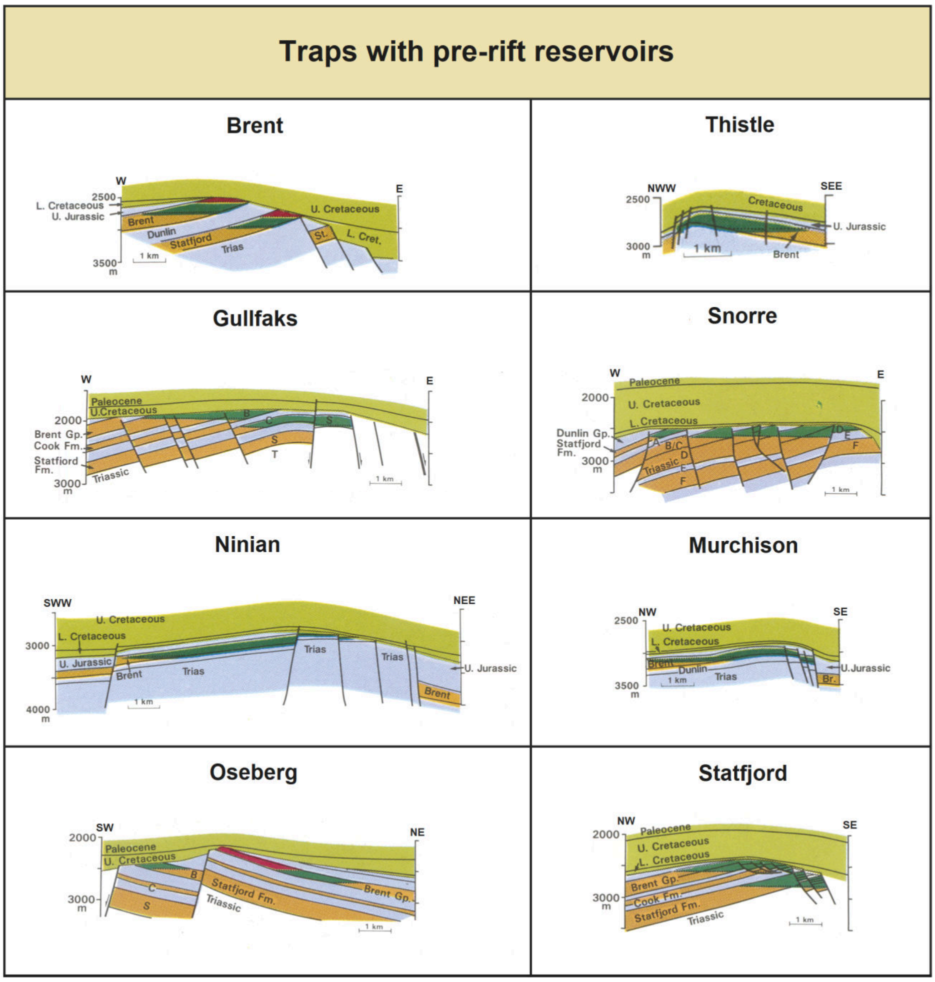


Figure 7.31: Field examples from the pre-rift trap classification. Sources: Murchison Field, Engelstad (1987); Thistle Field, Hallet (1981); Ninian Field, Albright et al. (1980); Brent Field, Bowen (1975); Statfjord Field, Roberts et al. (1987); Oseberg Field, Nipen (1987); Snorre Field. Hollander (1987). All field maps have the same scales and are contoured-using 100 m contour values and are layer-contoured. The profiles are also uniformly coloured, Cretaceous and younger, light green; Jurassic and older, blue; reservoirs, yellow; oil, dark green; gas, red (Spencer and Larsen, 1990).

The Upper Jurassic hydrocarbon traps are of several different types. The Magnus Field is a generally similar tilted fault-block but with a Kimmeridgian age submarine-fan sandstone reservoir. At the Brage and Troll fields, the reservoirs are shallow marine sandstones of Bathonian to Kimmeridgian age (Fig. 7.32). All these traps are analogous to the Lower-Middle Jurassic hydrocarbon traps, with traps in the footwalls of tilted fault-blocks where the reservoirs pre-date the main rifting movements.

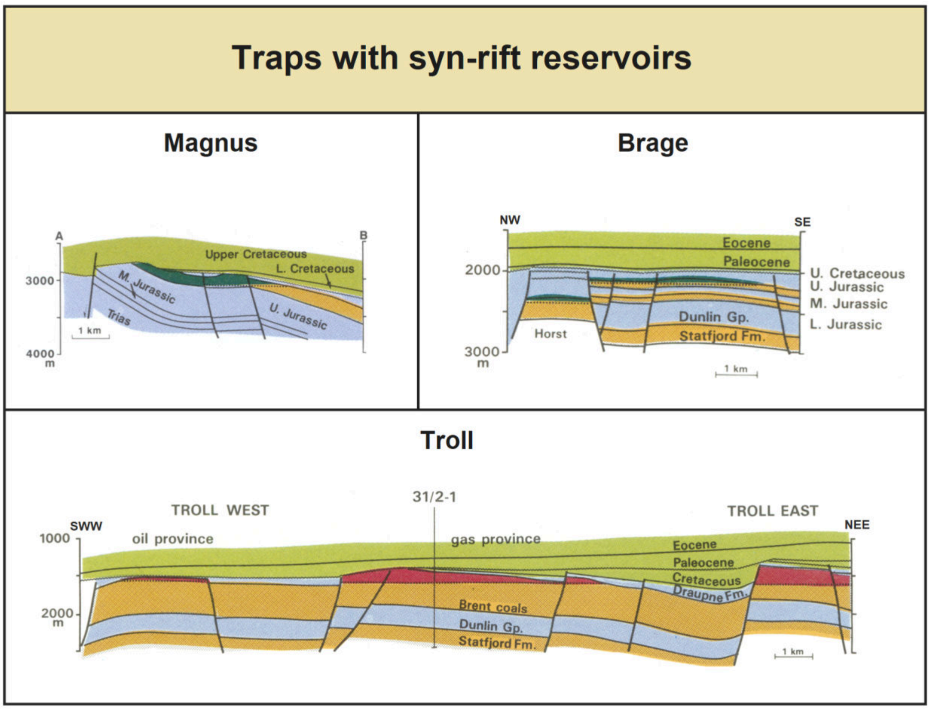


Figure 7.32: Field examples from the syn-rift trap-classification. Sources: Magnus Field, De'Ath and Schuyleman (1981); Troll Field, Gray (1987); Brage Field, Hage et al. (1987). All field maps have the same scales and are contoured-using 100 m contour values and are layer-contoured. The profiles are also uniformly coloured, Cretaceous and younger, light green; Jurassic and older, blue; reservoirs, yellow; oil, dark green; gas, red (Spencer and Larsen, 1990).

There are two main successful trapping mechanisms within the Paleogene sandstone trap classification: structural and stratigraphic (Bain, 1993). These may occur independently or in various combinations. Structural traps are most commonly associated with extensive Paleocene basin-floor fans above pre-Tertiary structural highs, which were reactivated during early Tertiary inversion to form relatively simple, low-relief anticlines, with four-way dip closure. Stratigraphic traps are of two main types: mounded closures and sand pinch outs. Mounded closures may be considered 'structural' as long as the trap geometry is defined by four-way dip closure. However, the origin of this dip closure is stratigraphic, resulting from the differential compaction of mudstones around sand-dominated parts of submarine fans. In general, sand pinch-out traps carry high exploration risk, with most potential traps failing due to inadequate seal (bottom, top and/or lateral seal failure). Notwithstanding this risk, these traps also contain significant remaining potential, because they have rarely been deliberately tested in optimal locations. The Lomre Terrace which is located on the eastern margin of the North Viking Graben in the northern North Sea Basin (Figure 7.33) is an example of how channelization and compensational stacking of sandstones have been at least partly controlled by differential compaction across previously deposited sandbodies. In general, the Cenozoic succession in the northern North Sea Basin is characterized by coarse-grained, deep-water deposits along the eastern margin of the basin, and hemipelagic, smectite-rich mudstones in the deeper, more distal parts of the basin (Jordt et al., 2000). The main study interval of the Lomre Terrace lies within the Paleocene to early Eocene Rogaland Group, which includes the Våle, Lista, Sele and Balder formations. Paleocene deep-water sandstones deposited on the eastern margin of the North Sea Basin are fine to coarse grained and occur in packages that are typically several tens of metres and up to 80 m thick. The sandstones most commonly have sharp and presumably erosive bases and pass abruptly upwards into mudstones.

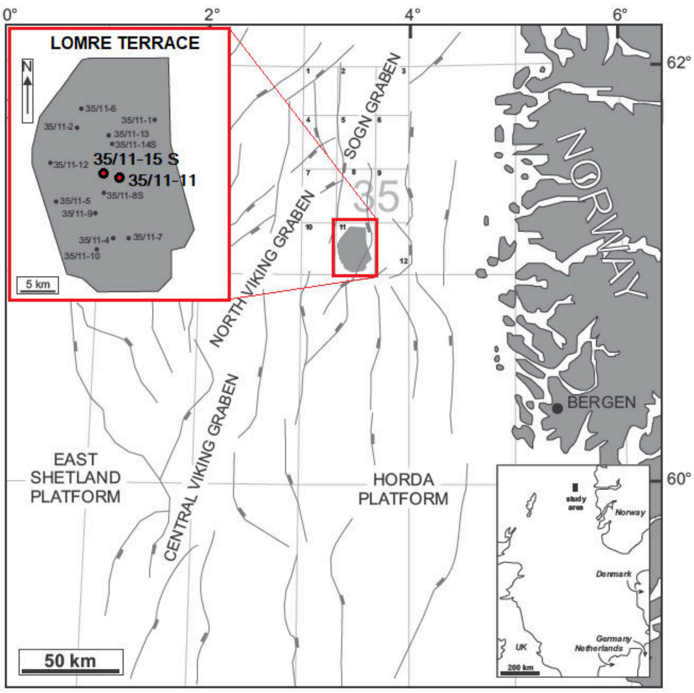


Figure 7.33: Simplified structural map of the North Sea Basin illustrating the locations of major structures associated with Permo-Triassic and Jurassic rifting (modified from Farseth, 1996; Dreyer, 1998). The study area in Block 35/11 is highlighted in grey. The lower right inset illustrates the regional geographical setting of the study area. The upper left inset illustrates the extent of 3D seismic coverage and the distribution of well data within the study area.

Having established the temporal and spatial distribution of Lower Paleogene deep-water sandbodies, the seismic expression and geometry of these units are investigated using observations from 3D seismic reflection data. The seismic expression of the deep-water sandbodies described from the eastern basin margin is similar to examples described from elsewhere in the North Sea Basin. Many of the sandbodies are characterized by high amplitude seismic reflections (Fig. 7.34), which do not appear to overlie erosional surfaces and which appear to lack flanking levees (Jenssen et al., 1993; Newman et al., 1993; Timbrell, 1993; Dixon et al., 1995; Jennette et al., 2000; Huuse et. al., 2004). Another similarity is that, although it is relatively straightforward to identify 'channel-shaped' or 'sheet-like' amplitude packages in cross-section, it is difficult to map, in plan-view, individual depositional elements, such as channels or fans. It is suggested that these difficulties arise because of the complex stacking of depositional elements, variably seismic imaging of sandstone- and mudstone-prone parts of the succession, and large-scale, post-depositional remobilization and injection of the sandstones.

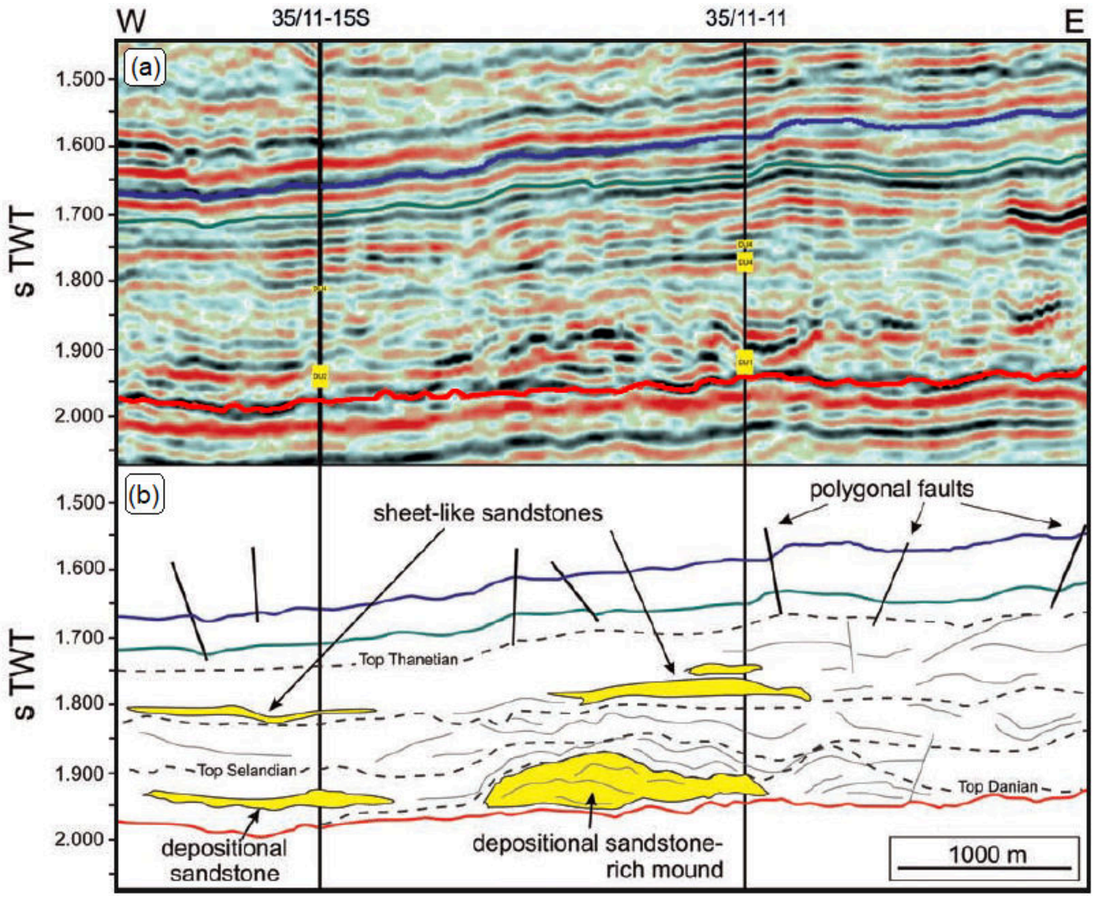


Figure 7.34: W-E orientated (a) seismic section across Lomre terrace and (b) geoseismic section illustrating the development of differential compaction related mounding across a thick Danian sandbody, and offset (i.e. compensational) stacking of a subsequent Selandinian sandbody (Dmitrieva at al., 2012).

7.6 PLAY CLASSIFICATION IN NORTHERN NORTH SEA

The North Viking Graben in the northern North Sea is a major petroleum province with several working play systems at many different stratigraphic levels. Johnson and Fisher (1998) classified the major northern North Sea plays as follows:

- Triassic-Lower and Middle Jurassic plays
- Upper Jurassic plays
- Cretaceous plays
- Paleogene plays

The existence of these plays is largely due to the combination of a regional Upper Jurassic source rock with a structural geometry created by a late Jurassic to early Cretaceous rift system and its subsequent subsidence (Spencer et al., 1996). The Lower and Middle Jurassic play is, however, the most explored and successful containing the majority of the discovered resources in the northern North Sea (Eriksen et al., 2003).

7.6.1 Triassic-Lower and Middle Jurassic plays

The pre-Jurassic play is of least importance and the most important field belonging to this play is the Snorre Field (Hollander, 1987). There, erosion has cut so deep that over large areas Cretaceous shales rest directly on the Triassic reservoir sequence and only in the west the important Statfjord Formation reservoir is still preserved. The pre-rift Upper Triassic to Middle Jurassic fluvial, deltaic and marginal marine sandstone play (Fig. 7.35) of the northern North Sea contains several major oil and gas fields (e.g. Gullfaks Field). This play alone contains 1/3 of the total Norwegian petroleum resources and more than half of the resources in the Norwegian North Sea. The Norwegian Petroleum Directorate (NPD) estimates that this play still has a significant undiscovered resource potential.

In the northern part of the North Viking Graben, the Lower-Middle Jurassic sequence is of outstanding importance. These rocks contain many of the largest fields. In Middle Jurassic times, the Brent Group delta system dominated the North Viking Graben. All the subdivisions of the Brent Group are diachronous. The delta system prograded northwards during early Middle Jurassic times, reached its maximum extent in the late Bajocian times, and retreated southwards during Bathonian and Callovian times (Graue et al., 1987). The Brent Group play is the most successful to date with over 50% of the discovered hydrocarbon reserves.

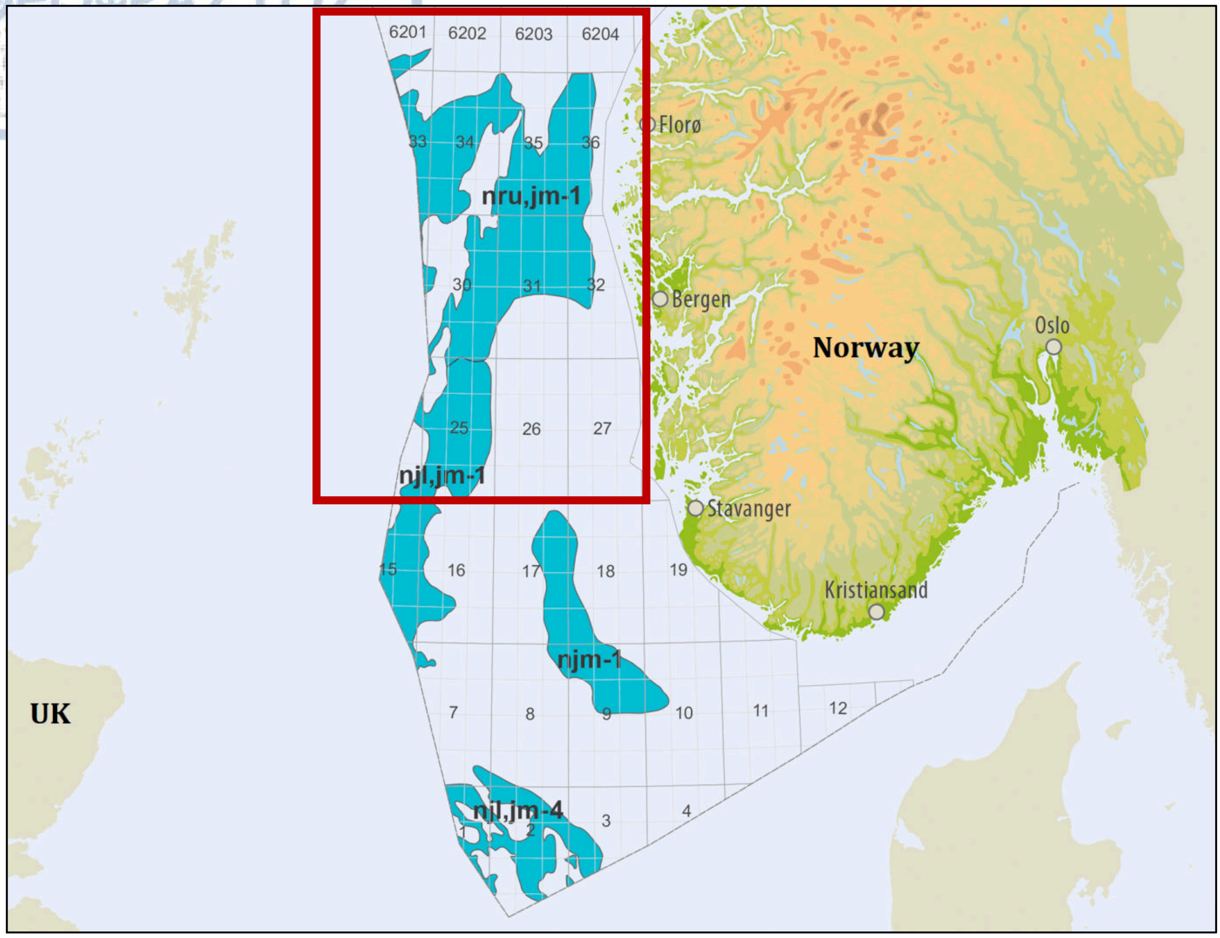


Figure 7.35: Northern North Sea Upper Triassic to Middle Jurassic plays (from NPD website www.npd.no). nru,jm-1: Hegre Group with Lunde Formation, Statfjord Group, Dunlin Group with Amundsen and Cook formations, Brent Group with Broom, Etive, Rannoch, Oseberg, Ness and Tarbert formations; njl,jm-1: Hegre Group with Skagerrak Formation, parts of Statfjord Group, Vestland Group with Sleipner and Hugin formations.

Although the basic source rocks throughout the northern North Sea are the Draupne and Heather formations, it seems that there are limited but further potential depocentres and kitchens such as at the Sleipner and Ness formations. The Middle Jurassic Hugin and Sleipner formations contain humic coals and coaly shales with potential to generate gas and some light liquids (Isaksen et al., 2002). The Sleipner Formation is found in the southern Viking Graben between approximately 58° and 60° N. The Ness Formation is present in the East Shetland Basin and is broadly equivalent to the Sleipner Formation. The name Sleipner Formation should be applied when the marine sandstones underlying the coaly sequence are absent. Non-marine sands, and associated strata, in the Central Graben and Norwegian-Danish Basin are referred to the Bryne Formation. Similarly, the seismic character of the Drake Formation seems to have a patchy distribution, indicative of varying contents of shale and sand, which is less favourable for source rock potential (Table 7.3).

Plays	nru,jm-1	njl,jm-1
Source rock	Upper Jurassic shale (Draupne and Heather formations) and Middle Jurassic shale and coal (Ness and Sleipner formations, possible Drake Formation)	
Reservoir rock	Sandstone	
Trap	Structural, rotated fault-blocks, occasionally with stratigraphic component	
Depositional environments	Fluvial, deltaic and shallow marine	
e.g. Fields	Statfjord, Kvitebjørn, Gullfaks, Oseberg, Snorre, Brage, Valemon, Visund, Knarr, Strathspey, Veslefrikk, Martin Linge	Ringhorne

Table 7.3: Play summary of the Triassic-Lower and Middle Jurassic plays in the Norwegian northern North Sea (from NPD website www.npd.no).

Triassic, Lower and Middle Jurassic plays have the characteristic that the source rock is younger than the reservoir rock, and it is only possible for the oil to migrate into the reservoir because fault tectonics during the Upper Jurassic brought the source and reservoir rocks into contact with each other, as illustrated in Figure 7.36.

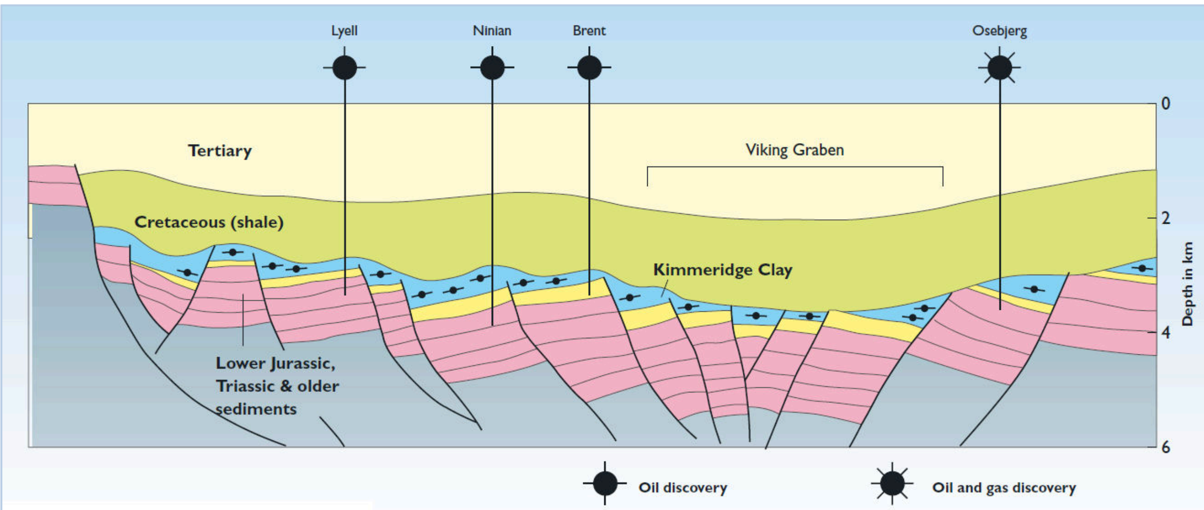


Figure 7.36: The Middle Jurassic play. The yellow layer represents the 'Brent' Group sandstones (from GEUS website www.geus.dk).

Example: Strathspey Field

The Strathspey Field is a sub-sea production facility located approximately 100 miles NE of the Shetland Islands, 300 miles NNE of Aberdeen and is tied back to the Ninian Central platform via a ten mile long pipeline. The field was discovered in 1975 by well 3/4-4 and lies wholly entirely Block 3/4a (Fig. 7.37) in a water depth of ~137 m. The field is a tilted fault block, unconformity trap and consists of two separate reservoirs, a volatile oil and a gas condensate reservoir: the Middle Jurassic, Brent Group and the Lower Jurassic/Upper Triassic, Banks Group respectively. Both have eroded crestal structures with fault scarp degradation products present on their eastern edges. The net-to-gross ration of the Brent Group reservoir in the Strathspey Field varies from 0.1 to 0.5 within the drilled wells, averaging 0.2 (Husmo et al., 2003), and accurate prediction of the sand-body distribution and connectivity is critical to effective reservoir management. The recovery factor in the Brent Group reservoir was estimated at 30-35% prior to production (ERC Tigress, 1993).

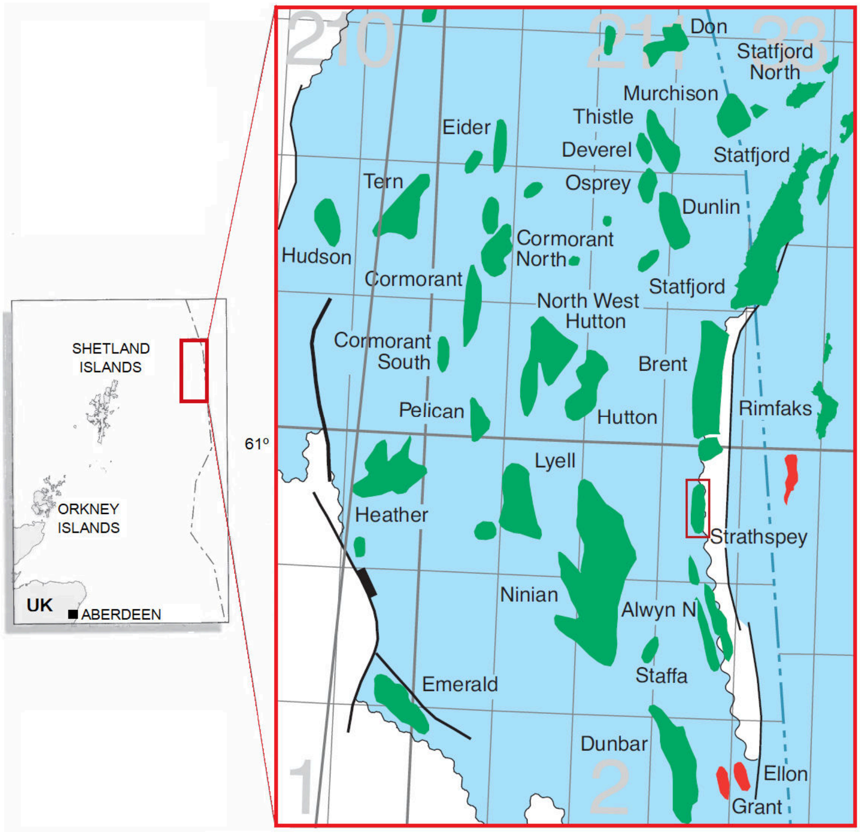


Figure 7.37: Location of the Strathspey Field (Maxwell et al., 2003).

Three major E-W faults cut the Brent Group reservoir (Southern, Central and Northern faults) (Fig. 7.38). The source rocks responsible for generating the Strathspey Field hydrocarbons are from the Upper Jurassic, Humber Group. The Banks Group reservoir fluid is thought to consist of a mixture of fluids from thin, oil prone Kimmeridge Clay Formation and thicker, gas prone Dunlin Group from the Oseberg kitchen to the south east of the field (Thomas et al., 1985). The migration route is predominantly from over-spill routes from the North Alwyn Field to the south with possible contribution from the graben to the east of the field. The field has a structural trap, 10 km^2 in area, created during the late Middle Jurassic and Upper Jurassic extension when block rotation of the Strathspey structure took place and was subsequently onlapped by non-reservoir, Cretaceous mudstones and marls. The Brent Group accumulations are constrained purely by dip closure to the north, south and west. To the east the onlap of the thick Cretaceous deposits provide lateral and top seal.

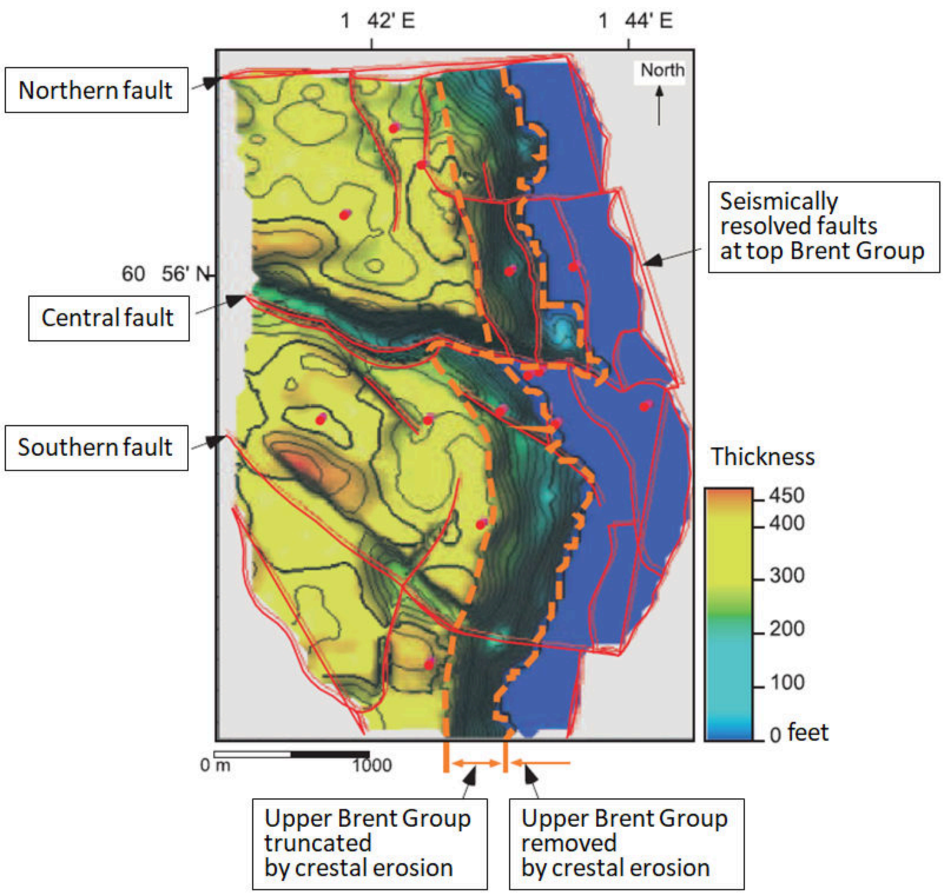


Figure 7.38: Isochore map of the Upper Brent Group. The Upper Brent Group thins gradually eastwards at the crest of the field, reflecting angular truncation at the Base Cretaceous Unconformity (BCU). Thickness variations on the flank of the field occur abruptly across several W-E and NW-trending lineaments that are interpreted at extensional faults (Morris et al., 2003).

The Strathspey Field has had two full 3D seismic surveys acquired across it. The original survey was acquired in 1985 for the development planning and in 1995/1996 a Vertical Cable

Seismic Survey (VCS) was recorded. The VCS survey was planned to better image the crest of the field where low-angle rotational slides cut both Brent and Banks Group reservoirs forming footwall degradation complexes (Leach, 1999). The VCS survey clearly demonstrates better imaging of the crest of the structure, of reflectors within the Brent Group and basal reflectors of the Raude Formation vastly improving interpretation (Fig. 7.39).

Overlying the Cormorant Formation are the Hettangian to Sinemurian sediments of the Banks Group which are found to be up to ~245 m thick and form the lower of the two reservoir sections in the Strathspey Field. The Dunlin Group is a mudstone and siltstone unit that separates the Brent and Banks Group reservoirs. It is has a uniform thickness of ~260 m in the Brent-Strathspey-Alwyn area (Struijk and Green, 1991) and was deposited under marine shelf conditions. The Brent Group reservoir is characterized by thin, eroded, low angle fault terraces at the western edge of the degradation complex. East of these, listric slide geometry can be illustrated more clearly where there is greater preservation of the hanging wall section and greater throw can be demonstrated across the gravitational slides.

