Cut surface and block of coralline limestone from the Lower Devonian Iberg limestone in the Harz Mountains, Germany. The voids in the corals are partly filled by pyrobitumen (impsonite). Foreground is a drusy macropore partly filled with sparitic calcite cement and a droplet of impsonite. Photograph: montage; the droplet is ~1 cm across; corals are ~0.5 cm wide. Specimens courtesy of Barbara Teichert and Hans-Dieter Vosteen; Prepared by Peter Rendschmidt; Photographed by Wolfgang Hake; all BGR.
Chapter 13  Petroleum generation and migration

1 Introduction

Petroleum migration, its way from the source rock to the reservoir, takes place out of sight in the deep subsurface. Even in places where former sedimentary basins have been uplifted and eroded to expose the present or fractured rocks that form the petroleum migration pathways, there are no visible traces of its movement. However, evidence of the process is occasionally seen in the form of bitumen occurrences.

1.1 Definitions

Petroleum generation and migration is an area of science so large and geologically complex as the SPB area is so diverse that an entire Atlas series would be required to cover all aspects. However, there are general traits across the basin that allow a summary to be made. The summary is organised referring to the main petroleum systems.

Petroleum is naturally occurring and consists mainly of hydrocarbon molecules that often contain substantial amounts of contaminants such as sulphur, nitrogen, oxygen, trace metals and other elements in both subsurface and surface rocks. Petroleum may occur in gaseous, liquid or solid state depending on the properties of these compounds and the temperature and pressure conditions. The commonly used synonyms for petroleum are ‘hydrocarbon’ and ‘oil and gas’.

A petroleum system is a conceptual framework that includes a pool, or a group of closely related pools, of active petroleum source rock that has generated oil and gas. A petroleum system also comprises the overlying strata that have brought the source rock into the appropriate temperature range whose petroleum is generated and expelled. These fluids usually start migrating, often along discrete pathways within carrier beds or tectonic fractures. Eventually, a portion of the migrated hydrocarbons may fill a trap and accumulate in economic quantities in one or more reservoirs beneath a seal. A petroleum system includes all formations, processes and products.

This following account also includes undiscovered accumulations, in much the same way as ‘total petroleum systems’ have been defined. Because this chapter focuses on petroleum generation and migration, the diverse histories, shallow-gas occurrences are characterised by the depth of their ultimate reservoir. Shallow gas is commonly defined as gas accumulations in sediments down to depths of 1000 m below surface, although the petroleum industry tends to be pragmatic, regarding it as gas above the first casing point. Shallow gas can be of either microbial (also referred to as ‘biogenic’ by geoscientists) or thermogenic origin. Biogenic gas is produced by microbial breakdown of organic matter at shallow depths and is almost always methane. Thermogenic gas is produced by thermal degradation of organic matter, usually at temperatures in excess of 100°C, to release volatiles such as methane and higher hydrocarbons.

In contrast to the petroleum systems, which are distinguished on the basis of their source-rock ages and histories, shallow-gas occurrences are characterised by the depth of their ultimate reservoir. Shallow gas is commonly defined as gas accumulations in sediments down to depths of 1000 m below surface, although the petroleum industry tends to be pragmatic, regarding it as gas above the first casing point. Shallow gas can be of either microbial (also referred to as ‘biogenic’ by geoscientists) or thermogenic origin. Biogenic gas is produced by microbial breakdown of organic matter at shallow depths and is almost always methane. Thermogenic gas is produced by thermal degradation of organic matter, usually at temperatures in excess of 100°C, to release volatiles such as methane and higher hydrocarbons.

Figure 13.1  The petroleum provinces and districts in the Southern Permian Basin area

Fields related to Paleozoic source rocks

- Oil
- Gas
- Oil and gas

Present-day distribution of Aukasford carbonates and认识 (bioclasts)

- Marine sediments (extracted/bioclasts)
- Tectonites (bioclasts)
- Cretaceous and local aquatic (bioclasts)
- Geopolymers and chemical sediments and cultural sites
- Not present or unknown

In the background of the frontispiece photograph on the opposite page, a site of coalification/lignite from the Brekenberg (East Utsira Formation) and the site of the Oligocene (Kongsfjord Formation) are shown along with the present-day distribution of the main source rocks. Marine sediments (extracted/bioclasts) and the bioclasts are shown along with the present-day distribution of the main source rocks.
1.2 Source-rock and petroleum characterisation, data handling and presentation

The various source rocks found in the SPB each have different characteristics with respect to their organic matter. These different properties influence the timing of hydrocarbon generation, the quality and quantity of the generated oil and gas. The optical and chemical characterisation of organic matter can be used to describe the source-rock properties, indicating organic richness, kerogen quality, source-rock maturity, and source-rock facies.

Hydrocarbon generation and subsequent expulsion are the result of processes associated with the thermal maturation of organic matter upon burial of a source rock. Kerogens is transformed to hydrocarbons at increasing temperature. Whether oil or gas is generated depends mainly on the type of kerogen, and thereby on the origins of the organic matter. Terrestrial organic matter is typically gas-prone (typical kerogen, type II), whereas aquatic (mostly algal) organic matter is primarily oil-prone (lignitic, type III), and whereas aquatic (mostly algal) organic matter is primarily oil-prone (lignitic, type III), whereas aquatic (mostly algal) organic matter is primarily oil-prone (lignitic, type III), whereas aquatic (mostly algal) organic matter is primarily oil-prone (lignitic, type III), whereas aquatic (mostly algal) organic matter is primarily oil-prone (lignitic, type III), whereas aquatic (mostly algal) organic matter is primarily oil-prone (lignitic, type III). The oil generation potential of organic matter is assessed on the basis of a combination of kerogen type and maturity. The HI expresses the kerogen’s hydrocarbon potential. The HI values decrease with increasing maturity, and source-rock facies.

Maturation is the process of thermal alteration of organic matter (kerogens) in a sedimentary rock. It is used as a more readily measurable proxy for generation of hydrocarbons from a source rock.

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The Rock-Eval pyrolysis data only include samples still retaining more than 0.5% TOC content and released the data. Further quality control criteria were stringently applied before presentation in this chapter. Rock-Eval pyrolysis data only include samples still retaining more than 0.5% TOC content and released the data. Further quality control criteria were stringently applied before presentation in this chapter.

All data in the database meet the quality assurance standards of the laboratories and institutes that released the data. Further quality control criteria were stringently applied before presentation in this chapter. Rock-Eval pyrolysis data only include samples still retaining more than 0.5% TOC content and released the data. Further quality control criteria were stringently applied before presentation in this chapter.

2 Main petroleum systems

2.1 Pre-Devonian

2.1.1 Baltic Basin

Excellent source rocks are well-known throughout the Lower Paleozoic (Cambrian, Ordovician, and Silurian) succession and are widespread in the eastern part of the SPB area (see Section 2.2 in Chapter 4). These organic-rich sediments are either unconsolidated or were buried too deep in the central and western part of the SPB to be considered prospective; their genetic potential was largely exhausted (Chapter 4, Figure 4.1). Post-Caledonian subsidence was only local in the western Baltic Basin (Pre-Baltic Syncline, Baltic Depression; Figure 13.4a), which lay distal to the Variscan foredeep. Moderate overthrust thickness and heat transport toward the platform. The Lower Ordovician source rocks are mature in the Baltic Basin from overmaturation, except in the north-western area adjacent to the Tyrissett-Tarta-Zone. Petroleum generation started during the Caledonian orogeny at about 400 Ma.

Lower Paleozoic pre-Devonian and post-Devonian source rocks are present in the Baltic Basin. These organic-rich sediments are either unconsolidated or were buried too deep in the central and western part of the SPB to be considered prospective; their genetic potential was largely exhausted (Chapter 4, Figure 4.1). Post-Caledonian subsidence was only local in the western Baltic Basin (Pre-Baltic Syncline, Baltic Depression; Figure 13.4a), which lay distal to the Variscan foredeep. Moderate overthrust thickness and heat transport toward the platform. The Lower Ordovician source rocks are mature in the Baltic Basin from overmaturation, except in the north-western area adjacent to the Tyrissett-Tarta-Zone. Petroleum generation started during the Caledonian orogeny at about 400 Ma.

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Maturity generally increases towards the south-west due to main tectonic subsidence in the Tertiary-Tertiary Zone during the Late Paleozoic, whereas source rocks are usually immature in north-eastern Latvia both onshore and offshore. Deviations from this general maturity trend are related to locally enhanced burial along the major faults that define the structural grain of the basin.

The main reservoirs are porous and fractured Middle Carboniferous sandstones. Their depth increase dramatically from surface outcrops in western Latvia to more than 3000 m in western Poland. The regional dip towards the south-west. Decrease in porosity (p) and permeability (k) properties decrease considerably beneath 2000 m depth due to increasing clay content and quartz overgrowth. Other reservoirs include Ordovician and Silurian carbonate mud mounds and Tertiary clastic deposits in the eastern Baltic Basin. Carbonate mud mounds form the regional top seal. Upper Carboniferous clays provide additional seals in the south-west Baltic Basin.

Traps are mostly structural in the sandstone play with tilted blocks and horsts generating 5- to 6-way dip closures. Mid-Divonian tectonics appear to have created both the structural traps and their fracture porosity. The overlapping erosive/slip-fault plane for the seals. Carbonate traps were repeatedly sealed by Carboniferous basement, Ordovician and Silurian. The carbonate plays often have a combination of structural and stratigraphic closures, where the carbonate mud mounds pass laterally into non-reservoir carbonates. Oil generation in the western part of the basin started during the late Silurian (Westphalian), whereas generation in the central part began during the Mid- to Late Devonian and lasted until the Early Carboniferous (Figure 13.6). Generation ceased in Premiss to Mesozoic times when Carboniferous and Silurian source rocks were buried to depths that allowed expulsion of dominantly liquid hydrocarbons in the east and gas plus hydrocarbons in the west.

The major regional faults are considered to be migration pathways. The Cambrian oil traps are related to local uplift during the long-term tectonic evolution of the basin. Oil generated in the most deeply buried Lower Palaeozoic source rocks in the south-western Baltic Basin migrated up-dip to the east and north-east, where reservoir properties were better than those directly above the source kitchen. In the eastern Baltic Basin, oil generation decreased after the Mid-Carboniferous times. Carboniferous uplift and erosion in the eastern Baltic Basin appear to strongly influenced the migration pathways and migration efficiency.

Crude oils within the Carboniferous reservoirs have typically gravities (28–42 °API) that decrease with reservoir depth, low sulphur (≤0.2%) and low asphaltene (≤5%) contents. The highest gravity crude oils have 22 to 76% saturated components with predominately light n-alkanes. C25–C35 n-alkanes, maxima at C30 and lower amounts of n-alkanes with a carbon number greater than 30. CPI values are close to unity. Pristane/phytane ratios range from 2.07 to 2.65 and increase towards the south-east.


