Cut surface and block of coralline limestone from the 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 sparry calcite cement and a droplet of impsonite. Photographic 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

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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 porous 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 impregnations.

1.1 Definitions

Petroleum generation and migration in an area as 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 allows a summary to be made. The summary is organised by 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 pod, or a group of closely related pods, 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 where 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.

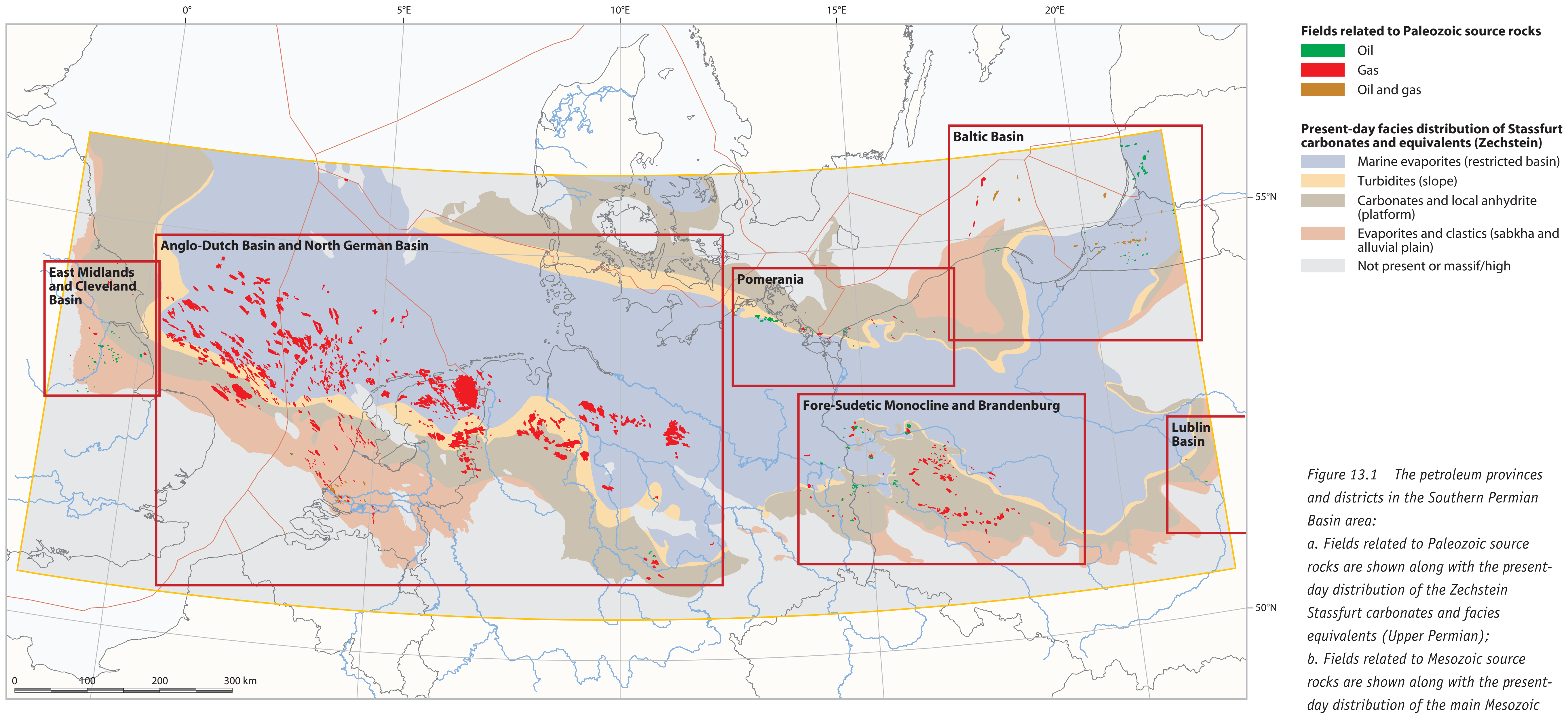
This following account also includes undiscovered accumulations, in much the same way as 'total petroleum systems' have been defined. Because this chapter focuses on petroleum generation and migration, the number of individual petroleum systems with differing reservoir stratigraphies have been summarised and referred to by their source-rock stratigraphy only.

Six major petroleum systems are described and grouped according to the age of the respective petroleum source rocks. The most important petroleum systems of the SPB in terms of petroleum reserves and regional distribution are associated with the Upper Carboniferous (Westphalian) coals for natural gas and the Lower Jurassic Posidonia Shale Formation for oil. Other petroleum systems are less productive and regionally widespread, but still provide a significant economic benefit.

A source rock is a sedimentary rock that contains sufficient and appropriate organic matter to generate petroleum under the conditions mentioned above. A number of petroleum provinces can be delineated within the SPBA, which host one or more petroleum systems (**Figure 13.1**) and are separated from other provinces either by areas that lack this particular productive or prospective petroleum system or, in the case of directly adjacent provinces, by significant differences in their generation and migration history.

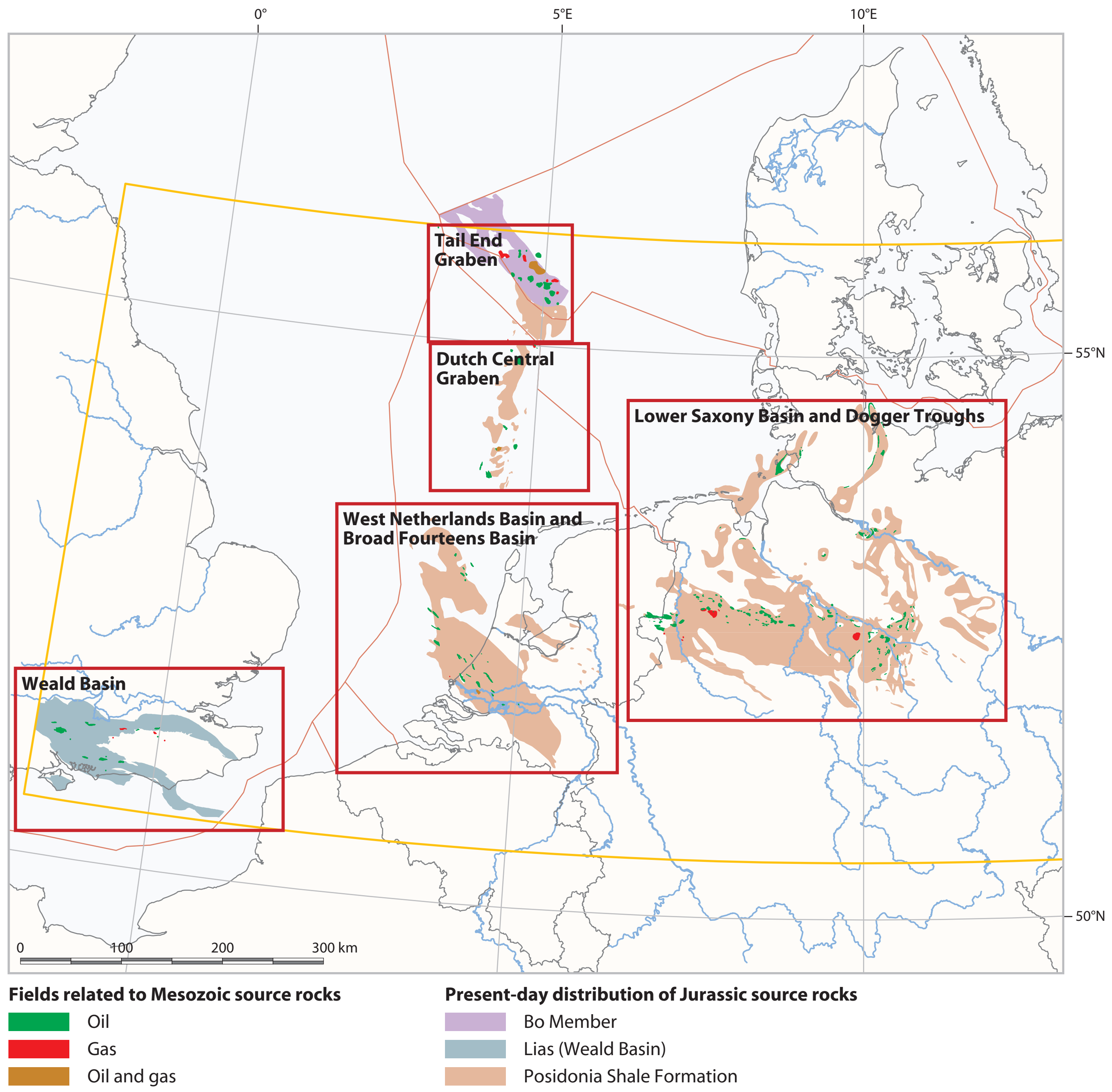
In contrast to the petroleum systems, which are distinguished on the basis of their source-rock ages and histories, shallow-gas occurrences are characterised by the depth of their ultimate reservoir. Shallow gas is commonly defined as gas accumulations in sediments down to depths of 1000 m below surface, 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 completely composed of methane. The microbes that generate methane from organic matter are archaea, a separate, ancient kingdom of organisms.