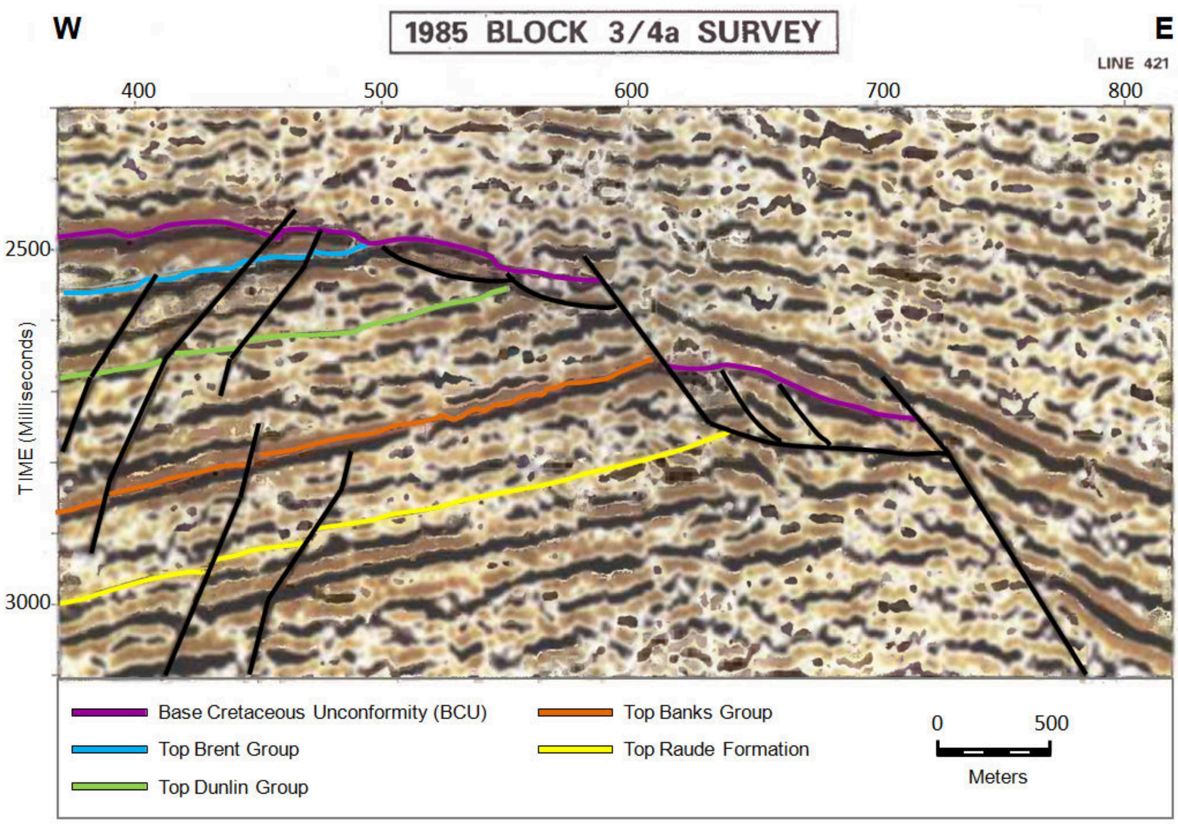


Figure 7.39: Vertical Cable Seismic (VCS) of the Strathspey Field (Maxwell et al., 2003).

Just north from the Strathspey Field another example of listric slide geometry can be clearly seen from the development of the Statfjord East Flank (Statfjord Field) (Figure 7.40). Footwall uplift of the main bounding fault results in the successive emergence of the Brent, Dunlin and Statfjord rocks. Three stages of detachment development occur as the major shale horizons are exposed. As the footwall uplifts a wider zone that becomes unstable, Brent rocks are progressively incorporated into the landslide, as well as deeper rocks. Early emplaced blocks in the hanging wall are of the higher stratigraphic units, but progressively older rocks are also incorporated as the complex develops and the proportion of mudslides, debris flows increases with time. Most authors have argued that listric faults formed by gravitational instability during rifting.

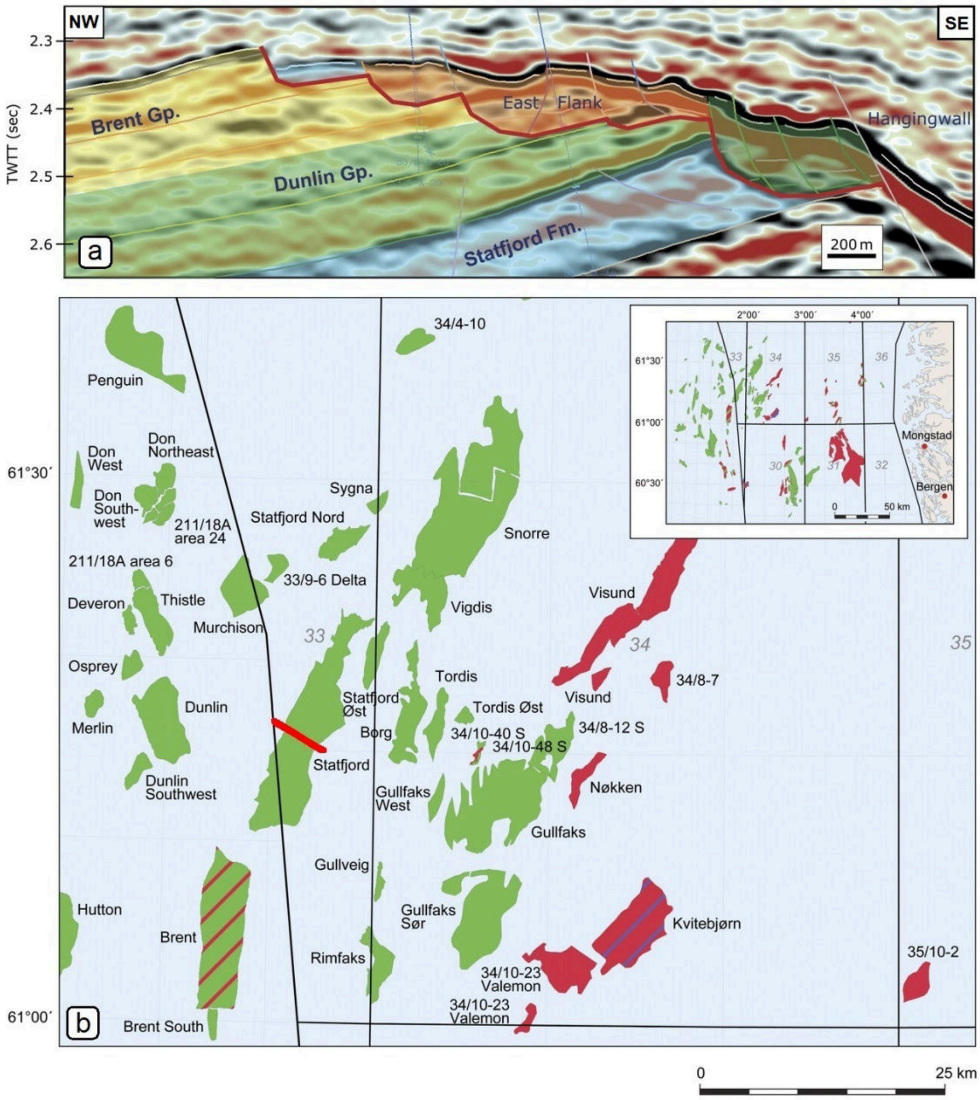


Figure 7.40: (a) Seismic cross-section through the Statfjord Field outlining the structural elements, including the main field, main bounding fault, the East Flank landslide complex, and the hanging wall; (b) Location of the seismic profile (Welbon et al., 2007).

7.6.2 Upper Jurassic plays

Upper Jurassic plays (Fig. 7.41 and Table 7.4) occur both in the southern and the northern parts of the Norwegian North Sea. Norway's largest field, the giant Troll Field (47×10^{12} scf gas + 1.8×10^{9} bbl liquids) belongs to this play. The Upper Jurassic is the most variable and complex in the North Sea both for regional-fairway analysis and prospect evaluation. It is also one of the most important plays in terms of proven discoveries and remaining undiscovered hydrocarbon potential (David, 1996; Johnson and Fisher, 1998).

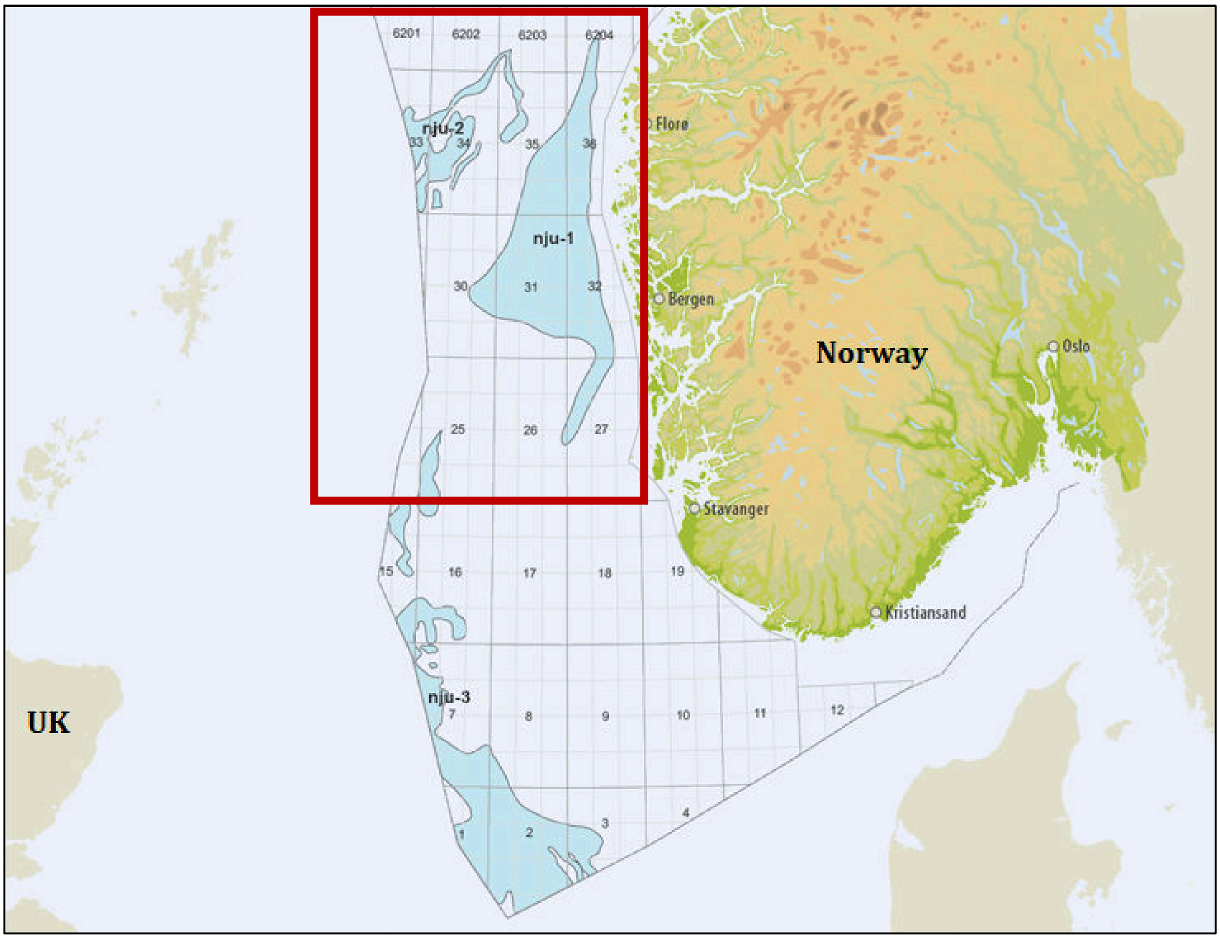


Figure 7.41: Northern North Sea Upper Jurassic plays (from NPD website www.npd.no). nju-1: Viking Group with Heather, Krossfjord, Fensfjord and Sognefjord formations; nju-2: Viking Group with intra Draupne and intra Heather formations.

Within the Upper Jurassic play fairway, the key controlling parameters of both the shallow-marine and deep-water sandstone plays are reservoir, top seal, and hydrocarbon charge (Johnson and Fisher, 1998). The key success factors of this play comprise: (i) widespread, high-quality sandstone reservoirs, although these have a complex distribution; (2) the overlying and/or interfingering Kimmeridge Clay Formation, which provides both the top seal and, in graben areas, a mature source rock; (3) short-distance migration routes, generally not more than 10-15 km up-dip of the mature oil kitchens (Cayley, 1987), and (iv) significant overpressures in the grabens, which have enhanced the preservation of porosity at depths of over 3900 m (Gaarenstrom et al., 1993).

Plays	**nju-1**	**nju-2**
Source rock	The main source rock is Upper Jurassic shale (Draupne Formation)	
Reservoir rock	Sandstone	
Trap	Stratigraphic and structural, rotated fault-blocks	
Depositional environments	Marginal to shallow marine and deep water	
e.g. Fields	Troll, Fram, Brage, Gjøa	Statfjord Nord

Table 7.4: Play summary of the Upper Jurassic plays in the Norwegian northern North Sea (from NPD website www.npd.no).

The Upper Jurassic reservoirs are complex. In fact, there is no single Upper Jurassic play, but rather several, because the reservoirs are so different from each other. The number of plays is the result of the geomorphology of the Upper Jurassic. The two main elements include the Upper Jurassic coastlines, and the morphology of the sea bed (bathymetry). The significance of these two elements is illustrated in the Upper Jurassic play Figure 7.42.

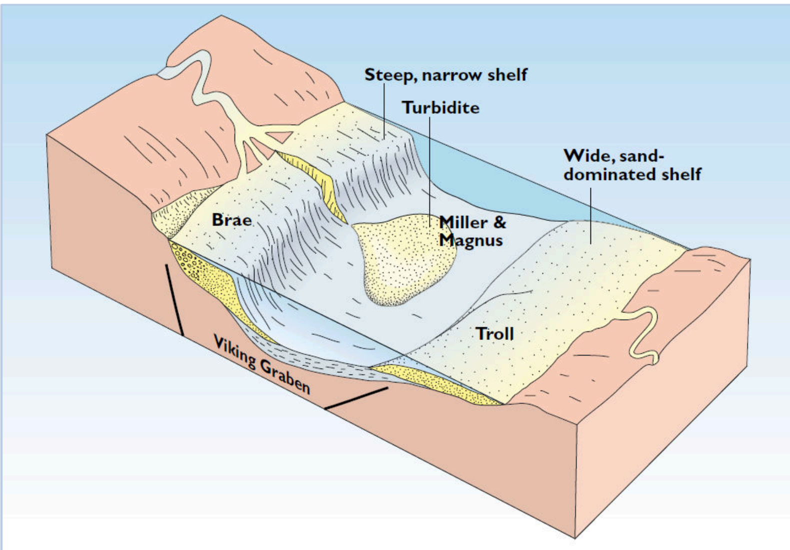


Figure 7.42: The Upper Jurassic play. The three main types of reservoirs that are found in the fields are named in the diagram (from GEUS website www.geus.dk).

Example: Brage Field

Brage is an oil field in the northern part of the North Sea, east of the Oseberg field. The water depth in the area is 140 m. Wildcat well 31/4-3 (Fig. 7.43) was drilled on the Bjørgvin Arch in the North Sea, east of the Oseberg main field. Two separate hydrocarbon-bearing sandstone intervals were encountered in the Late Jurassic Heather Formation. The Oxfordian to Kimmeridgian 'Intra Heather Sand I' from 2018 m to 2082 m had gas down to a gas-oil-contact (GOC) at ~2035 m and oil down-to 2048 m. The section below 2048 m had silty to shaley sand with 82% water saturation. The oil-water-contact (OWC) could be somewhere in this section between 2048-2054 m. The Callovian "Intra Heather Sand II" (Fensfjord Formation) from 2136 to 2246 m had oil (57.7% average water saturation) down to a possible OWC at 2172. This section was a silty/shaley sand and the net pay was 24 m. Below this the well penetrated 45 m of Middle Jurassic Brent Group sandstones, a 291 m thick Dunlin Group with sandstone in the Cook Formation and the Johansen Formation, and a 177 m thick Statfjord Group consisting of clean sandstone with some shale beds (Fig. 7.45). These sandstones were all found to be water-bearing. Below the Statfjord Group the well penetrated 1571 m of the Triassic Hegre Group, and ended up in rocks of possibly Permian age. These sections were also water-bearing. Apart from shows in the hydrocarbon bearing Intra Heather Formation sandstones only a weak oil show in the Lista Formation at 1890 to 1905 m was recorded. The well was permanently abandoned on 11 May 1980 as an oil and gas discovery.

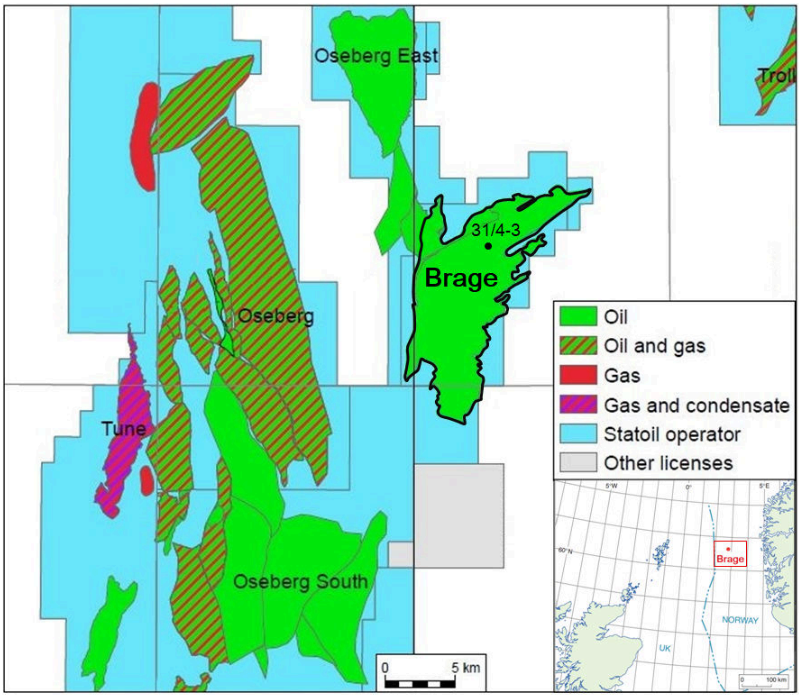


Figure 7.43: Location of the Brage Field.

The reservoir in the Brage Field contains oil in sandstone of Early Jurassic age in the Statfjord Group, and of Middle Jurassic age in the Brent Group and the Fensfjord Formation. There is also oil and gas in the Sognefjord Formation of Late Jurassic age. The reservoir quality varies from poor to excellent. Three rift phases are postulated to have taken place in the Late Jurassic: the first during the mid-Callovian to early Oxfordian, the second during the mid- or late Oxfordian to Kimmeridgian, and the third in the early to mid-Volgian. The Horda Platform became progressively more compartmentalised during these rift phases (Ravnås et al., 2000), but during the intervening tectonically quieter intervals it experienced overall subsidence and basinward rotation, a pattern more typical of post-rift evolution. During the first and second rift phases uplift in the footwall of the platform's western and north-western boundary faults, such as in the Brage area (Fig. 7.44), resulted in the creation of footwall islands that formed intrabasinal sediment sources around which local shoreline sandstones were deposited.

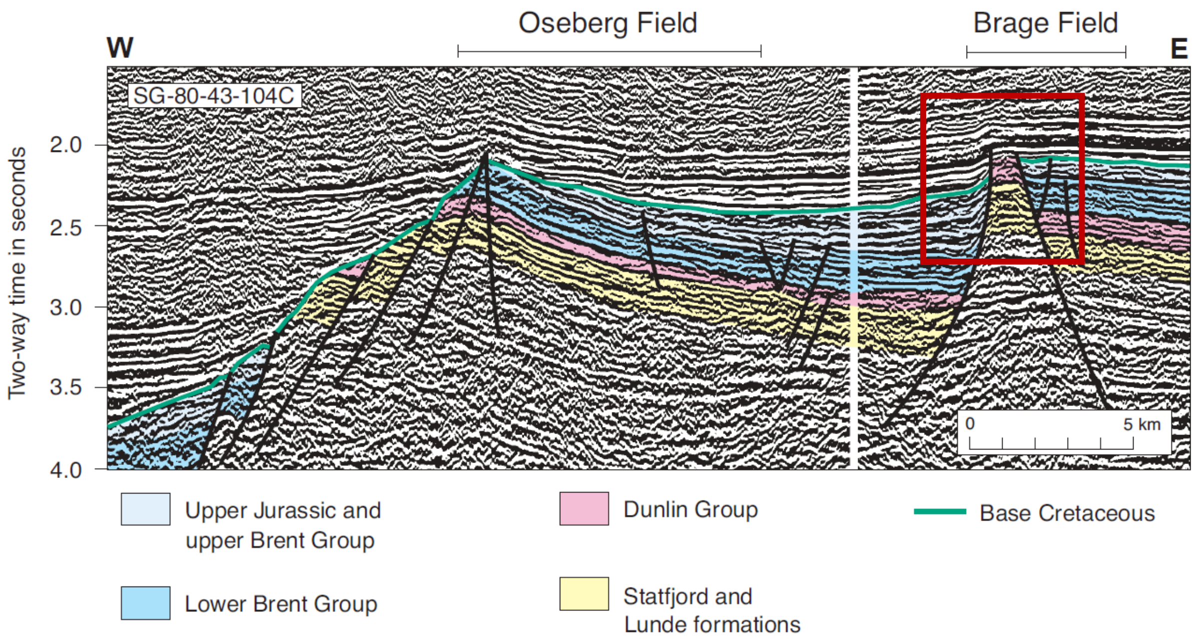


Figure 7.44: Regional seismic section through Brage Field (Evans et al., 2003).

Figure 7.45 shows cross sections of large faults with smear derived from thick source layers. The Brage East fault that delineates the Brage field to the east (Hage et al., 1987; Færseth, 1996; Aarland and Skjerven, 1998) was drilled by production wells. Jurassic (Bajocian-Volgian) extension resulted in a normal throw of 200-250 m across the fault at reservoir level (Fig. 7.45). The interpretation of the Brage East fault in the cross section is based on seismic data and core data from wells. The fault juxtaposes oil-bearing sandstones of the Lower

Jurassic Statfjord Formation in the footwall (Brage Field) against water-bearing sandstones of the Middle Jurassic Brent Group in the hangingwall (self-separated reservoir).

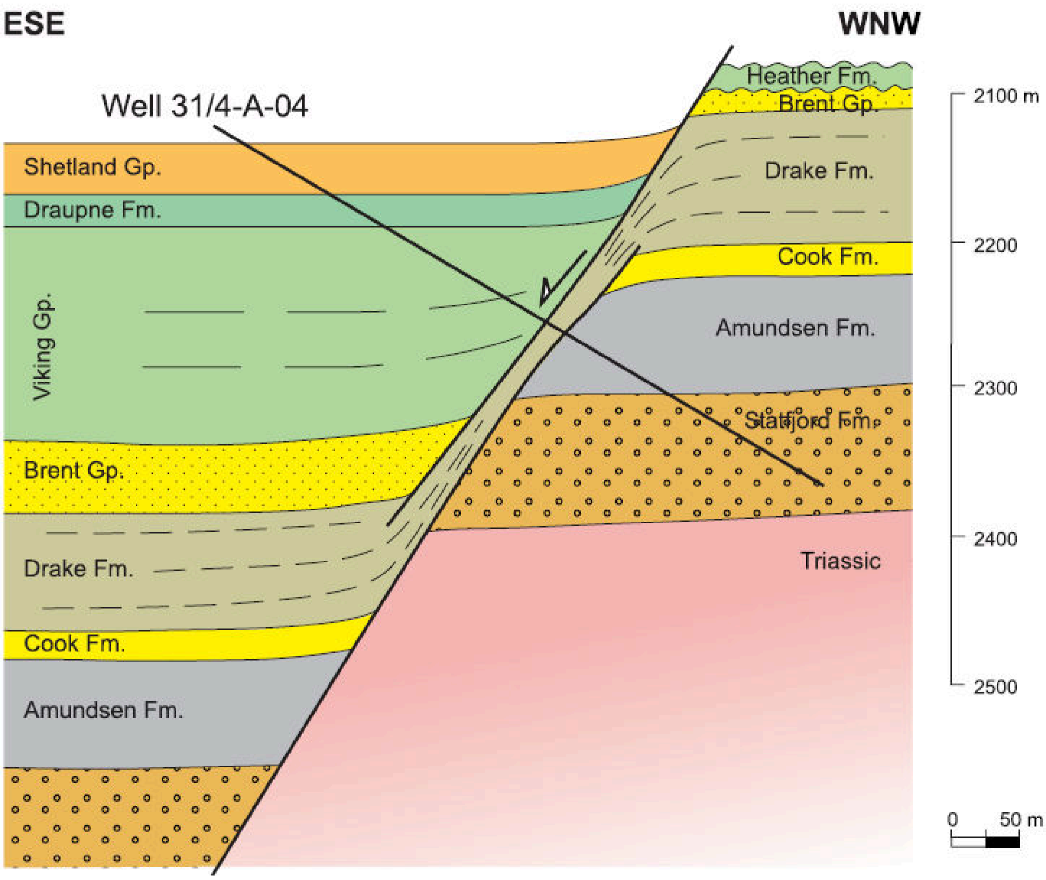


Figure 7.45: Cross section of large faults with smear derived from a thick source layer from the Brage Field (modified from Færseth, 2006).

7.6.3 Cretaceous plays

In recent years, the hydrocarbon potential of Lower Cretaceous sediments has increasingly been the focus of exploration effort in the mature areas of the North Sea area. Hydrocarbon reserves in Lower Cretaceous mass-flow plays in the UK suggests a substantial remaining potential (Garrett et al., 2000), and this potential may be extended into the untested graben settings of the North Viking Graben (Fig. 7.46) and the East Shetland Basin (Crittenden et al., 1988). Drilling in these areas will be costly due to the depth of burial of the Lower Cretaceous sediments, consequently predictive models need to be as robust as possible, and the depositional-sequence framework outlined above provides a basis for such models.

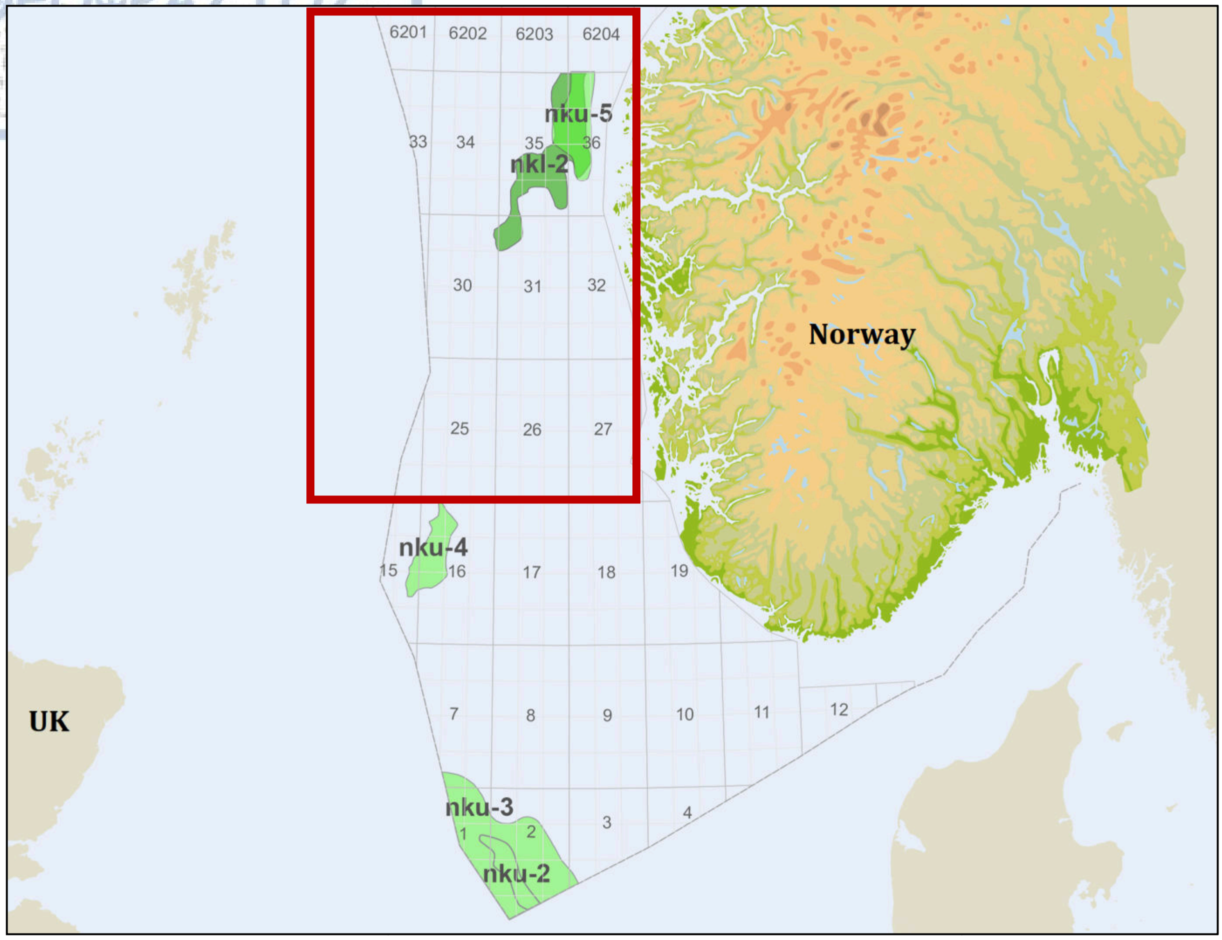


Figure 7.46: Northern North Sea Cretaceous plays (from NPD website www.npd.no). nkl-2: Cromer Knoll Group with Agat Formation; nku-5: Shetland Group with Kyrre Formation, and possibly Tryggvason Formation.

A marine environment prevailed during the entire Cretaceous period with deposition of hemipelagic clay, interrupted by sand deposition in certain periods. The sand was deposited in a slope-to-basin-floor setting by gravity mass flows, primarily debris flows and turbidity currents, and was probably sourced from shallow marine sands in the east. The sand transport was concentrated in certain fairways and followed topographic lows. Some of the Albian sands in the Agat area seem to be deposited in local slide scars, thus explaining why there is no pressure communication between large sandstone bodies. Upper Turonian-Coniacian sands were deposited after the topography was filled in and have a slope-fan geometry. Structural closures of Cretaceous strata are few and limited in extent in the northeastern North Sea, and any hydrocarbon prospectivity will depend purely or partly on stratigraphic closure (Table 7.5).

Plays	**nkl-2**	**nku-5**
Source rock	Upper Jurassic shale (Draupne and Heather formations), Lower to Middle Jurassic shale and coal (Ness Formation?)	Upper Jurassic shale (Draupne and Heather formations), Lower to Middle shale and coal
Reservoir rock	Sandstone	
Trap	Stratigraphic	Mainly stratigraphic, structural is a possibility
Depositional environments	Deep marine	
e.g. Fields	Agat	(Within the Agat and Kyrre formations)

Table 7.5: Play summary of the Cretaceous plays in the Norwegian northern North Sea (from NPD website www.npd.no).

The upscaled regional depositional model (Fig. 7.47) shows the generalized extension of the fans of the Agat sandstone Member on the slope of the Måløy terrace. Its hypothetical extension into the Sogn Graben, as postulated by Shanmugan et al. (1984) and Skibeli et al. (1995), remains to be proven by drilling.

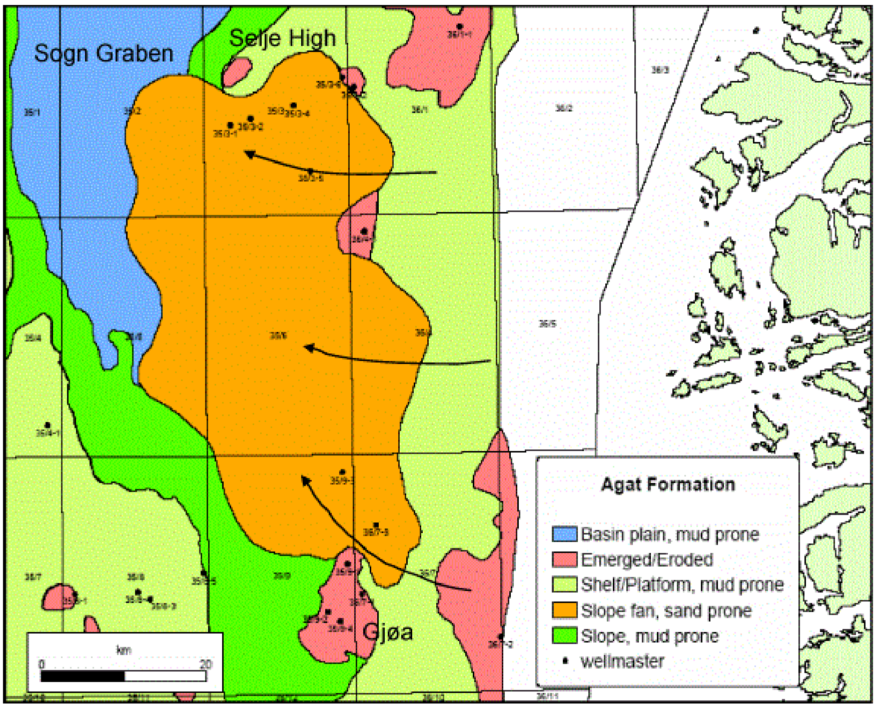


Figure 7.47: Regional depositional model of the Agat Formation ((from NORLEX website www.nhm2.uio.no).

Since the Agat gas discovery, more attention has been given to both Lower and Upper Cretaceous sandstone plays. The Agat discovery (Fig. 7.48) is made up of two complex small discoveries in stratigraphically trapped sub-marine sandstone lobes of the Cromer Knoll Group, but the extent of the sandstones have been difficult to map on conventional seismic. The top of the Formation (Lower Cretaceous Agat sands) displays high amplitudes, and sand distribution can be seen quite prominently on the seismic (Fig. 7.49).

Figure 7.48: Location map of well 35/9-3 (Agat Cretaceous gas discovery) within the Cretaceous play: (from NPD website www.NPD.no).

Well 35/9-3 is located on the Måløy Slope ~55 km west off the Norwegian mainland and ~11 km North of the Gjøa Field (Fig. 7.48). The primary objective of the well was to prove commercial oil and gas resources in the prospect of the Early Cretaceous Agat Formation. Secondary targets were seen in the Late Cretaceous to Early Paleocene.

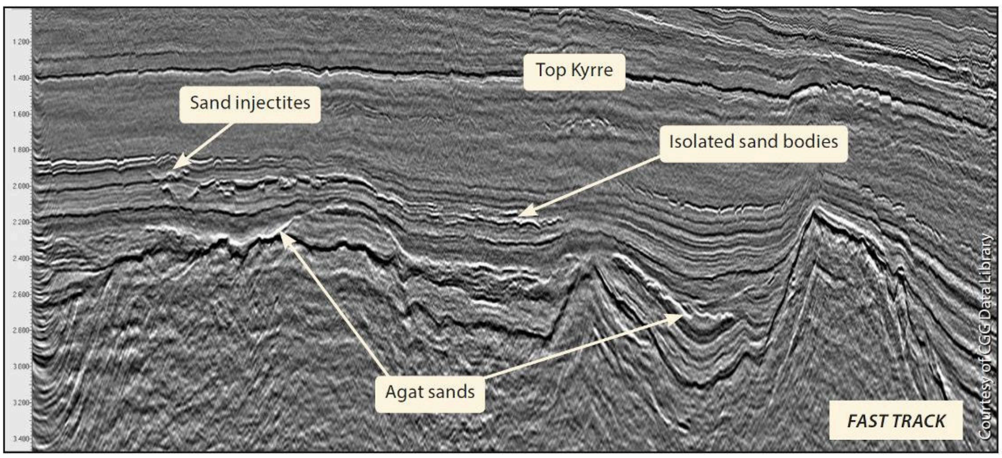


Figure 7.49: Seismic line focusing on the Cretaceous section (from CGG database).