Figure 13.7 Geochemical data of Precambrian to Cenozoic samples of the SFB area. a. Pyrolytic yield (S2) versus Total Organic Carbon (TOC) plot modified after Langford and Blanc-Valleron (1990). The lines in the diagram indicate the Hydrogen Index (HI), which is calculated from the two parameters in the plot. Higher HI values correspond to higher quality (more oil-prone) source rocks. b. Pyrolytic yield (S2) versus Pyrolytic yield (S1) plot modified after Langford et al. (1997). The ideal lines show the transformation pathways upon maturation for the standard kerogen types (modified after Cornford et al., 1998). The plot can be used to determine the approximate kerogen type and provides an indication of the maturity level at which the source-rock kerogens transform and hydrocarbons are generated. c. Pyrolytic yield (S1) versus Total Organic Carbon (TOC) plot modified after Langford et al. (1997) and Peters (1986). The graphic curves for the standard kerogen types are shown. Each kerogen follows a different pathway during maturation and the kerogens are identified as hydrocarbon and gas-prone relative to carbon. The combination of the HI and Hydrogen Index (HI) in this diagram provides an estimate of kerogen type and maturity of a sample. d. Pyrolytic yield (S1) versus Production Index (PI) plot modified after Butz (1986). This trend line shows the increase in volatile organic compounds (VOC) with maturity as hydrocarbons are generated from the source rock. At higher maturity hydrocarbons are no longer retained by the source rock and the system is drained (pristane in HI). The diagram also reveals hydrogenation starting in immature samples (High HI but low TMax). e. Pyrolytic yield (S1) versus Pyrolytic yield (S2) plot modified after Langford et al. (1997). The proportion of saturated and aromatic hydrocarbons is applied to the C25–C35 n-alkanes from the distributions of the aromatic C25–C35 and C25-C36 n-alkanes to modern environments. The diagram works on the principle that C25–C35 n-alkanes are generally associated with plant waxes, whereas the primary producers are C25–C29 n-alkanes (Zumberge, 1973). However, there is much overlap between the different source environments (Kusznir et al., 1985). The main use of the diagram is to characterize different source rocks by their strata distribution signature. Puts produced using API ≥ 30.5.
had remained limited (e.g. on the Derbyshire Block; the Bowland and Geverik members). In the basinal across the central NWECB. Black shales formed in fully marine deep-water troughs (basins) and coals Lower Carboniferous and Namurian source rocks were deposited in two distinct depositional environments delta complex (the Yoredale delta) prograded into the north-west of the basin. A foredeep filled with platform debris and some siliciclastic fine-grained material (Chapter 6, Figure 6.9). An extensive (Chapter 6), a fault-block system comprising horsts and grabens probably characterised the central NWECB. role in charging known petroleum accumulations. However, as they are inferred to be widespread, Lower Cambrian and Lower Ordovician organic-rich mudstones (Alum Shale and contributed a negligible fraction to the biomass by the time of source-rock formation; a. Pyrolytic yield (S2) versus TOC. Most immature source rocks contain type II kerogen irrespective of their age. Another implies an organic-matter composition that is less thermally labile than standard type II kerogen; d. Pr/n versus Ph/n; gradients within closely adjacent locations in Pomerania. T max values display an unusual maturity increase upsection.

Lower Carboniferous and Namurian source rocks in the central Northwest European Carboniferous Basin (NWECB, the Netherlands, Denmark and Germany onshore area) have proven to be a significant contributor or of charge to petroleum discoveries and developed fields in the area. High maturity levels and unbeatable timing of generation are the main reasons that this otherwise prolific source rock does not play a greater

Lower Carboniferous and Namurian source rocks have the potential to feature in future discoveries. The NWECB experienced a tectonic régime during the Early Carboniferous. An area in northern England (Chapter 6), a fault-block system comprising horsts and grabens probably characterised the central NWECB. The horst blocks are typically sites where carbonate platforms developed, whereas the grabens were filled with platform detritus and some siliciclastic fine-grained material (Chapter 6, Figure 6.8). An extensive delta complex (the Trydevoll delta) prograded into the north-west of the basin. A foredeep filled with flysch sediments developed parallel to the southern NWECB margin. This system was largely incorporated into the Variscan fold-and-thrust belt during the Late Carboniferous.

Lower Carboniferous and Namurian source rocks were deposited in two distinct depositional environments across the central NWECB. Black shales formed in fully marine deep-water troughs (basins) and coals developed on terrestrial to marginal-marine delta plains (Chapter 6, Figure 6.16). Basinal black shales, once enriched in organic matter, were deposited alternating with carbonates on the slopes of the carbonate platforms and on the basin. When carbonate production ceased at the Rhenanian-Viennese transition, basal black shales were also deposited on the carbonate platforms in areas where sedimentation rates had remained limited (e.g. on the Derbyshire Block; the Bowland and Geverik members). In the basinal

Figure 23.4 The Baltic Basin petroleum province with locations of fields and accumulations charged by pre-Devonian source rocks. The distribution of Upper Carboniferous and Lower-Devonian exogenic-rich members (Alum Shale and Bricquemar Shale) is prior to erosion (from Hoekstra et al., 1986). The regional distribution and thickness of the Alum Shale is shown in Figure 4.18.

2.2 Early Carboniferous, Namurian

2.2.1 Anglo-Dutch and North German basins

Lower Carboniferous and Namurian source rocks in the central Northwest European Carboniferous Basin (NWECB, the Netherlands, Denmark and Germany onshore area) have proven to be a significant contributor or of charge to petroleum discoveries and developed fields in the area. High maturity levels and unbeatable timing of generation are the main reasons that this otherwise prolific source rock does not play a greater role in charging known petroleum accumulations. However, as they are inferred to be widespread, Lower Carboniferous and Namurian source rocks have the potential to feature in future discoveries. The NWECB experienced a tectonic régime during the Early Carboniferous. An area in northern England (Chapter 6), a fault-block system comprising horsts and grabens probably characterised the central NWECB. The horst blocks are typically sites where carbonate platforms developed, whereas the grabens were filled with platform detritus and some siliciclastic fine-grained material (Chapter 6, Figure 6.8). An extensive delta complex (the Trydevoll delta) prograded into the north-west of the basin. A foredeep filled with flysch sediments developed parallel to the southern NWECB margin. This system was largely incorporated into the Variscan fold-and-thrust belt during the Late Carboniferous.

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The original source-rock composition and quality of Lower Carboniferous and Namurian black shales is poorly known due to the limited amount of well data and elevated maturity (Figure 13.4). Low-maturity Namurian hot shales (equivalent to the Bowland Shale) from the Eastern European area have more than 2% TOC content andkerogen types I and II. In the southern Netherlands, Namurian hot shales have TOC contents of up to 10%, mostly of type II. In the south-eastern North Sea, organic matter is of type III kerogen with TOC contents up to 2%. Dispersed terrestrial organic matter in pacific Namurian deposits has a mode to low HI values (50-60) and maturity (<0.8% Rr).

Maturity is generally low along the northern NWECB margin where the burial depth and thickness of the Carboniferous succession are rather limited. The maturities of Lower Carboniferous Yoredale Formation coals and Namurian deposits of the northern Dutch offshore and Danish areas indicate that they are in the oil window. In the western German sector of North Sea, the Tournaisian successions are moderately mature, showing good gas potential, whereas Visean deposits, with the exception of those with high vitrinite reflectance values caused by local Penn-Carboniferous magmatic activity, are in general below the gas window. In the south-eastern North Sea, the present-day maturity of Lower Namurian and Visean deposits is often below 1.3% Rr (excluding areas affected by Penn-Carboniferous magmatic intrusions). The deposits south of the present Yoredale facies in the UK and Dutch offshore areas have in general maturity in the gas window or are overmature. For example, the present-day maturity of Lower Namurian source rocks in the East End area vary from 5.5% to 5.9% Rr. Further east and to the south, Lower Carboniferous and Namurian source rocks are also found or expected to be overmature.

Magnetotelluric soundings indicate a good conductor at 7000 to 9000 m depth ascribed to black-shale facies deposition were confined mainly to the central and southern NWECB. Wells to the north of the Ruhr Basin are usually not stratigraphically sealed and therefore there is a poor relationship between gas and hydrocarbons.

Thermal modelling suggests Late Carboniferous generation (Figure 13.13). The western area of the Northwest European Carboniferous Basin with location of rift and accumulations charged by source rock units. Elevated nitrogen concentrations in Rottliefen reservoirs broadly correlate with the occurrence of overmature Lower Carboniferous black shales.
All of the accumulations in the West Midlands are trapped in structural traps that are either sulci rollovers, inversion fault controlled, or above horst blocks. Most of these structures formed early during the Cretaceous. This is clearly seen for example on the Rockhal Crossing where about two phases of charge can be recognised; an early charge associated with Carboniferous basalts and a subsequent charge, probably coinciding with migration at the end of the Carboniferous. Anything generated more recently (i.e. Jurassic to Cretaceous) was available to charge structures essentially in their present-day configuration with insignificant secondary alteration, other than possibly biodegradation if reservoired at shallow depths. Reservoir presence is a problem for exploration in the East Midlands, which has abundant reservoir-quality carbonates and particularly clastic beds. The principal producing reservoirs are sandstones within the Westphalian Coal Measures (e.g. Gainsborough, Eakring, Duke’s Wood, Welton, Beckingham). In places where the head sands of migrating deltaic channels are locally stacked, reservoirs more than 100 m thick are possible. Oil is also found in lenses and distributary mouth bar sands, usually thinly interbedded with siltstones. These are sealed intraformationally by overbank and floodplain shales. A second important reservoir is the Namurian Millstone Grit (e.g. Gainsborough-Bentham, Eakring, Duke’s Wood and Beckingham), sealed by shales at the base of the Coal Measures. These are fluvio-deltaic and turbidite and, although somewhat scattered, they usually have a very significant net-to-gross ratio in their upper part. Other minor reservoir intervals include fractures at the top of the Donnaintian Carboniferous limestones, sealed by Namurian shales, which have produced small quantities of oil at Hartford, Eakring, Duke’s Wood, Plinspur and Bourton. The basal Permian sands have not yet yielded a commercial discovery but contain a significant oil show at Norton. The extensive syn-rift Devonian Old Red Sandstone, which underlies the Coal Measures in much of the basin, is also a prospective future target although the limited tests so far have proved fruitless, as would Devonian patch-reefs if they could be found in the subsurface (analogous to the now-exposed Wisty Knoll) exposure in Derbyshire.

For further information see Hawkins (1979), Kirby & Swallow (1987), Fraser and Kawthorpe (1990) and Powell et al. (1990).

2.2.3 Cleveland Basin

The Cleveland Basin from the north-west extension of the Southern North Sea Gas Basin and shares much of its geology with the adjacent Soluk P1 Throg. It is mainly Jurassic to Early Cretaceous structure, emerging as an older Carboniferous basin. In both cases, the dominant fault zone appears to have been in the north although antithetic faults are also present to the south. The basin is fault-bounded to the north against the Durham coalfield (cemented Westphalian) and to the south by a complex fault zone (Vale of Pickering-Flamborough Head Fault Zone) against the Market Weighton Anticline and the Selby coalfield (also cemented Westphalian), which separates it from the East Midlands province (see previous section, Figure 13.15).