For further information see Miles (1994), Magoon & Dow (1994), Magoon & Beaumont (2000), Magoon & Schmoker (2000), Gluyas & Swarbrick (2003), Allen & Allen (2005).



a.

Figure 13.1 The petroleum provinces and districts in the Southern Permian Basin area:
a. Fields related to Paleozoic source rocks are shown along with the present-day distribution of the Zechstein Stassfurt carbonates and facies equivalents (Upper Permian);
b. Fields related to Mesozoic source rocks are shown along with the present-day distribution of the main Mesozoic source rocks.



b.

In the background of the frontispiece photograph on the opposite page, a slab of coralline limestone from the Devonian Iberg in the Harz Mountains of Germany shows voids in the corals that are filled with impsonite, a dense and hard bitumen. In the foreground, a piece of carbonate rock from the same formation has cavities that are partly filled with sparry calcite cement and a droplet of impsonite. The impsonite is attributed to petroleum generation from Middle Devonian source rocks and migration into the voids of the Upper Devonian reefal limestone (Jacob et al., 1981).

1.2 Source-rock and petroleum characterisation, data handling and presentation

The various source rocks found in the SPBA each have different characteristics with respect to their organic matter. These different properties influence the timing of hydrocarbon generation, the quality and quantity of generated oil and gas. The optical and chemical characteristics 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. Kerogen is transformed to hydrocarbons as temperatures increase. Whether oil or gas is generated depends mainly on the type of kerogen, and thereby on the origin of the organic matter. Terrestrial organic matter is typically gas-prone (vitrinitic, type III), whereas aquatic (mostly algal) organic matter is primarily oil-prone (liptinitic, types I and II). The Rock-Eval Hydrogen Index (HI) expresses the kerogen's hydrocarbon potential. The HI values decrease with increasing maturity as generation progresses and the kerogen is converted to oil, wet gas and condensates, and dry gas (**Figure 13.2a**). Whereas the different kerogen types can be distinguished from their initial, immature HI values, these characteristics do not apply at advanced levels of maturation (**Figure 13.2b**). Type III kerogen will retain hydrocarbon potential at higher maturities than kerogen types I and II. The main phase of oil generation is therefore at lower temperatures than the main gas-generation phase. Hydrocarbon generation and subsequent expulsion also reduces the total organic carbon (TOC) content of a source rock. These factors influence the interpretation of data from mature source-rock samples.

Organic geochemical and optical analyses provide insight into kerogen characteristics. Samples are analysed from cores, sidewall cores, drill-cuttings and outcrops, as well as oil and gas samples. Elemental analysis and Rock-Eval pyrolysis yield bulk source-rock properties such as TOC content, HI, Production Index (PI) and T_{max}. Organic petrology, the optical study of sedimentary organic matter, not only provides information on the origin of the kerogen but also yields maturity parameters such as vitrinite reflectance (% Ro), Spore Colour Index (SCI) and the Thermal Alteration Index (TAI). High-resolution geochemical analyses, such as gas chromatography-mass spectrometry (GC-MS) and gas chromatography-isotope ratio mass spectrometry (GC-IRMS), investigate the molecular and isotopic signatures of the organic matter. This includes the study of biomarkers (e.g. steranes), or geochemical fossils, which preserve characteristics of the original biochemical precursors. Molecular indicators can be used to assess the effects of thermal maturity, biodegradation and migration.

Maturation is the general process of thermal alteration of organic matter (kerogen) in a sedimentary rock. It is used as a more readily measurable proxy for generation of hydrocarbons from a source rock, applying indicators such as Rock-Eval T_{max}, vitrinite reflectance and spore colour indices. The relationship between the most commonly used maturity parameters, T_{max} and vitrinite reflectance, is shown in **Figure 13.2c** for data from the SPB. It should be noted that both parameters may differ slightly with different kerogen types or lithology, but also with different laboratories.

The data presented in the graphs and diagrams in this chapter were compiled from various sources, representing the different regions in the SPB and the different petroleum systems. The majority of data were supplied by the national institutes TNO-NITG, POGC/PGI, BGR, and GEUS, with additions from CCGS, IGI's World Data, and selected publications (see 'further information' suggestions at the end of the regional sections). The data were arranged by region, following the geographical distribution of source-rock intervals, with the focus on the source rocks relevant for the petroleum systems in each region.

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 with a pyrolytic yield (S2) of 2 kg/tonne or higher. This is a prerequisite for a reliable T_{max} value. As a further criterion, only T_{max} values between 360 and 600°C are included. HI values were deemed unreliable if outside 20 to 1200 mg/g TOC. Vitrinite reflectance measurements were only used when values were within the range 0.2 to 4% Ro, which provides the most reliable measurements. Care was taken to minimise the inclusion of measurements of cavings and reworked vitrinite.

Geochemical data are made available for interpretation through the graphs and diagrams included in this chapter. In addition to being a powerful visualisation tool, combining parameters in cross-plots allows better sample discrimination and identification of trends. The main plot-types used in this chapter to describe the different source rocks are shown in **Figure 13.3**. Trend lines and interpretations are based on published literature.

For a full list of technical terms the reader is referred to the Glossary (**Appendix 1**), which includes the various terms for optical and geochemical analyses and other relevant parameters. For further information see Staplin (1969), Espitalié et al. (1977, 1985), Peters (1986), Tissot & Welte (1984), Smith (1993), Mukhopadhyay & Dow (1994), Tyson (1995), Hunt (1996) and Peters et al. (2005).