Well 35/9-3 discovered hydrocarbons in reservoir sandstones of the Late Cretaceous, Kyrre Formation and of the Early Cretaceous Agat Formation. The main target, the Agat Formation reservoir, contained hydrocarbons in a 44 m sequence of mixed sand and shale layers (2657.5-2701.5 m) (Fig. 7.50). The uppermost sand layer contained gas with a gas-oil-contact (GOC) at 2666.5 m depth. The discovery may relate to an accumulation within a small structural closure at this level. MDT (Modular Formation Dynamics Tester) samples confirmed formation water in the thin sand intervals in the lower part of the Rødby reservoir zone, except in the lowermost sand interval, where oil was sampled. The MDT test showed low mobility and pressure draw down from barriers in the vicinity of the well in these sand layers. The reservoir interval of the Kyrre Formation consisted of stacked thin sands separated by shale layers in the interval 1868-1904.5 m (Fig. 7.50). The gas-water-contact (GWC) was found at 1896 m and probably relates to a small structural closure with a fill-spill to the east.

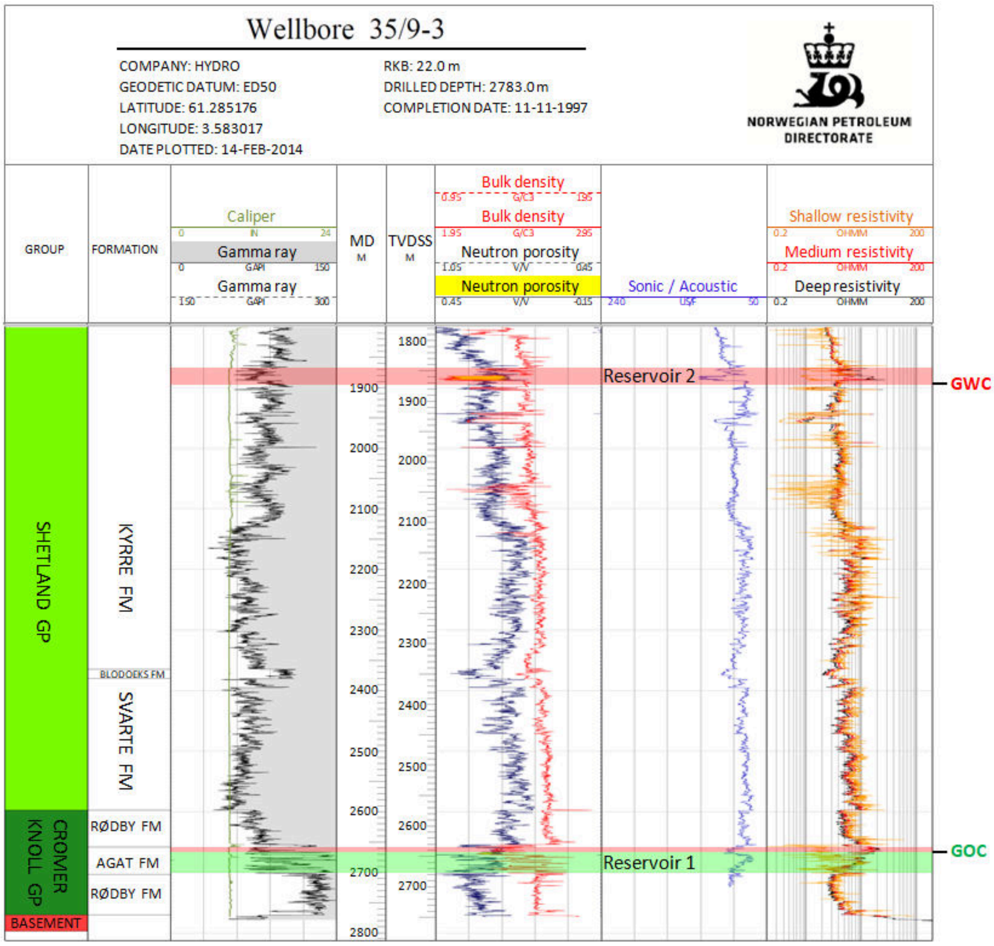


Figure 7.50: Well-log interpretation of the discovery well 35/9-3 (modified from NPD website www.npd.no).

During the Late Jurassic to Early Cretaceous, the Måløy Slope was compartmentalised into a series of half-grabens bounded by N-S to NNW-SSE-trending normal faults. The syn- to post rift transition occurred during Early Cretaceous and was defined by an overall decrease in the number of active normal faults and a transition from relatively rapid fault-controlled subsidence to relatively slow thermally controlled subsidence (Gabrielsen et al., 2001; Fraser et al., 2003). Although Late Cretaceous is generally perceived to be dominated by thermal rather than fault-related subsidence, it is likely that the Øygarden Fault Complex was active at this time. The Gjøa fault zone, which was most active during the latest Jurassic to Early Cretaceous, may have experienced minor reactivation during the Late Cretaceous based on the observation of minor offset of Lower and Upper Cretaceous reflection events (Fig. 7.51B). A series of approximately N-S-trending, low-relief anticlines are developed throughout the Cretaceous and lower Tertiary successions. These anticlines gradually decrease in amplitude upwards (Fig. 7.51B). At present-day, these anticlines are up to 30 km in length and have amplitudes of ~104 m at the Early Cretaceous level.

Figure 7.51 illustrates the presence of amplitude anomalies in the Late Turonian interval which are the seismic expression of the slope systems, and the major erosional truncation beneath the Upper Jurassic Unconformity (UJUNC). In proximal regions the UJUNC and overlying Base Cretaceous Unconformity (BCU) form a composite unconformity. The five key seismic reflection events referred to in the text are labelled and correlated to the stratigraphic column in Figure 7.51A.

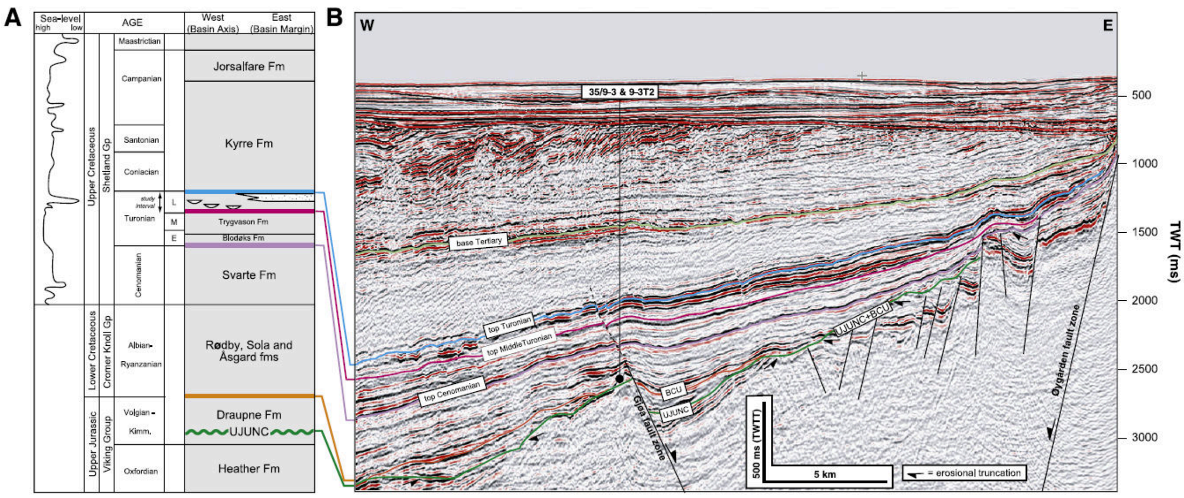


Figure 7.51: Stratigraphic and sub-regional structural setting of the Måløy Slope (Jackson et al., 2008). (A) Simplified stratigraphic column of the region indicating the interval of interest and the stratigraphic location of mapped seismic reflection events. An eustatic sea-level curve is indicated for the Late Cretaceous (redrawn from Haq et al., 1987; Surlyk, 2003). Grey shading corresponds to mudstone-dominated stratigraphic units; stipple corresponds to sandstone-dominated stratigraphic units. (B) W-E seismic section across the Måløy Slope. Two-way time (TWT) in milliseconds (ms).

Reflection mean strength (RMS) amplitude maps indicate that both the narrow channel-like and the broader sheet-like amplitude anomalies form overall channel-shaped features which are straight to slightly sinuous, trend SE-NW to ESE-WNW and can be traced westwards downslope for up to 20 km (Figs. 7.52A and 7.52C). In addition, channel-shaped features located in the south terminate downslope to the west into small fanshaped anomalies which are up to 5.5 km wide (Figs. 7.52C-E). In cross-section, these fan-shaped anomalies are expressed seismically as flat-based packages of high-amplitude reflection events, up to 40 m thick and 10 km wide. Channel-shaped anomalies in the north do not appear to pass downslope into fan-shaped anomalies; they either deviate NW outside of the seismic coverage or become more poorly imaged due to increased noise in the seismic data (Fig. 7.52A).

Channel or fan-shaped amplitude anomalies are confidently interpreted as the seismic expressions of sand-rich slope systems based on: (i) the clear channel or fan-shaped geometries of the units in both cross-section and plan view (Figs. 7.52A-D); (ii) the similar seismic response, in particular the upper, high to moderate-amplitude peak reflection event, to a demonstrably sand-bearing slope fan, and (iii) the occurrence of channel-parallel anticlines above the channel-shaped anomalies. The youngest slope system identified in the Kyrre Formation is a fan located in the southeastern part of the study area (Fig. 7.52F). These amplitude maps indicate that four stratigraphically distinct intervals can be identified on the slope (here in termed slope system units; SSU-1, 2, 3 and 4). Although care was taken to ensure that each amplitude map would only image time-equivalent depositional systems, due to the complex stacking of individual depositional elements it is often difficult to image individual depositional units clearly (i.e. within SSU-1; Fig. 7.52A). As a result, channels or channel complexes at slightly lower (i.e. older) or slightly higher (i.e. younger) stratigraphic levels may be partially imaged on the same map.

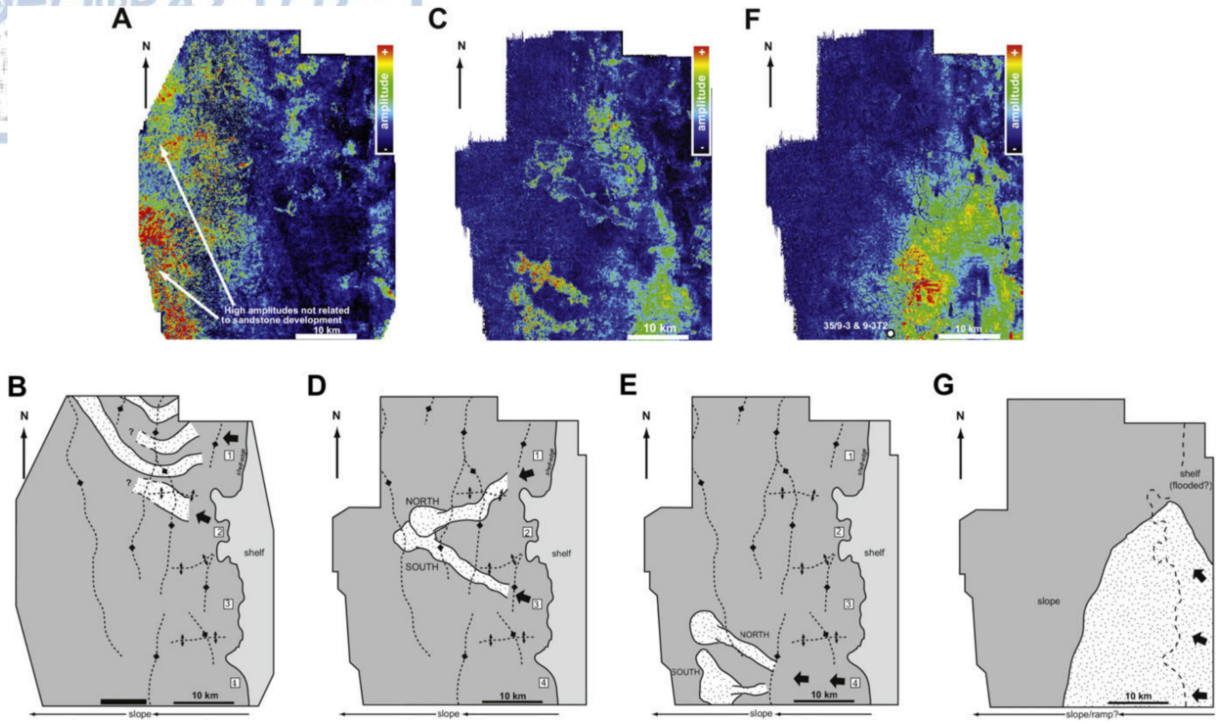


Figure 7.52: Reflection mean strength (RMS) amplitude maps and corresponding interpretative maps through the Late Turonian interval of the Kyrre Formation illustrating the temporal and spatial development of sand-rich, high amplitude slope system units (SSU) (Jackson et al., 2008). (A) and (B): SSU-1; (C) and (D): SSU-2; (C) and (E): SSU-3; (F) and (G): SSU4. Note that amplitude map (C) images channel complexes in both SSU-2 (D) and SSU-3 (E) due to large clastic injections adjacent to these channel complexes. The location of shelf-edge canyons, key morphological features and dominant interpreted sediment supply pathways (black arrows) are indicated on the interpretive maps.

7.6.4 Paleogene plays

The Paleogene of the northern North Sea is characterised by thick, sand-rich fans in the upper Paleocene and more isolated, although still tens-of-meter-thick, sandstones in the Eocene section (Den Hartog Jager et al., 1993; Ahmadi et al., 2003; Jones et al., 2003). The sandstones constitute a highly prolific hydrocarbon play (Fig. 7.53) in the northern North Sea (e.g. Bain, 1993; Jones et al., 2003) and occur in a succession of hemipelagic smectite-rich mudstones that are extremely fine grained (Thyberg et al., 2000). The smectitic mudstones are very poorly permeable and, thus, form efficient seals baffles to fluid migration (e.g. Jones et al., 2003). The uppermost Paleocene-Eocene mudstones are offset by pervasive polygonal fault systems caused by layer-bound contraction and fluid expulsion (Cartwright, 1994; Cartwright and Lonergan, 1996). The sandstone intrusions found in the upper Paleocene-Eocene of the North Sea area are the largest scale sandstone intrusions recorded thus far, and it has been argued that their formation is somehow linked to the occurrence of polygonal fault systems (e.g. Lonergan et al., 2000).

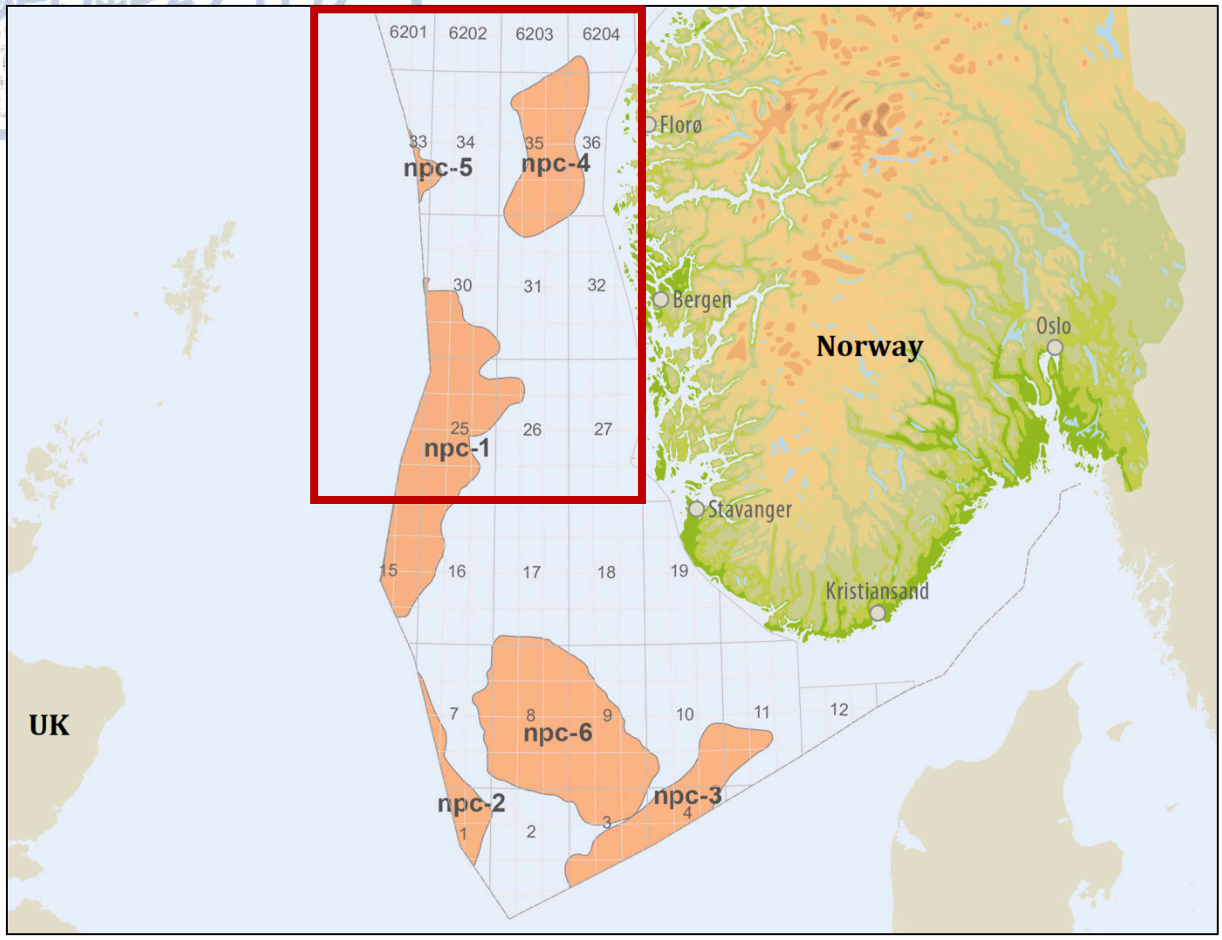


Figure 7.53: Northern North Sea Paleocene plays (from NPD website www.npd.no). npc-1: Rogaland Group with Ty, Heimdal, Hermod and intra Balder formations; npc-4 (unconfirmed): Rogaland Group with intra Sele and intra Lista formations; npc-5 (unconfirmed): Rogaland Group with intra Lista Formation.

The North Sea area is considered data rich and well understood. Half a century of oil exploration and research has resulted in a world-class hydrocarbon province, but the Cenozoic succession still contains many poorly understood structures and deposits. Stratigraphic or combination traps are the focus of current Paleogene exploration in the North Sea, where only small 4-way dip Paleogene traps remain untested (Table 7.6).

Paleocene Plays	npc-1	npc-4 (unconfirmed)	npc-5 (unconfirmed)
Source rock	Upper Jurassic (Draupne and Heather formations) and Lower to Middle Jurassic shale and coal (Sleipner Formation)		
Reservoir rock	Sandstone		
Trap	Stratigraphic and structural, or combination of the two		
Depositional environments	Deep water		
e.g. Fields	Heimdal, Balder, Jotun, Grane, Alvheim, Volund, Vøula, Svalin	–	–

Table 7.6: Play summary of the Paleocene plays in the Norwegian northern North Sea (from NPD website www.npd.no).

Paleocene strata are extensively distributed throughout entire North Sea area (Fig. 7.54), and provide one of the most prolific hydrocarbon plays in the northern North Sea. The Tertiary sedimentary sequence of the northern North Sea is up to 3000 m thick. It is dominated by mudstones, but sandstones are also present especially along the western flank of the basin. These sandstones are principally Paleocene and Lower Eocene and provide important reservoirs for both oil and gas. The basin axis exerted an important control on the submarine fan sands; the turbidity currents were unable to flow 'uphill' and were deflected into axial directions. The abrupt retardation of the flows resulted in some areas in massive, clean sands being deposited in distal positions, (Sleipner Øst: Pegrum and Ljones, 1984).

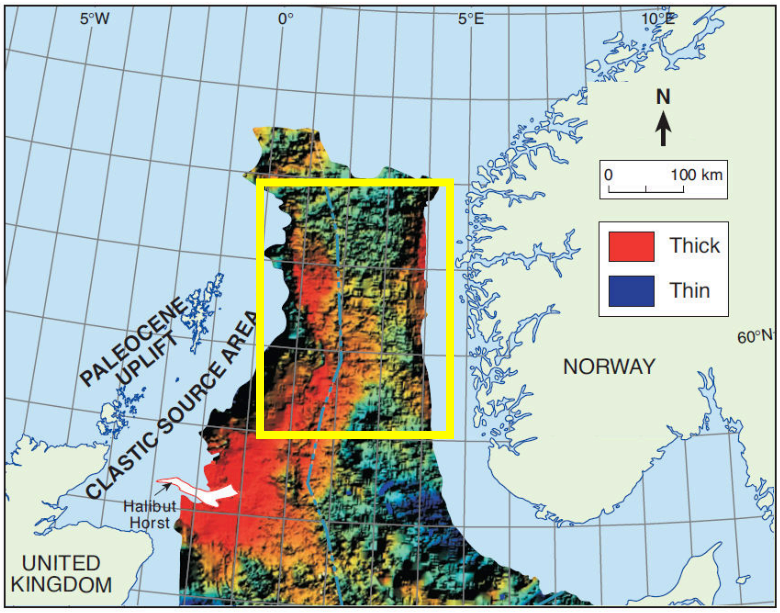


Figure 7.54: Paleocene distribution in the northern North Sea (Evans et al., 2003).

The 'post-Paleocene' play (Fig. 7.55 and Table 7.7) amounts to less than 4% of the total reserves/resources, and these are evently distributed between the UK and Norwegian sectors. Oil production started in 1992, and is dominated by the UK sector portion with a share of 87%, which shows that the UK has been able to exploit the resources to a greater extent than Norway, despite the Norwegian Balder Field being discovered by the first well targeting the play. Norway has the greater share of gas production; next to Balder, Frigg and Odin fields are the major Norwegian post-Paleocene discoveries. Major UK discoveries/fields were Alba in 1984, Gryphon in 1987 and Harding in 1988.

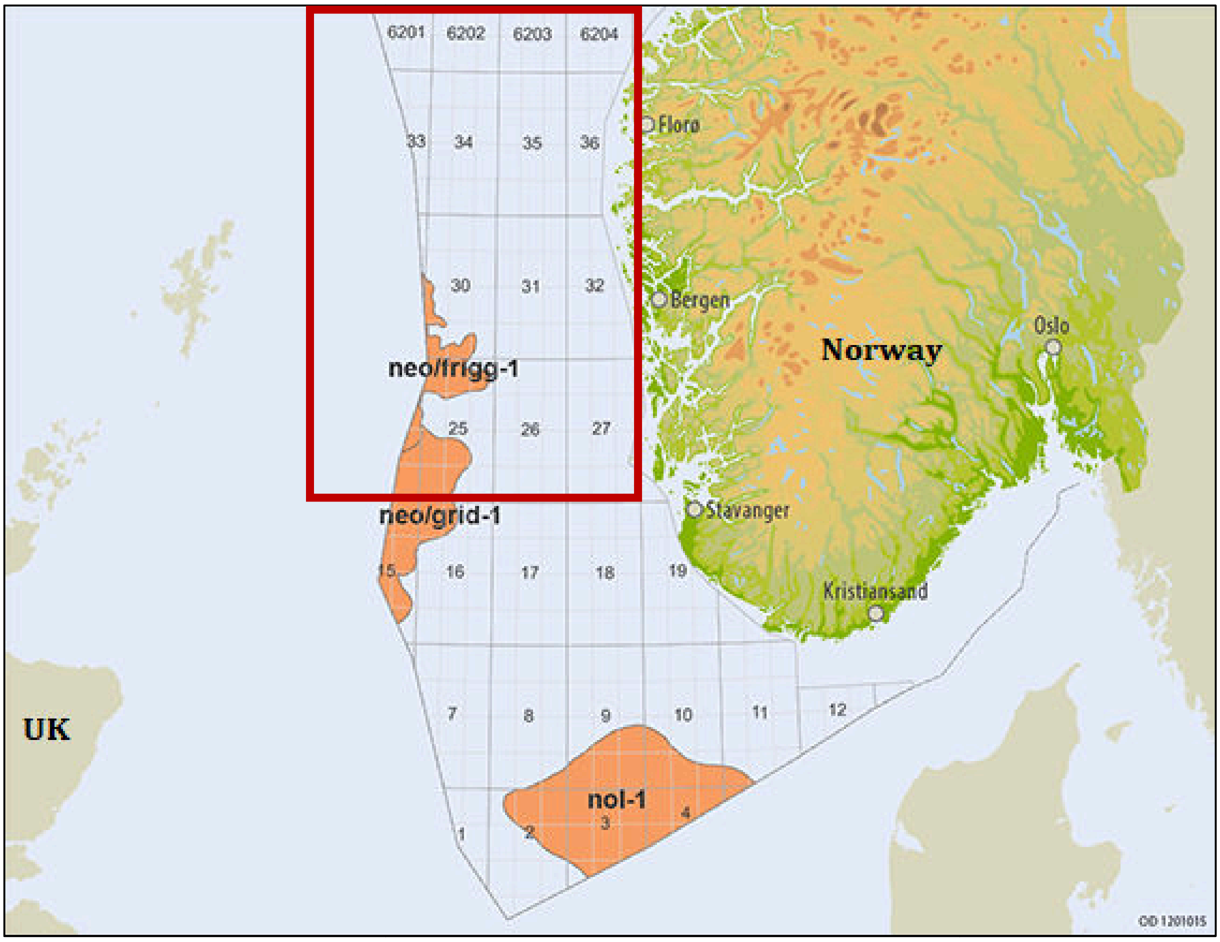


Figure 7.55: Northern North Sea supra-Paleocene plays (from NPD website www.npd.no). neo/grid-1: Hordaland Group with Grid Formation; neo/frigg-1: Hordaland Group with Frigg Formation.

Deep-water turbidite reservoirs can be altered by post-depositional remobilization and injection processes. Commonly, turbidite sandstones are injected into the surrounding low-permeability background shale, and this injection process changes both the geometry and reservoir properties of the sandstones. Sand injectite features are interpreted to form by the fluidization of sand, often associated with overpressure occurring in the source sandbodies, which in turn causes seal failure with the sand becoming remobilized (Hurst et al., 2005). The occurrence of large-scale intrusions along the axis of the northern North Sea has led to the suggestion that overpressures could have been provided by hydrocarbon migration into shallow unconsolidated reservoirs (Jolly and Lonergan, 2002; Mazzini et al., 2003). It seems that disequilibrium compaction would be the most likely cause of regionally developed overpressures, which may have exacerbated locally by fluid and/or lateral transfer of fluids.

Supra-Paleocene Plays	**neo/grid-1**	**neo/frigg-1**
Source rock	Upper Jurassic shale (Draupne Formation) and Lower-Middle Jurassic shale and coal (Sleipner Formation)	
Reservoir rock	Sandstone	
Trap	Combined stratigraphic and structural	
Depositional environments	Deep marine	
e.g. Fields	–	Frigg, Nordøst Frigg, Øst Frigg, Odin

Table 7.7: Play summary of the supra-Paleocene plays in the Norwegian northern North Sea (from NPD website www.npd.no).

Exploration success began in the area in the 1960s with the discovery of the Balder field on the Utsira High (1966). Hydrocarbons were found in the Paleocene clastic sediments of the Balder Formation and successes within the Tertiary continued into the early 1970s with the discovery of the Eocene sands of the Frigg Field. However, these Tertiary plays can be complex in their distribution and development and difficult to model and map. However, new high-quality 3D seismic data provide the opportunity of reevaluating some of these difficult plays and prospects and offer the possibility of establishing new potential. Where the fan systems are compartmentalised (such as in Frigg Field) (Fig. 7.56) with a variety of barriers and baffles, the production of the hydrocarbons is not simple.

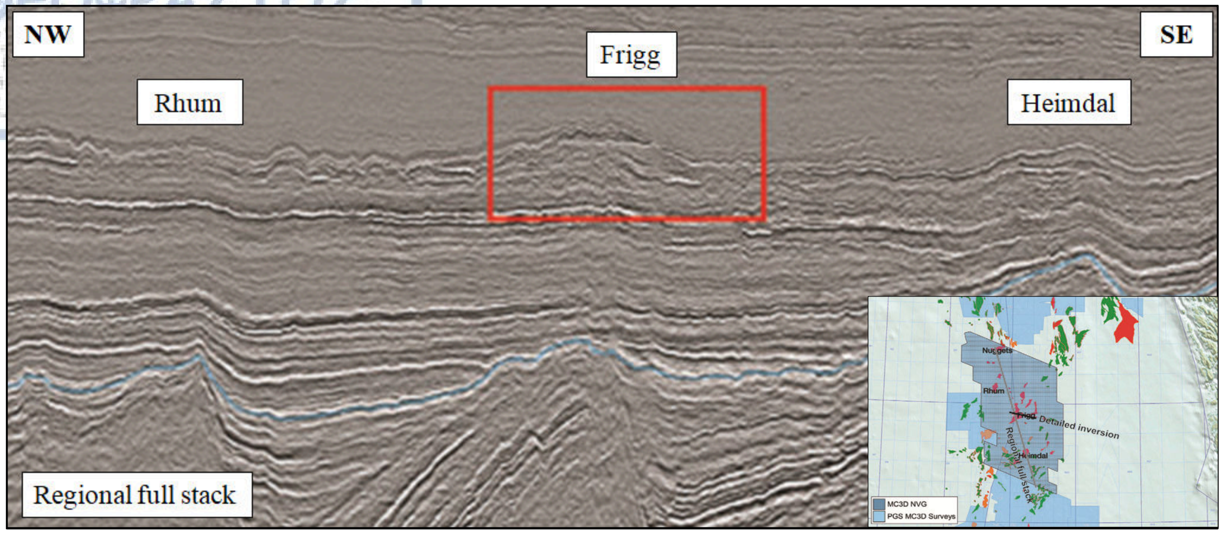


Figure 7.56: Regional full-stack seismic section from the Frigg Field (from website www.geoexpro.com; courtesy to PGS).

The Frigg fan was sourced from south the south-west by a submarine channel (Fig. 7.57a). The transition from channel to fan was probably controlled by a lessening of the slope gradient, which allowed turbidity currents to disperse. Declining flow power resulted in sheet-sand deposition. There is a general decrease in the reservoir quality distally from south-west to north-east; massive sandstones were deposited in channelised proximal areas, whereas stratified sheet-like sandstones were emplaced in more distal areas (Fig. 7.57a). Several intra-fan channels can be identified (Fig. 7.57b), and occasional sediment bypass of the Frigg fan evident from sandstones deposited in the area of the satellites to the north and west. The mud-poor system, which results from the derivation of sediment from a sand-dominated shelf, did not allow for the development of substantial channel levees, and channels were frequently shifting back and forth across the fan, preventing preservations of deposited mud and silt. This contention is supported by the occurrence of floating mud clasts in the sandy deposits.

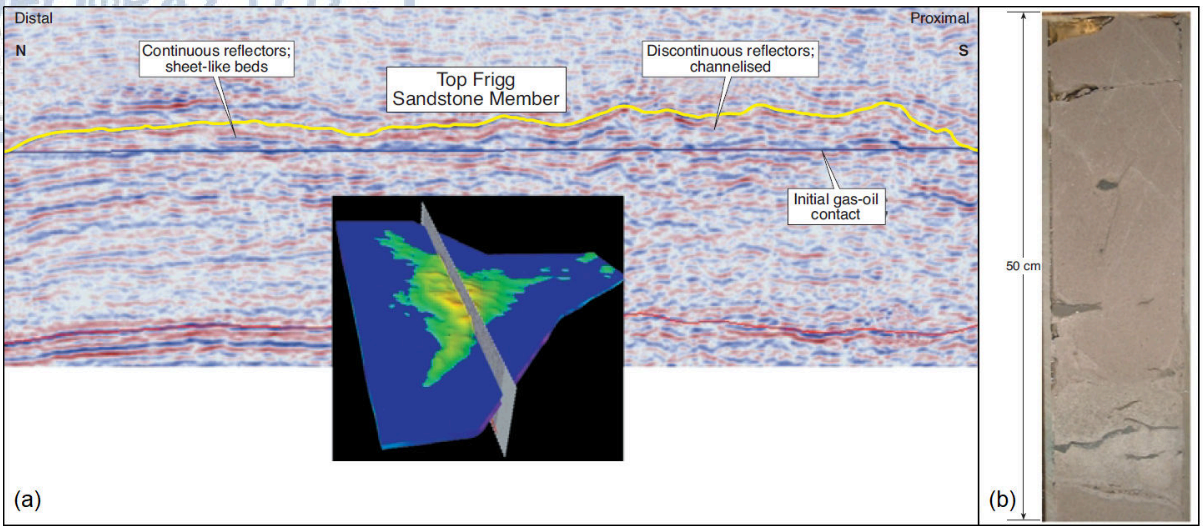


Figure 7.57: Seismic from the Frigg Field section showing the change in seismic facies between channelised areas and those where sheet sandstones have been deposited (Evans et al., 2003).

Remobilised Tertiary sandstone reservoirs (Fig. 7.58) also have become an important play to consider in both the UK and Norwegian sectors. They remain an underexplored and difficult play and the injected sand bodies generally have highly complex geometries and certain features that are infrequently successfully resolved on conventional seismic data. However, there are several well-known examples of injectite reservoirs including Gryphon and Leadon fields (UK) and Grane and Jotun fields (Norway). In these fields the injectites have excellent reservoir qualities, with high porosity and permeability values, and there is therefore every reason to believe that similar sands will in most cases form good reservoirs.