Seven gasfields have been discovered: Cayton Bay, Eakring, Kirby Misperton, Leckham, Wharram, Marnock and Pickering (Figure 13.14). During the Devonian, the Cleveland area probably acted as a sediment source. Sedimentation commenced during the Devonian, somewhat later than in the East Midlands. Due to its proximal setting with respect to the sediment source in the north, Namurian source rocks in the Cleveland Basin are mainly characterised by coals. Major periods of inversion took place at the end of the Carboniferous (Variscan Orogeny) and during the Cenozoic (Alpine Orogeny) towards the east-west basin axis (Figure 13.15). The basin thickens considerably to the east. Although there have been a number of small gas discoveries, the understanding of the petroleum geology of the Cleveland Basin is still at an early stage.

Namurian shales or coals are thought to be the source of the gas discoveries in the Cleveland Basin. Most of the Westphalian create were emplaced and now remain only as isolated outliers (e.g. a small north-south east-west-trending patch at Robin Hood’s Bay, Figure 13.14). The maturity of Namurian shales in the Cleveland Basin is thought to be high, probably in the dry-gas window, so even middle Jurassic coals might have vitrinite reflectance values between 0.82 and 0.87% Ro (Figure 13.14).

Hydrocarbon generation had probably started by Late Carboniferous times (Figure 13.17). Although the most important petroleum-generative phase took place during the Jurassic and Cretaceous. Migration during Jurassic and Cretaceous buried was mainly northwards to a post-rifted Market Weighton granite dome, although some north-east migration would also have been possible. Most production to date has been from fault traps along the shallow fault zone. These mainly east-west-trending Jurassic and Cretaceous fault cut across the predominately north-south-trending Permian fault belts. Consequently, the most recent discoveries (Maltby, Kirby Misperton and Pickering) are located along a north-south trend within this shallow fault zone. Trap breaching and migration towards the basin axis were the key features associated with Cenozoic Alpine inversion.
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There are reservoir rocks in Namurian sandstones (Koby Wrierské field), basal Permian Rotliegend sandstones (Koby Wrierské field), and fractured Zechstein dolomites (Koby Wrierské, Ełkóda, Maloń and Matkowsz) fields. The Jurassic sequence also includes numerous sandstones of reservoir quality. There is probably further potential along the faulted northern basin margin extending offshore; however, this has only been poorly explored so far.

2.2.4 Pomerania

Pomerania is situated on the Trans-European Suture Zone (TESZ), a mosaic of crystalline blocks separated from the East European Platform by the Kaminul Fault Zone. To the south, the Variscan Deformation Front forms the transition to the folded Carboniferous rocks of the Polish Trough. Twelve Carboniferous-earored gasfields have been proven in Pomerania (Figure 13.18).

During the Early Carboniferous, the Pomerania region formed the southern shelf area of the Eastern European Platform, characterized by mixed siliciclastic-carbonate shallow-marine deposits (see Chapter 6, Figure 6.15). The area was uplifted during the Namurian and acted as a source of elastic material for the sedimentary basins of central and southern Poland. Sedimentation resumed during Westphalian times. The transitions from delta to fluvial conditions only took place during the Westphalian C, in contrast to most areas in the NWBE, where it had occurred during the early Westphalian. From Rotliegend to Late Cretaceous times, the area was part of an extensive basin until Alpine inversion caused Pomerania to be uplifted (Figure 13.19). The Transmazian, Visean and Westphalian black shales that occur across the entire Pomeranian region are the main source rocks. Uplift has largely restricted Carboniferous source rocks to southern Pomerania. This Westphalian coal seems also occur.

Transmazian and Visean shales have average TOC contents of 1.5 and 1.1%, respectively, both with maximum values of about 10% (Figure 13.20a). Westphalian shales have average TOC content of 0.3% (up to 2.2%). Namurian and Westphalian bituminous coal strata and interbeds are usually less than 0.5 m thick. Kerogens is mainly gas-prone type II with admixtures of type III (Figure 13.20a, b). Average Hydrogen Indexes decrease upwards from the Lower Carboniferous (100 mg/g) to the Upper Carboniferous (110 mg/g), but they typically have a wide range. Stable carbon-isotopic data from natural-gas samples corroborate a major contribution from Carboniferous type II kerogen. Some thin layers are characterized by significant algal contents. The Lower Carboniferous clayey-marly Sgolsz Formation has considerable amounts of oil-prone, structures, fluorescing pyrobitumen organic-mineral associations with lipid tracts (type II kerogen). Transmazian samples in particular are predominantly in the type II kerogen field (Figure 13.20a). Saturated hydrocarbon compositions are generally homogamotic, which is reflected by indices such as the ratio of the abundance of odd carbon number normal alkanes to even carbon number normal alkanes (Carbon Preference Index, CPI), the pristane/n-C17 ratio, pristane/n-C18 ratio and pristane/phytane ratio (P/Pn).

Both Tmax and vitrinite reflectance values indicate that the Transmazian to Westphalian source rocks are mostly marginally mature to mature (Figure 13.20b). The highest present-day maturity values are 0.8% Ro. The area was uplifted during the Namurian and acted as a source of elastic material for the sedimentary basins of central and southern Poland. Sedimentation resumed during Westphalian times. The transitions from delta to fluvial conditions only took place during the Westphalian C, in contrast to most areas in the NWBE, where it had occurred during the early Westphalian. From Rotliegend to Late Cretaceous times, the area was part of an extensive basin until Alpine inversion caused Pomerania to be uplifted (Figure 13.19). The Transmazian, Visean and Westphalian black shales that occur across the entire Pomeranian region are the main source rocks. Uplift has largely restricted Carboniferous source rocks to southern Pomerania. This Westphalian coal seems also occur.

A first generation and migration phase took place in the Late Carboniferous at maturities of about 0.6 to 0.8% Ro (Figure 13.21). In places where the petroleum potential was not exhausted during the course of this early generation phase, there were two more generations phases in the Triassic-Jurassic and in Late Cretaceous times, when maturities reached 1.5 to 1.8% Ro. The latter phase generated gases that probably migrated over distances that did not exceed several tens of kilometers. Traps are both structural and stratigraphic, but are small and often accompanied by faults. Some traps have the characteristic of combined structural and stratigraphic trapping. Reservoirs include Visean limestones (R: 2-16%, K: 100-600 mD), Namurian (R: 16-22%; K: 208-274 mD), Westphalian (R: 5-15%; K: 74-190 mD) and Rotliegend sandstones. The fluvial Rotliegend sequence is up to 750 m thick (the total Rotliegend section is much thicker) and contains a number of potential reservoir units. The maximum thickness of the aeolian sandstones is usually less than 50 m. Both fluvial and aeolian sandstones have high porosities (R: 0-15%, generally <5%), although their permeabilities are mostly less than 1 mD. In contrast to the primary matrix porosity, fracture porosities and permeabilities can be considerable. Zeolite salt and aphyric basalt form the seal for the Carboniferous and Rotliegend reservoirs, whereas intraformational seals play only a minor role (Chapter 7, Figure 13.21).

Natural gas in the Pomeranian reservoir is rich in nitrogen (20-70%) and contains 22 to 50% methane, some ethane, propane and butane. The nitrogen content increases westwards and less evidently to the south. For further information see Kazimierski (1996, 1999b) and Kesteba et al. (2004, 2005).
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Figure 13.13: Event chart for the Early Carboniferous and Namurian petroleum system in the East Midlands petroleum province.

Figure 13.14: The Cleveland Basin petroleum province with locations of fields and accumulations charged by Namurian source rocks.
The Fore-Sudetic Monocline is subdivided into three regions on the basis of its reservoir rocks and gas compositions. Thirty-eight gasfields occur in the uppermost Rotliegend sandstones north of the Wolcryn High. The Wolcryn High is a pre-Pennian ridge where Rotliegend reservoir sandstones are absent (shaded in pre-Carboniferous rocks, Figure 13.22). There are six gasfields in the Zachritz Limestone of the Lower Cretaceous cycles on the Wolcryn High. South of the high, gasfields are found in the uppermost Rotliegend sandstones, in the Zachritz Limestone, and often in both.

Lower Carboniferous and Norian source rocks are mainly shales with dispersed organic matter that were deposited in the Variscan foredeep. Organic-carbon contents are generally lower (up to 4%), more humic and gas-prone in the Fore-Sudetic Monocline than in other Polish Carboniferous basins (Figure 13.24a). The organic material consists mainly of pyrite-trace group macerals, whereas the inertinite group is subordinate and the vitrinite group macerals are marginal. There are subordinate quantities of oil-prone and mixed type II and III kerogen. However, reliable characterisation of the original kerogen is severely hindered by the high maturity of most samples obtained from the area (Figure 13.24b).

Lower Carboniferous source rocks in the Fore-Sudetic Monocline are extensively in large areas due to deep burial. Early-Pennian evaporation and hydrothermal activity. Maturity increases towards the area of the Mid-Polish Trough and the eastern Fore-Sudetic Monocline due to deeper burial and higher heat flow. To values range from 420 to 500°C (Figure 13.24b) and vitrinite reflectance from 1 to 5%. Transformation ratios of Carboniferous deposits correspond mainly to the thermogenic-dry gas phase.

In rapidly subsiding areas with high heat flow (50-150 mW/m²), petroleum generation started as early as the Late Carboniferous (Figure 13.25) and kerogen was almost completely transformed (transformation ratio near 100%; Figure 13.24a & b). In the areas of the Fore-Sudetic Monocline where petroleum potential still exists after the Carboniferous, generation occurred in Mid- to Late Jurassic, and in Late Cretaceous times, as at did in the Pomeranian region. Peak thermal maturation locally reached 5% Ro leading to dry-gas generation and overmaturity. The main migration that led to the filling of numerous reservoirs took place during the Triassic to Jurassic. A second, Late Cretaceous migration phase was less intense. Gases migrated over short distances, up to some ten kilometres at most.

The most prominent reservoirs for the Carboniferous source rocks are quartzite Rotliegend sandstones. There are minor accumulations in Carboniferous and Zechstein reservoirs, which are sealed by Zechstein anhydrite and halite. North of the Wolcryn High, the Rotliegend successions consists of up to 750 m-thick asil crystals (between 1.7-1.9, 0.3-1.0x10⁶ μm²). Further north, their total thickness increases to about 1000 m (Rey. 1.16%, Eav. 0.25 μm²). About 100 m-thick fluvial and alwal Rotliegend sandstones form.