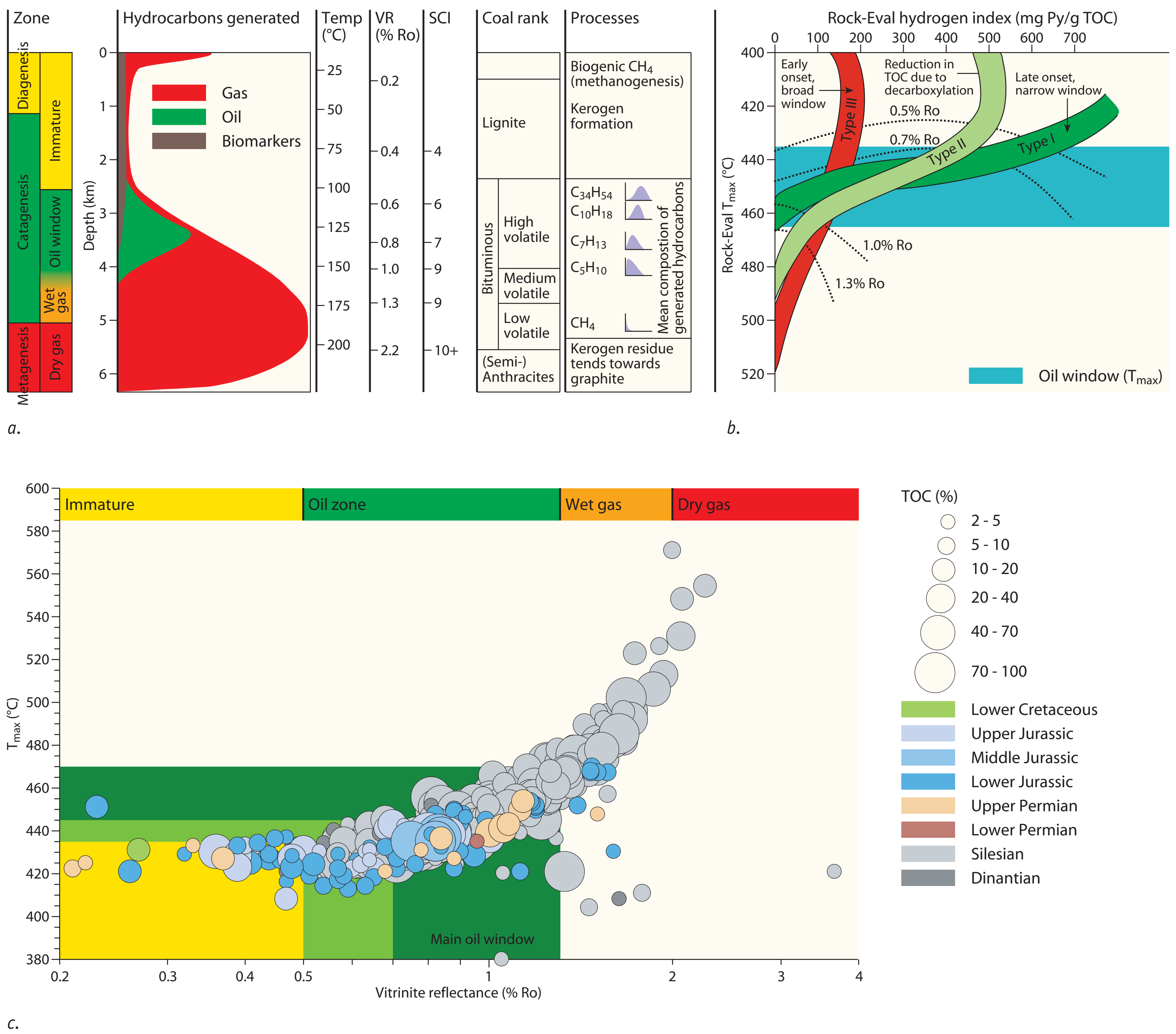


Figure 13.2 Source-rock characterisation, hydrocarbon generation and thermal maturity:
a. Cartoon illustrating hydrocarbon generation from a source rock as a function of maturity and the approximate equivalent burial depth (from IGI's ig.NET and modified after Tissot and Welte, 1984). This diagram is based on the assumption of a constant geothermal gradient with depth and time. At shallow depths, biogenic gas is produced as a product of fermentation, reaching commercial accumulations only where sedimentation rates are high. In oil-prone source rocks, oil generation commences between 80 and 115°C, but hydrocarbons will only be expelled where primary migration is highly efficient. The main phase of oil generation and expulsion is between 115 and 145°C. Oil is expelled from thicker source rock units with efficiencies typically in the range 60 to 80%. Between 145 and 160°C, the late phase of oil generation is associated with cracking of previously generated oil to give progressively lighter oils and condensate. At higher temperatures the oil-prone source rock is post-mature. No generative capacity remains and reservoired oil is cracking down to wet gas or condensate. Gas-prone (vitrinitic) organic matter requires higher maturities to generate hydrocarbons. Major gas generation starts in the late-mature oil stage (145-165°C) and continues to at least 220°C. Included in the figure is a comparative maturity table, showing the approximate level of maturation associated with each generative phase. It should be noted that SCI scales may vary;
b. Plot of Hydrogen Index (HI) versus T_{max}, showing the transformation paths of the different standard kerogen types with maturation (from IGI's ig.NET and modified after Cornford et al., 1998). Upon maturation, the HI drops as the source-rock kerogen is transformed and oil and gas are generated. The index value may initially rise as a result of TOC reduction due to decarboxylation. Different kerogen types follow different transformation pathways with maturity. Whereas the hydrocarbons are generated from type III kerogen over a broad maturity interval, the hydrocarbon generation window for type I kerogens is very narrow. The generative potential of liptinitic kerogens is lost at a lower maturity than that of vitrinitic kerogens, as shown by the crossing transformation pathways. The cartoon includes a tentative correlation of T_{max} with vitrinite reflectance (dashed lines). It should be noted that the T_{max} value is partly kerogen dependent;
c. Plot showing the relationship between the most commonly used maturity parameters, vitrinite reflectance and Rock-Eval T_{max}. The diagram includes all high quality data from the SPBA Project Database (TOC >2%, S2 >2kg/t). Even for this large dataset the scatter around the general correlation trend is limited. This underlines the usefulness of the generally less accurate T_{max} parameter as a maturity indicator. Samples may fall outside the general trend for a variety of reasons. T_{max} values may be influenced by factors like drilling mud contamination, bitumen staining, or the retention of pyrolysate in the kerogen or mineral matrix. Vitrinite reflectance measurements may also be influenced by bitumen staining or may represent allochthonous material (reworked, caved) rather than indigenous vitrinite.

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 3.2 in Chapter 4). These organic-rich sediments are either unknown or they were buried too deeply in the central and western SPBA to be considered prospective; their generative potential was largely exhausted (Chapter 4, Figure 4.3). Post-Caledonian subsidence was lower only in the western Baltic Basin (Peri-Baltic Syneclise, Baltic Depression; **Figure 13.4**), which lay distal to the Variscan foredeep. Moderate overburden thickness and heat flow consequently protected the prolific Lower Paleozoic source rocks in the Baltic Basin from overmaturation, except in the south-western area adjacent to the Teisseyre-Tornquist Zone. Petroleum generation started during the Caledonian Orogeny at about 400 Ma.

Lower Paleozoic proven and potential source rocks in the Baltic Basin include Lower to Middle Cambrian claystones, Upper Cambrian to Lower Ordovician black shales that correlate stratigraphically with the Alum Shale Formation in Scandinavia, the Middle Ordovician Kukersite and the Upper Ordovician to lower Silurian graptolite shales (see Chapter 4, Figure 4.16). These Cambrian, Ordovician, and Silurian source rocks contain relatively homogeneous type I or II kerogen (**Figure 13.5**).

It was only after the evolution of higher land plants in mid-Silurian times that humic organic matter formed a major constituent of source rocks. This should be taken into account when interpreting Rock-Eval data of pre-Devonian source rocks that indicate type III kerogen. Obviously, this kerogen can not be attributed to a terrestrial source, but other reasons for the type III composition of the organic matter could be the existence of marine organic structures with pyrolytic character resembling that of humic compounds or the depletion of hydrogen-rich compounds, the course of maturation, or oxidation of organic matter.

Lower to Middle Cambrian shales are widespread in the north-western, deeper part of the Baltic Basin. They may attain more than 100 metres thickness; however, their TOC contents are usually modest (0.5-1%). Their role as an effective source rock is not proven.

The Upper Cambrian to Lower Ordovician Alum Shale Member is a regional black-shale source rock that is found from southern Norway to Estonia. It is thickest (up to 150 metres) in an elongated, north-west–south-east-trending trough (Chapter 4, Figure 4.18). Southwards, the Alum Shale isopachs are truncated by the Caledonian Deformation Front extending from southern Denmark across Rügen Island to the Łeba High, where the Alum Shale is up to 20 m thick. The sequence pinches out eastwards, where there are partly correlative, Upper Cambrian shelf sandstones (**Figure 13.4**). The Alum Shale is an excellent source rock, with increased organic-carbon contents and pyrolytic yields. The sequence has retained major generative potential in spite of its increased maturity at its southern limit. The Alum black shales have been eroded in the central Baltic Basin to the north-east of Kaliningrad and Gotland. The Lower Ordovician *Dictyonema* and *Ceratopyge* Shales may contribute to the overall source potential of the Baltic Basin, but their input to existing discoveries is not proven.