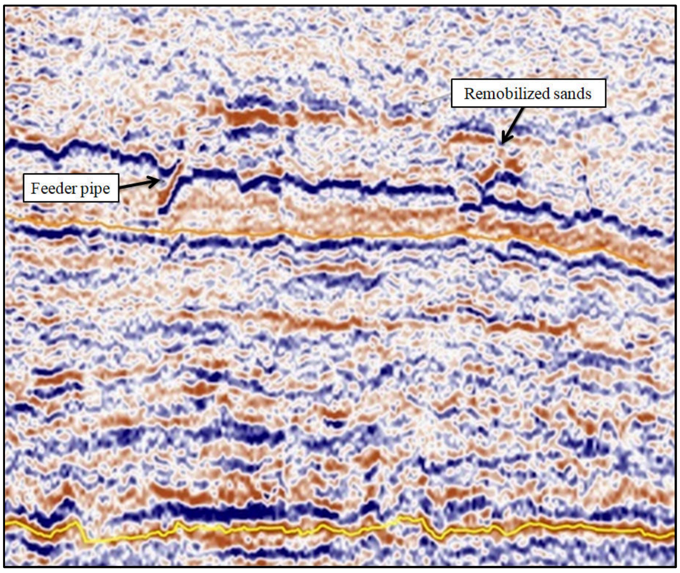


Figure 7.58: A cross-section showing a high amplitude package, interpreted to be remobilized sand body. A bright reflector indicates the location of the feeder pipe from Eocene sands below. Yellow: base Tertiary; orange: top Balder; blue: top Reservoir (from website www.geoexpro.com; courtesy to PGS).

The features which define the sand injectites, and which can be recognised within seismic, include mounds, detached reflectors which are often bright, and lateral wings and ridges which may crosscut original stratigraphic relationships. In the cores the injectites are often seen to be of different generations with networks crosscutting and connecting each other. This indicates that the sand injection process occurred at repeated stages through burial (Fig. 7.59).

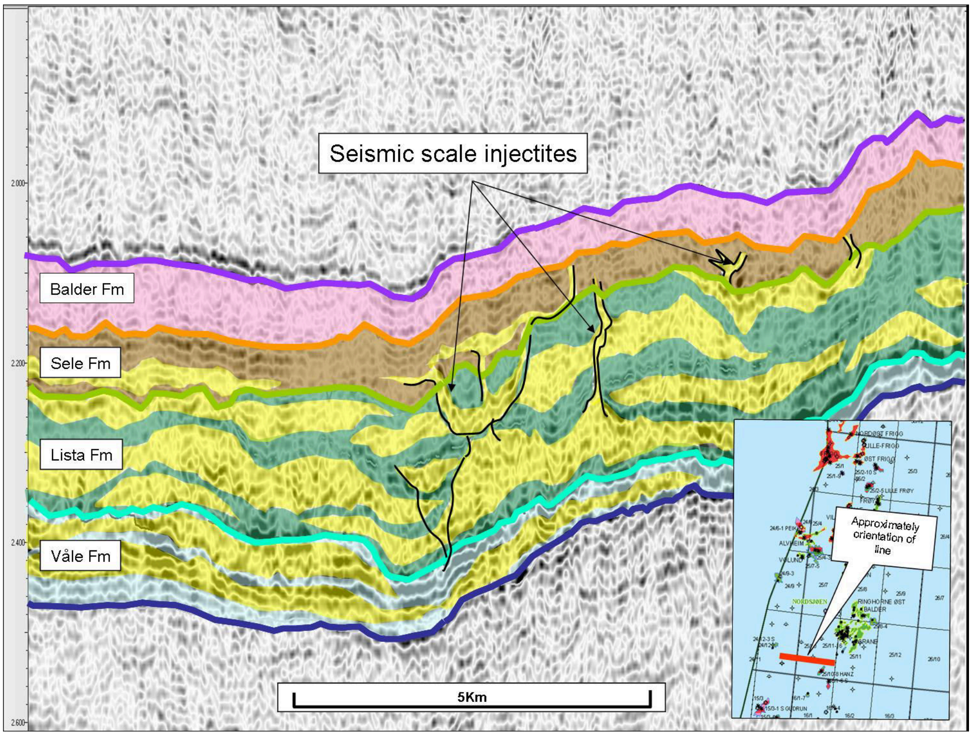


Figure 7.59: Example of seismic character of sandy facies of the Rogaland Group, seen from a W-E seismic section through southern parts of block 25/10 (Brunstad et al., 2008).

Main geologic plays

Chapter 8
MAIN FIELDS AND DISCOVERIES

8.1 FIELD DISTRIBUTION AND EXISTING FACILITIES

The main fields and discoveries in both the UK and Norwegian sectors in the northern North Sea, in relation to the major structural elements in the area, are shown in Figure 8.1. It is almost 50 years since oil and gas production started in the Norwegian part of the northern North Sea. The area is considered to be rich in resources, and production is expected to continue for at least another 50 years. Plans are being made to extend the lifetime of fields that already have been producing for a long time in this part of the North Sea, such as the Snorre Field. The Troll Field (Fig. 8.1) is the cornerstone of Norway's offshore gas production and will be the main exporter of Norwegian gas exports for several decades to come. Troll was also the field on the Norwegian shelf that produced most oil in 2016.

Throughout the 1960s interest was concentrated on the shallow waters of the southern North Sea. Up until the end of 1969, 146 exploration wells were drilled in the UK sector, of which 130 were in the southern part and only 16 in Scottish waters. There were a few gas discoveries during this period, some of which have proved fairly substantial, but given the predominant interest in oil, rather than gas, the level of interest in the southern North Sea was relatively small and declined sharply after 1969. Exploration activity gradually moved northwards as improvements in technology allowed the rigs to operate in deeper waters. There is obviously a close link between the level of exploration activity and the success/discovery rate. Interest has remained high in the northern North Sea because of the large number of commercial discoveries, of which the biggest have been the Forties, Brent, and Ninian fields in UK sector, and Statfjord, Oseberg, Gullfaks, Troll and Frigg fields in Norwegian sector.

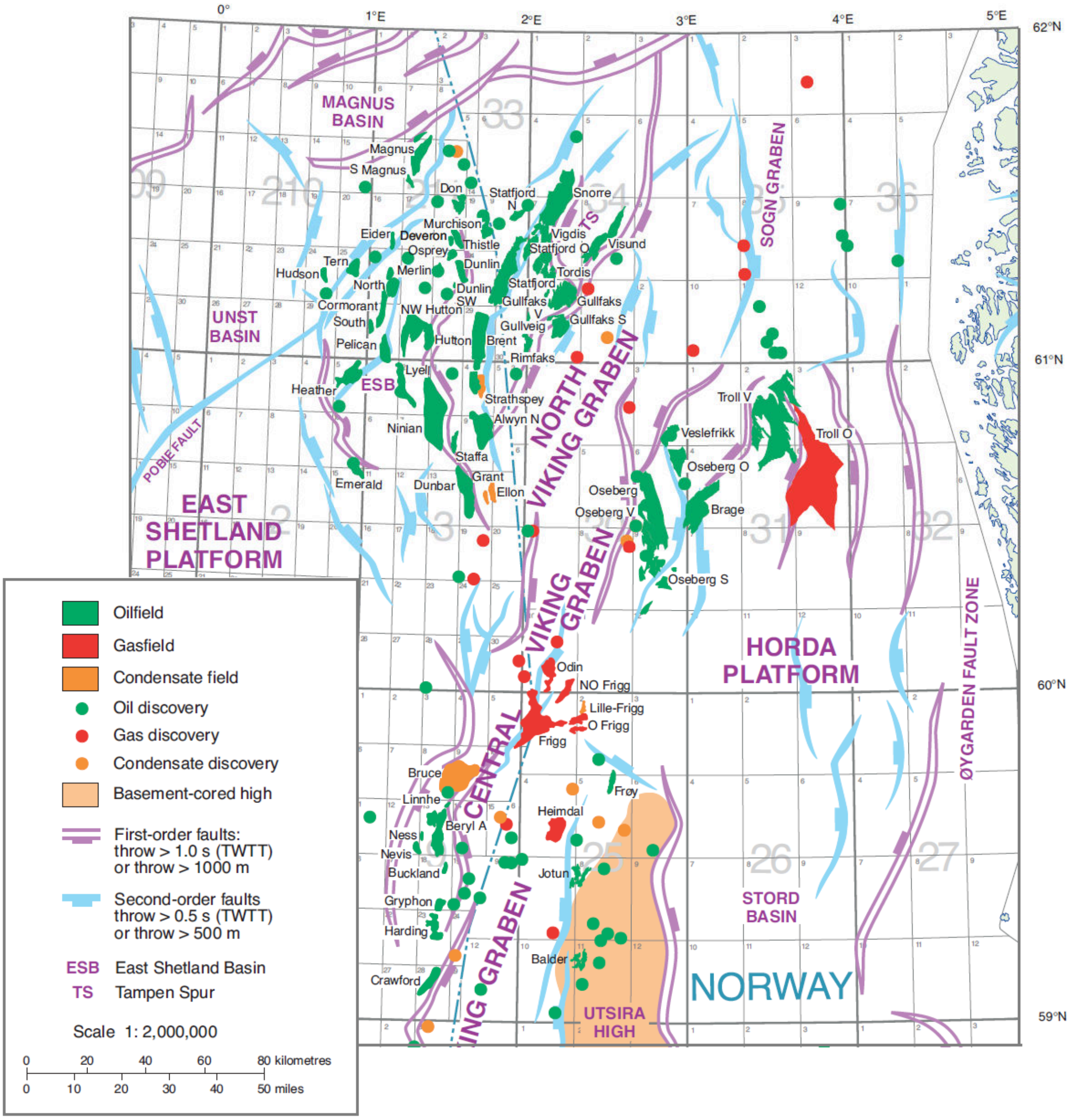


Figure 8.1: The distribution of fields and discoveries in relation to the major structural features of the northern North Sea (Evans et al., 2003).

The next maps show the fields, discoveries, and currently licensed acreage in both the Norwegian (Fig. 8.2) and UK (Fig. 8.3) sectors.

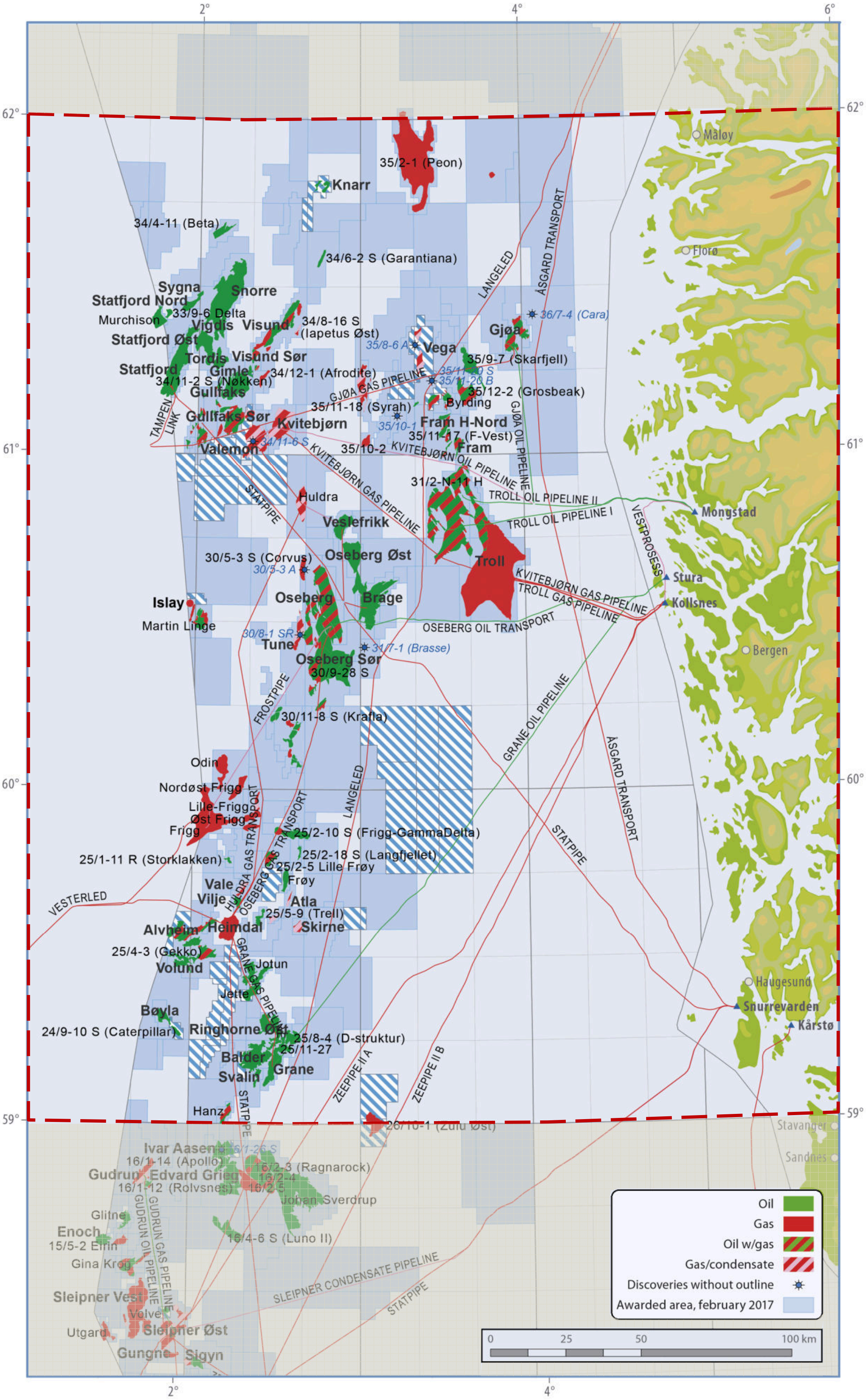


Figure 8.2: Fields and discoveries of the Norway-sector northern North Sea. Blue and hatched rasters indicate active production licenses (from NPD website www.npd.no) (last updated September 2017).

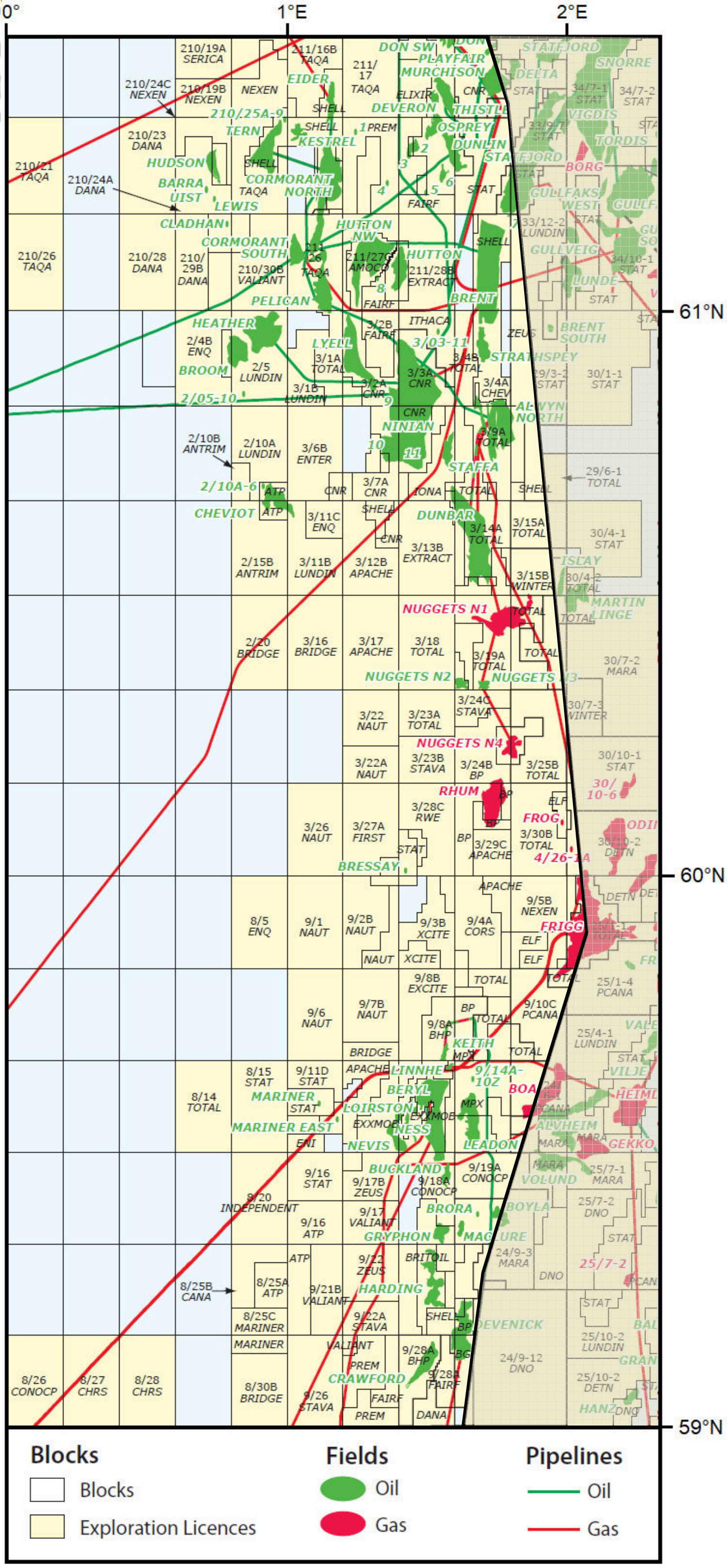


Figure 8.3: Fields and discoveries of the UK-sector northern North Sea (from CGG website www.cgg.com) (last updated in 2013).

As the major oil fields reach the end of production, substantial gas volumes may be produced in a gas blow-down and low pressure production period. Oil and gas from the fields in the northern part of the North Sea is transported by tankers or in pipelines (Fig. 8.4) to onshore facilities in Norway and the United Kingdom.

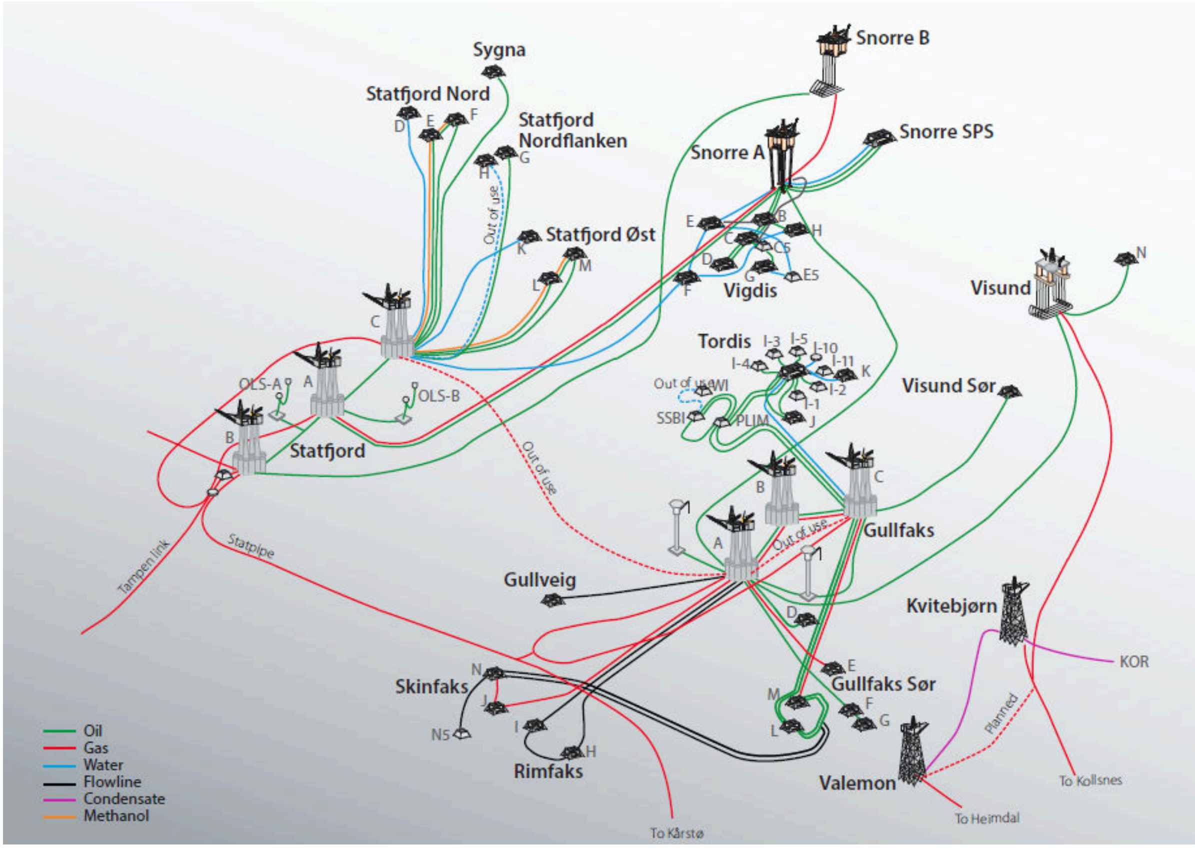


Figure 8.4: Facilities in the Tampen area (NPD, Facts 2013).

Major investments in transport solutions are characteristic of gas production. The Norwegian pipeline system (Fig. 8.5) currently has a transport capacity of about 120 billion Sm^3 per year. Three onshore gas facilities are integrated into the pipeline system in mainland Norway Kårstø, Kollsnes and Nyhamna which receive rich gas from the fields. Dry gas is separated from the rich gas for further transport via pipeline to the receiving terminals. There are four receiving terminals for Norwegian gas on the European continent; two in Germany, one in Belgium and one in France. In addition, there are two receiving terminals in the UK. The Norwegian gas transport system includes a network of pipelines with a total length of more than 8000 km. This roughly corresponds to the distance from Oslo to Beijing. Treaties have been drawn up that govern rights and obligations between Norway and countries with landing points for gas from the Norwegian shelf.

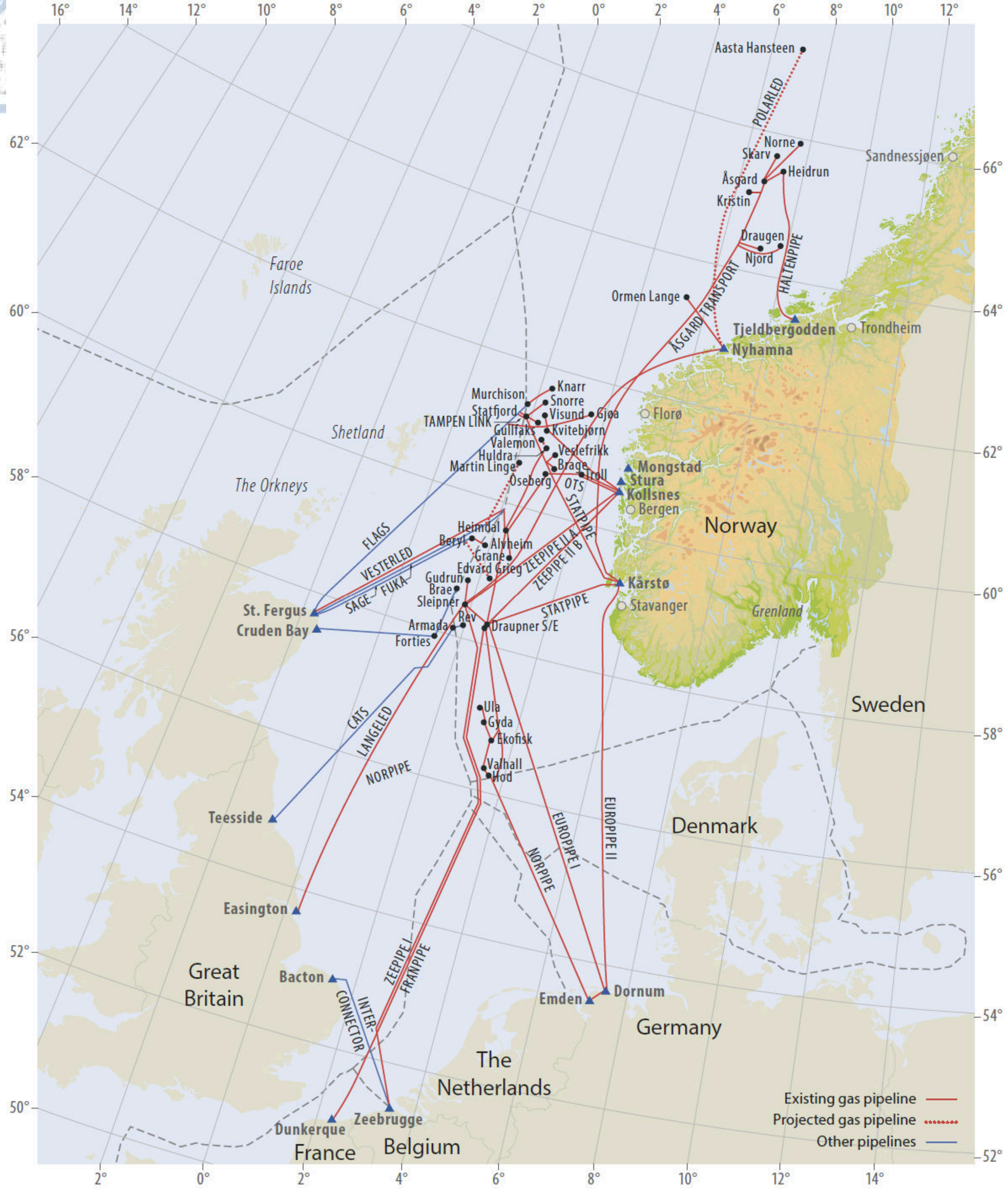


Figure 8.5: Norwegian gas-pipeline system (from NPD website www.npd.no).

8.2 TRIASSIC FIELDS

A small number of fields in the northern North Sea have Triassic reservoirs compared to those of Lower-Middle Jurassic age. The Snorre Field comprises a large south-westward tilted and differentially eroded graben-margin fault-block typical of the northern North Sea. The Beryl

Field, together with the adjacent Nevis Field, both in the UK-sector, form eroded tilted fault-blocks in a graben-margin basin. All these structures were formed during Late Jurassic to Early Cretaceous extention. Table 8.1 shows the general characteristics of some selected Triassic fields of the northern North Sea.

UK AND NORWAY					
FIELD NAME	**DISCOVERY YEAR**	**LOCATION**	**RESERVOIR AGE**	**TRAP TYPE**	**PRODUCTION STARTED (CEASED)**
BERYL A	1972	Beryl Embayment	Triassic/Jurassic	Tilted fault block	1976
CRAWFORD	1975	Crawford Spur	Triassic/Jurassic	Tilted fault block	1989 (1990)
DUNBAR	1973	East Shetland Basin	Triassic/Jurassic	Tilted fault block	1994
GULLFAKS	1979	Tampen Spur	Triassic/Jurassic	Tilted fault block	1986
NEVIS	1974	Beryl Embayment	Triassic/Jurassic	Tilted fault block	1996
SKENE	1976	Beryl Embayment	Triassic	Tilted fault block	2002
SNORRE	1979	Tampen Spur	Triassic	Tilted fault block	1992
STATFJORD	1975	Tampen Spur	Triassic/Jurassic	Tilted fault block	1979
STRATHSPEY	1975	East Shetland Basin	Triassic/Jurassic	Tilted fault block	1993

Table 8.1: General characteristics of the main Triassic fields in the northern North Sea (Evans et al., 2003).

8.3 LOWER-MIDDLE JURASSIC FIELDS

Hydrocarbons have been found in Lower-Middle Jurassic reservoirs in many structures, some of which are single-well discoveries and others are finds that are under evaluation to determine their economic viability. The fields with Lower-Middle Jurassic reservoirs constitute the most important group in terms of oil production and economic value in the North Sea petroleum province. This is reflected in the rapidity with which they were explored and set in production, the production rates they have achieved, and the huge amount of geoscientific work that has been undertaken on them. The early history of exploration was dominated by the success of the UK Brent Field, which is the second largest field of the play, and was discovered by the first exploration well in the northern North Sea to target a tilted fault-block. This success created great enthusiasm, and the first Norwegian exploration well targeted at the play in 1974 discovered the Statfjord Field, which is the largest oil-field in the North Sea. In addition, the giant Gullfaks Field discovered in 1978, and the Oseberg Field was discovered in 1979. All the major fields were found in the first fifteen years of exploration; the largest field discovered since 1981 is the Kvitebjørn gas-field. The history of the discovery of the fields shows a rapid growth in the number of finds and a steep rise in the discovered resources in the early years. Production from the Lower-Middle Jurassic fields started at the Brent field in 1976, followed by large, early-discovered fields in the years through to 1980. Tables 8.2 and 8.3 show the general characteristics of some selected main fields in Lower or Middle Jurassic reservoirs of the northern North Sea.

NORWAY					
FIELD NAME	**LOCATION**	**H/C**	**RESERVOIR AGE**	**TRAP TYPE**	**API GRAVITY**
BRAGE	Horda Platform	O/G	Early to Late Jurassic	Tilted fault block	35°
GULLFAKS	Tampen Spur	O/G	Upper Triassic/ Lower/Middle Jurassic	Tilted fault block	29°
GULLFAKS SØR	North Viking Graben	O/G	Upper Triassic/ Lower/Middle Jurassic	Tilted fault block	34°
GULLVEIG	Tampen Spur	O/G	Middle Jurassic	Tilted fault block	42°
HULDRA	North Viking Graben	O/G	Middle Jurassic	Tilted fault block	43°
KVITEBJØRN	North Viking Graben	O/G	Middle Jurassic	Tilted fault block	47°
MURCHISON	East Shetland Basin	O	Middle Jurassic	Tilted fault block	39°
OSEBERG	Horda Platform	O/G	Middle Jurassic	Tilted fault block	34°
OSEBERG SØR	Horda Platform	O/G	Middle Jurassic	Tilted fault block	39°
OSEBERG ØST	Horda Platform	O/G	Middle Jurassic	Tilted fault block	37°
RIMFAKS	Tampen Spur	O	Upper Triassic/ Lower/Middle Jurassic	Tilted fault block	36°
STATFJORD	Tampen Spur	O/G	Middle Jurassic	Tilted fault block	39°
STATFJORD NORD	Tampen Spur	O/G	Middle Jurassic	Tilted fault block	40°
STATFJORD ØST	Tampen Spur	O/G	Middle Jurassic	Tilted fault block	38°
TORDIS	Tampen Spur	O/G	Middle Jurassic	Tilted fault block	37°
VESLEFRIKK	Horda Platform	O	Middle Jurassic	Tilted fault block	86°
VIGDIS	Tampen Spur	O/G	Lower/Middle/Late Jurassic	Tilted fault block	39°
VISUND	North Viking Graben	O	Late Triassic/ Early/Middle Jurassic	Tilted fault block	37°

Table 8.2: General characteristics of some selected Norway-sector Lower-Middle Jurassic main fields in the northern North Sea (Evans et al., 2003).

UK					
FIELDS	**LOCATION**	**H/C**	**RESERVOIR AGE**	**TRAP TYPE**	**API GRAVITY**
ALWYN NORTH	East Shetland Basin	O/G	Lower/Middle Jurassic	Tilted fault block	37°
BERYL A	Beryl Embayment	O/G	Upper Triassic/ Lower to Upper Jurassic	Tilted fault block (uplifted horst)	38°
BRENT	East Shetland Basin	O/G	Triassic/Lower to Middle Jurassic	Tilted fault block	36°
BUCKLAND	Beryl Embayment	O/G	Middle Jurassic	Tilted fault block	37°
CORMORANT N	East Shetland Basin	O/G	Middle Jurassic	Tilted fault block	36°
CORMORANT S	East Shetland Basin	O/G	Middle Jurassic	Tilted fault block	36°
DEVERON	East Shetland Basin	O	Middle Jurassic	Tilted fault block	38°
DON	East Shetland Basin	O	Middle Jurassic	Tilted fault block	42°
DUNBAR	East Shetland Basin	O/G	Triassic/Jurassic	Tilted fault block	42°
DUNLIN	East Shetland Basin	O	Lower/Middle Jurassic	Tilted fault block (horst)	35°
EIDER	East Shetland Basin	O	Middle Jurassic	Tilted fault block	34°
HEATHER	East Shetland Basin	O	Middle Jurassic	Tilted fault block	32°
HUDSON	East Shetland Basin	O	Middle Jurassic	Tilted fault block	33°
HUTTON	East Shetland Basin	O/G	Middle Jurassic	Tilted fault block	35°
HUTTON NW	East Shetland Basin	O/G	Middle Jurassic	Tilted fault block	37°
LYELL	East Shetland Basin	O/G	Middle Jurassic	Tilted fault block	37°
MURCHISON	East Shetland Basin	O/G	Middle Jurassic	Tilted fault block	39°
NESS	Beryl Embayment	O/G	Middle Jurassic	Tilted fault block	36°
NINIAN	East Shetland Basin	O/G	Middle Jurassic	Tilted fault block	36°
OSPREY	East Shetland Basin	O	Middle Jurassic	Tilted fault block (horst)	36°
STRATHSPEY	East Shetland Basin	O/G	Triassic/Jurassic	Tilted fault block	41°
TERN	East Shetland Basin	O	Middle Jurassic	Tilted fault block (horst)	35°
THISTLE	East Shetland Basin	O/G	Middle Jurassic	Tilted fault block	38°

Table 8.3: General characteristics of some selected UK-sector Lower-Middle Jurassic main fields in the northern North Sea (Evans et al., 2003).

Table 8.4 shows the volumes of recoverable petroleum reserves and resources in ascending order in both UK and Norway fields. Many of the producing fields are ageing, but some of them still have substantial remaining reserves. Moreover, the resource base in these fields increases when small discoveries in the northern North Sea are tied in to existing infrastructure.

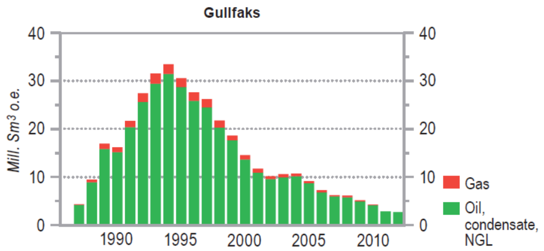
UK AND NORWAY					
FIELD NAME	**STATUS**	**DISCOVERY YEAR**	**ORIGINAL RESERVES (Sm^3 o.e.)**	**REMAINING RESERVES (Sm^3 o.e.)**	**PRODUCTION START**
STATFJORD	Producing	1974	707,66	23,51	1979
OSEBERG	Producing	1979	539,71	102,19	1988
GULLFAKS	Producing	1978	407,52	16,1	1986
GULLFAKS SØR	Producing	1978	170,17	61,58	1998
KVITEBJØRN	Producing	1994	150,66	48,21	2004
VISUND	Producing	1986	106,91	63,59	1999
OSEBERG SØR	Producing	1984	90,68	25,19	2000
TORDIS	Producing	1987	74,61	8,17	1994
BRAGE	Producing	1980	69,06	5	1993
GJØA	Producing	1989	66,03	25,28	2010
VESLEFRIKK	Producing	1981	64,41	3,87	1989
STATFJORD ØST	Producing	1976	45,99	2,13	1994
STATFJORD NORD	Producing	1977	45,89	4,17	1995
MARTIN LINGE	Approved for production	1975	29,8	29,8	Planned for 2018
OSEBERG ØST	Producing	1981	27,69	6,99	1999
HULDRA	Shut down	1982	22,69	0	2001
TUNE	Producing	1995	22,48	-1,1	2002
RINGHORNE ØST	Producing	2003	14,9	2,9	2006
MURCHISON	Shut down	1975	14,77	0	1980
SKIRNE	Producing	1990	13	0,8	2004
SYGNA	Producing	1996	11,3	1	2000
FRØY	Shut down	1987	7,3	0	1995
LILLE-FRIGG	Shut down	1975	3,5	0	1994
ISLAY	Producing	2008	0,1	0	2012

Table 8.4: Original and remaining reserves measured in million standard cubic meters oil equivalents (Sm^3 o.e.) of the main Middle-Lower Jurassic fields in the northern North Sea (last updated in 2016) (from the Norwegian Petroleum website www.norskpetroleum.no).