The Fore-Sudetic Monocline is subdivided into three regions on the basis of its reservoir rocks and gas compositions.
effective gas reservoirs along the margins of the Wolsztyn High. The reservoir quality deteriorates rapidly with increasing burial depth towards the north, due to compaction and diagenetic processes. These zones with reduced reservoir quality are prospective for tight gas and hydrocarbon traps. Zeolite reservoirs, including several limestone units up to several tens of meters thick (Bar: ~15%; Ear: ~60 m) are found on the Wolsztyn High and other local basement highs. They host a number of gas fields (e.g. Kizian, Brzukowo, Paprty M and Wolsztyn). South of the Wolsztyn High, Rotliegend aeolian and fluvial sandstones are again the major reservoirs, although they are thinner than those to the north of the high (up to 550 m, mostly less than 300 m; 8–3–2%, K: 0.1–0.3%). Producing reservoirs are also found in shallow-marine barrier and platform facies limestones (porosities: 1–13%). Both the Zechstein carbonates and Rotliegend sandstones are productive in some fields (e.g. Grabówka and Dobrzec).

The composition of natural gas in the Fore-Sudetic Monocline is diverse. North of the Wolsztyn High, it is mostly methane (70–95%) with admixture of nitrogen (2–15%). Higher hydrocarbons (>5%) C2 (4%) and traces of helium. The gas quality decreases southwards and south-westwards, whose fields contain 16–40% of methane, 20–70% of nitrogen, similar C2, and higher hydrocarbon contents, but with increased helium concentrations (up to 8%).

The Lublin Basin is situated in the south-west of the East European Platform and is bordered to the south-west by the Holy Cross Mountains and Mährisch-Ostrau. To the north-west, it passes into the poorly known and deeply buried Mid-Polish Trough. Petroleum in the Lublin Basin is mostly natural gas with limited amounts of oil. There are four fields in the basin, which are probably sourced from Carboniferous rocks, at Stypa, Siednik (oil and gas), Wójcica, and Piaskowice (gas). The Carboniferous development of the Lublin Basin is associated with a system of approximately north-west–south-east-trending longitudinal fault zones related to Variscan reactivations of the Tornquist Zone (Figure 13.26).

The Carboniferous (upper Visean) succession consists of almost exclusively older Palaeozoic formations in large areas of the Lublin Basin (Figure 13.27). An alternating sequence of clastics and carbonates was deposited during the Visean. In Cambrian times, coal-bearing deposits were formed during cycles of shallow-shallow, deltaic and fluviolacustrine environments with low to moderate sand content. By late Westphalian times, the Lublin Basin had undergone structural inversion in the thrust-fault stress regime and fluviolacustrine deposits with high sand content had accumulated. Post-Carboniferous development of the Lublin Basin was characterised by steady subsidence during the Permian to Early Cretaceous. Late Cretaceous and Early Cenozoic inversion led to uplift of the basin.
Source rocks occur across the entire Lublin Basin except at the margins and a central north-west–south-east trending axis where Jurassic sediments were partly eroded. As seen in Poland and the Fare-Dolomitic Molasse, the source rocks in the Lublin Basin are typically thick Visean to Westphalian shales with dispersed organic matter. Coal seams occur in the Namurian and lower Westphalian sub-units.

Visean shales have an average TDC content of 1.8%, the organic matter is mixed type I/III (Figure 13.28a).

In addition to the predominantly low-TDC shales, there are local thin coal layers (<0.4 m thick) mainly in the eastern Lublin Basin. Increased pyrolytic yield (S2) values are attributed to higher contents of liptinite group macerals in some samples. In contrast to the marine or transitional (subordinately terrestrial) origin of the Visean organic matter, the Namurian and Westphalian organic matter is mainly terrestrial. Namurian bituminites have similar average TDC contents (1%) and maximum values (15.5%). Westphalian bituminites have an average TDC content of 1.9%. In addition to the dispersed organic matter, there are up to 100 intercalated coal seams, eight of which are up to 3.5 m thick. Coal seams comprise up to 8% of the lower Westphalian section and up to 3% of the Namurian section. In general, the Namurian and Westphalian coals in the Lublin Basin are marginally mature (0.71-0.81% Ro) with minor quantities of methane.

Samples are mostly marginally mature to mature and comprise some unusual samples with type I kerogen; c. Tmax versus c. Ro (Figure 13.28b). The T_(max) (415-645°C) and Ro (0.4-1.2%) values of the organic matter from the entire top Westphalian to base-upper Visean section are surprisingly uniform (Figure 13.28c).
The timing of petroleum generation and migration in the Lublin Basin, as well as reservoir and seal stratigraphy, differ significantly from the Pennsylvanian and Permo-Triassic petroleum provinces (Figure 13.29). Generation started during the Westphalian in the north of the area (transformation ratio mainly ~25%, reaching up to 60%) and had ended by the time of the Asturian inversion (~304 Ma). In the north-western Lublin Basin, petroleum generation continued until the end of the Cretaceous (95 Ma), with transformation ratios never exceeding 15% at the base of the Lower Carboniferous. Many of the source rocks still have generating potential, and petroleum migration from the latest Westphalian throughout the Mesozoic was probably minor (Figure 13.29).

Hydrocarbon accumulations are found within a north-west–south-east-trending zone of anticlinal structures along the basin axis. Structural fault-related traps formed mainly during the Asturian (latest Carboniferous to Early Permian; ~300 Ma), but trap formation resumed in Mesozoic times as seen in Figure 13.30. Generation started during the Westphalian in most of the area (transformation ratio ~25% at the base of the Upper Carboniferous), although there are considerable variations in other aspects of their petroleum geology such as their generation, migration and accumulation. There are also considerable contributions to parts of the dacronves and fields of the region from Lower Carboniferous and Mesozoic source rocks.

The region is cross-cut by numerous Mesozoic faults, associated horsts, grabens and platforms, which resulted in differences in burial depth and timing of the generation of the Cretaceous oils, along with a wide range of post-Carboniferous traps and seals. More than 700 reservoirs were filled with gas sourced mainly or exclusively from the Coal Measures.

Although the oldest coal seams are found in Lower Carboniferous rocks (Tonsberg Formation; Section 2.2.1), the most important oil-bearing deposits, the Westphalian Coal Measures, are Langsettian to Bulganian. The deposits are up to 300 m thick. The coals can form up to 6% of the section after compaction. The coals in most areas, the coals have a cumulative thickness of several tens of metres. The swamps in which these peat deposits developed were part of an extensive lower-lower delta plain that covered large areas of the BRERES.

The Coal Measures (Chapter 8, Figure 6.17) are found in large areas of the SPB, although their present-day distribution is affected by erosion. In particular, the northern and southern margins have been uplifted and the coal-bearing succession has been removed. Regardless, tectonic inversion, especially during the late Cretaceous, has resulted in partial or locally complete removal of the Coal Measures.

Figure 13.31a shows that the position of the main East-West trend that shaped the boundary between oil-prone type II and gas-prone type III over a large range of TOC contents (Figure 13.11a). Oil staining is found above some of the shale layers overlying the coal seams, especially in the basins formed during marine inversions, which indicate their oil-generation potential.

Within a wider maturity range, large parts of the Westphalian Coal Measures in the North Sea and adjacent onshore areas are in the oil and gas window (Figure 13.31b-f). Local modification anomalies are related to magmatic intrusions. In the southern North Sea and the Netherlands, the Coal Measures are mostly in the gas window, although in parts of the Cleaver Bank High area the Coal Measures are still in the oil window. The slightly higher coal maturity in the Broad Fourteens Basin than on the Cleaver Bank High is due to the deeper burial of the former (Figure 13.31f). Further east in the North German Basin, Westphalian organic matter is mostly in the gas window or reservoir. The anomalously high maturity of gas-prone source rocks is due to the early onset of the Emsian in the basin as a result of increased subsidence and increased basin heat flow. As a consequence, the generation in these areas was almost completely transformed. In the Lower Saxony and East Foreland basins for instance, gas generation was most intense from Jurassic to Late Cretaceous times and left no generation potential. Because the Zechstein seal is missing in the latter, most gas generated prior to the main phase of trap formation (Late Cretaceous and younger) was lost.

In contrast, Jurassic uplift of the platforms and highs led to interruption of hydrocarbon generation in these areas. In places where subsequent burial reduced the generation potential, the uplift and inversion events preserved the generation potential. Generation from Westphalian coal was widespread until Miocene times (Figure 13.32), following which there is a distinction between the Cimmerian rift basins and the platforms and highs (see Chapter 3, Figure 3.19 for the locations of Jurassic rift basins in the SPB). During Late Jurassic to Early Cretaceous rifting, hydrocarbon generation occurred within the rift basins as a result of increased subsidence and increased basin heat flow. As a consequence, the generation in these areas was almost completely transformed.

For further information see Botor et al. (2000), Kotarba et al. (2002), Karnkowski (2003a) and Grotek (2004).
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Hydrocarbons generated from the Eel Measure accumulated in reservoirs at almost all stratigraphic levels. The major control appears to be the presence or absence of sealing units in the overburden. Troughs in combination with Carboniferous reservoirs are mostly dip-fault closures at the base Permian unconformity. Stratigraphic traps also occur in places such as the Weensmeer field in Germany. Where there are Rotliegend sandstones, the Carboniferous sandstones only contain gas where the height of the trap exceeds the thickness of the Rotliegend, for example, in the Grenige field. In the area from Grenige southwards to offshore k linea E and L gas in Rotliegend reservoirs is mostly trapped in simple fault blocks. Zechstein traps are predominantly fault-fault closures, with some 4-way dip closures. In the Jurassic basins of the southern Netherlands, the typical trapping style in the Triassic play comprises Late Jurassic horst blocks, whereas in the offshore sector most traps are tectonic basin traps, salt-wall bounded or fault-/dip-closure related to breakouts of the Zechstein salt.

The seals in the Silverpit / Cleaver Bank High area are formed by claystones and evaporites of the Sinemurian Formations and locally by intra-Westphalian shales and tight faults. Zechstein evaporites are the most important seal in the southern Netherlands and neighboring Germany.

The majority of fields in the Anglo-Dutch Basin (98%) have reservoirs in Rotliegend sandstones. Most of these fields are located in the basin axial area where thick Zechstein reservoirs were deposited and which form the major seal. A minority are located on the basin margins with slope and lagoon/platform Zechstein facies. Deposition in these marginal deposits appear to form a proper seal to the Rotliegend reservoirs. There are no Rotliegend fields in the so-called ‘Fringe’ Zechstein where there is a lack of evaporites that could form a seal. The presence of Rotliegend reservoirs is also facilitated and therefore their distribution is not occurring in the shallow parts of the Silverpit Formation.

Where the Zechstein salt is present, it provides an effective seal for Carboniferous and especially Rotliegend reservoirs. Carboniferous reservoirs are found in the Silverpit / Cleaver Bank area, in the north-eastern part of the Netherlands and in western Germany. Gas-bearing Westphalian sandstones often show good pore permeability in the UK and the Netherlands (20% of the fields). sealing by Zechstein evaporites and salt domes. Fractured Salt rocks are the most important reservoirs in the Zechstein area as the Rotliegend deposits are much thinner and have suffered severe reservoir deterioration due to illite growth.

Most of the gasfields that produce from Zechstein platform-carbonate reservoirs are found along the southern margin of the SPB. A small number of Zechstein fields are connected to Rotliegend reservoirs, forming a stack of multiple reservoirs (e.g. the Creddon field). There is a direct relationship between the migration barriers and migration pathways in the Zechstein. The Upper Triassic evaporites generally seal the Rotliegend reservoirs more effectively and have suffered severe reservoir deterioration due to illite growth.