Middle Ordovician (Caradocian) deep-water black shales are excellent source rocks in Lithuania and onshore Kaliningrad where they are up to 40 m thick and their TOC contents can exceed 6%. The black shales are thermally mature in the south-western Baltic Basin. Lower Silurian black shales and other organic-rich facies within the thick Silurian section provide some of the prolific source rocks throughout the basin. A 5 to 25 m-thick sequence of lower Silurian (Llandovery) deep-water black shales is rich in oil-prone organic matter.

Maturity generally increases towards the south-west due to maximum subsidence near the Tesseiyre-Tornquist 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 Cambrian sandstones. Their depth increases dramatically from surface outcrops in western Lithuania to more than 3000 m in western Poland (Chapter 4, Figure 4.11) following the regional dip towards the south-west. Reservoir poro-perm (porosity Ø 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 reefal limestone in western Lithuania. Ordovician and Silurian shales form the regional top seal. Upper Cambrian clays provide additional seals in the south-west Baltic Basin.

Traps are mostly structural in the sandstone play with tilted blocks and horsts generating 4-way dip closures. Mid-Devonian tectonics appear to have created both the structural traps and their fracture porosity. The overlying organic-rich shales provide the seals. Cambrian traps were repeatedly charged from Cambrian, Ordovician and Silurian sources. The carbonate plays often have a combination of structural and stratigraphic closure, 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 (Wenlock), whereas generation in the central part began during the Mid- to Late Devonian and lasted until the Early Carboniferous (**Figure 13.6**). Generation resumed in Permian to Mesozoic times when Cambrian and Silurian source rocks were buried to depths that allowed expulsion of dominantly liquid hydrocarbons in the east and gaseous 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 Paleozoic 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-Devonian and stopped by Mid-Carboniferous times. Carboniferous uplift and erosion in the eastern Baltic Basin appear to have strongly influenced the migration pathways and migration efficiency.

Crude oils within the Cambrian reservoirs have moderate gravities (26-42°API) that decrease with reservoir depth, low sulphur (<0.25%) and low asphaltene (<3%) contents. The highest gravity crude oils have 42 to 78% saturated components with predominantly light *n*-alkanes. C_{13}-C_{19} *n*-alkanes, maxima at C_{15} and lower amounts of *n*-alkanes with a carbon number greater than 19. CPI values are close to unity. Pristane/phytane ratios range from 2.07 to 2.65 and increase towards the south-west.

For further information see Neumann & Weil (1984), Buchardt & Lewan (1990), Brangulis et al.(1992), Gérard et al. (1993), Kanev et al. (1994), Bandlova et al. (1995), Kattai et al. (1997), Zdanaviciute & Bojesen-Koefoed (1997), Buchardt et al. (1999), Domżalski et al. (2004), Otmans (2004), Zdanaviciute & Lazauskiene (2004, 2007).

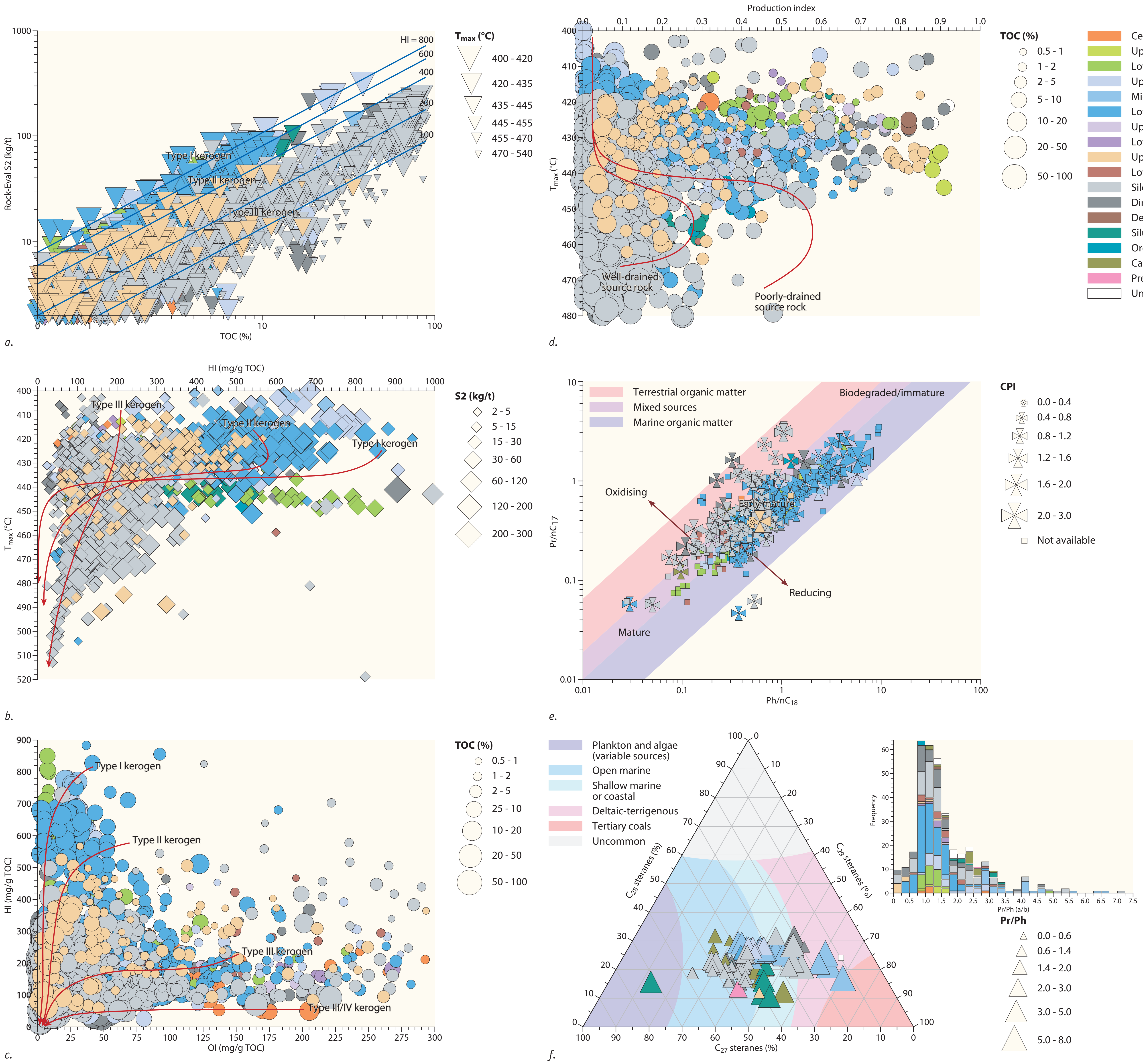
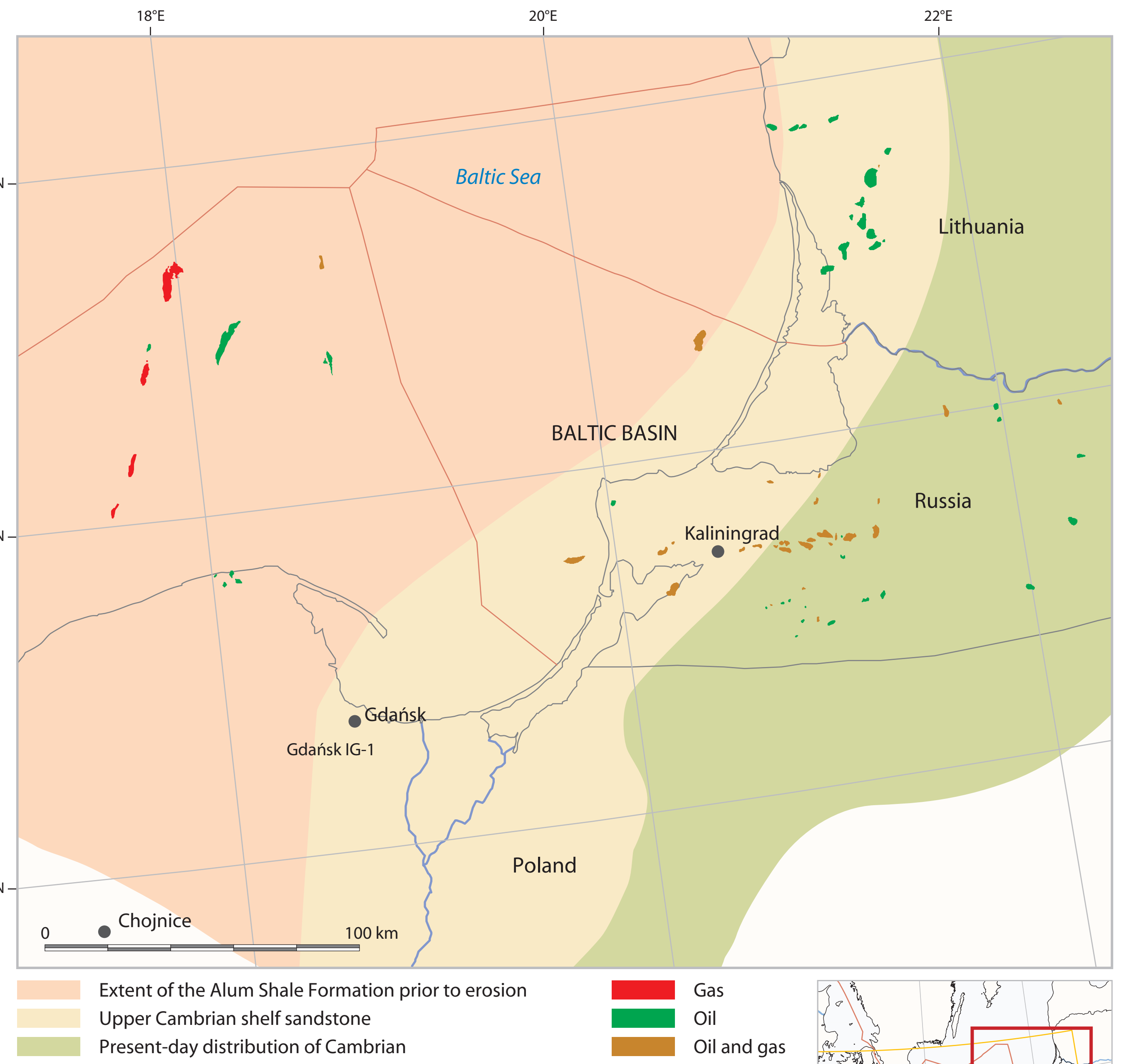