Figures 8.6 and 8.7 show a condensed overview of the production history of the largest fields of the northern North Sea in the Norwegian sector.

Gullfaks

Blocks and production licences	Block 34/10 - production licence 050, awarded 1978 Block 34/10 - production licence 050 B, awarded 1995.	
Development approval	09.10.1981 by the Storting	**Discovered** 1978
On stream	22.12.1986	
Operator	Statoil Petroleum AS	
Licensees	Petoro AS	30.00 %
	Statoil Petroleum AS	70.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**
	365.5 million Sm^3 oil	11.6 million Sm^3 oil
	23.1 billion Sm^3 gas	
	2.8 million tonnes NGL	
Estimated production in 2013	Oil: 39 000 barrels/day	
Expected investment from 2012	39.6 billion 2012 values	
Total investment as of 31.12.2011	74.9 billion nominal values	
Main supply base	Sotra and Florø	



Oseberg

Blocks and production licences	Block 30/6 - production licence 053, awarded 1979. Block 30/9 - production licence 079, awarded 1982.	
Development approval	05.06.1984 by the Storting	**Discovered** 1979
On stream	01.12.1988	
Operator	Statoil Petroleum AS	
Licensees	ConocoPhillips Skandinavia AS	2.40 %
	Petoro AS	33.60 %
	Statoil Petroleum AS	49.30 %
	Total E&P Norge AS	14.70 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2011**
	384.6 million Sm^3 oil	22.7 million Sm^3 oil
	104.1 billion Sm^3 gas	69.2 billion Sm^3 gas
	12.1 million tonnes NGL	3.8 million tonnes NGL
Estimated production in 2013	Oil: 59 000 barrels/day, Gas: 2.96 billion Sm^3, NGL: 0.40 million tonnes	
Expected investment from 2012	21.5 billion 2012 values	
Total investment as of 31.12.2011	66.6 billion nominal values	
Main supply base	Mongstad	

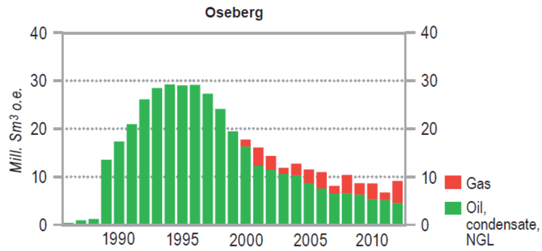
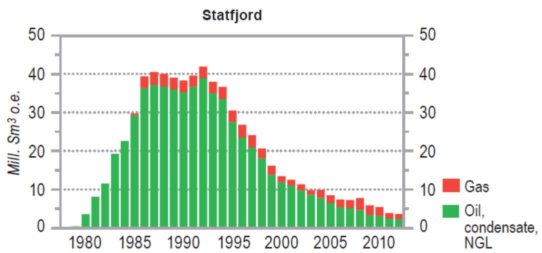


Figure 8.6: Production history and status of the Gullfaks and Oseberg fields (NPD, Facts 2013).

Statfjord

Blocks and production licences	Block 33/12 - production licence 037, awarded 1973. Block 33/9 - production licence 037, awarded 1973. The Norwegian part of the field is 85.47 %, the British part is 14.53 %	
Development approval	16.06.1976 by the Storting	**Discovered** 1974
On stream	24.11.1979	
Operator	Statoil Petroleum AS	
Licensees	Centrica Resources (Norge) AS	19.76 %
	ExxonMobil Exploration & Production Norway AS	21.37 %
	Statoil Petroleum AS	44.34 %
	Centrica Resources Limited	14.53 %
Recoverable reserves (Norwegian part)	**Original**	**Remaining as of 31.12.2012**
	570.4 million Sm^3 oil	4.3 million Sm^3 oil
	77.4 billion Sm^3 gas	11.4 billion Sm^3 gas
	23.0 million tonnes NGL	6.1 million tonnes NGL
	1.1 million Sm^3 condensate	0.6 million Sm^3 condensate
Estimated production in 2013	Oil: 23 000 barrels/day, Gas: 1.05 billion Sm^3, NGL: 0.47 million tonnes. Condensate: 0.05 million Sm^3	
Expected investment from 2012	9.7 billion 2012 values	
Total investment as of 31.12.2011	65.3 billion nominal values	
Main supply base	Sotra and Florø	



Kvitebjørn

Blocks and production licences	Block 34/11 - production licence 193, awarded 1993.	
Development approval	14.06.2000 by the Storting	**Discovered** 1994
On stream	26.09.2004	
Operator	Statoil Petroleum AS	
Licensees	Centrica Resources (Norge) AS	19.00 %
	Enterprise Oil Norge AS	6.45 %
	Petoro AS	30.00 %
	Statoil Petroleum AS	39.55 %
	Total E&P Norge AS	5.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**
	27.3 million Sm^3 oil	9.8 million Sm^3 oil
	89.1 billion Sm^3 gas	49.8 billion Sm^3 gas
	11.5 million tonnes NGL	8.1 million tonnes NGL
Estimated production in 2013	Oil: 34 000 barrels/day, Gas: 7.03 billion Sm^3, NGL: 0.34 million tonnes	
Expected investment from 2012	8.2 billion 2012 values	
Total investment as of 31.12.2011	13.7 billion nominal values	
Main supply base	Florø	

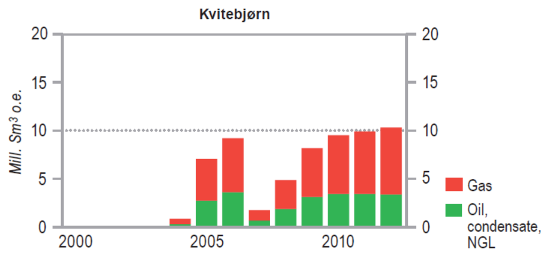


Figure 8.7: Production history and status of the Statfjord and Kvitebjørn fields (NPD, Facts 2013).

A creaming curve is a diagram used to present the relationship between aggregated or cumulative resource growth from discoveries and wildcats drilled. Its name probably derives from the fact that the biggest discoveries in an area or a play (the cream of the crop) are normally made early in the exploration history of the area or play. As time passes, remaining prospects will be smaller and have a lower discovery probability. Such a curve presents the exploration history of an area or play. The most important discoveries of the Lower and Middle Jurassic plays of the North Sea that increased the cumulative resources are located in the northern North Sea, as shown in Figure 8.8.

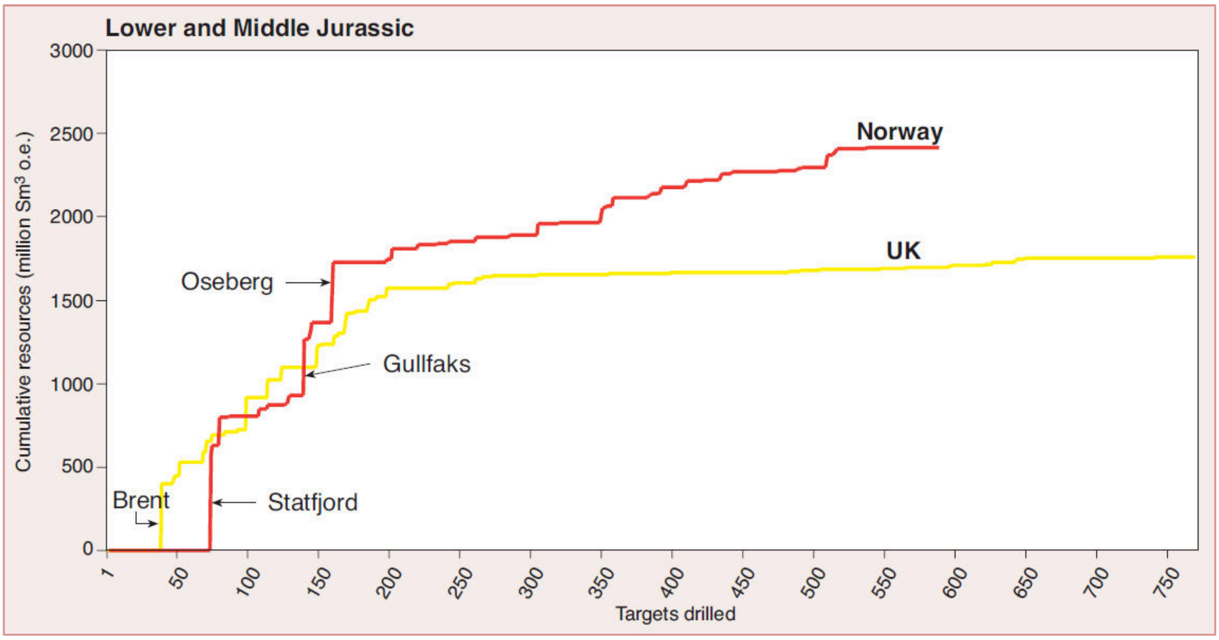


Figure 8.8: Creaming curve for the Lower and Middle Jurassic plays of the North Sea (Evans et al., 2003).

8.4 UPPER JURASSIC FIELDS

Upper Jurassic oil, gas and condensate fields have been discovered in the North Sea area and further discoveries are under appraisal or development but a significantly smaller number of fields is present in the northern North Sea than in southern areas. The majority of accumulations are located in the relatively mature UK sector in three sub-regions: the Central Graben including the adjacent West Central Shelf, the South Viking Graben, and the Outer Moray Firth Basin. However, two extremely large, but somewhat isolated and atypical accumulations dominate hydrocarbon volumetric distribution; these are the Troll Field on the Horda Platform to the east of the North Viking Graben, and the Magnus Field at the northern end of the East Shetland Basin. The reservoirs of both the Troll and Magnus fields reflect the laterally extensive nature of the sand-dominated shoreface systems in which thick sandstone occurrences result from syn-depositional tectonics, and their high reservoir quality results from wave and storm reworking.

The Troll gas field is located on the North Viking Graben/Sogn Graben, comprising two main structures namely Troll East and Troll West, and accounts for approximately 40% of total gas reserves on the Norwegian continental shelf (NCS). Troll is also one of the largest oil fields on the Norwegian continental shelf. In 2002, the oil production was more than 400,000 barrels per day. Troll is estimated to have recoverable reserves in the amount of 1330.8 Mbbl of oil, 184.5 Mbbl of NGLs/condensate, and 1287.1 billion m^3 (45.4 Tcf) of gas. Hydrocarbons in the Upper Jurassic of the Troll Field (West and East) are trapped in a large fault-bounded, horst structure. The Troll Field was discovered in 1979 and produces a 50° API gravity crude oil from the Sognefjord Formation. On the other hand, the Magnus Field was discovered in 1974 and it is estimated to have recoverable reserves in the amount of 781.6 Mbbl of oil, 61.7 Mbbl of NGLs/condensate, and 8.6 billion m^3 (0.3 Tcf) of gas with a 39° API gravity crude oil from the Magnus Formation sandstone. Trapping at the Magnus Field is largely a combination of stratigraphic pinch-out and reservoir truncation, but with the dip-closure and truncation both directly related to footwall uplift and rotation. The Magnus Field is unusual as it comprises a basin-floor fan reservoir; most other large footwall-related traps contain laterally extensive, shallow-marine sandstone reservoirs such as the Troll Field mentioned before. The creaming curve of the Upper Jurassic play in the northern North Sea is shown in Figure 8.9. This play retains an interesting potential for undiscovered resources.

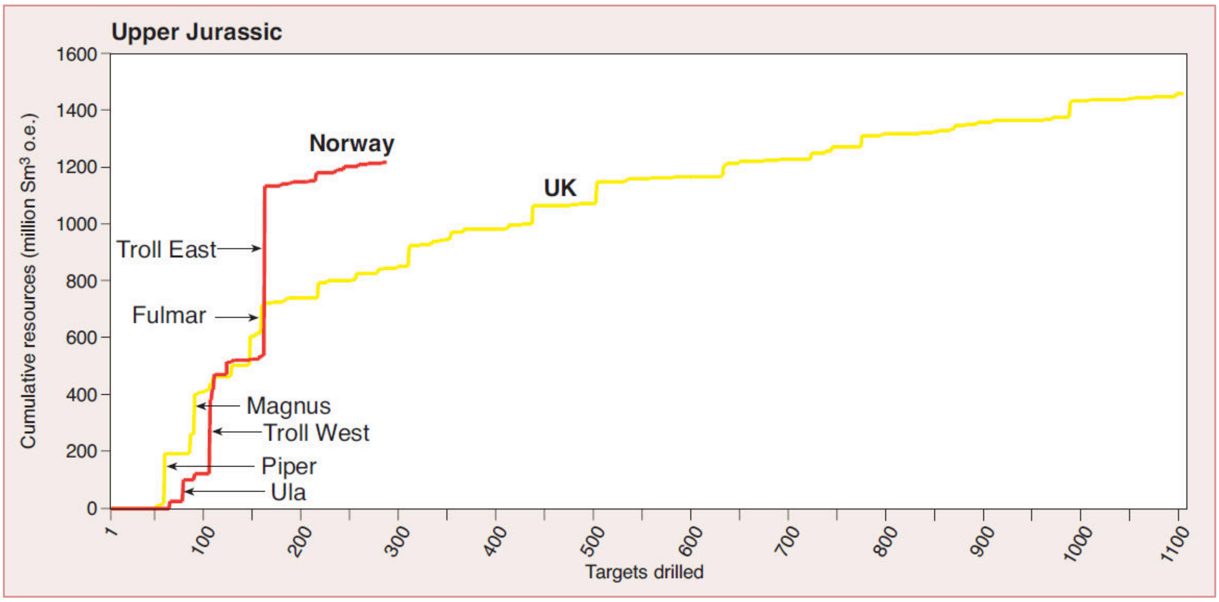


Figure 8.9: Creaming curve for the Upper Jurassic play of the North Sea (Evans et al., 2003).

8.5 CRETACEOUS FIELDS

The only significant Lower Cretaceous discovery of the northern North Sea is the Agat discovery, which is a gas condensate discovery located 50 km west of the Norwegian coastline in the northeastern part of the North Sea. Potential hydrocarbon volumes in the Agat complex (gas-in-place) have been estimated as 65 billion Sm_3 (2.29 Tcf) (Gulbrandsen, 1987) derived from the Agat Formation. However, the complex reservoir geology and the poorly known distribution of the gas pools have made economic exploitation of the discovery impossible to date. The Agat discovery is a prime example of a deepwater, clastic reservoir-lowstand systems tract of Late Aptian-Albian to Cenomanian age (Gulbrandsen, 1987; Skebeli et al., 1995, Crittenden et al., 1999, Copestake et al., 2003) in the Norwegian sector of the North Sea.

8.6 PALEOCENE/EOCENE FIELDS

Table 8.5 shows recoverable reserves originally present in descending order of some selected Paleocene fields in the northern North Sea.

NORWAY					
FIELD NAME	**STATUS**	**DISCOVERY YEAR**	**ORIGINAL RESERVES (Sm^3 o.e.)**	**REMAINING RESERVES (Sm^3 o.e.)**	**PRODUCTION START**
GRANE	Producing	1991	144,2	37,5	2003
FRIGG	Shut down	1971	116,7	0	1977
BALDER	Producing	1967	77	9,9	1999
ALVHEIM	Producing	1997	56,7	20,3	2008
HEIMDAL	Producing	1972	52,7	0,7	1985
ODIN	Shut down	1974	27,5	0	1984
JOTUN	Shut down	1994	24	0	1999
VOLUND	Producing	1994	14,1	4,6	2009
NORDØST FRIGG	Shut down	1974	11,7	0	1983
MARTIN LINGE	Approved for production	1975	10,9	10,9	Planned for 2018
ØST FRIGG	Shut down	1973	9,3	0	1988
BØYLA	Producing	2009	3,6	2,1	2015
JETTE	Shut down	2009	0,4	0	2013

Table 8.5: Original and remaining reserves measured in million standard cubic meters oil equivalents (Sm^3 o.e.) of the main Paleocene/Eocene fields in the northern North Sea (last updated in 2016) (from the Norwegian Petroleum website www.norskpetroleum.no).

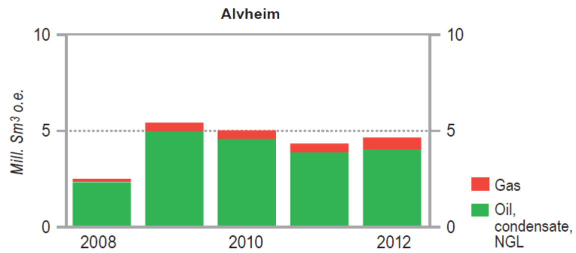
Figures 8.10 and 8.11 show an overall production history of some of the most important Paleocene/Eocene fields of the northern North Sea in the Norwegian sector.

Alvheim

Blocks and production licences	Block 24/6 - production licence 088 BS, awarded 2003 Block 24/6 - production licence 203, awarded 1996. Block 25/4 - production licence 036 C, awarded 2003 Block 25/4 - production licence 203, awarded 1996.	
Development approval	06.10.2004 by the King in Council	**Discovered** 1998
On stream	08.06.2008	
Operator	Marathon Oil Norge AS	
Licensees	ConocoPhillips Skandinavia AS	20.00 %
	Lundin Norway AS	15.00 %
	Marathon Oil Norge AS	65.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**
	37.2 million Sm^3 oil	17.5 million Sm^3 oil
	6.8 billion Sm^3 gas	4.7 billion Sm^3 gas
Estimated production in 2013	Oil: 59 000 barrels/day, Gas: 0.58 billion Sm^3	
Expected investment from 2012	1.8 billion 2012 values	
Total investment as of 31.12.2011	17.7 billion nominal values	

Balder

Blocks and production licences	Block 25/10 - production licence 028, awarded 1969. Block 25/11 - production licence 001, awarded 1965. Block 25/8 - production licence 027, awarded 1969 Block 25/8 - production licence 027 C, awarded 2000 Block 25/8 - production licence 169, awarded 1991.	
Development approval	02.02.1996 by the King in Council	**Discovered** 1967
On stream	02.10.1999	
Operator	ExxonMobil Exploration & Production Norway AS	
Licensees	ExxonMobil Exploration & Production Norway AS	100.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**
	72.1 million Sm^3 oil	16.2 million Sm^3 oil
	2.0 billion Sm^3 gas	0.6 billion Sm^3 gas
Estimated production in 2013	Oil: 32 000 barrels/day, Gas: 0.04 billion Sm^3	
Expected investment from 2012	9.6 billion 2012 values	
Total investment as of 31.12.2011	23.2 billion nominal values	
Main supply base	Dusavik	



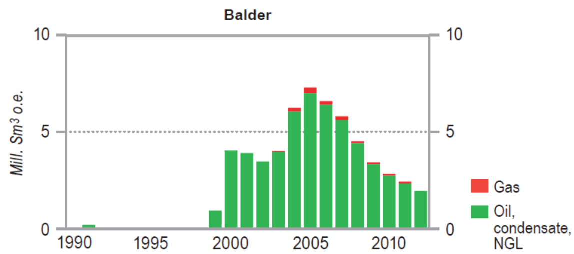


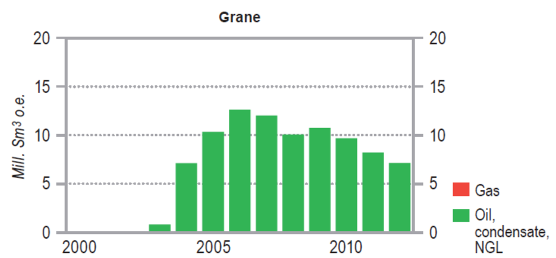
Figure 8.10: Production history and status of the Alvheim and Balder fields (NPD, Facts 2013).

Grane

Blocks and production licences	Block 25/11 - production licence 001, awarded 1965 Block 25/11 - production licence 169 B1, awarded 2000.	
Development approval	14.06.2000 by the Storting	**Discovered** 1991
On stream	23.09.2003	
Operator	Statoil Petroleum AS	
Licensees	ConocoPhillips Skandinavia AS	6.17 %
	ExxonMobil Exploration & Production Norway AS	28.22 %
	Petoro AS	28.94 %
	Statoil Petroleum AS	36.66 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**
	124.6 million Sm^3 oil	36.1 million Sm^3 oil
Estimated production in 2013	Oil: 98 000 barrels/day	
Expected investment from 2012	10.0 billion 2012 values	
Total investment as of 31.12.2011	19.7 billion nominal values	
Main supply base	Mongstad	

Heimdal

Blocks and production licences	Block 25/4 - production licence 036 BS, awarded 2003.	
Development approval	10.06.1981 by the Storting	**Discovered** 1972
On stream	13.12.1985	
Operator	Statoil Petroleum AS	
Licensees	Centrica Resources (Norge) AS	33.80 %
	Petoro AS	20.00 %
	Statoil Petroleum AS	29.44 %
	Total E&P Norge AS	16.76 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**
	8.2 million Sm^3 oil	1.6 million Sm^3 oil
	46.9 billion Sm^3 gas	1.7 billion Sm^3 gas
Estimated production in 2013	Oil: 330 barrels/day, Gas: 0.11 billion Sm^3	
Expected investment from 2012	0.2 billion 2012 values	
Total investment as of 31.12.2011	10.0 billion nominal values	
Main supply base	Mongstad	



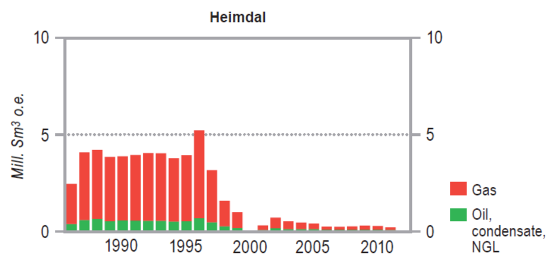


Figure 8.11: Production history and status of the Grane and Heimdal fields (NPD, Facts 2013).

Similarly, the most important Paleocene/Eocene discoveries played an important role on the cumulative resources of the northern North Sea, as shown in Figure 8.12.

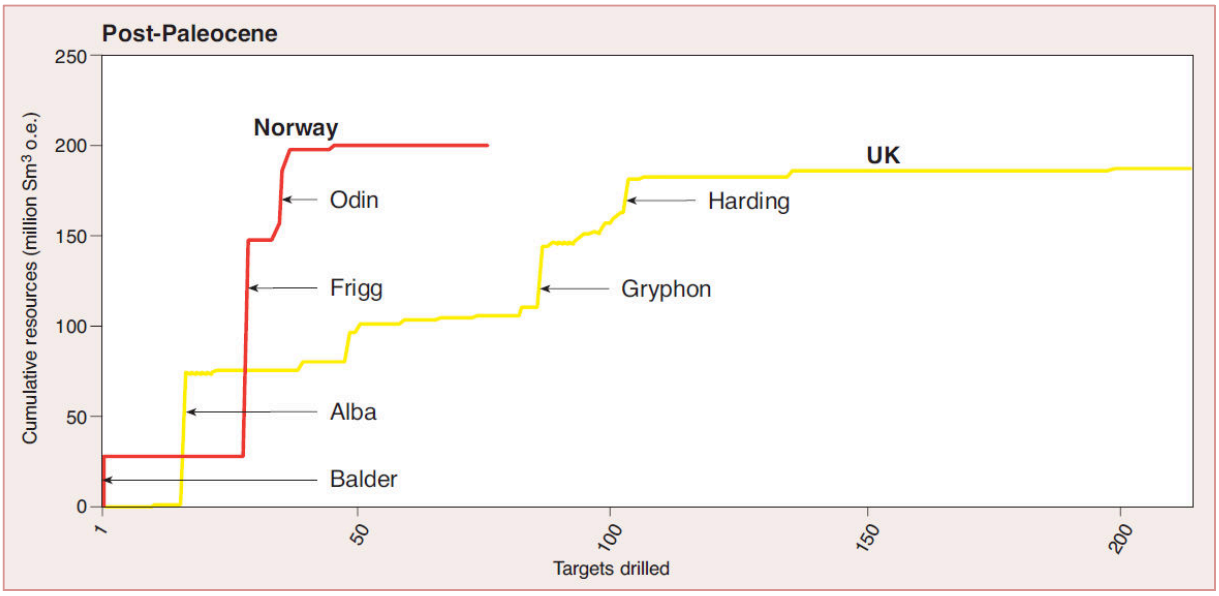


Figure 8.12: Creaming curve for the Paleocene/Eocene play of the North Sea (Evans et al., 2003).

The Frigg Field and the nearby undeveloped Nuggets discovery in the south-central blocks of UK Quadrant 3 have four-way dip closure enhanced by compaction. A well-defined seismic flat-spot over much of the Frigg area (Heretier et al., 1979) corresponds to the initial gas-oil-contact (Brewster, 1991), and probably has a diagenetic origin. The sandstones in this area form mounds that are relatively easy to spot on seismic profiles. However, they have proved difficult to exploit due to their limited lateral extent, although their special variation is in part compensated for by their relatively high reservoir quality. The Frigg Field and its immediate satellite fields have been documented by a number of authors (Heretier et al., 1981; Revoy, 1984; Thouand et al., 1986; Brewster and Jeangeot, 1987; De Leebeeck, 1987; Mure, 1987a; Brewster, 1991). The main Frigg Field covered an area of over 100 km^2 and has had a gas column that is up to 163 m high, with an oil rim up to 10 m thick. Total reserves were estimated at 184 billion m^3 of gas (Bowman, 1998). The oil migrated earlier than the gas, with subsequent biodegradation to its present form. Migration occurred through fractured shales, which results in the formation of gas chimneys that can be seen on seismic profiles throughout this area; in UK-Quadrant 9, seismic data clearly show the existence of gas chimneys protruding up through the Upper Cretaceous Shetland Group.

Gas in the Frigg area was predominately dry. Published data for oils underlying the gas accumulations suggested that these were degraded to varying degrees. In the main Frigg Field, the 10 m-thick oil leg comprised low-gravity (23-24° API) napthenic oil with normal alkanes almost absent. Oil in Frigg North East was napthenic with a gravity of 27.5° API (Mure, 1987c) whereas oil in Frigg East was much less degraded with a gravity of 39° API and contained significant normal alkanes (Mure, 1987b). Gas in the main Frigg Field was dry with small amounts of nitrogen and carbon dioxide (Heritier et al., 1979) (Table 8.6). Data for the Frigg-East Field Alpha and Beta structures (Mure, 1987b), and for the Frigg North-East Field (Mure, 1987c), show that the gas in the satellite fields of similarly dry composition. Production in the Frigg Field has been completed and the field was shut down in 2004, and all related facilities have been dismantled and removed.

FIELD NAME	C_1	C_2	C_3	C_4	N_2	CO_2
HEIMDAL	86	6	3	2	0.9	0.4
FRIGG	95.5	3.5	0.04	0.01	0.4	0.3
FRIGG EAST	94.9-95.6	3.6-3.9	0.07-0.08	0.01-0.02	0.6-0.7	0.05-0.30
FRIGG NORTH-EAST	94.2	4.65	0.07	0.02	0.67	0.3

Table 8.6: Gas composition for the Heimdal and Frigg fields (Evans et al., 2003).

8.7 FIELDS/DISCOVERIES UNDER DEVELOPMENT

8.7.1 Licensing rounds as a means to maintain exploration and production

Exploration activity is essential if undiscovered resources are to contribute to production and create value both for the industry and for society. The oil-companies are given access to exploration acreage in both mature and frontier areas. Concerning Norway, a high level of exploration activity on the Norwegian Continental Shelf (NCS) since 2005 has resulted in a number of profitable discoveries. The production licence gives a company or a group of companies a monopoly to perform investigations, exploration drilling and recovery of petroleum deposits within geographical area stated in the licence. The licensees become owners of the petroleum that is produced. A production licence may cover one or more blocks or parts of blocks and regulates the rights and obligations of the participant companies with respect to the Authorities. Production licenses are awarded by the Norwegian Ministry of

Petroleum and Energy in numbered licensing rounds, or by nearly awards in predefined areas (APA) (Fig. 8.13).

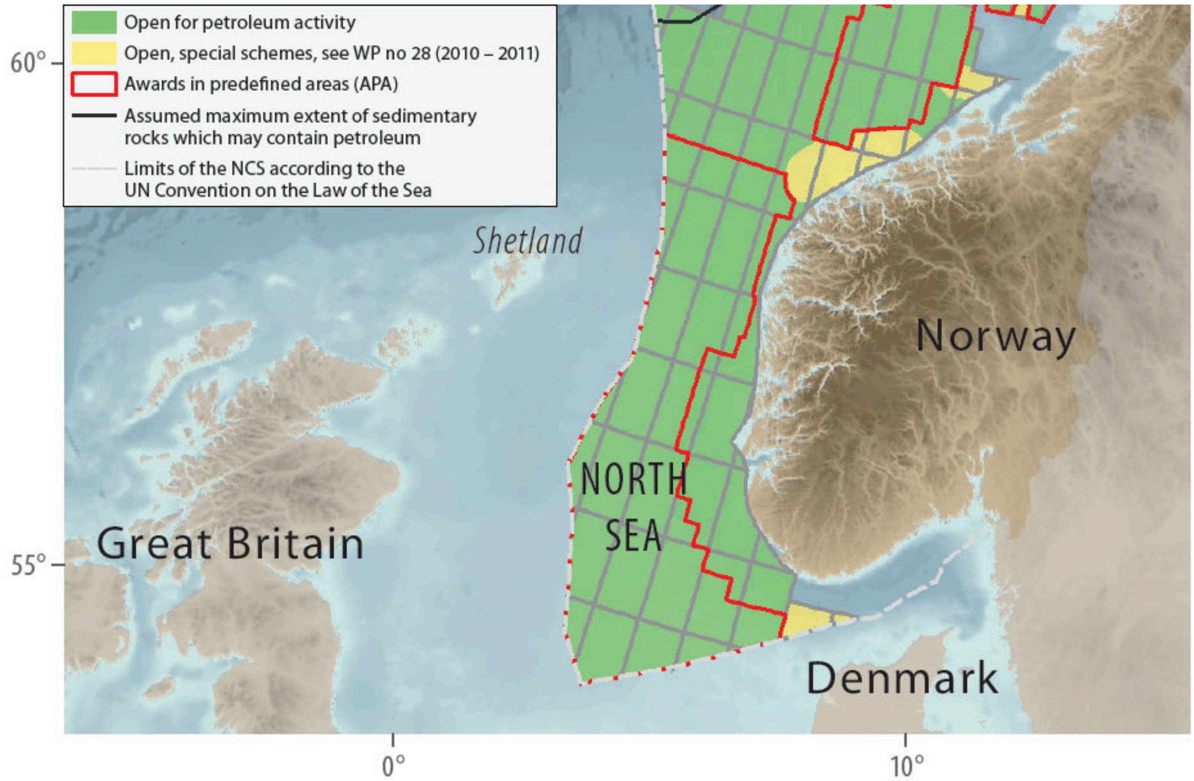


Figure 8.13: Exploration status of the northern North Sea in the Norwegian Continental Shelf (from NPD website www.npd.no).

Two types of licensing round with equal status are conducted on the NCS. Awards in predefined areas (APA) cover mature areas, while numbered rounds concentrate on frontier areas. Mature areas are characterised by known geology and well-developed or planned infrastructure. They usually offer a greater probability of making discoveries than frontier areas, where geological knowledge is more limited and infrastructure lacking. Frontier areas are likelier to yield large discoveries than mature ones.

Increased availability of acreage has led to more licence awards (Fig. 8.14). Over the past 15 years, the Norwegian Government has strengthened the predictability of the allocation system by holding APA rounds annually, while the numbered rounds generally take place every other year. In addition, the companies know in advance which principles govern the kind of acreage included and the general work commitments for production licences in the APA rounds compared with the numbered ones.

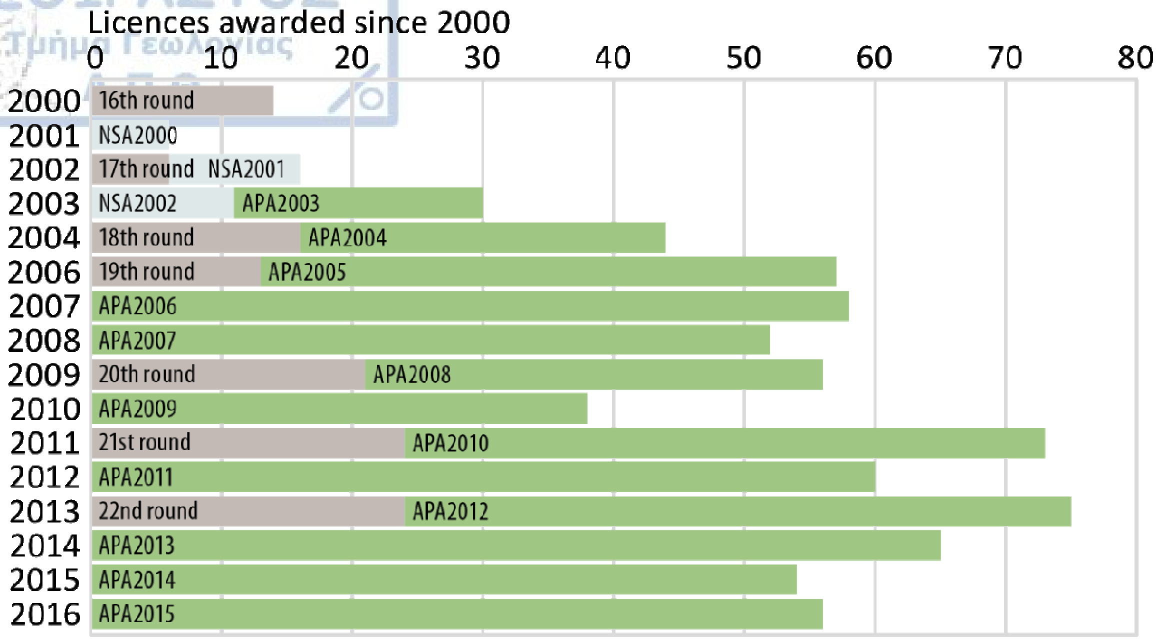


Figure 8.14: Awards since 2000 by licensing round. North Sea awards (NSA) were introduced in 1999 as a predecessor of the APA (from NPD website www.npd.no).