Tectonic migration occurs in a variety of trap styles at locations where the Zechstein seal is absent or breached. The distribution of Jurassic-Triassic fields can be correlated with the underlying Rotliegend sandstones or the productive Westphalian carbonates. There is a direct relationship between the migration barriers and migration pathways in the Zechstein. The Upper Triassic evaporites generally seal the Rotliegend reservoirs more effectively and have suffered severe reservoir deterioration due to illite growth.

Some of the Upper Jurassic and Lower Cretaceous hydrocarbon fields have a varying contribution (major to minor) from Westphalian source rocks. The distributions of these fields is correlated to the Cimmerian rift basins. This contribution is also limited by an unfavorable timing of charge, with pre-inversion generation from the Westphalian prior to the main phase of trap formation during the Late Cretaceous.
Minor accumulations of Westphalian-dated gas are found in the Chałuszki and the Gosenitz (e.g. the Hattingen field in the Netherlands).

For further information see Pelosi (1864), Faber et al. (1975), Matthäus & Bülow (1990), Schädel et al. (1997a), Lichtenthaler et al. (1985), Gettings et al. (1990a, 1990b), Hoffman et al. (2005) and De Jager & Geluk (2007).

2.4 Zechstein

The lower Zechstein is a petroleum system. In contrast to other systems, rock units of the same stratigraphic group, such as the carbonate and evaporite members of the Main Dolomite and Older Halite, as well as the Stassfurt Carbonate and Halite members (Chapter 8), constitute the petroleum source rocks, the reservoir rocks and the regional top seals.

The evaporative conditions that controlled deposition of the lower Zechstein succession limited the accumulation of terrestrial organic matter and its riverine transport towards the Zechstein Sea. The deposition of basinal kerogen was greatly reduced as a result. The contribution of basinal type III kerogen is usually subordinate, both in the basinal mudstones and on the carbonate platforms. In contrast, accumulations of lower plant, mostly algae, organic matter dominated the open-marine and lacustrine environments. Saproplegic kerogen consequently prevails in the depositional environments of the Main Dolomite Formation (Zechstein Carbonate), although during maturity it may have lost its potential to generate oil or gas.

Oil source rocks such as the basal Zechstein Bogdenschlacke (Copper Shale) Member and the Stichkohle Member of the lower Hauptdolomit / Main Dolomite Formation are widely distributed across the SPB Oil source rocks such as the basal Zechstein Kupferschiefer (Copper Shale) Member and the Stinkschiefer kerogen is usually subordinate, both in the basinal mudstones and on the carbonate platforms. In both the accumulation of terrestrial organic matter and its riverine transport towards the Zechstein Sea. The arid evaporative conditions that controlled deposition of the lower Zechstein succession limited stratigraphic group, such as the carbonate and evaporite members of the Main Dolomite and Older Halite, (2007).

For further information see Patijn (1964), Faber et al. (1979), Mathisen & Budny (1990), Schröder et al. (1991), Lokhorst et al. (1998), Gerling et al. (1999a, 1999b), Hoffmann et al. (2005) and De Jager & Geluk (2007).

Figure 13.34. Average reservoir porosities in the Zechstein carbonate / Main Dolomite members vary widely (0-10%) on the Kazimier Patronomic Platform and average permeability commonly varied 10 md. Zechstein source rocks in Pomerania reached the early generation phase (10-15% transformation ratio) during the Early Triassic in the axial part of the Zechstein Basin and in the Bunter reservoirs, whereas in the western parts of the basin (Figure 13.35). Early generation started at burial depths greater than 2500 m. Subsidence of the source-rock interval into the oil window, equivalent to the expulsion window (25-45% transformation ratio), took place from Mid-Triassic to Cretaceous times at more than 2700 m burial depth. Late generation, up to the exhaustion of the source potential (65-90%), took place from the Early Triassic to the Late Cretaceous on the slopes and platform, where the petroleum potential of kerogen from the Main Dolomite source rocks became exhausted.

The most favourable reservoir properties are found in carbonate grainstones and packstones deposited in high-energy barrier and slope environments. However, secondary cementation and recrystallisation under these properties highly variable, both laterally and vertically, even within individual reservoirs, and may lead to severe reservoir deterioration. For example, in the Kazimier Patronomic field, zero-porosity and zero-permeability zones within the reservoir considerably constrain the migration pathways. The directly overlying Basal Anhydrite (A2) and Older Salt (A3a) members, and other Zechstein evaporites, from efficient seals for the Main Dolomite reservoirs.

Pomeranian Zechstein-sealed crude oils have density higher than 0.8 g/cm³ (less than 40° API). The heaviest oils occur in slope accumulations (Myśko Kamieński) and the lightest oils are found in basinal deposits. Organic sulfur content (0.18-1.12 wt %) is positively correlated with oil density throughout the region. Oil composition is relatively homogenous across the geopetalographic zones of the province. Oils mostly consist of saturated hydrocarbons (>70%), which have low saturated versus aromatic hydrocarbons ratios (0.8-2.2) that suggest short migration distances. The composition of polycyclics and n-alkanes (C₇-C₃₀; C₇-C₃₀; C₇-C₃₀) varies widely in all oils indicating anoxic conditions during deposition of the organic matter. Geochemical fingerprints, such as carbon isotopic composition and their impact on the heavy oil formation/riserate function. Isoprene benzene and isoprene toluene (C₁₇ iso) and CPI of alkylcyclohexanes markedly higher than 1.

Changes from algal source rocks were probably largest in the platform areas where conditions for growth of the algae that create this type of kerogen were most favourable. Type I kerogen significantly improves the source-rock quality, yet its contribution to the overall charge is difficult to assess due to its great volume (Figure 13.33). This is partly related to the limited thickness (minor petroleum yield) of the Zechstein source rocks and to late flushing of many Zechstein-sealed accumulations by Westphalian gas.

Another reason for the patchy distribution of major Zechstein-sealed petroleum accumulations is that the uppermost palynofacies often have limited source-rock qualities. Organic-carbon contents and generative potential within the Stichkohle Member (fossil shale), the correlatives Stichkohle and Stichkohle are mineralized on isolated pods on the platforms and plugs around the Zechstein basin (Figure 8). The Zechstein-carbonates were considered to be among the most prospective reservoirs for both oil and gas in the Netherlands and Germany until the late 1980s. However, Zechstein discoveries in the western SPB are scarce, from Carboniferous dolostones and only a few have a Zechstein source rock.

This is partly related to the limited thickness (minor petroleum yield) of the Zechstein source rocks and to the lack of flushing of many Zechstein-sealed accumulations by Westphalian gas.

For further information see Patijn (1964), Faber et al. (1979), Mathisen & Budny (1990), Schröder et al. (1991), Lokhorst et al. (1998), Gerling et al. (1999a, 1999b), Hoffmann et al. (2005) and De Jager & Geluk (2007).

2.4.2 Pomerania

On the north-eastern margin of the Zechstein Sea, Stassfurt Carbonate and Main Dolomite sediments were laid down on Westphalian reservoirs on a narrow, poorly differentiated north-west–south-east-trending platform. Most Zechstein petroleum reservoirs and fields in Pomerania contain oil, although gas also absent (Figure 13.33).}

Figure 13.34: Geochemical data from lower Zechstein samples of the Pomeranian petroleum province:

a. Pyrolytic yield (S2) versus TOC. Most samples are immature and contain type II kerogen. The presence of some samples of type II kerogen is probably unrelated to input of higher plant remains, but likely reflects deposition due to thermal restriction.

b. Pyrolytic yield (S2) versus hydrogen index (HI). The normally low HI values of the richest samples may indicate an oxygen-water comparison that is thermally more favorable than standard type II kerogen; c. Pyrolytic yield (S2) versus Production Index (PI). Shelly shaly HI values are likely related to the presence of migrated hydrocarbons.

- a. Chromatograms of n-alkanes and isoprenoids in Zechstein Main Dolomite carbonate reservoir samples.
- b. Chromatograms of n-alkanes and isoprenoids in Zechstein Main Dolomite oil samples.

Paleo-plots produced using ISIS p:IGI-3.

Slightly restricted conditions developed in the lagune along the Thuringian margin; however, more pronounced restrictions influenced the environments on the Fore-Sudetic Slope, including its fluvial segment (Brandenburg Slope). The Brandenburg Slope developed much like the Fore-Sudetic Monocline with continuous facies belts around the Zechstein Basin. In contrast to the open slopes of the Fore-Sudetic Monocline and Lower Lusatia, Stassfurt deposits of the Thuringian Basin were deposited in an originally north-south-trending extension of the central European Zechstein Sea. Before it was flooded by the Zechstein Sea, the Thuringian Basin was part of the San-Saale Trough that accumulated up to several hundred meters of Westphalian and Bunter clay deposits in an intramontane setting.

Opinions are divided regarding the major source-rock facies of the area. The platform carbonates appear to be the source in the Fore-Sudetic Monocline, whereas the main charge on the Brandenburg Slope stems from source rocks deposited on the slope and in the basin.

The Gottrud subzone (Figure 13.37) is an excellent example of variability in lithofacies, palaeogeography and structure of the most prospective zone of the Fore-Sudetic Monocline petroleum province. The potential source and reservoir facies were deposited close to each other within the basin, slope and platform environments. Carbonates deposited on the platforms, and within calcrete barriers, commonly consist of grainstones and packstones with porosities up to 26%. However, deposits with average permeabilities up to several hundred metres of Westphalian and Rotliegend siliciclastics in an intramontane setting. Sudetic Monocline and Lower Lusatia, Stassfurt deposits of the Thüringian Basin were deposited in an intramontane setting.

In addition to the Zechstein hydrocarbons, nitrogen probably entered several reservoirs on the Brandenburg Slope and in the Thuringian Basin after the reservoirs became hydrocarbon-charged. The nitrogen is derived from deeply buried Palaeozoic sediments. High C2 isotopic ratios in the gasfields of Thüringen correlate with German basinal winoration. The H2S can be explained by either bacterial or thermochemical sulphate reduction. The methane content in the larger deposits (Behringen, Mühlhausen) is about 50%.

Major source rocks were formed during various episodes in Jurassic times, notably in the lowermost Jurassic (Moenkhuslino to Stensanen Lias Shales), the lowermost Jurassic (Toarcian) Ponsionia Shale Formation, the Middle to Upper Jurassic (Callovian-Oxfordian) Oxford Clay Formation, and the upper Kimmeridgian Clay Formation (Chapter 10, Figure 10.13). In contrast to the central North Sea, where the Kimmeridgian Clay is the main source rock, the Ponsionia Shale is the most important source rock for oil in large areas of the SPV. Its bituminous character results from pelagic deposition under anoxic conditions. The composition of oil generated from the Ponsionia Shale is similar to that from the Upper Jurassic bituminous intervals that occur locally in the Lower Jurassic in Upper Cretaceous sections. It is therefore difficult to distinguish and quantify the individual source-rock contributions in a single with multiple sources.