Figure 13.3 Geochemical data of Precambrian to Cenozoic samples of the SPB area:
a. Pyrolytic yield (S2) versus Total Organic Carbon (TOC) plot, modified after Langford and Blanc-Valleron (1990). The lines in the diagram indicate the Hydrogen Index (HI), which is calculated from the two parameters in the plot. Higher HI values correspond to higher quality (more oil-prone) kerogen;
b. T_{max} versus HI plot (modified after Espitalié et al., 1984). The trend 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 kerogen transforms and hydrocarbons are generated;
c. Pseudo- Van Krevelen plot (modified after Espitalié et al., 1977 and Peters, 1986). The genetic curves for the standard kerogen types are shown. Each kerogen type follows a different pathway during maturation as it becomes more depleted in hydrogen and oxygen relative to carbon. The combination of the HI and Oxygen Index (OI) in this diagram provides an estimate of kerogen type and maturation of a sample;
d. T_{max} versus Production Index (PI) plot (modified after Banerjee et al., 1998a). The trend lines show the increase in volatile organic compounds (S1) 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 (decrease in PI). The diagram also reveals hydrocarbon staining in immature samples (high PI at low T_{max});
e. Pr/nC_{17} versus Ph/nC_{18} plot (modified after Lijmbach, 1975). The proportion of pristane and phytane to their neighbouring n-alkanes on the chromatogram provides an indication of the source-rock depositional environment, in particular with respect to oxygenation and organic-matter type. However, interpretations are complicated as the ratios decrease with increased maturity, but increase through biodegradation;
f. Sterane ternary diagram (modified after Huang and Meinschein, 1979). The source environment interpretation applied to the C_{27}, C_{28} and C_{29} steranes is based on the distributions of the precursor C_{27}, C_{28} and C_{29} sterol-homologues in modern environments. The diagram works on the principle that C_{29} sterols are more typically associated with land plants, whereas algae are the primary producers of C_{27} and C_{28} sterols (Zumberge, 1987b). However, there is much overlap between the different source environments (Moldowan et al., 1985). The main use of the diagram is therefore to characterise different source rocks by their sterane distribution signature. Plots produced using IGI's p:IGI-3.



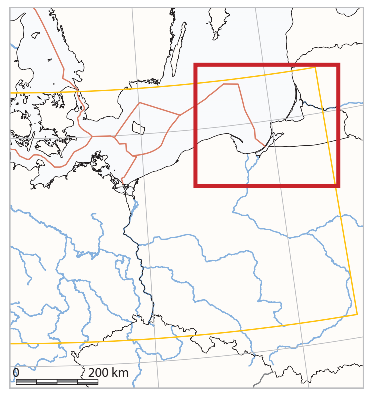


Figure 13.4 The Baltic Basin petroleum province with locations of fields and accumulations charged by pre-Devonian source rocks. The distribution of Upper Cambrian and Lower Ordovician organic-rich mudstones (Alum Shale and Dictyonema Shale) is prior to erosion (from Vejbæk et al., 1994). The regional distribution and thickness of the Alum Shale is shown in Figure 4.18.