As Figure 8.14 shows, the largest number of awards has been made in the APA rounds. Since these cover areas with known geology and well-developed infrastructure, they generate more applications than the numbered rounds. Opportunities to develop smaller discoveries through tie-ins to existing infrastructure have made the APA rounds especially attractive to new players on the NCS, particularly the smaller companies. Frontier areas are investigated gradually through sequential exploration. New licence awards in the numbered rounds are generally limited to a small number of key blocks.

New (medium to small size) exploration companies have been especially prominent in APA rounds, where blocks in mature areas are announced. Exploration in frontier areas, on the other hand, is mainly carried out by the larger companies. The little known geology increases the potential for discoveries, but greater challenges may be met during exploration, development and production. Exploration costs include costs related to seismic data acquisition to map potential petroleum deposits under the seabed and to drilling exploration wells. In 2016, preliminary estimates of exploration costs on the Norwegian shelf totaled about NOK 22 billion (~2.5 billion Euros). Figure 8.15 shows a comparison between oil price, number of companies on the shelf and spudded exploration wells at year-end, 2000-2016.

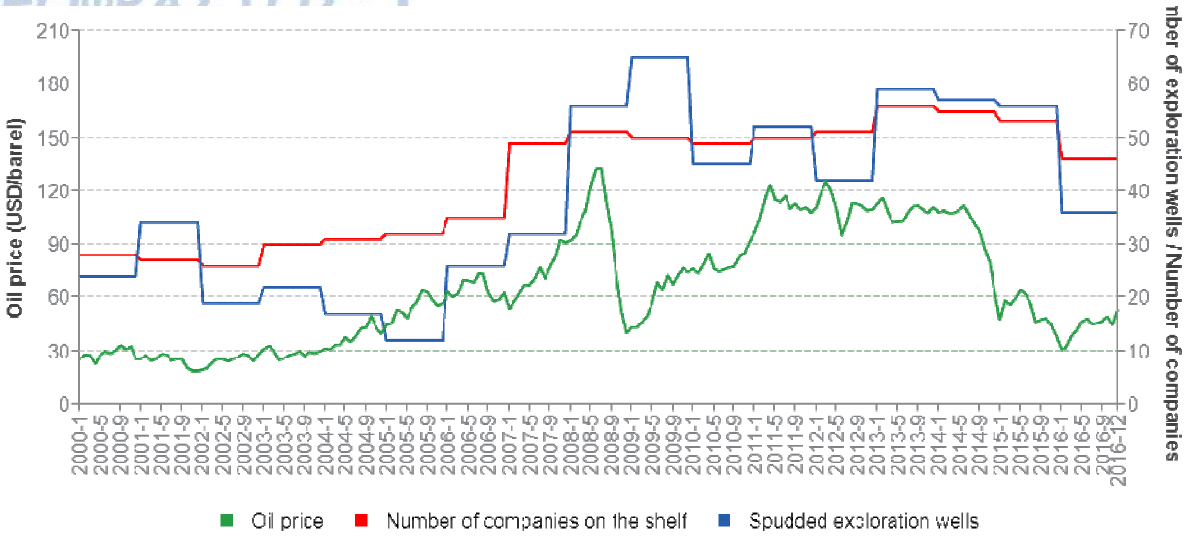


Figure 8.15: Oil price, number of companies on the shelf and spudded exploration wells at year end, 2000-2016 (updated 13.03.2017) (from Norwegian Petroleum website www.norskpetroleum.no).

The following sub-chapters below provide some details of the Johan Sverdrup and Martin Linge fields which are both under development. Just over two years have passed since work began on the Johan Sverdrup Field. Constructing the platforms for the largest Norwegian offshore development in many years has come half-way. The PDO (Plan for Development and Operation) for the largest by far, the first development stage for Johan Sverdrup Field, was approved on 20 August 2015. Production start-up is scheduled for late 2019. Although the Johan Sverdrup Field is located in the Central North Sea, it provides a paradigm of revived and focussed exploration efforts in a highly explored mature basin area. Martin Linge Field was discovered back in 1978. Technology development and new information about the subsurface led the license partners to decide to develop the field. The PDO was approved in 2012.

8.7.2 Johan Sverdrup Field

The Johan Sverdrup Field was discovered in 2010 by exploration well 16/2-6, drilled by PL501 operator Lundin Norway and partners Statoil and Maersk Oil in the Norwegian part of the North Sea (Fig. 8.16). The trap is structural-stratigraphic, and is located at the southern end of the Utsira High, a complex basement-cored megaclosure (Fig. 8.17). Johan Sverdrup is a giant field, with an estimated 3.5 billion barrels of in-place oil (NPD, 2015), with the majority occurring in the Upper Jurassic intra-Draupne Formation sandstone. That a giant discovery could be made in such a mature hydrocarbon province as the North Sea was a welcome surprise to the industry. The primary pre-drill risk was considered to be the lack of a viable hydrocarbon migration route from the South Viking Graben source rock kitchen to the west, and the lack of any such kitchens in the Stord Basin to the east and Ling Graben to the south (Fig. 8.17). Early exploration wells located updip to the west and downdip to the east, though quite sparse (Fig. 8.16), were disappointing and interpreted by most to severely downgrade the prospectivity of the entire area. Early exploration drilling around the southern Utsira High did actually point to the possibility of an Upper Jurassic stratigraphic trap east of the Haugaland High (Fig. 8.17). Crestal wells 16/2-1, 16/ 2-3, 16/2-4 and 16/2-5 (Fig. 8.16, drilled between 1967 and 2009) were all located updip, reached TD in granitic/metamorphic basement, and failed to encounter Jurassic sediments of any kind. Downdip wells to the east and southeast, 16/3-2 and 16/6-1 (drilled in 1976 and 1968), on the other hand, encountered porous Upper Jurassic sand (34 m and 4 m, respectively). The nearest well to the north, 16/2-2, stopped in the Middle Cretaceous. This left an untested stratigraphic pinchout between the updip and downdip wells.

The concept of an Upper Jurassic stratigraphic trap lying on the eastern side of the Haugaland High was not incompatible with North Sea petroleum exploration thinking as far back as the 1980's. Various authors described tectonic, eustatic sea level and sequence stratigraphic conditions that favoured deposition of marine sands around the flanks of prominent palaeo topographic highs created by Late Jurassic rifting (e.g. Pegrum and Spencer, 1990; Fraser et al., 2003). There is a general consensus that eustatic sea level changes or local tectonism alone cannot explain the presence and distribution of these sands. It is rather the interplay of the two, which controlled the distribution of local sediment sources (i.e. eroding highs) and adjacent accommodation space (i.e. basinal lows) (e.g. Brekke et al., 2001; Fraser et al., 2003).

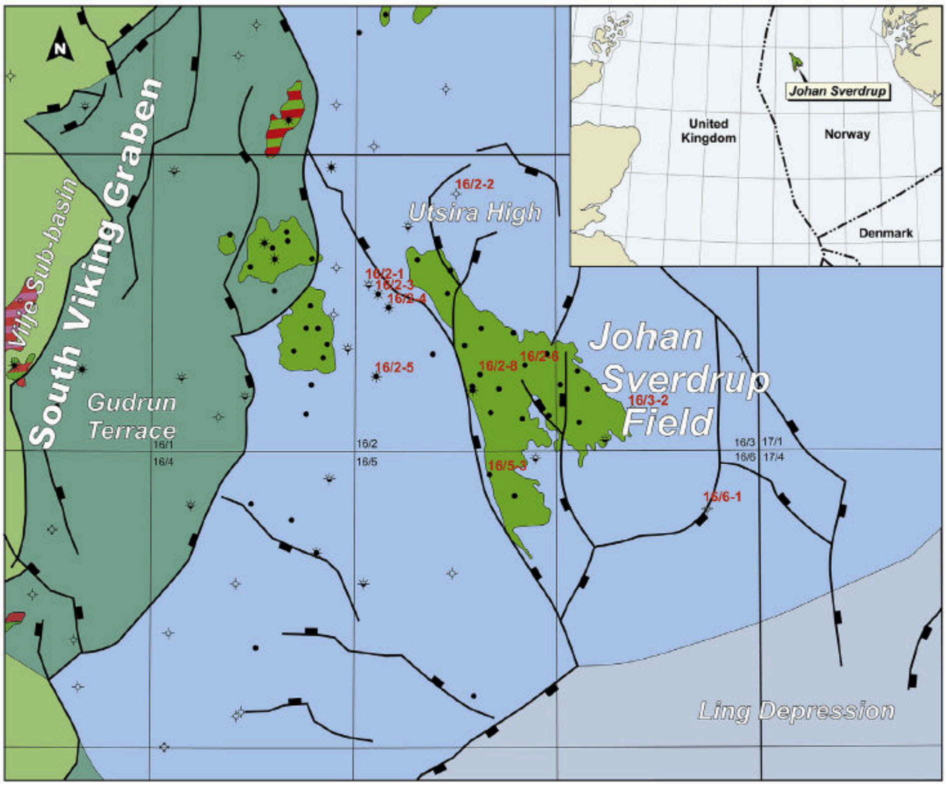


Figure 8.16: Location map of southern part of Utsira High and surrounding areas (based on NPD, 2016) with key wells mentioned in the text (Olsen et al., 2017).

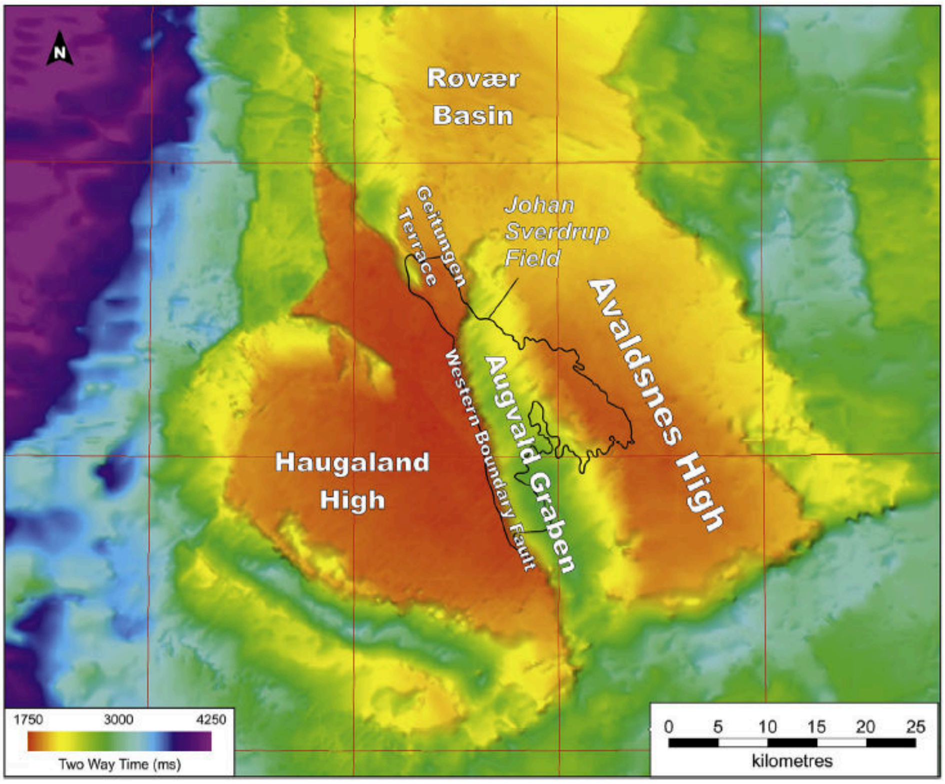


Figure 8.17: Top Basement two-way-traveltime structure map over the area with additional structural subdivision (Olsen et al., 2017).

The intra-Draupne Formation sandstone in the Johan Sverdrup Field is one of the best Upper Jurassic reservoirs ever encountered in the North Sea. It has an exceptionally high net-to-gross, porosity, permeability, aerial distribution and lateral continuity. The success of Johan Sverdrup has not only given a boost to the oil-industry in Norway but also challenged explorers worldwide to look for oil in well-explored mature basins. The development master plan envisages additional phases of development to recover the vast quantities of oil contained in Johan Sverdrup over a period of 50 years. Johan Sverdrup is located in the area in which the very first licence on the Norwegian Continental Shelf was awarded in 1965 (PL001). After several dry wells were drilled in the 1960s and 1970s, the area was considered to have no hydrocarbon potential. Many concluded it was impossible for oil to migrate to this area. However, the resource has proved prolific in size and exceptional in quality. The recoverable resource range of 1.7 to 3.0 billion barrels of oil equivalent (MMboe) makes Johan Sverdrup one of the five largest fields ever discovered in Norway (Fig. 8.18). The APA licensing system in Norway had a major contribution in the focussed exploration in the vicinity of the Utsira High and the consequent discovery of the Johan Sverdrup Field.

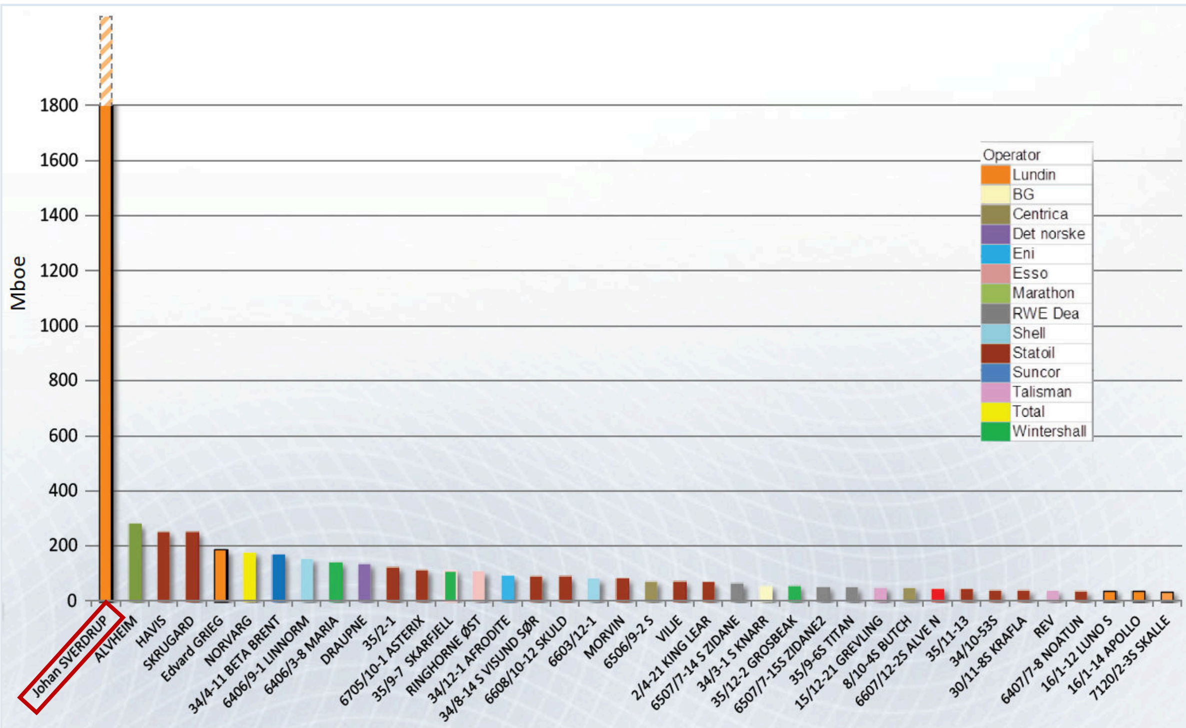


Figure 8.18: Discovered resources in Norway 2001-2012 (Jørstad, 2012).

8.7.3 Martin Linge Field

Total-operated Martin Linge Field (28/11/2017: Statoil announced the purchase of Total's working interest in the field and the take-over of operatorship) is located about 42 kilometres west of the Oseberg area near the border to the UK sector. A storage ship will be used for the oil that is recovered, in addition to the gas resources. Martin Linge will be operated using power from shore. Planned production start-up for Martin Linge is early 2018. In the Martin Linge Field, it was invented a new way to design safer and more environmentally friendly platforms. The fully electric facilities are powered via a 160 km subsea cable to the Norwegian coast (Fig. 8.19), making it the longest AC power link in the world. By eliminating the need to use offshore generators, the cable helps reduce our CO_2 emissions by two million metric tons. A fiber-optic cable relays all of the platform's data, which will allow managing the facility remotely and in real time. Martin Linge is also equipped with two control rooms, one offshore and one onshore. This will keep the employees safer, since a smaller team can perform all the necessary offshore operations. Only 19 team members are needed to carry out maintenance and upkeep on the facilities at any given time.

Figure 8.19: Martin Linge Field and subsea cable location (from TOTAL website www.total.com).

8.8 IMPROVED OIL RECOVERY (IOR)/ENHANCED OIL RECOVERY (EOR)

After the application of conventional oil extraction techniques, about 2/3 of discovered reserves still remain to be produced. In view of high probability for oil presence and oil price increases, investments in research of possibilities for higher recoveries and higher production with application of appropriate Improved Oil Recovery (IOR) and Enhanced Oil Recovery (EOR) methods are justified, naturally under economic conditions. EOR is an oil recovery enhancement method using sophisticated techniques that alter the original properties of oil. Once ranked as a third stage of oil recovery that was carried out after secondary recovery, the techniques employed during enhanced oil recovery can actually be initiated at any time during the productive life of an oil reservoir. Its purpose is not only to restore formation pressure, but also to improve oil displacement or fluid flow in the reservoir.

The three major types of enhanced oil recovery operations are chemical flooding (alkaline flooding or micellar-polymer flooding), miscible displacement (carbon dioxide [CO_2] injection or hydrocarbon injection), and thermal recovery (steamflood or in-situ combustion). The optimal application of each type depends on reservoir temperature, pressure, depth, net pay, permeability, residual oil and water saturations, porosity and fluid properties such as oil API gravity and viscosity. EOR methods, also known as tertiary recovery methods, mobilize oil trapped by capillary and viscosity forces during reservoir waterflooding in the secondary stage. Oil is freed by chemical and thermal activity, by injecting solvents and chemicals and heating of the reservoir. IOR processes are applied mainly in the secondary and tertiary reservoir depletion stage to increase reservoir sweep efficiency coefficients by displacing fluids, looking for trapped oil by denser well spacing pattern, drilling of horizontal wells and sidetracking from existing holes, fracturing and use of polymers to improve fluid mobility ratio (Fig. 8.20).

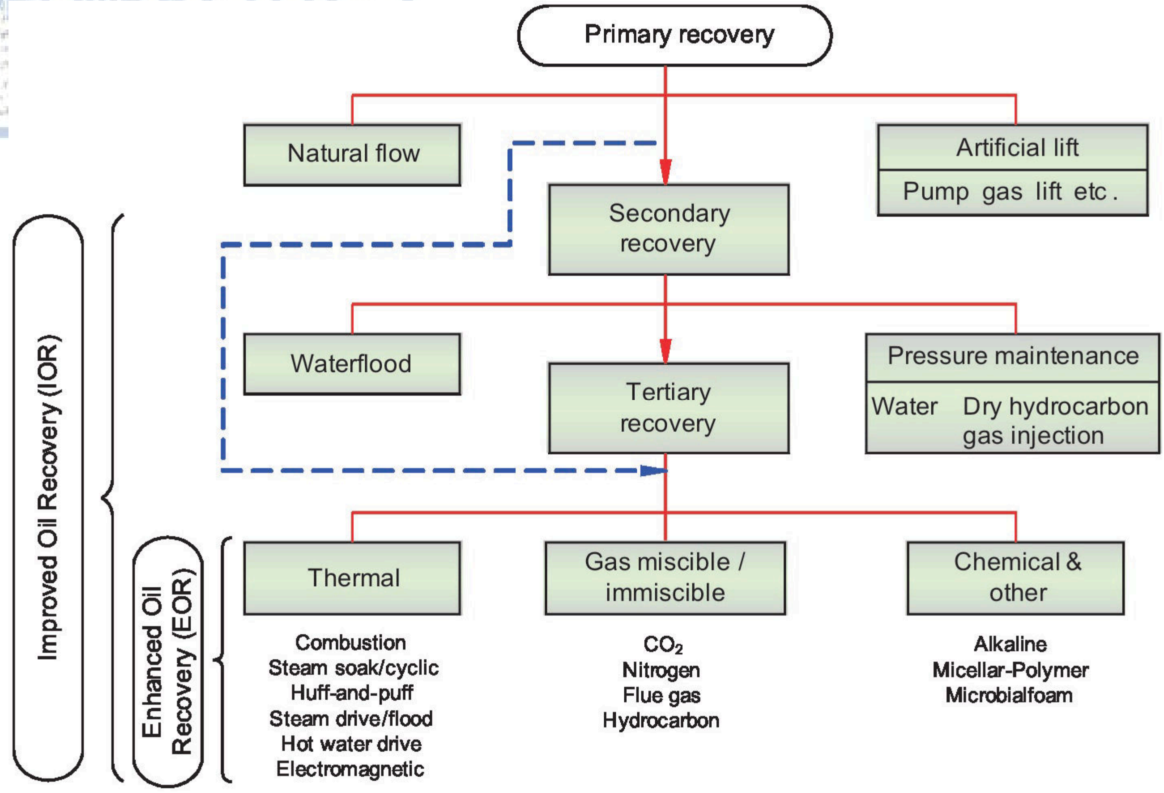


Figure 8.20: Proposed definitions of the EOR and IOR terms (Sečen, 2005).

The average oil recovery rate for oil fields on the Norwegian shelf is currently about 47%, and the aim is to increase this further. However, recovery rates differ greatly from field to field, partly because reservoir conditions vary and different technical solutions are applied. There is great potential for improving recovery on the Norwegian shelf. An increase of only one percentage point in the average recovery rate from the 25 biggest producing oil fields (Fig. 8.21) equals about NOK 60 billion (~6.5 billion Euros) in sales revenues (based on 50 USD/boe and 8 NOK/USD). However, this would require considerable effort and new investment decision by the licensees.

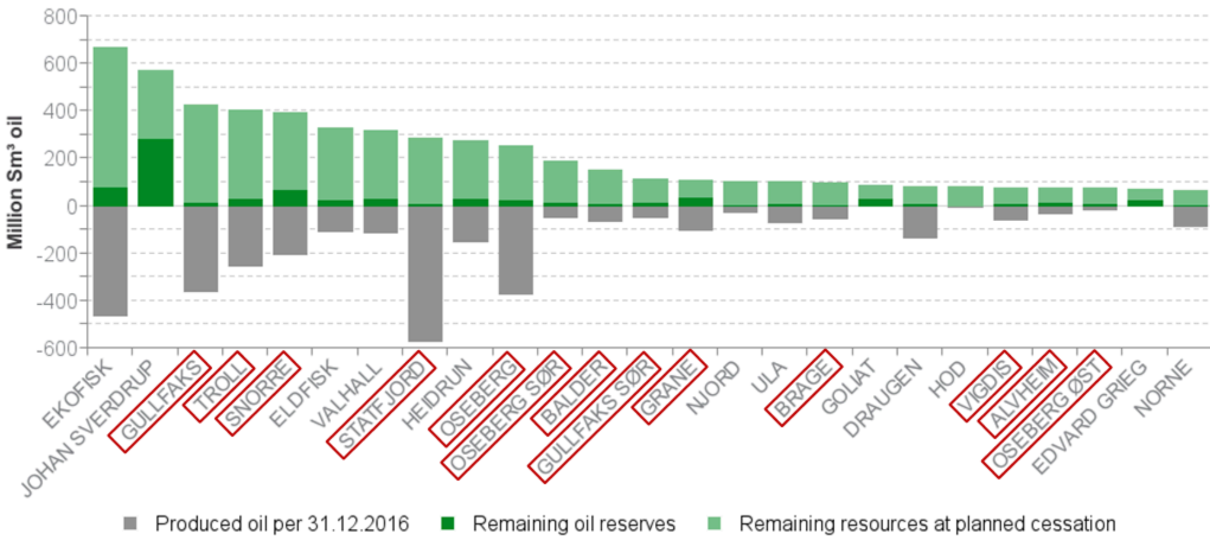


Figure 8.21: Distribution of oil reserves and resources for the largest oil fields in the northern North Sea (red rectangles) as of 31 December 2016 (from Norwegian Petroleum website www.norskpetroleum.no).

The process of ensuring the highest possible recovery rate from a field starts when development is being planned and the facilities are being designed. Most oil fields on the Norwegian shelf incorporate pressure support in the form of water and/or gas injection from the time they come in stream. Constant improvements in technology for and knowledge about reservoir monitoring are making it possible to design better recovery strategies for the fields. Systematic data acquisition and use of production and reservoir data increase understanding of reservoir properties throughout the production phase. An improved understanding of where oil and gas are located and their flow paths makes it possible to place wells more effectively. As new drilling targets are identified in this way, additional wells need to be drilled. The steady improvement in understanding of reservoir properties throughout the production phase tends to result in considerable differences between the production forecast used in the original plan for development and operation (PDO) for a field and the volumes actually produced. Figure 8.22 shows an example of the differences between the prognosis at PDO and actual production for the Oseberg Field of the northern North Sea.

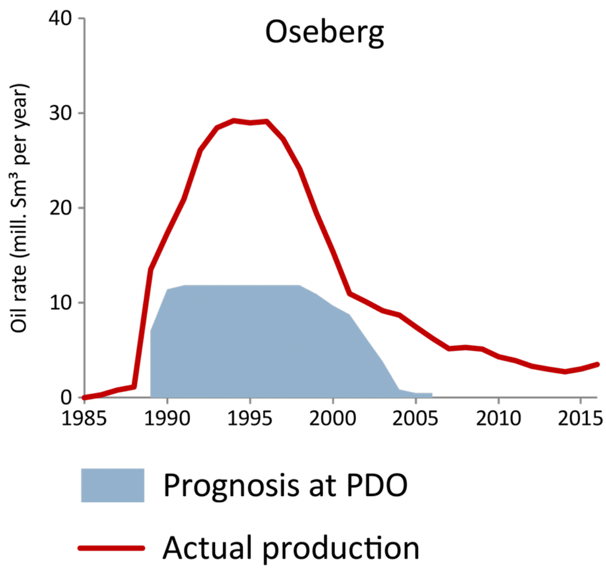


Figure 8.22: Extended lifetime and production trends for the Oseberg Field of the northern North Sea (from Norwegian Petroleum website www.norskpetroleum.no).

The amount of oil that can be produced from a field is a function of factors including reservoir conditions, the development solution chosen, the production strategy and the available technology. It may be possible to extract oil not included in current production plans by using improved recovery methods. This oil can be divided into two categories: mobile and immobile. Mobile oil can in principle be recovered using conventional production wells and techniques, by drilling additional wells and increasing the duration of water and/or gas injection. Immobile oil adheres to the pore walls in the reservoir, and cannot be forced out of the pores and produced by water or gas injection. More advanced methods, known as enhanced recovery techniques, are needed to mobilize a proportion of the immobile oil.

Chapter 9

FUTURE EXPLORATION & PRODUCTION CHALLENGES

9.1 YET-TO-FIND RESOURCES

Since production started in 1971, oil and gas have been produced from a total of 102 fields on the Norwegian Continental Shelf (NCS). At the end of 2016, 62 fields were in production in the North Sea. The first well on the NCS, well 8/3-1 in the south-eastern part of Norway's North Sea sector, was spudded in 1966. Since then, some 615 wildcats have been drilled in the Norwegian-sector of the North Sea and provide the data set for the creaming curve. The creaming curve in Figure 9.1 shows that discoveries were made after a few wells in the North Sea. In addition Figure 9.1 presents the uncertainty range of ~3000 to 8000 Mboe for the undiscovered resources. The latter are estimated on the basis of current knowledge about the areas, and the figure will probably change with new information.

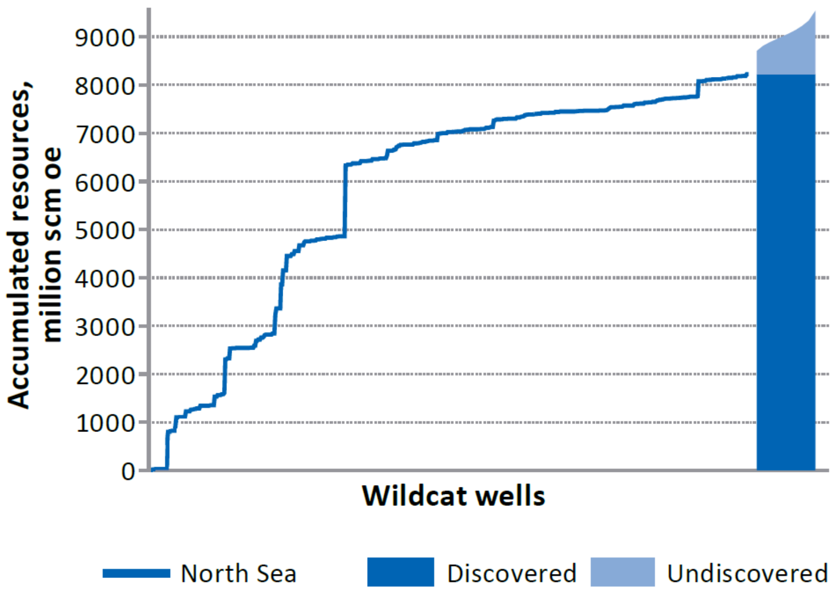


Figure 9.1: Proven and undiscovered resources (light blue) in the North Sea. The creaming curve also includes discoveries in resource class 6, which are not included in the resource account (from NPD website www.npd.no).

The resource accounts for the North Sea show that 160 million Sm^3 o.e. were sold and delivered from this part of the Norwegian shelf over the year 2015. At the same time, the growth in gross reserves, or the licensees' estimates before production is deducted, amounted to 59 million Sm^3 o.e. This means that the reserves that remain in the North Sea were reduced by 101 million Sm^3 o.e. in 2016 (Table 9.1). The resource estimate for the unproven resources was not updated in 2016. The expected value is estimated at 700 million Sm^3 o.e. This is a reduction of 45 million Sm^3 o.e. in relation to last year's accounts, and approximately corresponds to the volume proven in new discoveries in 2016.

ORIGINAL RECOVERABLE RESOURCES						
RESOURCE CLASS	**OIL (mill Sm^3)**	**GAS (bn Sm^3)**	**NGL (mill tonnes)**	**CONDENSATE (mill Sm^3)**	**SUM (o.e.)**	**CHANGE SUM (o.e. y-o-y)**
Produced	3581	1722	136	75	5635	160
Reserves	842	1220	72	-4	2194	-101
Contingent resources in fields	312	130	12	0	464	42
Contingent resources in discoveries	139	121	9	1	277	-30
Undiscovered resources	430	230	0	40	700	-45
Total	5303	3422	228	111	9270	26

Table 9.1: Original recoverable petroleum resources in the North Sea as of 31.12.2016 (from Norwegian Petroleum website www.norskpetroleum.no).

The Upper Triassic is included in Lower to Middle Jurassic plays in the North Sea, but contributes a smaller share of their resources (Fig. 9.2). Plays older than the Late Triassic account for less than two-three per cent of total expected resources in the North Sea.

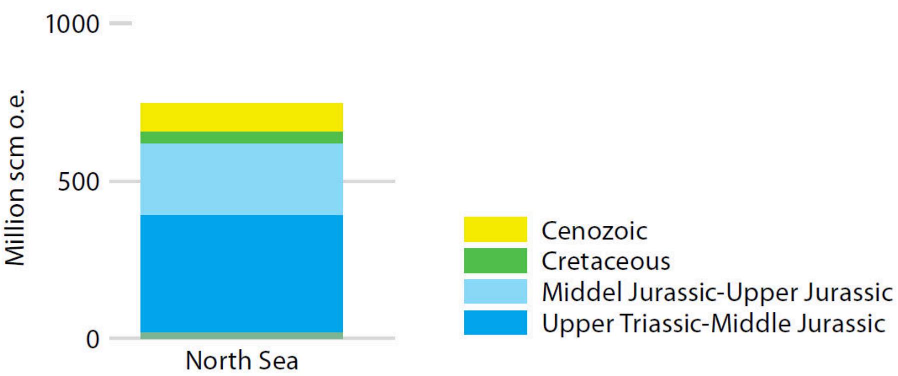


Figure 9.2: Recoverable undiscovered resources for the North Sea by geological stratigraphic level. (from NPD resource report, 2016).

In 2016, Norway produced 230.6 million Sm^3 o.e. of marketable petroleum. By way of comparison, total production was 228 million Sm^3 o.e. in 2015 and 264.1 million Sm^3 o.e. in the record year 2004. Oil production rose in 2016 for the third year running, after a continual decline from 2001 to 2013. Important reasons for this are higher production regularity of

Norway's oil fields and new fields coming on stream. Gas production remained high in 2016, at about the same level as in 2015. Gas sales totaled 115 billion Sm^3 (40 MJ) in 2016. The growing demand for natural gas in other parts of Europe is an important explanation for this rise. In 2016, natural gas accounted for just under 50% of total production by oil equivalents. In the 50 years since Norwegian petroleum activities began, about 48% of the estimated total recoverable resources on the continental shelf have been produced and sold. Thus, there are large remaining resources, and it is expected that the level of the activity on the Norwegian shelf will continue to be high for the next 50 years as well. Figure 9.3 shows annual production from fields in the North Sea.