The Ponsionia Shale is a very distinctive interval throughout the western SPV areas and shows up as an excellent reflector on seismic profiles. Its present-day distribution is restricted to the centres of rift basins that formed in the Late Jurassic (e.g. West Netherlands and Brabant Massif basins, Dutch Central Graben, Lower Saxony Basin and Poerger Trough). Given the uniform character and thickness (mostly around 15 m of dark-grey to brownish-black, bituminous, fine-grained) across these basins, the Ponsionia Shale was probably deposited over a greater area; its present-day distribution reflects erosion on the basin margins and bounding highs.

The wide distribution of the Ponsionia Shale from the UK (Jet Rock Member) to Germany (Ponsionienkohle, or Rüthkohle) suggests deposition during a period of high sea level and restricted sea-floor circulation. In eastern Germany (Mecklenburg and Brandenburg), the lower Toarcian is represented by greenish-gray mudstones with calcareous concretions in the lower part. Farther east and into Poland, source-rock quality deteriorates with the common intercalation of silstones and fine-grained sandstones in the progressively organic-poor mudstones (Chapter 10, Figure 10.13).

2.5.2 World Basin

The World Basin of southern England is the north-east extension of the larger Wessex Basin, which formed on the eastern side of an extensive Triassic rift system. The World Basin itself forms an asymmetric east-west-trending structure (Figure 13.40). Triassic strata in the Wessex Basin are initially complemented by sandstones (the Sherwood Sandstone Group) overlain by marls and clays of the Mercia Mudstone
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The unusually low T_max values of the richest samples may indicate an organic matter composition that is thermally more sensitive to overlying heat, and likely reflects depletion due to thermal maturation.

c. Chromatography of 3-volumes and dispersed distribution in Zechstein Main Dolomite carbonate source rocks.
   
   Figure 13.26: Geochemical data from Zechstein samples of the Fano-Galateo Monocline petroleum province.

   a. Synchronous yield (SC) versus TOC. Most immature source rocks contain type II kerogen. Another group of samples, most of which are mature, contain type I kerogen. Note that the presence of type I kerogen is probably unrelated to input of higher plant remains, but likely reflects depletion due to thermal maturation.

   b. T_max versus Hydrogen Index (HI).

   The unusually low T_max values of the richest samples may indicate an organic matter composition that is thermally more sensitive to overlying heat, and likely reflects depletion due to thermal maturation.

   c. T_max versus Production Index (PI). Unusually elevated PI values likely related to the presence of migrated hydrocarbons.

   d. Chromatography of 3-volumes and dispersed distribution in Zechstein Main Dolomite carbonate source rocks.


   Group, although their distribution is largely restricted to the west of the Weald Basin. Early Jurassic transgression resulted in a thick deltaic sequence of variably thick clays and carbonates controlled by continued extensional faulting. Tectonic activity continued into the Early Cretaceous with deposition of the nonmarine Wealden Series of shales, marls and sands. Mid-Cretaceous (Late Cimmerian Deformation) times, extension had ceased and thermal subsidence resulted in deposition of an initially clastic sequence (the Greensand) overlain by a thick Upper Cretaceous Chalk Group sequence. Sedimentation finally ended during the Miocene when inversion of the original extensional fault was associated with Alpine movements to the south. During this time, the whole Wealden area was uplifted to form the present-day Wealden Antiflexure" (Figure 13.41).
There are three major source rocks in the Weald Basin; Liassic shales, the Oxford Clay and the Kimmeridge Clay. The upper Liassic rocks (including the Trenton-Pennsylvanian Shale equivalent) may contain low levels of generally poor-quality organic matter, but they are widely considered to be volumetrically insignificant. Liassic source rocks are restricted to the Bettsandian to Sinemurian section. These rocks have a distinct small-scale rhythmicity of organic-rich shales and intervening organic-poor limestone attributed to periodic influence of clastic sediment associated with the development of slightly fresher water capping that restricted water overturn. Organic-carbon contents are typically in the order of a few percent, although limited data show organic-rich shales and intervening organic-poor limestones attributed to small-scale rhythmicity of organic-rich shales and intervening organic-poor limestones attributed to slow-moving currents flowing southwards in the North Sea. The Kimmeridge Clay is immature wherever it is encountered although basin-modelling studies suggest that the basal sections may be marginally mature in the basin axial region. There are numerous clastic and carbonate reservoirs in the Weald Basin, almost exclusively within the Jurassic succession, although there is an accumulation in Bartonian beds at Humly Grange. The most important reservoir is the Bathonian Great Oolite, sealed by the Oxford Clay (Storrington 1 well, Humly Granger, Horsenden, Goodworth, Singleton, Stockridge, Loxley and Eastern Capes). There are minor accumulations in other units such as Upper Jurassic Cretaceous limestones sealed by Kimmeridge Clay (Palmer’s Wood; see Section 3.6.1 in Chapter 10), or Upper Jurassic Portland beds sealed by the Patheak anticline (Gosford Bridge). The Thrift Sheet Sandsfolds Group is a potential reservoir in the west of the basin, sealed by the Meata Madstone Group, which has proven success in the gas-sourced Wytch Farm field.

The Oxfordian-age Oxford Clay Formation consists of a sequence of commonly sulphur-rich marine black shales with TOC contents up to 12%. Organic matter is mainly type II with low levels of type III (Figure 13.42). The Oxford Clay appears to have been deposited in a large restricted basin that filled up over time, as evidenced by a general decrease in TOC contents and indications of bottom-water oxygen depletion upwards in the sequence. Vitrinite reflectance values of up to 0.74% have been reported. There are several source rocks, including the Lias-Jurassic and the Kimmeridge Clay. The Lias source rocks are restricted to the Hettangian to Sinemurian section. These rocks have a distinct small-scale rhythmicity of organic-rich shales and intervening organic-poor limestones attributed to periodic influence of clastic sediment associated with the development of slightly fresher water capping that restricted water overturn. Organic-carbon contents are typically in the order of a few percent, although limited data show organic-rich shales and intervening organic-poor limestones attributed to small-scale rhythmicity of organic-rich shales and intervening organic-poor limestones attributed to slow-moving currents flowing southwards in the North Sea. The Kimmeridge Clay is immature wherever it is encountered although basin-modelling studies suggest that the basal sections may be marginally mature in the basin axial region. There are numerous clastic and carbonate reservoirs in the Weald Basin, almost exclusively within the Jurassic succession, although there is an accumulation in Bartonian beds at Humly Grange. The most important reservoir is the Bathonian Great Oolite, sealed by the Oxford Clay (Storrington 1 well, Humly Granger, Horsenden, Goodworth, Singleton, Stockridge, Loxley and Eastern Capes). There are minor accumulations in other units such as Upper Jurassic Cretaceous limestones sealed by Kimmeridge Clay (Palmer’s Wood; see Section 3.6.1 in Chapter 10), or Upper Jurassic Portland beds sealed by the Patheak anticline (Gosford Bridge). The Thrift Sheet Sandsfolds Group is a potential reservoir in the west of the basin, sealed by the Meata Madstone Group, which has proven success in the gas-sourced Wytch Farm field.
probable limit of mature Liasic source rocks. Reversed extensional faults provided additional tectonic controls on migration. Where inversion was extensive, these faults allowed petroleum flow into numerous vertically aligned reservoir intervals via reservoir-seal juxtaposition.

The most important traps in the area are structural closures associated with Cenozoic inversion. These are often found in tilted fault blocks on the original normal of extensional faults or in isolated horsts. Potential also exists in original yellow breccia anticline structures, although tilted during inversion, these have not as yet proved successful. No stratigraphic pinch-out traps have been identified so far. Significantly, inversion on these structures also had a dramatic effect on fault-seal breaching during the Cenozoic.


2.5.2 Dutch Central Graben

The thickness of Upper Triassic to Lower Jurassic deposits varies considerably across the Dutch Central Graben. The average TOC content is about 8%, but can be as high as 20% with the higher values found mainly in the southern part of the basin. Erosion took place in the easternmost part of the basin point to an eastward shoaling. Within this section, which is up to 800 m thick, organic-rich sediments accumulated in a very restricted depositional environment and form a member of the Toarcian Posidonia Shale Formation. Geochemical data indicate an anoxic, brackish-water environment. Pyrolysis data have been interpreted as involving reduced salinities in the surface-water layer. This intercalated in the main source rock for hydrocarbons within the Lower Saxony Basin east of the River Elbe.

2.5.4 Lower Saxony Basin and Dogger Trough

A sequence of fine-grained marine sediments was deposited during the Early Jurassic within the intracratonic Lower Saxony Basin and the Dogger Trough (Figures 13.54 & 13.55). The gradual transition from the mainly grey clays and marlstones west of the Elbe River to more frequent sandstone beds and sediments into a more continental part of the basin points to an outward shoaling. Within this section, which is up to 800 m thick, organic-rich sediments accumulated in a very restricted depositional environment and form a member of the Tournaisian Posidonia Shale Formation. Geochemical data indicate an anoxic, brackish-water environment. Pyrolysis data have been interpreted as involving reduced salinities in the surface-water layer. This intercalated in the main source rock for hydrocarbons within the Lower Saxony Basin east of the River Elbe.

The Dogger Troughs include the West and East Holstein troughs on the eastern and western flanks of the Glückstadt Graben, and the Jutland Trough in the North German Basin. The Glückstadt Graben formed during Late Permian Early Tertiary rifting and rapidly filled with several kilometres of Upper Tertiary calcilutite. After the Late Tertiary, rising Zeolitic salt formed north-east-west-trending diapiric plug and wall structures. Marginal basins (sin-rifts) subsided around the periphery of the diapirs. The sin-rifts include the Holstein Trough, which subsided in Early to Mid-Quaternary times. The Posidonia Shale deposited within the Holstein Trough was buried by a relatively thin Upper Jurassic to Lower Cretaceous cover with a number of erosional unconformities. Further subsidence resulted within the intracratonic rifts.

The source rock has an average thickness of 25 m, but may reach up to 50 m thick in the Glückstadt Trough. The average organic-carbon content is 8%, but can be as high as 20% with the higher values found mainly to the west of the West. The organic matter consists mainly of alginite and bituminite with increasing, algalic, haemipelagic and pelagic values as the basin width increases. The average organic-carbon content is 8%, but can be as high as 20% with the higher values found mainly to the west of the West. The organic matter consists mainly of alginite and bituminite, and increasing, algalic, haemipelagic and pelagic values as the basin width increases.
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e. Vitrinite reflectance and Rock-Eval T max parameters of Silesian to Cenozoic samples plotted against sub-bottom depth.

which show a predominance of the C27 steranes (Figure 13.57).

Posidonia Shale, mostly classify the organic matter as type II kerogen with a transition to a mixed type III/II kerogen in the easternmost part of the basin. This interpretation is corroborated by biomarker data, which show a predominance of the C32 sterane (Figure 13.56c) and carbon-isotopic data. The genetic potential of this source rock can be as high as 120 kg HE/t rock, but averages about 50 kg HE/t rock.