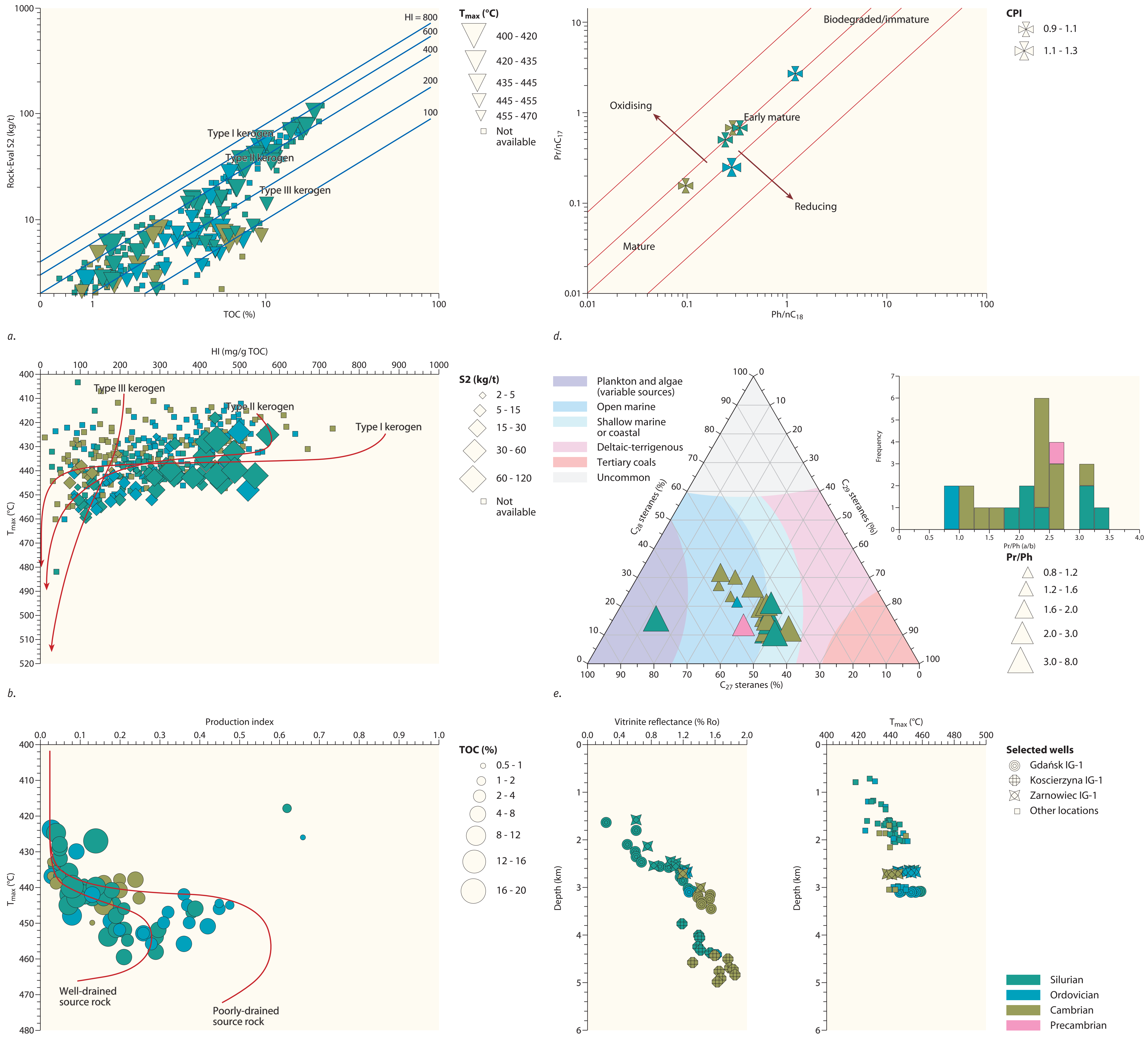


Figure 13.5 Geochemical data from different Precambrian, Cambrian, Ordovician, and Silurian formations in the Baltic Basin:
a. Pyrolytic yield (S2) versus TOC. Most immature source rocks contain type II kerogen irrespective of their age. Another group of samples, most of which are mature, plots as type III kerogen. Note that land plants that evolved in Silurian times contributed a negligible fraction to the biomass by the time of source-rock formation;
b. T_{max} versus Hydrogen Index (HI). The unusually elevated T_{max} values of the richest Silurian and Ordovician samples implies an organic-matter composition that is less thermally labile than standard type II kerogen;
c. T_{max} versus Production Index (PI). Mature Ordovician samples partly retain already generated hydrocarbons;
d. Pr/n versus Ph/n;
e. Sterane ternary diagram. The sterane composition indicates marine algal organic matter. Inset shows pristane/phytane ratios, which are high compared to the Mesozoic source rocks in the region;
f. Vitrinite reflectance and Rock-Eval T_{max} parameters plotted against sub-bottom depth. Note two different reflectance gradients within closely adjacent locations in Pomerania. T_{max} values display an unusual maturity increase upsection. Plots produced using IGI's p:IGI-3.

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 unfavourable 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 tensional regime during the Early Carboniferous. As seen 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 debris and some siliciclastic fine-grained material (Chapter 6, Figure 6.9). An extensive delta complex (the Yoredale 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 6.18). Basinal shales, some enriched in organic matter, were deposited alternating with carbonates on the slopes of the carbonate platforms and in the basinal areas. When carbonate production ceased at the Namurian-Viséan transition, basinal 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

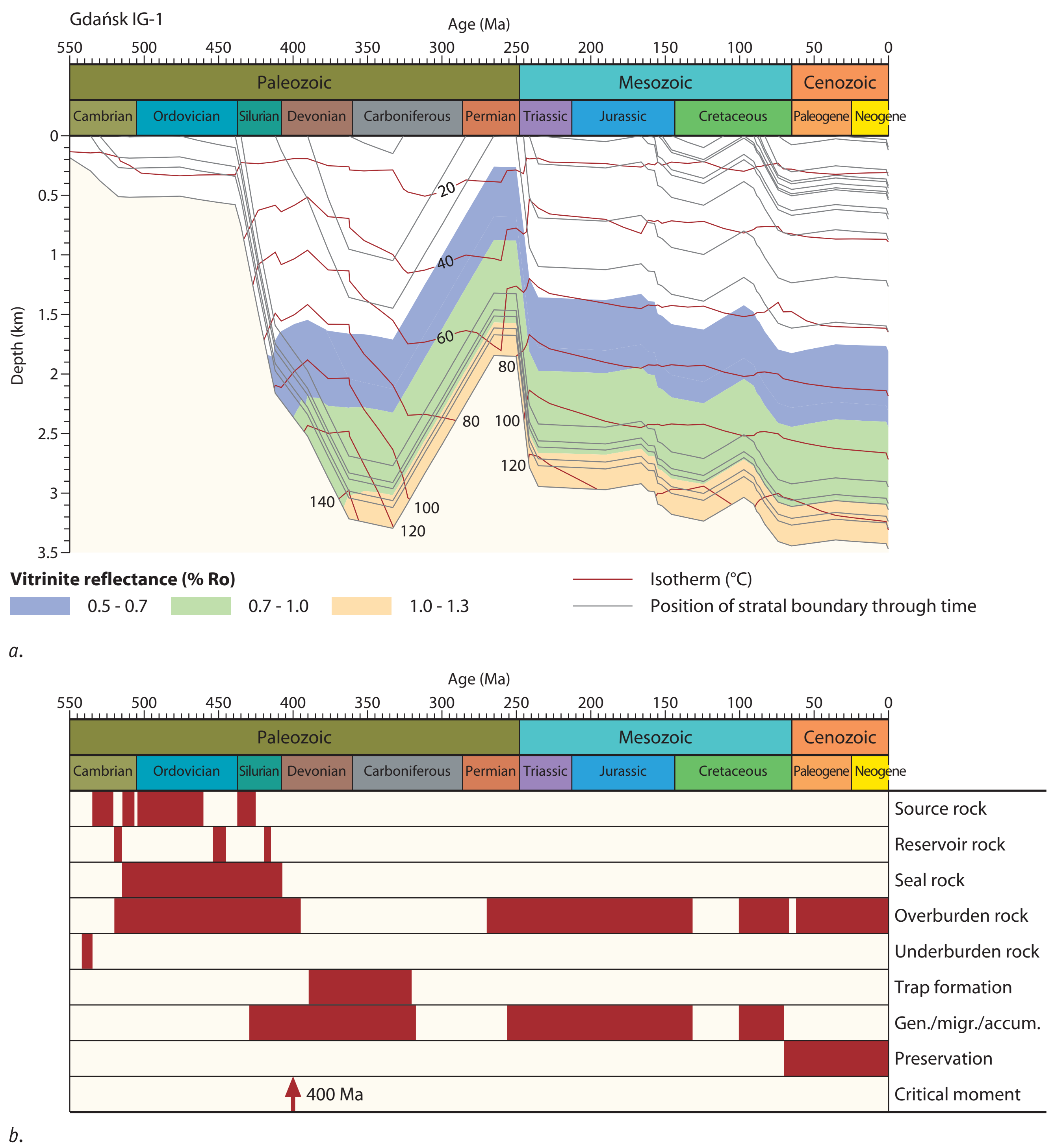


Figure 13.6 a. Burial and thermal history model results for Gdánsk IG-1 well. See Figure 13.4 for location. Note the rapid subsidence and burial during Silurian to Devonian times and ensuing Carboniferous and Permian uplift, followed by renewed rapid burial in the earliest Mesozoic (modified after Botor & Kosakowski (2000) using the Harland et al.(1989) time scale); b. Event chart for the pre-Devonian petroleum system of the western Baltic Basin. Note three periods of petroleum generation.