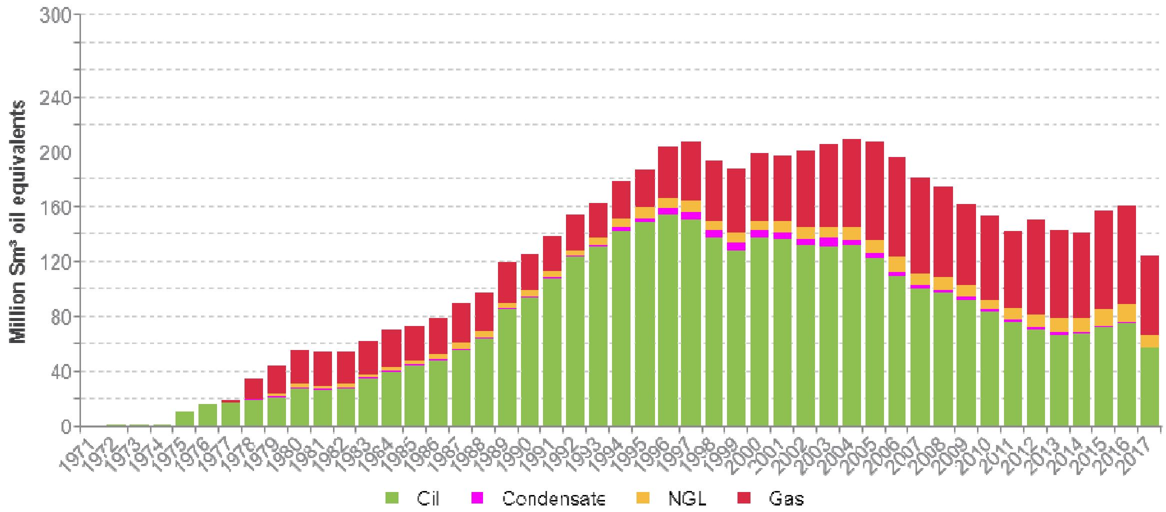


Figure 9.3: Annual production from fields in the North Sea (from Norwegian Petroleum website www.norskpetroleum.no).

The production profile of a typical oil field shows a rapid increase to a maximum production rate, then a stable period of high production (the plateau phase), followed by a gradual decline in production. Without further investments, oil production will decline rapidly, and even with considerable investment to improve recovery, it can be difficult to maintain production from a field. Without new fields or large-scale intervention to maintain production from existing fields, oil production from the Norwegian shelf would, therefore, continue to decline as it did from 2001 to 2013. Given the high-level of development activity in recent years, production is expected to remain relatively stable for the next few years. The level of production will depend on new discoveries being made, the development of discoveries and the implementation of improved recovery projects on existing fields.

Proving resources close to existing and planned infrastructure represents one of the main challenges in the North Sea. Finding additional resources while the big facilities are still on stream is important. Even very small discoveries can be profitable if existing infrastructure can be utilised effectively. Phasing discoveries into fields on stream also helps to extend the producing life of the latter, and thereby maintains their profitable production and improves recovery from them. Relatively few wells were drilled in the North Sea from 2000 to 2005 (Fig. 9.4).

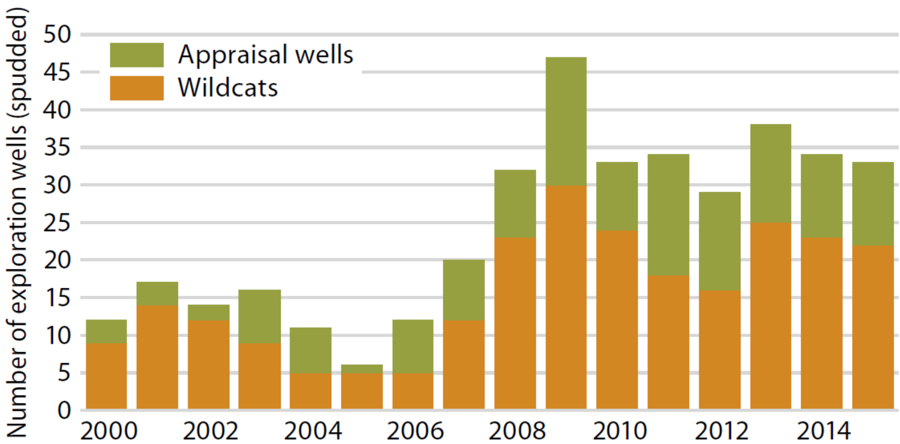


Figure 9.4: Exploration wells spudded per year in the North Sea (2000-2015) (from NPD resource report, 2016).

However, their number rose substantially from 2005 and peaked in 2009 at 47. Exploration activity has remained high since 2010, with an annual average of 34 wells. A total of 127 discoveries have been made since 2000 (Fig. 9.5).

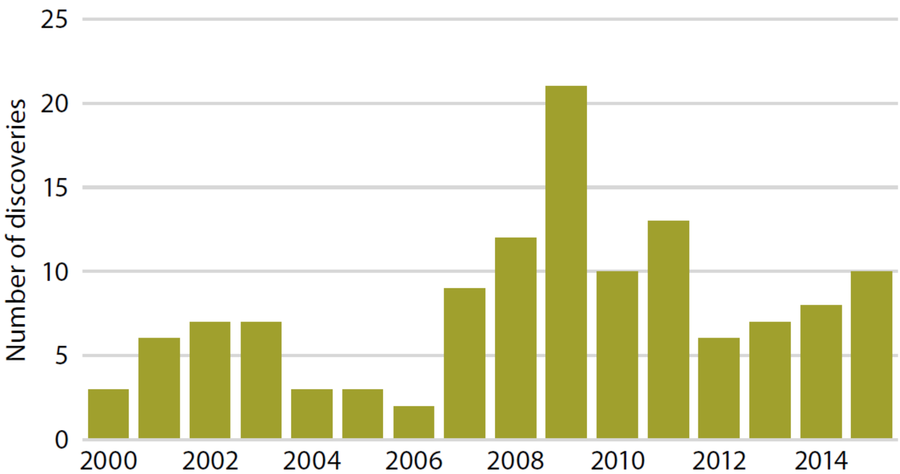


Figure 9.5: Discoveries per year in the North Sea (from NPD resource report, 2016).

The finding rate in the North Sea has been relatively high over the same period, averaging 0.2-0.7 per annum (Fig. 9.6).

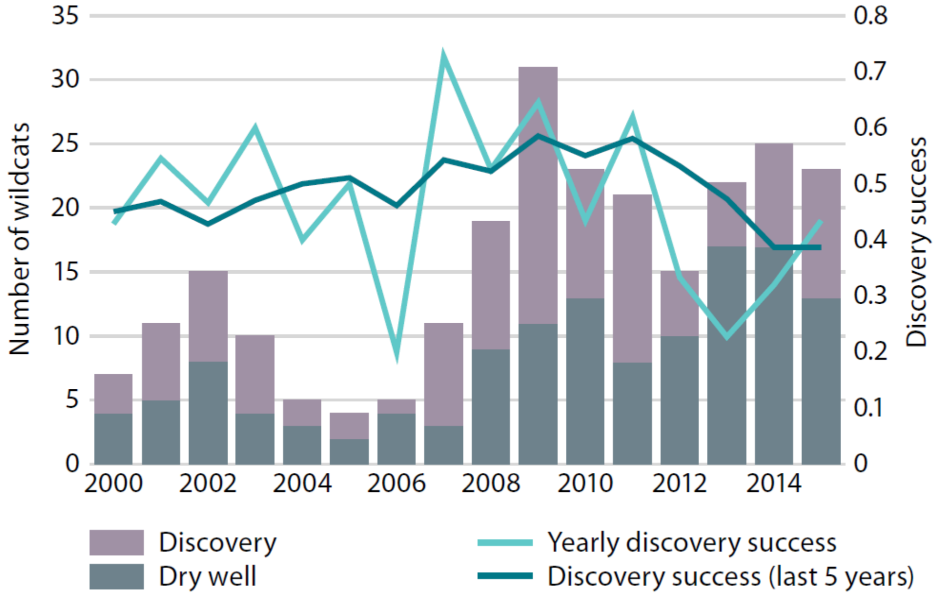


Figure 9.6: Completed wildcats and finding rate in the North Sea (2000-20015) (from NPD resource report, 2016).

Resource growth since 2000 has been highest in the North Sea, but most of the discoveries are small (Fig. 9.7). It peaked in 2008-2011 at about 600 million scm o.e., largely thanks to the discovery of Johan Sverdrup.

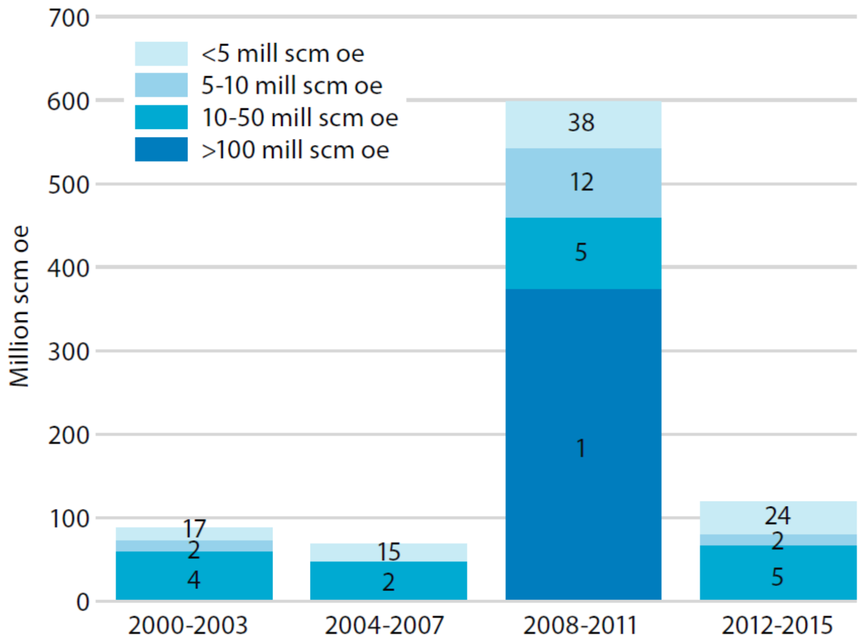


Figure 9.7: Resources in discoveries by discovery size in four-year periods, North Sea (2000-2015). Number of finds specified in the columns (from NPD resource report, 2016).

9.2 OIL vs. GAS

Some 3000 billion Sm^3 of gas and 5100 million Sm^3 of liquids had been proven in the North Sea at 31 December 2012 (Fig. 9.8). Statfjord and Ekofisk are the biggest oil fields, and by far the largest gas field is Troll East. After Grane was discovered in 1991, the curve for liquids rose weakly until 16/2-6 Johan Sverdrup was found in 2010. The curve for gas shows a weak rise after the discovery of Kvitebjørn in 1994. The estimate for undiscovered resources in the North Sea is less uncertain than for the Norwegian and Barents Seas because this area has been more thoroughly explored. Over three times as many wildcats have been drilled there than in the Norwegian Sea, and about eight times more than in the Barents Sea. Opportunities for making interesting discoveries in the North Sea are still present.

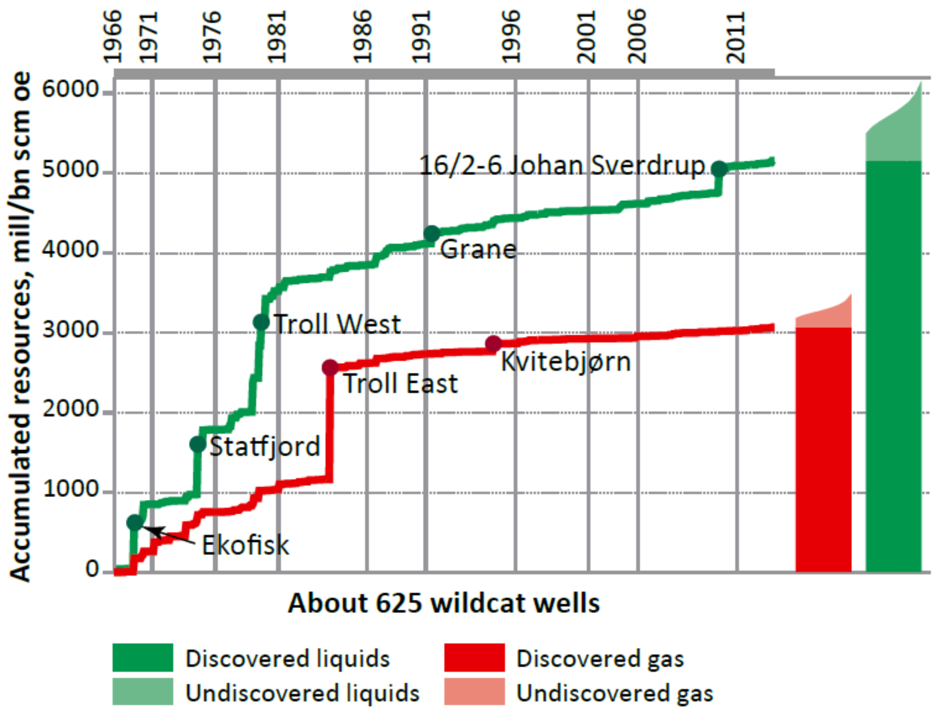


Figure 9.8: Proven and undiscovered (light colours) liquid and gas resources in the North Sea (from NPD resource report, 2016).

Generally, oil production has historically been larger than gas output. This position has been reversed over the past five years. Gas revenues outstripped income from oil for the first time in 2015. The Figure 9.9 in each column show expected recoverable volumes not yet discovered at year 2015 end. The plays discussed are Upper Triassic-Middle Jurassic, Upper Jurassic and Paleocene.

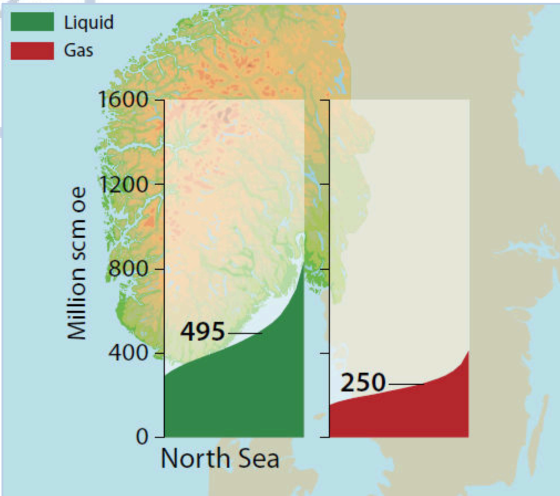


Figure 9.9: Recoverable undiscovered resources for the North Sea, broken down by liquid and gas. The expected value is specified in the columns. The uncertainty in the estimates is shown in the slanted line; low estimates on the left. High estimates on the right. (from NPD resource report, 2016).

The Upper Triassic to Middle Jurassic play in the central and northern areas of Norway's North Sea sector is the best explored on the NCS, and many of the biggest finds lie there. Most of these are on the Tampen Spur. The biggest discoveries were proven before 1980, and no large finds have been made in this play since Kvitebjørn in 1994 (Fig. 9.10). However, small discoveries are frequently proven, which is illustrated in the curve by a steady rise. One of the largest finds since 2010 is 35/9-6 (Titan). Although very considerable resources have been proven in this play, it still has a significant potential within a range of ~750 to 1500 Mboe.

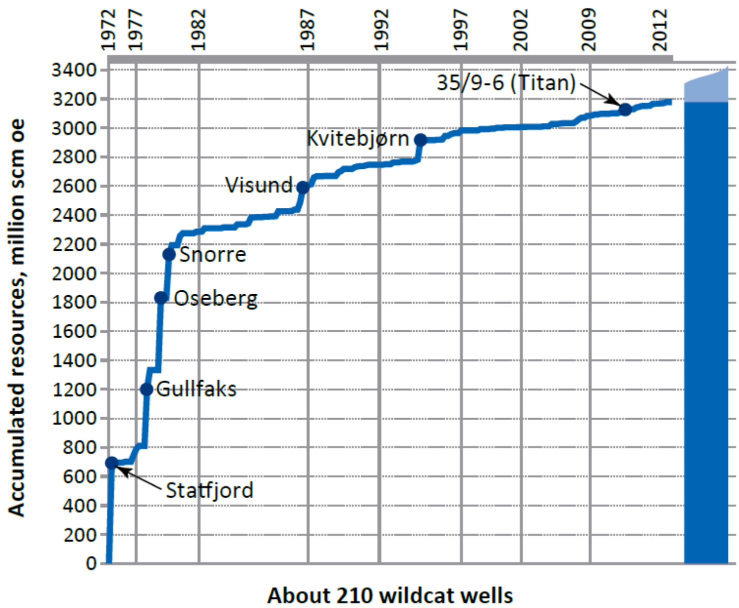


Figure 9.10: Total resources, proven and undiscovered (light blue), in the Upper Triassic to Middle Jurassic play in the central and northern North Sea sector (from Petroleum resources on the NCS report, 2013).

The Upper Jurassic play in the northern part of Norway's North Sea sector contains the Troll field, as shown in Figure 9.11. This giant find means that the other discoveries in the play barely show up on the curve when Troll is included. The Upper Jurassic play in the northern North Sea sector has a potential within a range of ~300 to 800 Mboe.

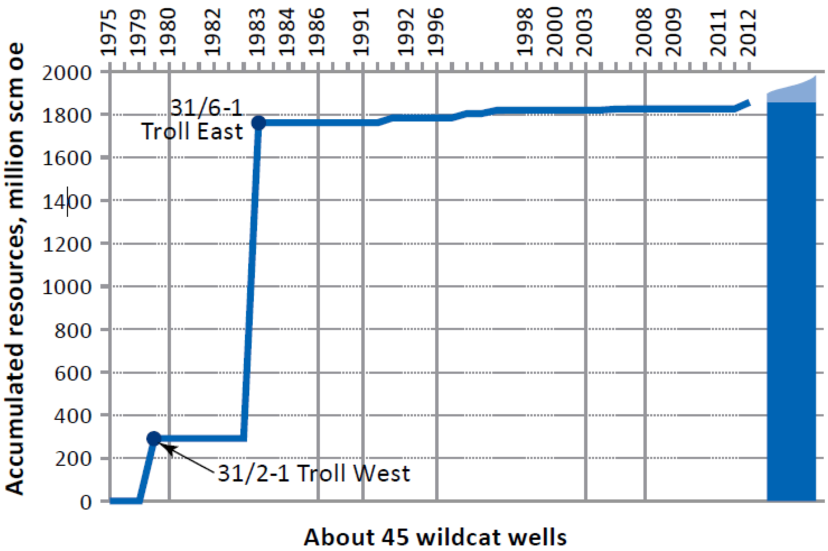


Figure 9.11: Total resources, proven and undiscovered (light blue), in the Upper Jurassic play in the northern North Sea sector (from Petroleum resources on the NCS report, 2013).

A creaming curve has accordingly also been produced without Troll (Fig. 9.12). The curves show that relatively few discoveries have been made or resources proven when Troll is excluded. This play retains an interesting potential for undiscovered resources within a range of ~250 to 800 Mboe.

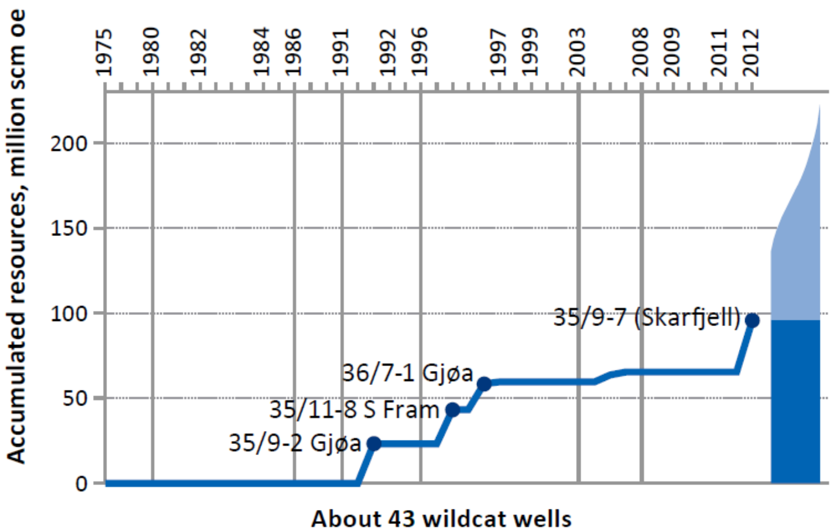


Figure 9.12: Total resources, proven and undiscovered (light blue), in the Upper Jurassic play in the northern North Sea sector after excluding Troll (from Petroleum resources on the NCS report, 2013).

Deep offshore drilling was classified as "unconventional" in the 1950s and 1960s, just as shale oil and gas are considered today. But that perception soon changed. A combination of higher oil prices, advances in technology and increasing resource nationalism in many developing countries encouraged oil companies to explore new areas. This included the North Sea, which emerged as an important oil-producing area in the 1980s and 1990s. The region's political stability and proximity to major European consumer markets made it an alternative to and more reliable source of supply than the Organization of the Petroleum Exporting Countries (OPEC). By the late 1990s, Norway and the United Kingdom together accounted for almost 9% of global oil production.

In the past decade, the North Sea began a new phase. Oil output peaked and entered (until 2015) a period of long-term decline, driven by the maturing of many of the major fields and the lack of significant new discoveries. Oil production in the UK Continental Shelf (UKCS) peaked at 2.9 million barrels per day (Mb/d) in 1999, while the Norwegian Continental Shelf (NCS) peaked at 3.4 Mb/d in 2001 (Fig. 9.13). By 2014, the two countries supplied just over 3 percent of global oil.

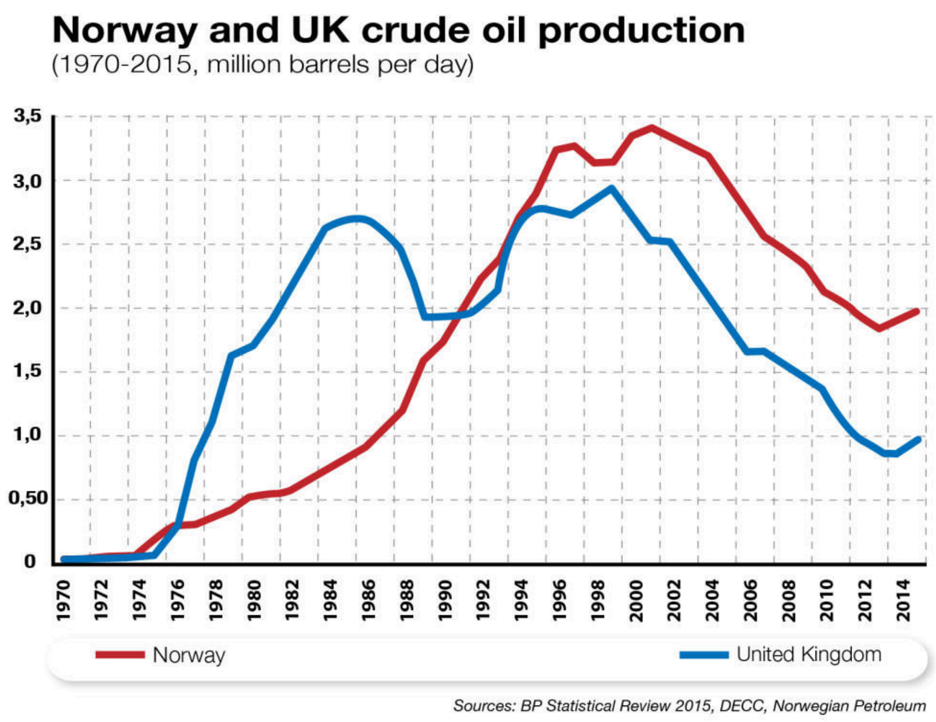


Figure 9.13: Norway and UK crude oil production of the North Sea (http://www.crystolenergy.com).

Gas production from the UKCS reached its maximum in 2000 at 108 billion cubic meters (bcm), though in Norway peak gas output has not yet been reached (Fig. 9.14). Recently, however, this decade-long decline in oil output has reversed. In the words of the International Energy Agency (IEA), the North Sea continues to surprise: In Norway, the production increase has lasted for two consecutive years (2014 and 2015) and exceeded estimates, while gas production also bounced back after a short-lived dip. In the UK, oil and gas production rose more than 7% in 2015, the first rise in more than 15 years.

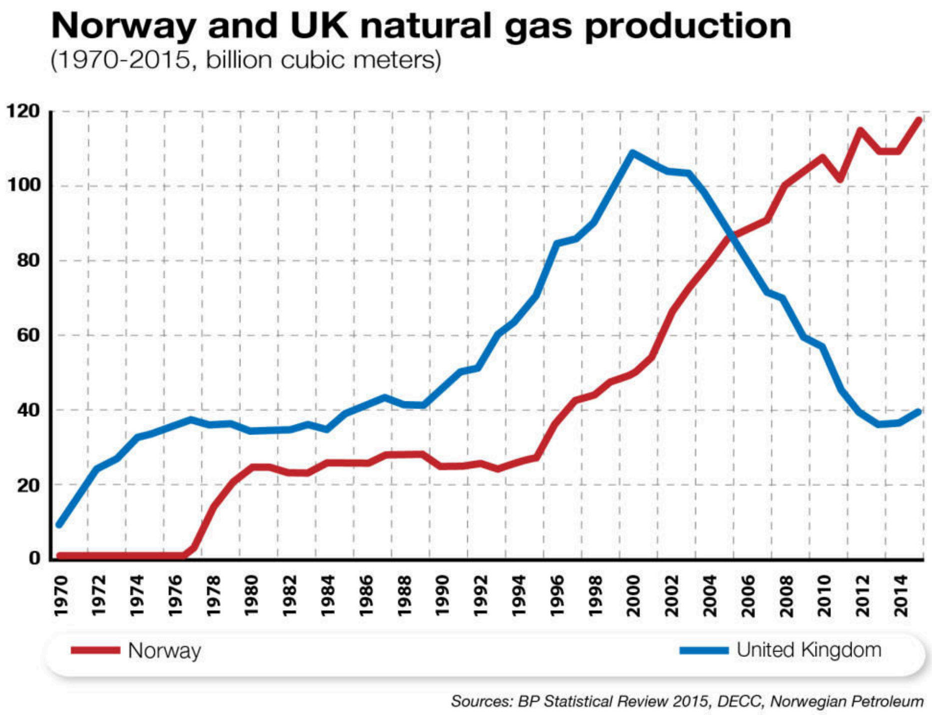


Figure 9.14: Norway and UK natural gas production of the North Sea (http://www.crystolenergy.com).

Future exploration and development activities will depend on a combination of factors. The fall in oil prices since the summer of 2014 has threatened the commerciality of some fields, particularly those with low production and high costs. While the impact of oil prices cannot be understated, other variables such as costs, technology and government policy will also play an important role.

9.3 EXPLORATION CHALLENGES

9.3.1 Glacial erosion and tilting

The traditional view of the Pleistocene glacial history of the North Sea suggests that the region has encountered three major glacial episodes during the past 500 ka, referred to as the Elsterian Stage (oldest), Saalian Stage, and Weichselian Stage (youngest) glaciations. The retreat formed sea-floor moraine ridges and meltwater channels and a prominent glacial trough offshore is observed paralelling the Norwegian mainland.

Figure 9.15 illustrates a schematic model of Early Quaternary sediment delivery to the North Sea Basin that relates to sources from both the major European river systems to the south and from an ice sheet over Scandinavia to the east of the basin. The principal evidence for a major contribution from the great European rivers, including the paleo-Rhine and the Baltic River system, is the fact that the clinoforms are built out towards the northwest and sediment fill in the central basin clearly suggests northwestern progradation through the Early Quaternary from a source to the south and south-east. The sediments making up the fill of the Early Quaternary of the Central North Sea Basin are fine-grained, suggesting a distal fluvial or glacifluvial origin with an additional hemipelagic component. Gibbard (1988), for example, has mapped the major northwest European river systems for the Early Quaternary period, and these locations are shown in Figure 9.15.

The northern North Sea has been filled largely by prograding sediments, interpreted as glacigenic debris flows (Fig. 9.15), from the east. These sediments were deposited along the western margin of the advancing Scandinavian Ice Sheet outside western Norway.

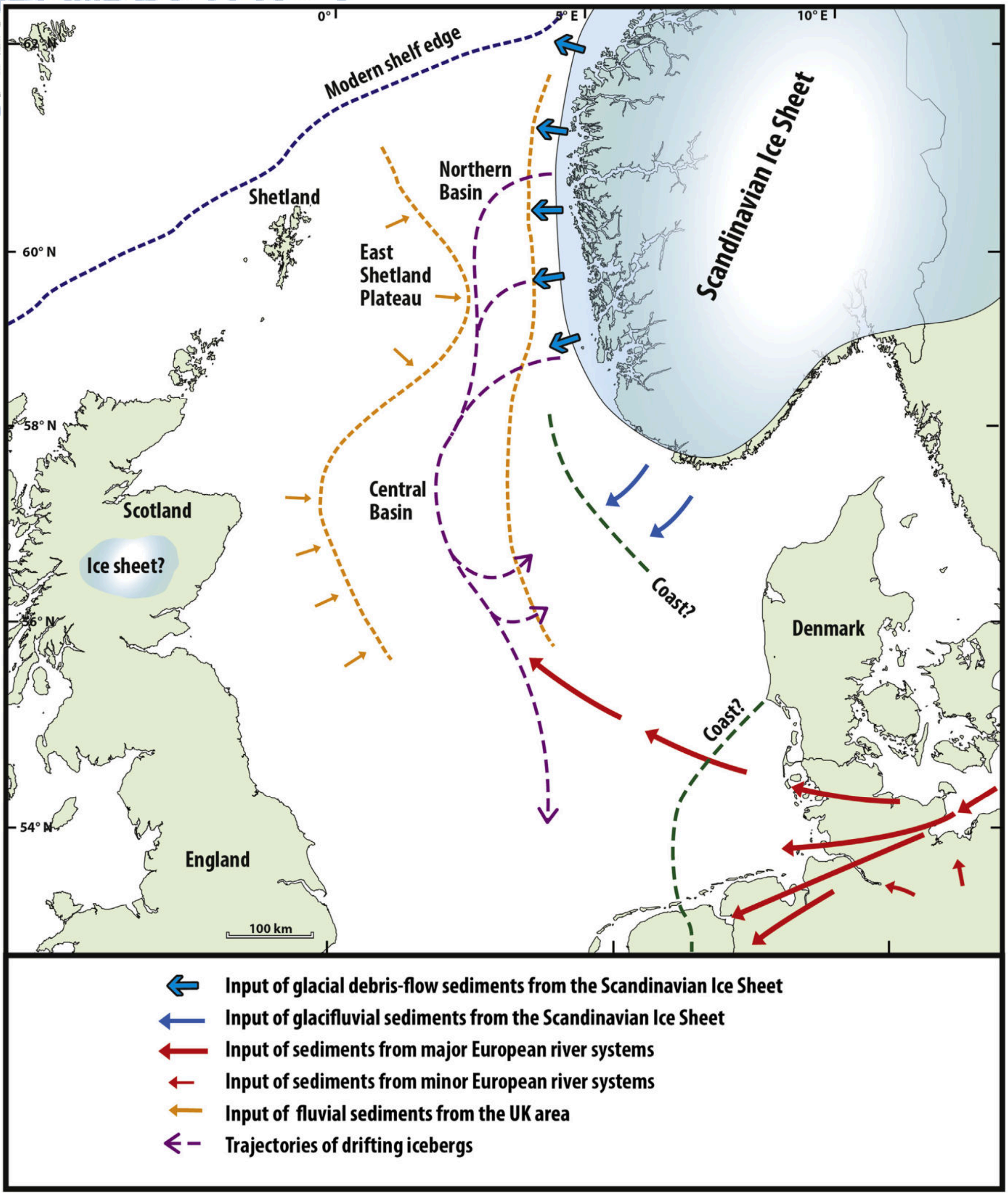


Figure 9.15: Schematic model of landscape, ice-sheet configuration and delivery of sediments in the Early Quaternary of the North Sea. Large and small red arrows show input of water and sediment from major and minor European river systems during the Early Pleistocene partly derived from Gibbard (1988). Orange stippled lines show the general form of the North Sea Basin (500 m contour of the Base Naust-equivalent reflector) (Ottesen et al., 2014).

Based on the identification and correlation of seismic data from the northern North Sea, the Early Quaternary seismic stratigraphy is summarized in the schematic diagram in Figure 9.16. For the northern North Sea Basin, the schematic diagram in Figure 9.16 shows the infilling of the basin during the Early Quaternary by a series of prograding clinoform units (Units A-C), followed by Unit D, which is thickest in the northwest. During this period, the northern North Sea was subsiding and the Norwegian landmass was rising (Riis, 1996), providing accommodation space in the basin (Fig. 9.16). The diagram also shows the modern sea floor and the presence of the Scandinavian Ice Sheet that provided sediment to the basin.

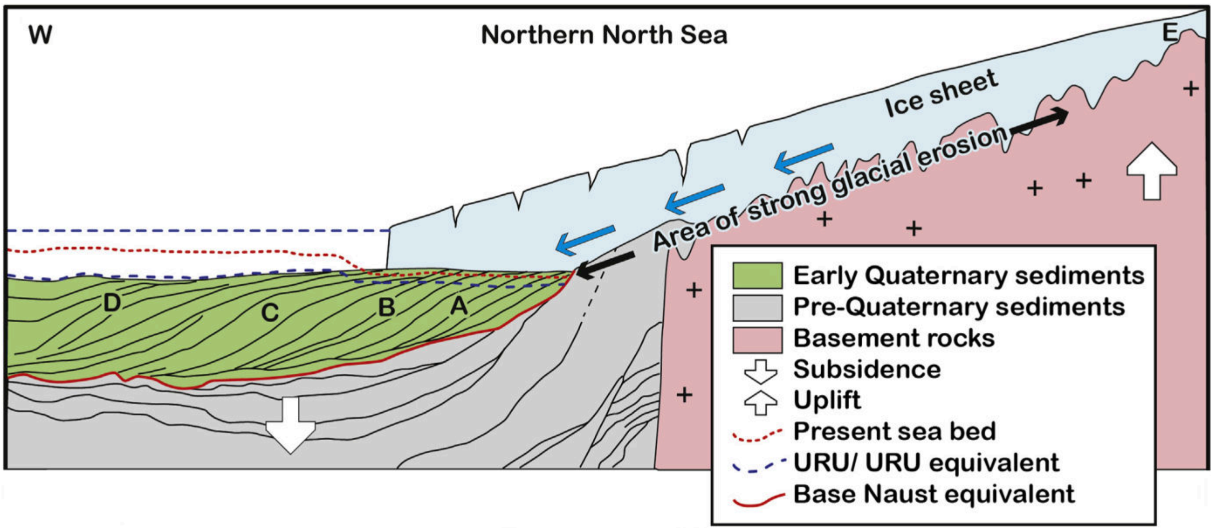


Figure 9.16: Schematic summary sections of the seismic stratigraphy of the northern North Sea Basin in the Early Quaternary, before the cutting of the Norwegian Channel by ice-stream activity (also showing continuation of clinoforms across the Norwegian Channel) (Ottesen et al., 2014).