The reservoir rocks for the hydrocarbons sourced from the Posidonia Shale within the Lower Saxony Basin are mostly siliciclastic, to a lesser extent calcareous sandstones, ranging in age from Rhaetian to Cretaceous. The age of the productive reservoir rocks generally decreases from east to the west. The majority of oil reservoirs in the eastern basin are in Aalenian sandstones, whereas between the Weser and Elbe rivers, most of the production is from reservoirs in Bajocian, Bathonian and Callovian sandstones or Oxfordian and Kimmeridgian limestones. In the western basin, the Valanginian sandstones are the most important hydrocarbon reservoir rocks.

The seals for most oil accumulations are formed by Lower to Middle Jurassic and Cretaceous clays, and locally by Tithonian evaporites. In addition to their importance as seals, the thick Cretaceous clays capable of as overburden before the Late Cretaceous inversion.

A variety of traps are found throughout the Lower Saxony Basin. Structural traps are the most widespread and include traps related to salt diapirs (e.g. Figure 13.55). These structures or anticlines. Both faults and syn-rift-related stratigraphic traps are common in the easternmost Lower Saxony Basin. Unconformity traps predominate in areas where transgressive Targheense to Albian sedimentary rocks truncate the Jurassic reservoir rocks.

Thermal maturation of the Posidonia Shale source-rock interval occurred mainly during pre-Turonian times before the Santonian, although almost all of the oil has been lost from the pre-inversion reservoir rocks due to structural rearrangement or erosion. This event represents the critical moment in the evolution of the Posidonia Shale petroleum system in the Lower Saxony Basin.

At the beginning of the inversion in contrast to pronounced pre-Santonian subsidence, especially west of the Elbe. In most areas of the basin, the Posidonia Shale had already reached the oil window during the Early Cretaceous and attained the gas window, at least in the southern and western areas of the basin, during the Cenozoic. Differing subsidence/spill history locally resulted in the preservation of immature Posidonia Shale, for example, in the southern Hå Spectrume where the maturity sequence is within a short distance. Maturity in the Orogenic Triangle is usually lower than in Posidonia Shale-sourced accumulations of the Lower Saxony Basin, with most fields showing less than 0.7% R.

Asphalt relics and the results of basin-modeling studies indicate a first phase of oil generation and migration before the Santonian, although almost all of the oil has been lost from the pre-inversion reservoir rocks due to structural rearrangement or erosion. This event may be continuing today (Figure 13.57). For most fields, the geochemical-maturity data of the oils equal the maturity of the underlying Posidonia Shale in the directly surrounding areas, implying a very short and mainly
The depth and moderate reservoir temperatures (<100°C) preclude thermal cracking as a mechanism. Oil maturity. Lower maturity oils occur at greater depths, which excludes gravitational segregation as the dominant control of oil (and source-rock) maturity on oil quality. Oil quality improves with increasing the analyses of oils from different Mittelplate reservoirs corroborated their derivation from a compositionally has frequently affected the quality of the organic matter. The petroleum in several reservoirs, especially in deeper parts of the Heide Trough; lateral migration was up to 5 km. Numerical modelling of the thermal subsidence increased around some of the diapirs leading to a maturity of up to 0.8% Rr in the structurally due to missing traps. Petroleum generation in the Holstein Troughs reached its peak at 55–35 Ma when 5%, indicating that most of the hydrocarbons have been lost during Late Cretaceous inversion or later.

thermogenic gas or to oils already in place. East of the Weser, the generation-accumulation efficiency compositions of the gases invoking their thermal generation. This may point to either admixture of vertical migration path of less than 5 km. Several oilfields exhibit high gas-oil ratios with stable isotopic Figure 13.49 Seismic cross-section through the Dutch Central Graben. Petroleum generated from the Posidonia Shale Formation migrates upward to reservoirs associated with salt tectonics. See Figure 13.44 for location.

Figure 13.50 The West Netherlands and Broad Fourteens basins petroleum province with locations of fields and accumulations charged by the Posidonia Shale Formation. The compositions and carbon-isotopic signatures of associated gases reveal different types. The associated gases, most of which are microbiologically generated methane in the Jurassic coals formed in a humid, warm-temperate to subtropical, weakly seasonal climate. The Bryne Jurassic discoveries in the Danish Central Graben have all been drilled where significant structural components have been recognised. This highlights the less-mature exploration status of the plays compared with other parts of the North Sea, where the focus has been long on Jurassic stratigraphic traps. In the Feda Graben, the basal Farsund Formation also has good seal-retention properties, as indicated by the Gt-2.5 well north of 19°E. Similarly good source potential is reported in the Outer Rough Basin, although the Farsund Formation probably thins westwards.

The source-rock potential of the Farsund Formation is very variable. The prolific, more terrigenous influenced, oil-prone source-rock intervals are found in the lower part of the Upper Jurassic (Lola Formation) and may contribute additional source for liquid petroleum. In many areas, the upper Farsund Formation has not reached the level of maturity required to generate enough hydrocarbons to explain the in-place reserves. Lower Jurassic deposits are known to occur in the Central Graben (Dutch and German sectors), but not developed as source rocks. In contrast, the Middle Jurassic Bryne Formation contains coal and organic-rich lacustrine shales with good to excellent type III kerogen source rocks (Figure 13.64). The Lower to Middle Jurassic mires formed in a humid, warm-temperate to subtropical, weakly seasonal climate. The Bryne Formation is best known from the Søgå Basin north of 54°N. The Middle Jurassic coals in the Søgå Basin are mostly found at depths between about 3400 to 3800 m (TR II from 0.75-80% Rr) although they may be located around 3000 m towards the Tail End Graben. Nine coal mires have been identified in the basin; the thickest seam is about 2 m thick. The coals are vitrinite-rich and characterised by high inertinite contents, which may be the dominant component. Similar intervals may be present in the Tail End Graben, but data coverage is poor and therefore it is difficult to give average values. The timing of oil generation from the Farsund Formation depends on the location within the Danish Central Graben (Figure 13.62).

Figure 13.51 Schematic section through the West Netherlands Basin (after De Jonge et al., 1994).
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Figure 13.52: Geochemical data from the Posidonia Shale Formation in the Broad Fourteens and West Netherlands basin:

- a. Pyrolysis yield (S2) versus TIC. A. T_max versus hydrogen index (HI). C. T_max versus Production Index (PI).
- b. S1/S2 versus TIC. Early marine Posidonia samples with the highest TIC plot in the right indicating marine deposits in a reduced environment suggesting restricted-water circulation. Shown shows pyrolysis/100×.
- c. S1/S2 versus HI. Posidonia shale source rocks with the highest HI plot in the left indicating marine deposits in a reduced environment suggesting restricted-water circulation.
- d. S1/S2 versus HI. Posidonia shale source rocks with the highest HI plot in the left indicating marine deposits in a reduced environment suggesting restricted-water circulation.
- e. S1/S2 versus HI. Posidonia shale source rocks with the highest HI plot in the left indicating marine deposits in a reduced environment suggesting restricted-water circulation.
- f. S1/S2 versus HI. Posidonia shale source rocks with the highest HI plot in the left indicating marine deposits in a reduced environment suggesting restricted-water circulation.

Figure 13.53: Event charts of a. the Broad Fourteens Basin; and b. the West Netherlands Basin.

Figure 13.54: The Lower Eocene source area and deeper Troughs petroleum province with locations of fields and accumulations charged by the Posidonia Shale Formation.
variations in overburden and the possible local influence of deep magmatic intrusions led to sharp central and southernmost part of the basin, it entered the gas window in the Cenozoic. The strong times, especially west of the Ems, is less pronounced for the Wealden shale than for the Posidonia Shale.

Thermal maturation of the Wealden shale source-rock interval started during pre-Turonian subsidence, part of the Lower Saxony Basin. Large anticlines, which may be combined with adjacent overthrusts, sequences acted as overburden before Coniacian inversion. Structural traps predominate in the western Hauterivian and Aptian reservoir rocks, also yield minor production mainly to the west of the Ems River.

Hauterivian and Aptian reservoir rocks, also yield minor production mainly to the west of the Ems River. The thickness of the paper-shale source rock is not well defined, mainly because detailed knowledge of the variability of the hydrocarbon potential within the Wealden is very limited. Average thickness is commonly assumed to be 25 m, but the total of the lacustrine Wealden 1 to 6 sequence may account for up to 1100 m of sediments in the northern subsiding grabens at the southern basin margins (Figure 13.64: Chapter 11). The organic-carbon content is up to 1% with an average of about 5% west of the Weser. The organic matter in the Wealden paper shale in the lake area consists mainly of alginites (Figure 13.65) with some bituminite. Adumbrations of transition zone organic particles are more pronounced toward the west and the north, building up local real seams in the delta areas. Rock-Oil data (Figure 13.65) point to the excellent hydrocarbon potential of a mixed type I/II kerogen with HI values up to 950 (average of 600) in the lake area that developed between the Weser and Ems areas. Eastwards, low HI and increased Oxygen Index (OI) values indicate a type III/III’ mixtype. The biomarker data support the latter conclusion by the higher percentages of C19 steranes (Figure 13.65) in source-rock samples from the area. The potential of this source-rock interval may be as high as 125 kg HC/100 m3 rock, but it is highly variable as mentioned above. The Wealden paper shale between the Weser and Ems has gained petroleum potential values of up to 45 kg HC/100 m3 rock. The most important reservoir rock for the hydrocarbons sourced from the Wealden paper shale within the Lower Saxony Basin are Tithonian sandstones. Intratidal mudstones and peats, and Haarlemmer and Apriote reservoir rocks, also yield minor production mainly to the west of the Ems River. Soils for most of the oil accumulations sourced or re-sourced from Wealden paper shale are formed by Haarlemmer to Allum soils. In addition to these importance seals, the rich Cretaceous claystone sequences acted as overthrusts before Cenozoic inversion. Structural traps predominate in the western part of the Lower Saxony Basin. Large anticlines, which may be combined with adjacent overthrusts, are typical of the trap style in the area west of the Ems.

Thermal maturation of the Wealden shale source-rock interval started during pre-Turonian subsidence, but continued after the Santonian during the Coniacian. The importance of extensional heating by magnetic intrusions at the beginning of the inversion, in contrast to pronounced subsidence during pre-Santonian times, especially west of the Ems, is less pronounced for the Wealden shale than for the Posidonia Shale. In most areas of the basin, the Wealden paper shale reached the oil window in the Late Cretaceous; in the central and southwestern part of the basin, it entered the gas window in the Cenozoic. The strong variations in overburden and the possible local influence of deep magnetic intrusions led to sharp maturity gradients between different tectonic blocks in the Lower Saxony Basin. The indications for a first phase of oil generation and expulsion from the Wealden paper shale prior to Santonian inversion are concentrated in the area west of the Ems. However, as mentioned above for the Posidonia Shale-sourced oils, no economic oil accumulations occurred in the subsequent structural changes and Cretaceous erosion. The second phase of oil generation and migration started in the Early Cenozoic and may be continuing today (Figure 13.65). In fields west of the Ems, peochronal maturity data from the oils are comparable to the maturity of the Wealden paper shale in the vicinity, implying short migration distances. Several fields near the Ems exhibit increased gas oil ratios, with stable isotopic compositions of the gases indicating their thermal generation, probably from deep-seated Cretaceous reservoirs. This may point to either admixture of thermogenic gas or to oils already in place. In the areas west of the Weser, the generation-accumulation efficiency is about 10% for the Wealden paper shale, indicating that most of the hydrocarbons generated have been lost either during the inversion interval, or more probably later due to missing traps. Hydrocarbons in the reservoirs of several fields were generated from both the Posidonia Shale (Figure 13.65) and the Wealden/Coevorden Formation, especially those west of the Ems. Both source rocks can be identified by biomarker and isotope data.
Figure 13.57 Event chart of the Faunoza Shale petroleum system in the Lower Saxony Basin (after Kechel et al., 1994).