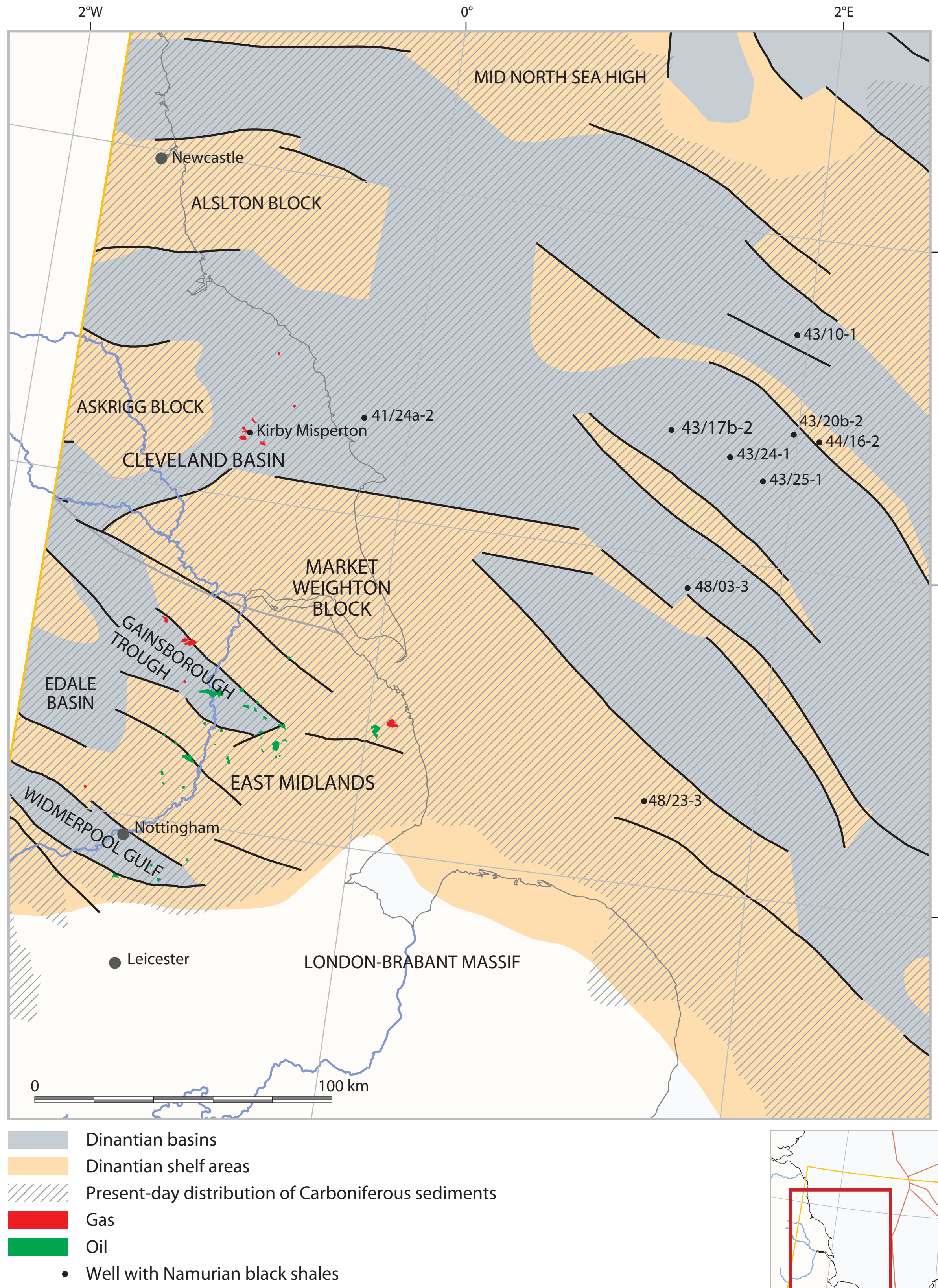
areas, black-shale deposition may well have continued from the Visean into the Namurian. As the most important sediment source area was to the north, sediment-starved conditions and associated black-shale deposition were confined mainly to the central and southern NWECB. Wells to the north of the Ruhr Basin and in the eastern Netherlands (Winterswijk-01) have penetrated Lower Carboniferous sections that consist almost entirely of basinal black shales (Culm facies and Upper Alum Shale Formation (Chapter 6, Figure 6.7).

Magnetotelluric soundings indicate a good conductor at 7000 to 9000 m depth ascribed to black-shale facies deposited in graben structures in the central NWECB (Chapter 6, Figure 6.18). Lower Carboniferous or Namurian black shales can be inferred based on nitrogen concentrations in reservoirs in the central NWECB, as these may have contributed nitrogen during late maturation. The relatively high nitrogen content (15%) in reservoirs such as Groningen may point to an 'old' charge event with nitrogen being sourced from Namurian basinal shales. Gas composition in the Ems Estuary area and the south-eastern North Sea also indicates a pre-Westphalian sapropelic source rock. In the UK offshore, Namurian source rocks are inferred to have contributed to the Flora field in the southern Central Graben. In the German offshore sector, reservoirs with a Namurian contribution are found in Zechstein carbonates and in Carboniferous, Rotliegend and Upper Jurassic sandstones. Namurian source rocks were encountered in hole Q1 in the south-eastern North Sea and in boreholes in the Ems Estuary area. Based on this information and limited well and seismic data, the basinal shales are likely to occur from the UK (**Figure 13.7**) to eastern Germany (Chapter 6, Figure 6.18).

In the north-western NWECB, extending into the present-day German and Danish offshore sectors, Lower Carboniferous and Namurian coal seams were formed in the Yoredale delta system (Chapter 6, Figure 6.6). In the south-eastern North Sea, lower Namurian deposits consist of alternating shales and sandstones with conglomeratic horizons and sporadic coal seams, coal tonstein and seat earths.

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 13.8**). Lowermost Namurian hot shales (equivalent to the Bowland Shale) from the Ems Estuary area have more than 2% TOC content and kerogen types I and II. In the southern Netherlands, Namurian hot shales have TOC contents of up to 10%, mainly 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 paralic Namurian deposits has moderate to low HI values (50-80) 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 D and E offshore blocks 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 localised Permo-Carboniferous magmatic sills, 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 well below 1.5% Rr (excluding areas affected by Permo-Carboniferous magmatic intrusions). The deposits south of the proven Yoredale facies in the UK and Dutch offshore sectors have maturities in the gas window or are overmature. For example, the present-day maturity of lower Namurian source rocks in the Ems Estuary area vary from 3.7% to 5.1% Rr. Farther east and to the south, Lower Carboniferous and Namurian source rocks are also found or expected to be overmature.



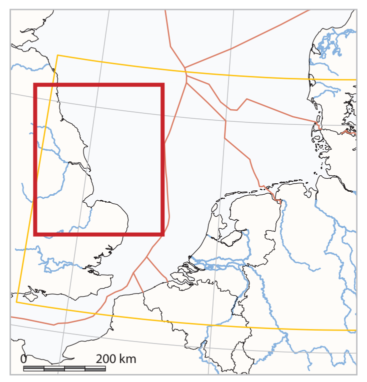


Figure 13.7 The western area of the Northwest European Carboniferous Basin with location of fields and accumulations charged by Namurian source rocks. Elevated nitrogen concentrations in Rotliegend reservoirs broadly correlate with the occurrence of overmature Lower Carboniferous black shales.

Analogous to the lower maturity of Lower Carboniferous and Namurian source rocks along the northern NWECB margin and the south-eastern North Sea, gas generation only began during the Cenozoic and continues to the present day. In the central NWECB, the great thickness of Upper Carboniferous rocks and the high heat flow at the end of the Carboniferous caused the main phase of hydrocarbon generation from Lower Carboniferous and lower Namurian source rocks to range from the mid-Westphalian (B-D) well into Stephanian times. The most important reservoir (Rotliegend sandstones) and seal (Zechstein) in the NWECB had not been deposited by then; therefore, much of the hydrocarbons must have migrated to the surface and been lost (**Figure 13.9**). Late Cretaceous inversion induced decreasing temperatures and hydrostatic pressures in the uplifted pre-Westphalian source rocks in the western German sector of the North Sea and the Duck's Bill region, causing gas generation to cease. Desorption from gas-prone source rocks and free-gas exsolution added to the pool of newly accumulated gas.