The effects of the glaciation on the filling history of the Southern Utsira High appear to be important. It is clear that several erosional surfaces in the Pliocene can be identified, as well as glacial channels and moraine deposits, indicating that significant deposition and erosion occurred in the last five million years. Importantly, the effects of glacial rebound mean that the Southern Utsira High more than likely underwent tilting and possible leakage, not just once, but several times in the last 1 million years. The recent discovery of the giant Johan Sverdrup oil-field in the Norwegian North Sea is suggested to be oil-charged during Quaternary (Stoddart et al., 2015). Backstripping modelling of the Johan Sverdrup top reservoir surface (Fig. 9.17) shows that the structure was formed in the last 1.5 Ma. Interestingly, since early Eocene time the apex of the Utsira High has shifted considerably, giving the impression that re-migration of oil throughout the high is important to the charge history of Johan Sverdrup and the Utsira High as a whole.

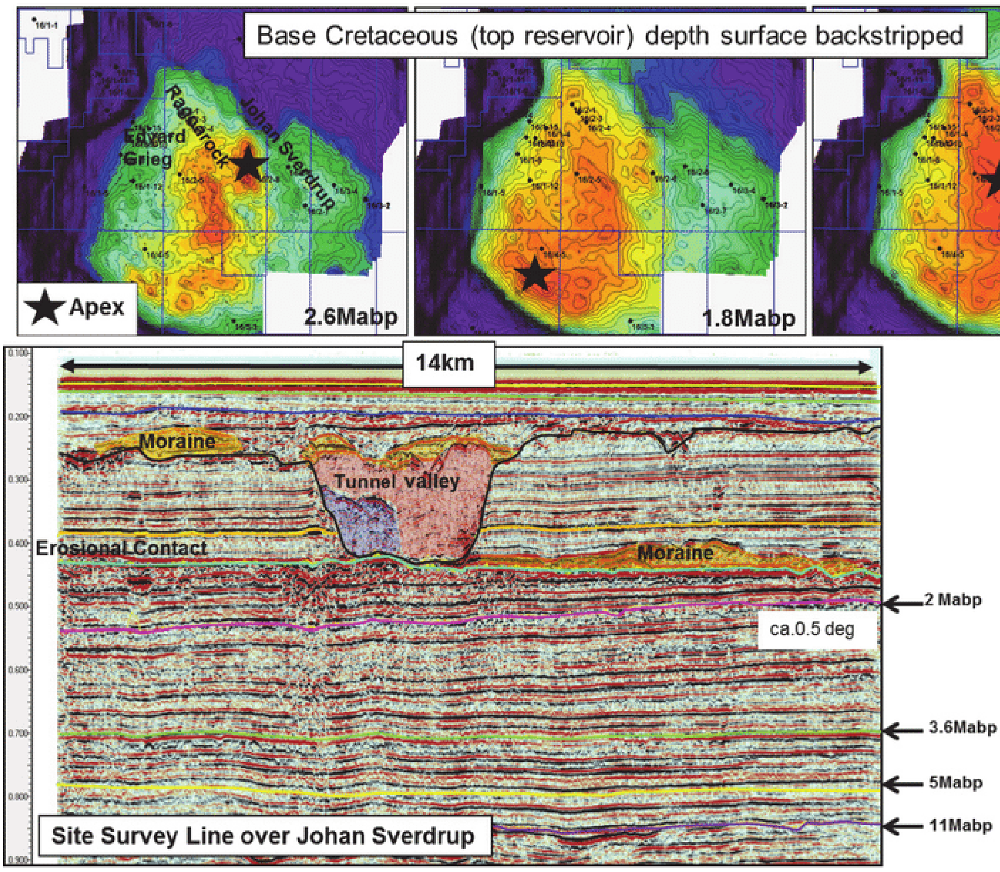


Figure 9.17: Backstripping of the top reservoir surface shows that the apex of the Johan Sverdrup structural closure is shifting through time (Stoddart et al., 2015).

The implications of the detailed assessment of tilting of a "structural high" through time are: 1) opening up areas where oil migration is thought to be of high-risk or impossible; 2) identify possible paleo-oil columns aiding the de-risking of discovery appraisal strategies. This work can change to way we look at oil/gas migration on the Norwegian Continental Shelf and other areas around the world that have experienced glaciations.

9.3.2 Pressure distribution

The importance of formation pressures for a wide range of applications within petroleum exploration can hardly be overstated, because for petroleum geologists and engineers the fluids that occupy pore spaces are more important than the rock itself. Most of this fluid is water; it is called formation water and it varies in pressure, temperature and density around the basin. The pressure of the formation water within rock pore spaces is called the pore pressure; variations in pore pressure are particularly important, and understanding them has several applications for petroleum geology in the North Sea. The basic tool used by geologists when looking at formation pore pressures is the pressure/depth plot that shows how formation-water pressure varies with depth. Such tools are augmented by 3D and 4D (involving time) modelling studies that analyse the pressure evolution of whole basins or individual fault blocks or sequences of strata (Mann et al., 1997).

In many instances, the open-pore connection to the surface is lost because the sedimentary layers are impermeable or are of very low permeability, preventing the free movement of formation water. In an area like the northern North Sea where sediments have effectively been continuously deposited over a long period of time, the formation waters will begin to carry some of the weight of the overburden if the pore water cannot escape. When this happens the sediment is described as being overpressured. Overpressured formation waters are common in most northern North Sea reservoirs. Overpressure is a serious drilling hazard and remains one of the biggest safety issues that needs to be assessed into shallow top-hole section or into reservoirs, especially the deep, high-pressure-high and high-temperature reservoirs in the deepest parts of the northern North Sea.

The deeper parts of the stratigraphic intervals in the centre of the North Sea Basin have the highest pressures, which are seen to dissipate fairly smoothly towards the basin margins. The Cenozoic and Cretaceous strata are relatively open-pressure systems with only minor compertmentalisation. The pressures in the Jurassic rocks in the basin are highly compertmentalised due to the high degree of faulting that has affected these strata. An overpressure seismic section across the North Viking Graben is illustrated in Figure 9.18.

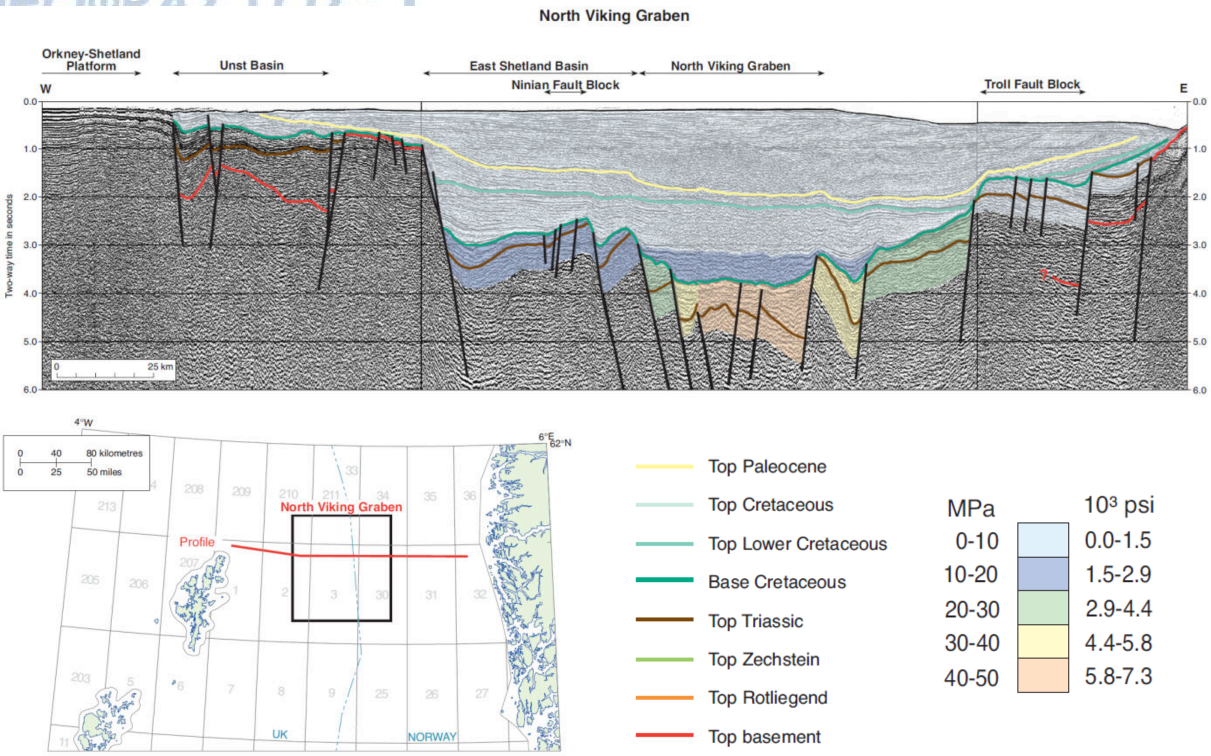


Figure 9.18: Overpressure profile across the northern North Sea (Evans et al., 2003).

In the Viking Graben, the laterally extensive Middle Jurassic Brent reservoir is strongly compartmentalised. Only those faults that have a throw exceeding the reservoir thickness form compartment boundaries. Unlike the Central North Sea, the overpressures in the Northern North Sea are less variable at a given depth, suggesting that lateral fault leakage is an important control on overpressure magnitude. For instance, there is high-magnitude overpressure at shallow depth in the Gullfaks Field at the crest of a series of connected blocks whose pressures are equilibrated despite the presence of many intervening faults. Other high-magnitude overpressures are found in the deepest parts of the basin that have been drilled, including the Martin Linge Field where gas condensate is the principal petroleum type in the reservoir. This observation indicates that the dip of the reservoir in many of the fault-blocks, which may have base-to-crest height in excess of 1 km, may contribute to lateral-transfer effects whereby overpressures at the crest are increased by processes which relate to deeper burial down-dip.

9.3.3 Complex hydrocarbon migration

Hydrocarbons migrate out from the graben axes, but large parts of the Norwegian sector are immature for hydrocarbon generation (Fig. 9.19). Fields in the vicinity of Troll Field are charged by long-distance migration and overspill from the vicinity of the Brage Field. The migration patterns in Figure 9.19 have been modelled using top-Middle Jurassic and base-Cretaceous depth-structure maps. Secondary migration pathways may be inferred from depth-structure maps that are back-stripped and decompacted to correspond to the main phase of hydrocarbon generation and expulsion as derived from modelling, combined with sandstone-distribution and porosity/permeability maps for the likely carrier beds (Field, 1985). Structure maps may be partitioned into drainage areas corresponding to basin configuration at the time of source-rock maturation, hydrocarbon generation and the main phase of hydrocarbon migration. This may be facilitated by computer-aided flow-path or ray-trace modelling (Sylta, 1993; Hindle, 1997; Hantschel et al., 200) or by a combination of flow-path and Darcy-flow modelling (Welte et al., 2000).

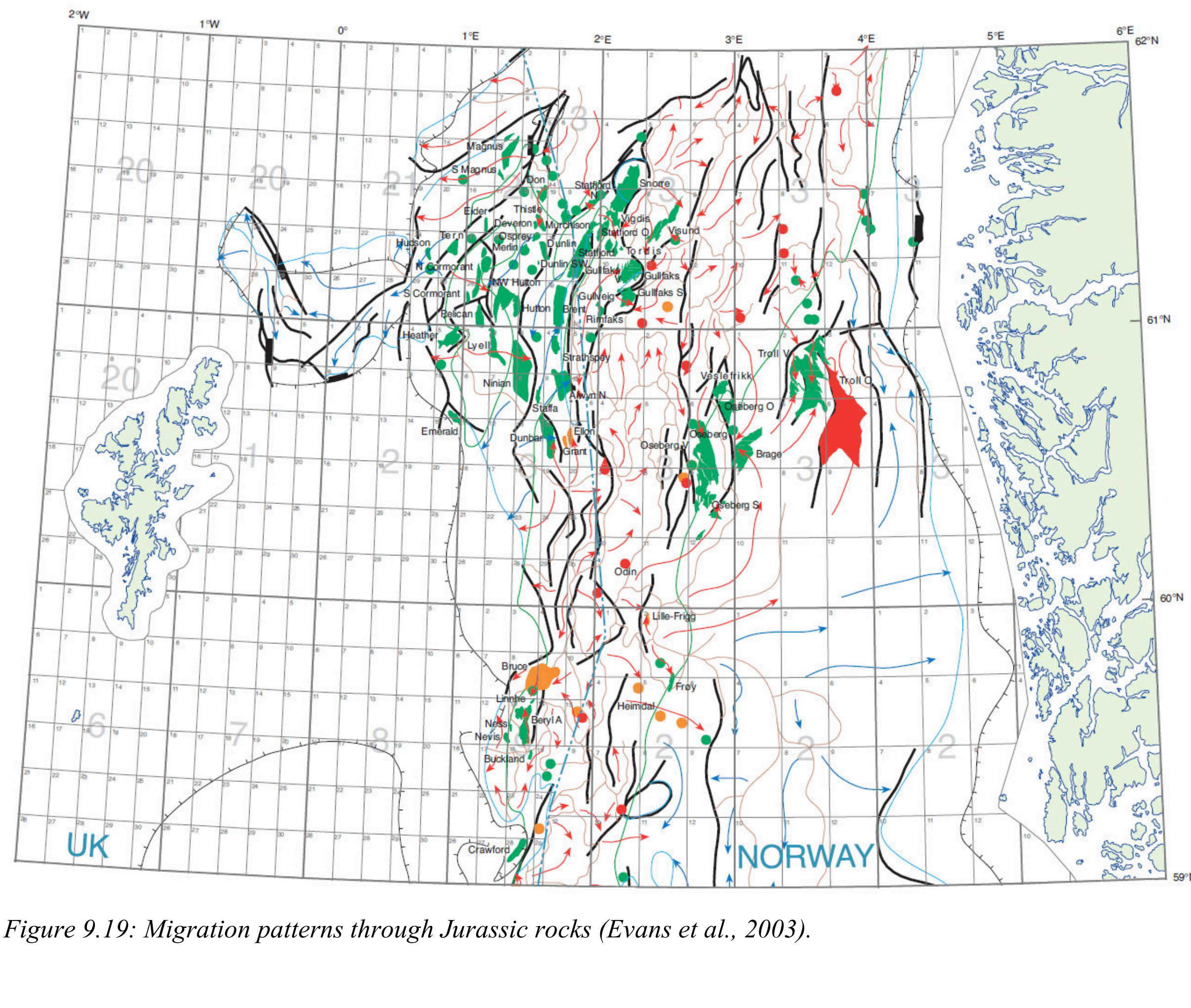


Figure 9.19: Migration patterns through Jurassic rocks (Evans et al., 2003).

Hydrocarbon distributions in the North Sea are complex, since reservoirs occur at several levels within the Mesozoic and Tertiary section. In some areas hydrocarbon migration patterns seem to be almost entirely vertical, and fields are coincident with mature kitchen areas, whilst in others large-scale lateral migration is apparent. On many occasions, migration has occurred to a stratigraphically lower level. Some parts of the basin appear to be predominantly gas-prone, e.g. the Frigg and Sleipner areas; others are prolife oil provinces, e.g. Ekofisk area and Tampen Spur. Geochemical data from the deep mature kitchen areas suggest that hydrocarbon charge vastly exceeds the available volume in adjacent traps. Many structures appear to be filled to spill-point and, in some areas, long chains of fields can be seen to be related to each other and a common kitchen area as a continuous fill-and-overspill sequence (Gussow, 1954).

9.4 GREENHOUSE GAS EMISSIONS AND CO_2 STORAGE

In 2016, greenhouse gas emissions from petroleum activities corresponded to about 13.8 million tonnes CO_2 eq (carbon dioxide equivalent) (Fig. 9.20), most of which (13.3 million tonnes) was CO_2, and the rest CH_4 (methane). Emissions from the petroleum sector account for about one quarter of Norway's aggregate greenhouse gas emissions. CO_2 emissions from the petroleum sector are expected to be fairly stable over the next few years.

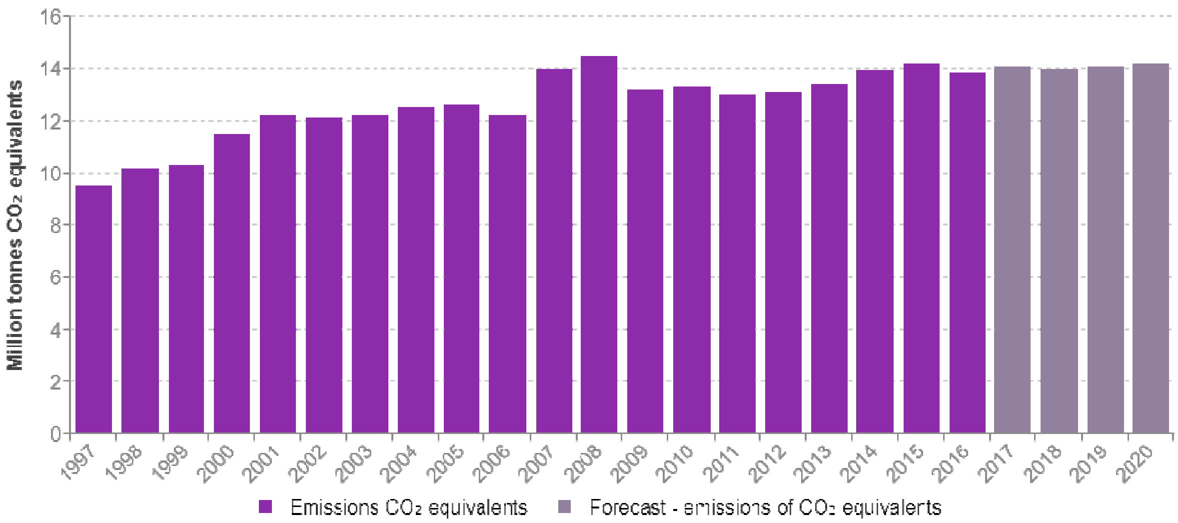


Figure 9.20: Greenhouse gas emissions from the petroleum sector and historical numbers for 1997-2016 and projections for 2017-2020 (updated 22.03.2017) (from Norwegian Petroleum website www.norskpetroleum.no).

The companies operating on the Norwegian shelf are world leaders in the use of solutions to reduce greenhouse gas emissions. Emissions per unit of oil and gas produced are therefore lower than those from similar operations in other petroleum-producing countries. Energy efficiency measures, including the introduction of energy management systems and the installation of more energy-efficient equipment such as compressors and pumps, have helped to reduce emissions from petroleum activities. Combined-cycle gas turbines (CCGT) are one technological solution, in which waste heat from the turbines is used to produce steam, which in turn is used to generate electricity. CCGT plants improve energy efficiency and reduce emissions. They have been installed on several fields, including Oseberg, Snorre and Eldfisk.

Since 1996, about 1 million tonnes of CO_2 per year has been separated during processing of natural gas from the Sleipner West Field (Central North Sea), and stored in the subsea Utsira Formation. Since 2014, CO_2 has also been separated from natural gas from the Gudrun Field (Central North Sea) and also stored in the Utsira Formation. To prevent ocean acidification and mitigate greenhouse gas emissions, it is necessary to capture and store carbon dioxide. The Sleipner storage site, offshore Norway, is the world's first and largest engineered waste repository for a greenhouse gas. CO_2 is separated from the Sleipner Field gas condensate field and stored in the pore space of the Utsira Formation, a saline aquifer approximately 1 km below the surface and 200 km from the coast. The storage site, a saline formation and sandstone aquifer, is 800 m below sea level (mbsl). This is considered to be a shallow depth setting for a storage environment (Chadwick et al., 2008) as the pressure and temperature conditions are likely to be close to the critical point above which CO_2 becomes a more buoyant gas phase. The overlying Nordland Group, which extends from the top of the Utsira Formation to the seafloor, is predominantly shale (Fig. 9.21), and is expected to provide a caprock with a high threshold pressure, sufficient to seal the site and prevent leakage of the buoyant CO_2 fluid over several millennia, i.e. the timescale required to offset climate change (Lindeberg and Bergmo, 2003). Saline formations worldwide are considered to be candidates for carbon sequestration because of their suitable depths, large storage volumes, and common occurrence. However, one of the critical uncertainties for saline formation storage is the ability of the caprock (primary seal), and the overlying containment geology (secondary seals), to retain buoyant CO_2 without leakage. The fluid flow processes currently occurring in the Sleipner storage site provide a crucial example for saline formation storage projects worldwide.

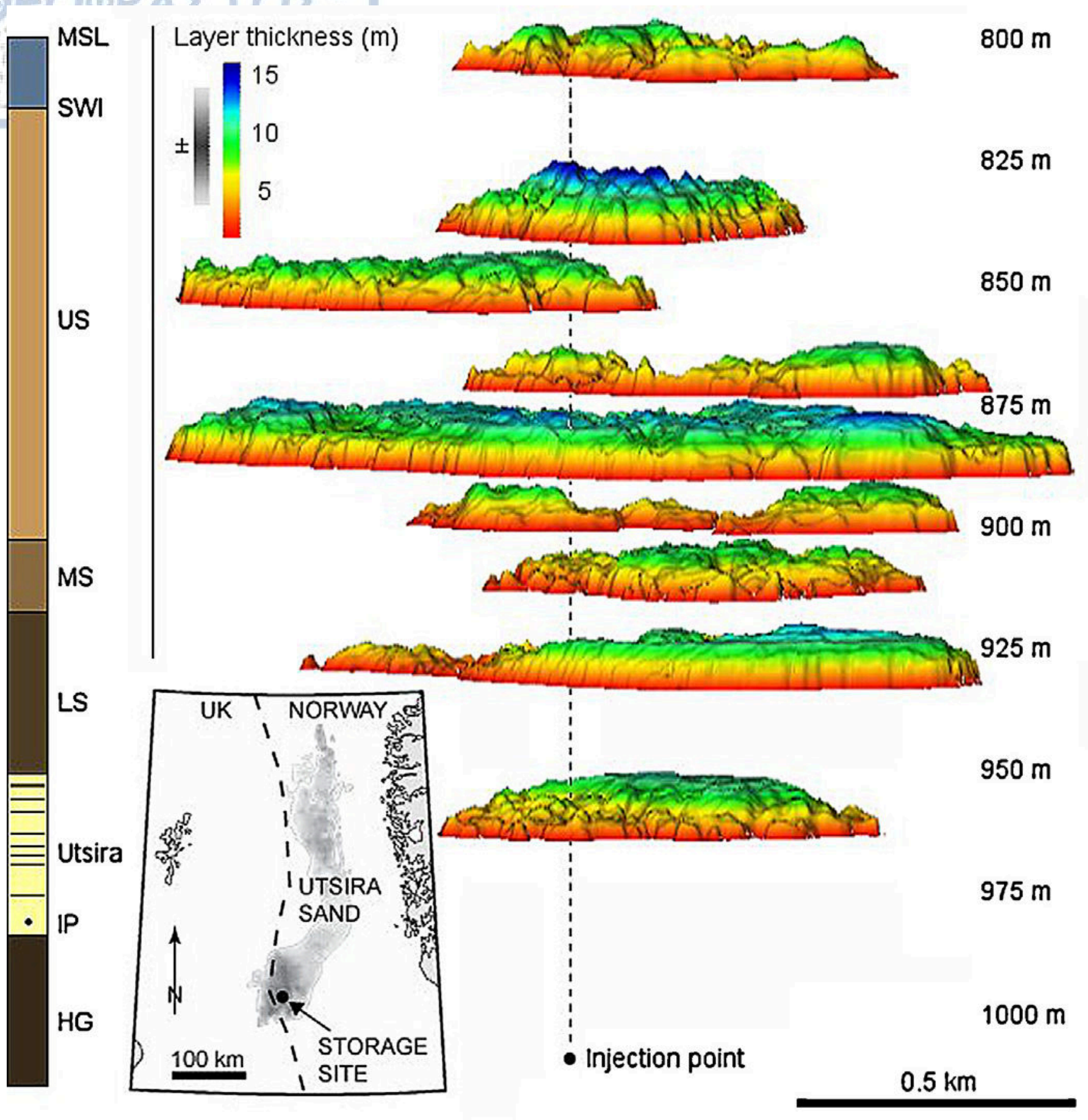


Figure 9.21: The Sleipner plume profile, viewed from the southeast, circa July 2002. The figure shows the distribution of injected CO_2 after 5 Mt of injected CO_2 (Bickle et al., 2007). The nine plume layers are well defined aerially, having ponded beneath intra-formational shales within the Utsira Formation sandstone. The uncertainty relating to layer thickness is high. The ninth layer first appeared in 1999, indicating that the CO_2 has migrated approximately 220 m vertically from the injection point (IP) at 1012 mbsl in 3 years. The left panel is a regional stratigraphic column: MSL, Mean Sea Level; SWI, Sediment Water Interface; The Nordland Group extends from the caprock to seafloor, and is subdivided into three seals: US, Upper Seal (Pleistocene); MS, Middle Seal (Upper Pliocene); LS, Lower Seal (Upper Pliocene); Utsira, storage site (Middle Miocene–Early Pliocene); HG, Hordaland Group (Early Miocene).

Several producing fields on the NCS are already supplied with power from shore and the same solution will be used on Martin Linge and Johan Sverdrup when they come on stream.

9.5 REMAINING EXPLORATION POTENTIAL AND THE CONTRIBUTION OF TECHNOLOGY IMPROVEMENTS

Opportunities for making interesting discoveries in the northern North Sea are still present. Though the northern North Sea is now considered to be mature for exploration, plays such as the Upper Jurassic syn-rift play and the deep basin-axis high pressure/high temperature gas condensate play are expected to be the focus of much future activity. Future work will also focus on constraining the relative contribution of primary depositional mounding and secondary differential compaction to the observed stratigraphic architectures (Jennette et al. 2000).

One of the most important tools for unlocking further play identification and prospect generation is modern acquired high-quality and resolution 3D seismic reflection data (Fig. 9.22). This allows to unravel and interpret the complex geological features: stratigraphy, geometry, deep and/or fractured targets etc. and enables to unveil new and earlier unexplored potential. The significance of this technology was proven with the discovery of Johan Sverdrup from interpretation of GeoStreamer data, and in this modern 3D seismic dataset it is now possible to see improved resolution and penetration along with previously unidentified DHIs. Technological improvements in seismic acquisition and processing, and the application of high-resolution stratigraphic and biostratigraphic concepts (cf. Chapter 2) have created interest in stratigraphic traps or combined structural-stratigraphic traps in both the Upper Jurassic and Paleocene/Eocene intervals.

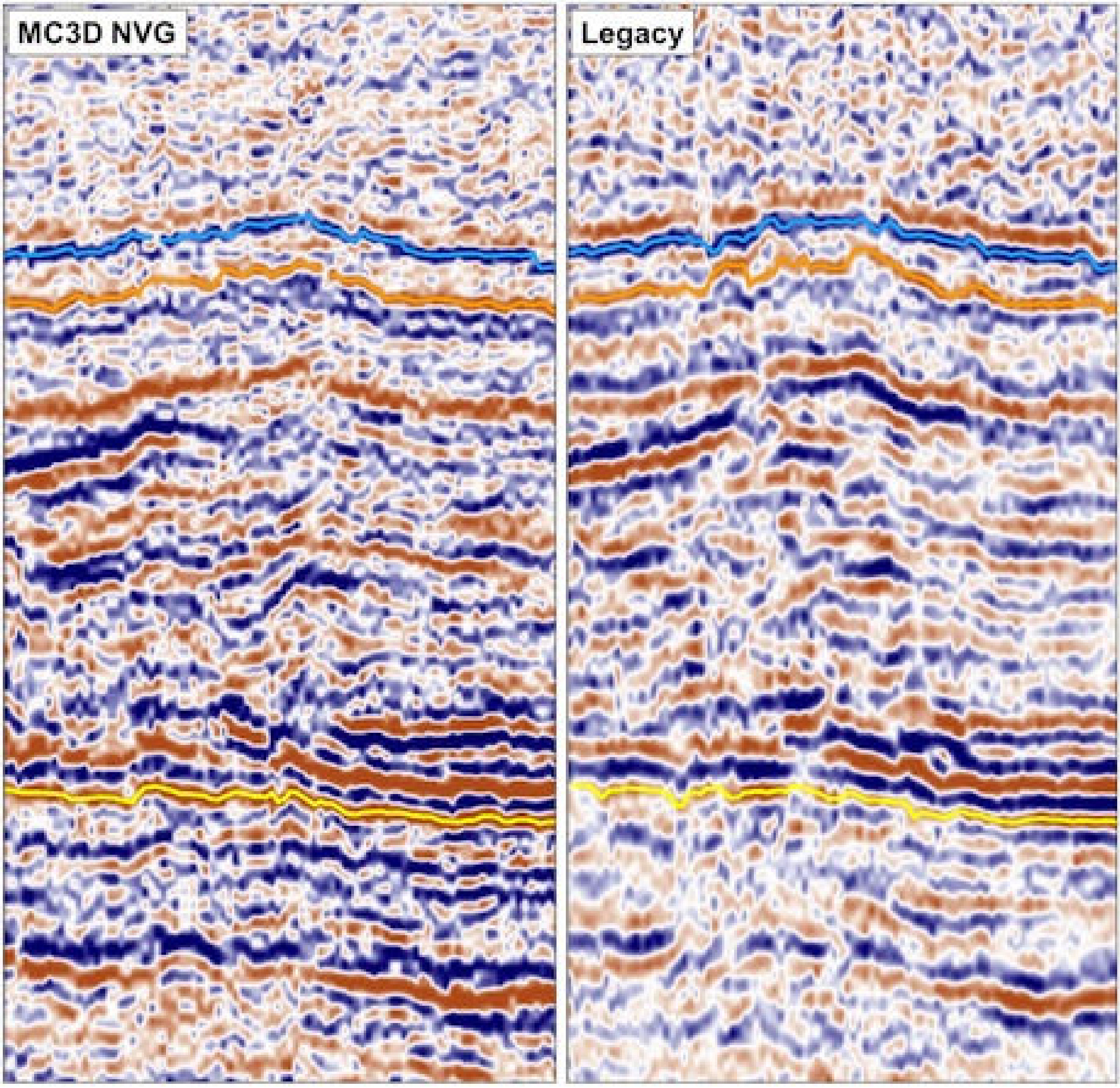


Figure 9.22: A comparison between PGS GeoStreamer and legacy data over a 3-way fault-assisted dip-closure prospect. A large difference between the datasets is the presence of the flat-spot in the GeoStreamer data, which is not resolved in the legacy data. Yellow-base Tertiary; orange-top Balder; blue-top Reservoir. Source: PGS (from GEOEXPO website www.geoexpo.com).

CONCLUSIONS

The northern North Sea tectono-stratigraphic evolution and main petroleum systems and plays have been described and thoroughly reviewed utilizing a large number of earlier conducted geological and geophysical studies for the region. A better understanding of the complexity of the different operating geological processes and their impact on hydrocarbon accumulations has been reached. The conducted work provides an up-to-date and best-evidence synthesis of the petroleum geology evolution of the northern North Sea.

The northern North Sea rift basin was developed on a heterogeneous crust comprising structures inherited from the Caledonian orogeny and the Late Devonian post-orogenic extension. Two major rifting events have been recognized to dominate the structural evolution of the region: the Permo-Triassic extension phase followed by thermal cooling and subsidence during Early-Middle Triassic, and the Middle-Late Jurassic to Early Cretaceous extension phase followed by Cretaceous post-rift subsidence. Late Permian-Early Triassic rifting accumulated sediments in half-grabens with thickening to the east, however mapping of the entire rift extent is hampered by limited seismic resolution at deep burial depths and, more importantly, by later reactivation of the rift structures. The Middle-Late Jurassic rift was the dominant tectonic episode that shaped the North Sea. It was dominated by reactivation of major striking faults, whereas a number of coeval but smaller faults were associated with partial collapse of crestal areas and development of prominent fault-blocks that formed structural terraces. Jurassic reactivation of pre-existing faults (and thus structural inheritance) and evolution of the graben normal-fault system were very significant during Middle Jurassic-Early Cretaceous rifting.

The pre-rift Triassic to Lower-Middle Jurassic play is the most important hydrocarbon play in the northern North Sea. It comprises 75% of the discoveries and has provided the largest proportion of the total oil production, split almost equally between the UK and Norway sectors. Although the syn-rift Upper Jurassic and Lower Cretaceous plays comprise currently isolated discoveries, they represent emerging plays with possibly considerable potential. During Paleocene and early Eocene, the nearby vicinity of the northern North Sea was elevated as a consequence of the growth of the Iceland plume and the nearby North Atlantic continental breakup processes. Deep-marine Paleocene and early Eocene sand-rich, turbidite-fan depositional systems have been developed along the margins of the Viking Graben. These deposits have undergone post-depositional remobilization and injection, which has further contributed to their discontinuous character and played a significant role to their excellent reservoir properties in many cases, giving rise to prolific discoveries.

The oil and gas exploration and production adventure in the northern North Sea reaches back to the 1960s. Hydrocarbon exploration revealed significant reserves. Over the years, production grew and with it the industry, the communities, the supply chain and the partnerships which make the northern North Sea one of the most challenging and rewarding oil provinces in the world. According to the latest estimates ~5635 million Sm^3 (~35 Bboe) of hydrocarbons have already been produced, ~2935 million Sm^3 (~18 Bboe) are the current reserves and contingent resources in fields and discoveries, and ~700 million Sm^3 (~4.5 Bboe) recoverable undiscovered resources remain for the Norwegian sector of northern North Sea. In the 1980s, gas reserves became increasingly important and new technology was developed to allow smaller reserves to be brought on-stream more cost-effectively. There has been a major increase in the total gas production in the northern North Sea mainly due to the start of production from the Frigg and Troll fields in 1977 and 1995, respectively. The distribution of the oil-fields and gas-fields in the northern North Sea shows that they are concentrated along the UK-Norway borderline which straddles approximately the Viking Graben. The petroleum system is almost entirely Jurassic-sourced mainly from the highly organic Kimmeridge Clay Formation (TOC: from <1 up to >7% wt, HI: from <100 up to >400 mg/g TOC, kerogen type: usually type II, to mixtures of types III and IV) which was deposited during Late Jurassic and has provided the source-rock for almost all of the oil and gas.

The northern North Sea is currently on a steady downward path and is considered a mature oil basin in which most of the petroleum is probably already discovered and under development. Hydrocarbon potential for reserve/resource growth and increased production is currently lying mainly in the development of smaller hydrocarbon accumulations, increased and enhanced recovery from the already producing fields, and exploration of old and new licence areas. Therefore, new discoveries, such as the Johan Sverdrup Field (reserves of 2-3 Bboe) discovered in 2010, need to be done in order to maintain hydrocarbon exploration at a high level. Technological improvements, such as long-reach and horizontal drilling or 3D along with 4D-seismic data that have made reservoir interpretation more precise, have been critical success components in the northern North Sea but technology on its own is not enough. It takes a company with the expertise to deploy it and the commitment to see through.

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