The Schoonebeek sill of the Netherlands and its extension into Germany (where it is still producing) is the most persistent sill in the SFB area that was charged from Lower Cretaceous deposits (Section 4.1 in Chapter 11). It is the largest onshore sill in Western Europe, with an initial in-place volume of about 1 Bcubic meters of which 2% had been produced before it was closed in 1994. The source rocks of the oil are lacustrine shales with zhip, type I source rocks of the Covenden Formation. Geochemical data indicate that the oil is an early expulsion product of a source rock with low maturity, consistent with the high maturity of the oil (25°API). There are no signs of biodegradation. However, a contribution from the Pliocene Shale source rock that occurs west of the field can not be excluded. The oil from the Schoonebeek field is produced from the Lower Cretaceous Berriasian at a depth of about 800 m.


3 Shallow gas and bright spots in the southern North Sea

The SFB, like many other petroleum provinces, contains several known accumulations and abundant indications of shallow gas (Figure 13.67). Shallow gas is commonly defined as gas occurring in sediments down to depths of 1000 m below surface, although the petroleum industry tends to be pragmatic, regarding it as gas above the first casing point. In addition to carbon dioxide, hydrogen sulphide, and nitrogen, there is a group of lighter hydrocarbons. The most common gaseous hydrocarbons is methane, although ethane, propane, butane and pentane (and the respective alkenes) also occur.

Hydrocarbons in sediments can originate from microbial/biogenic or thermogenic processes. Biogenic gas is by microbial breakdown of organic matter at shallow depth. It is almost completely composed of methane. The microbes that generate methane from organic matter are archaea which comprise the majority of the microbial communities.

Microbial gas found at greater depths may have generated in situ at this depth or it may have been buried during times of higher subsidence rates from originally shallower depths. Thermogenic gas is generated from organic matter by thermokinetic breakdown of carbon bonds of complex kerogen molecules at higher temperatures. Hydrocarbons can accumulate in traps during basin-bounding secondary migrations. Leakage from these traps leads to preferential dissipation of the lighter hydrocarbons into shallower sediments and, in some cases, to the surface. Microbial and thermogenic processes lead to different carbon-isotope signatures that can, in turn, be used to indicate the gas sources. Other sources of gas (dissociated gas hydrates, volcanic/hydrothermal emissions) are thought to be of minor importance.

The presence of gas in the shallow subsurface can be an indicator of deeper hydrocarbon fields. Further exploration is the prospect of future exploitation of large shallow-gas accumulations that might become economically viable. For example, local gas power-plants could supplement offshore windfarms during periods of low wind, which requires the amount of gas in place and its quality or composition to be studied, starting with shallow-gas indicators.

3-D seismic datasets are the best tools to evaluate the position and extent of shallow-gas indicators. In combination with other seismic-analysis methods such as amplitude variation with offset (AVO), and in comparison with data from wells, the gas assumed to be associated with seismic indicators can be corroborated and quantified. Gas in the pore spaces of rocks, even at concentrations as low as 0.5%, can change both its elastic properties and densities, which in turn may lead to considerable changes in the propagation and reflection of seismic waves. This may lead to peculiar features in P-wave reflection seismic data, such as bright spots, chimneys, and acoustic blanking.
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Figure 13.61: Geochemical data of samples from different Jurassic formations of the Southern Permian Basin:

a. Pyrolytic yield (2%) versus T2C. In addition to many mature and non-mature rock samples and a few immature coal samples with type 2 kerogen there are a number of samples with hydrogen-rich kerogen.

b. Tox versus Hydrogen Index (HI). Samples are mostly marginally mature to mature and comprise mainly type 1 kerogen samples.

c. T2C versus Production Index (P2). Maturity-induced depletion has led to well-drained source rock conditions.

d. Pi2C versus Pi2C/L.

a. Sterane ternary diagram:

- Fi: Marine
- Ci: Inland marine
- Ni: Non-marine
- O: Oil
- G: Gas
- NG: Dry gas
- BG: Wet gas
- I: Inert
- In: Inert interlayer
- E: Evaporite
- C: Clay
- G: Green
- Y: Yellow
- R: Red
- B: Black

b. Hydrocarbon migration path:

- Source rock
- Transition zone
- Trap formation
- Reservoir and migration pathways

f. Figure 13.62: a. burial history: dol. b. Vitrinite reflectance history for well in the South East Graben. c. Sterane ternary diagram for the Lower Jurassic Farsley Formation and the Middle Jurassic Ryne Formation in the South East Graben.

g. Figure 13.63: The Lower Jurassic Basin petroleum provinces with locations of fields and accumulations colored by Wettability source rocks.
The western part of the Ems River. See Figure 13.63 for locations.

Figure 13.64: Cross-section through the Lower Saxony Basin (after Buckland et al., 1998); a. Stratigraphy and thickness of the Basin’s rocks; b. Sedimentary basins in the area west of the Ems River. See Figure 13.63 for locations.

Figure 13.65: Sequence data from Wealden basins. a. Total organic carbon (TOC) vs. vitrinite reflectance (vitrinite reflectance). b. Vitrinite reflectance vs. TOC. c. Type I kerogen from the Wealden basin. d. Pyrolysis behavior characteristics of a Wealden shale sample from the center of the basin. The shaded pyrogram is from the sample and the non-shaded pyrogram is from a control sample. e. Raman spectroscopy analysis of a Wealden shale sample. f. Rock-eval T max parameters; g. Reflected light micrograph (thin section) of a particulate organic matter from a Wealden shale sample. Note the bright background fluorescence due to dispersed organic material in addition to the small yellow algal particles. Plots produced using IGI’s p:IGI-3.
Bright spots are common and among the best known direct hydrocarbon indicators in seismic data. They appear as strong-amplitude anomalies in seismic sections of different sedimentary and tectonic settings. They may indicate the presence of microbial as well as thermogenic gas and have been used in petroleum exploration since the 1970s.

Bright spots are induced by strong variation in seismic impedance in the rocks (i.e. seismic velocity and/or density changes). A single sudden increase of impedance with depth generates a seismic signal of unambiguously positive polarity ("hard kick"). A steep decrease in velocity and/or density results in negative polarity of the pertinent seismic reflection ("soft kick"). The reasons for increasing velocity include sediment cementation or pressure intrusion. Coal beds, peat, gas-charged or over-pressured sediments lead to decreasing velocity (Figure 13.65). The tuning effect of thinly bedded interfaces can also cause bright spots without a particular correlation between sediment properties and polarity of seismic response. Bright spots occur in a variety of petroleum trap systems, for example in anticlines and pinch-out traps.

3.1 Bright spots in anticlines

Salt tectonics have produced numerous anticlines in the shallow subsurface of the southern North Sea and northern Europe. These anticlines can serve as structural traps for hydrocarbons. The correlation of salt domes and bright spots can be established in the central and southern part of the north-western German sector (the so-called "Entenschnabel") and in the adjacent Danish and Dutch sectors in the Central and Dog provinces. In most cases, the bright spots align themselves in a circular pattern above the crest of salt diapirs where a complex system of crestal faults has developed. Along these faults, and often unilaterally aligned with them, numerous bright spots are observed that can be explained by either migration of gas along the faults into layers with higher permeability or by in situ generation of microbial methane trapped against sealing faults (Figures 13.69 & 13.70).

Well data confirmed the increase in methane concentrations in sandy layers above the salt diapirs. The available seismic data elsewhere in the German sector of the southern North Sea show a lack of bright spots associated with salt tectonics.

Gas is produced from shallow gasfields in the Netherlands and Denmark. The sources of these shallow-gas occurrences might be deeper types of source rocks, i.e. the gas in is of thermogenic origin. First arrivals of gas samples from the sea floor in the "Entenschnabel" corroborate the assumption that gas of thermogenic origin migrates from deeper sources towards the sea bed.

3.2 Bright spots in pinch-out traps

Bright spots may occur where porous strata pinch-out due to facies change or where they were erosively truncated and terminate against a seal (Figure 13.71). Pinch-out traps are common in fluvial and deltaic environments as well as in subaerial valleys. Many of the Miocene anticlines and associated pinch-out features are found in places where there are salt domes and where the associated normal faults provide effective migration pathways for thermogenic gas from deeper reservoirs.

Bright spots are induced by strong variation in seismic impedance in the rocks (i.e. seismic velocity and/or density changes). A single sudden increase of impedance with depth generates a seismic signal of unambiguously positive polarity ("hard kick"). A steep decrease in velocity and/or density results in negative polarity of the pertinent seismic reflection ("soft kick"). The reasons for increasing velocity include sediment cementation or pressure intrusion. Coal beds, peat, gas-charged or over-pressured sediments lead to decreasing velocity (Figure 13.26). The tuning effect of thinly bedded interfaces can also cause bright spots without a particular correlation between sediment properties and polarity of seismic response.
The chimney pattern is probably the result of destruction of stratification by overpressure or from the inhomogeneous distribution of gas within the sediments, which lead to variations in seismic velocities and chaotic reflections in the seismic profile. Because p-wave velocities of gas-charged porous sediments are lower than those of the same sediment with a liquid pore fluid, reflections beneath a gas chimney commonly display a push-down effect (Figure 13.68).

Other direct hydrocarbon indicators are common (pockmarks at the sea bed, acoustic blanking and acoustic turbidity near the surface), although they are difficult to identify on standard petroleum industry seismic data. Acoustic blanking, places where there are weak or absent reflections on seismic profiles, may occur where gas-charged sediment overlay the blanked zone and reduces the energy of the seismic wave, or where rising gas has disrupted the sediment structure/bedding. Gas concentrations of 0.5% are sufficient to cause acoustic blanking. Acoustic turbidity is a laterally limited zone of chaotic seismic reflections on seismic data. Reflections within these zones appear weakened and/or chaotic. This may result from the disruption of the sedimentary reflection by over-pressured fluids or from inhomogeneous gas distribution within the sediment. Both acoustic blanking and turbidity can best be observed on high-frequency seismic data.

For further information see Schouten & Schüttenhelm (2003), Schouten et al. (2005), Judd & Hovland (2007) and Kohlmann & Wong (2004).