For further information see Gerling et al. (1999a), Hoffmann et al. (2001, 2005, 2008), Kus et al. (2005), Kombrink (2008), De Jager & Geluk (2007) and Drozdzewski (2009).

2.2.2 East Midlands

The East Midlands oil province consists of a series of largely concealed Carboniferous sub-basins bordered on the south by the London-Brabant Massif, to the west by the Derbyshire Dome and to the north by the Market Weighton Block, which separates the province from the Cleveland Basin. Over 30 fields have been exploited, mostly for oil but with some gasfields in the west. Basin formation commenced in the Late Devonian and continued throughout most of the Early Carboniferous, producing structures with a dominant north-west–south-east trend and a subsidiary north-east–south-west trend controlled mainly by Caledonian structures in the basement (**Figure 13.10**). The timing of movements on individual faults varied considerably such that the main depocentres formed from early to late Dinantian and early Westphalian times. However, in general the main Dinantian tilted fault blocks were covered by Upper Carboniferous sediments (**Figure 13.11**).

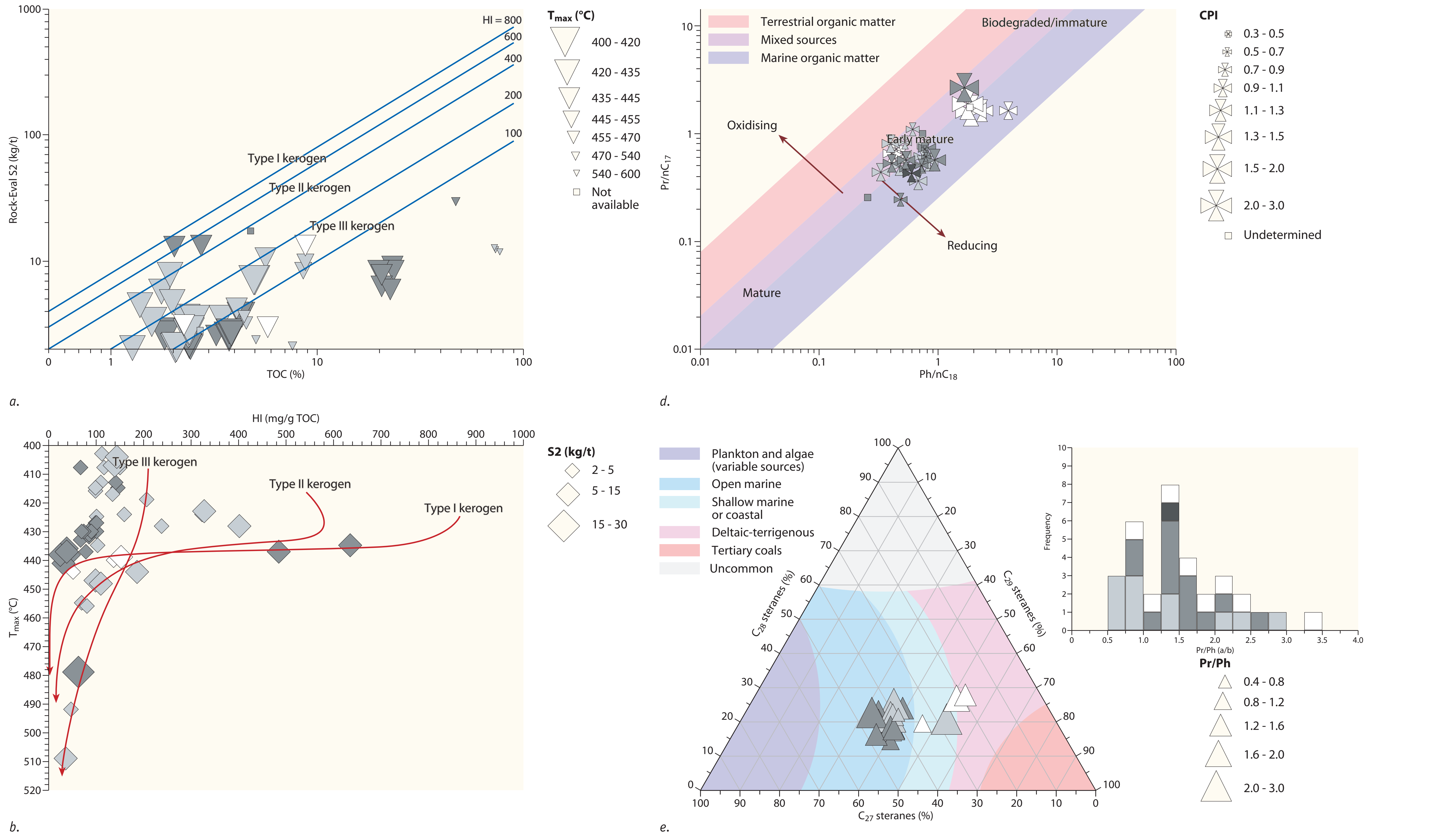
Late Carboniferous (Variscan) east–west compressional movements led to inversion of the area, commonly along the original extensional faults. This was followed by regional tilting to the east associated with Permian and Mesozoic subsidence in the North Sea, which resulted in a thin Permian to Mesozoic cover that generally thins north-westwards. These strata have only a few low-amplitude structural closures and are generally considered non-prospective for petroleum exploration. A further period of inversion of the whole sequence during the Cenozoic was associated with Alpine movements, and erosion from this inversion continues to the present day. The extent of Cenozoic uplift is not known with any certainty, although apatite fission-track analyses and sonic-velocity studies suggest about 1200 m of uppermost Cretaceous and Cenozoic strata have been removed.

The main source rocks in the East Midlands are found in Namurian strata. These are early Namurian distal prodelta shales (e.g. upper part of the Bowland Shales and equivalents), which were deposited in the main sub-basins (**Figure 13.10**). The middle Dinantian shales and limestones found at outcrop or in wells (e.g. Milldale Limestone) are less important potential source rocks. Westphalian coals are widespread and were previously worked extensively; however, generally they are not sufficiently mature to have contributed significantly to the area's petroleum accumulations. The TOC content of the Namurian shales is poorly known, but probably varies between 2 and 10%. Carbon-isotope data suggest that two main source rocks have contributed; a dominant source contributing oils around $\delta^{13}C$ of −30‰ correlates with the prodelta Namurian shales, whereas isotopically heavier (around −27‰) oil is encountered in the Caunton and Kelham Hills fields and the Newark discovery (**Figures 13.10** & **13.12f**). Oil from the Newark area is thought to be derived from marine bands and local interdistributary-channel mudstones, probably within the Namurian sequence.

Maturation is difficult to constrain due to the limited number of published maturity measurements in the region. Where data are available, most wells show a higher maturity gradient in the pre-upper Westphalian strata, suggesting a higher geothermal gradient at that time, although the picture is complicated by erosion at the Carboniferous Variscan Unconformity. Maturity of the Namurian source rocks is thought to be higher in the basinal areas (Gainsborough Trough and Widmerpool Gulf) and hydrocarbons probably migrated towards the shelf areas.

Thermal modelling suggests Late Carboniferous generation (**Figure 13.13**). This would have been arrested in the extreme west by erosion along the Pennine uplift during the Variscan Orogeny, although generation would have resumed and extended eastwards by regional subsidence during Permian and Jurassic times. Migration patterns were also influenced by the north-west–south-east-trending structural grain, which concentrated source rocks in the elongated grabens (Gainsborough Trough, Widmerpool Gulf etc.; **Figure 13.10**). Migration routes over significant distances are anticipated to explain the hydrocarbon occurrences in the region.

All of the accumulations in the West Midlands are trapped in anticlinal structures that are either relic rollovers, inversion fault controlled, or above horst blocks. Most of these structures formed early during rifting, but all have been significantly modified during subsequent inversion periods. This inversion, and the Permian-Jurassic tilting episode, has resulted in considerable remigration of all oil and gas generated during the Carboniferous. This is clearly seen for example in the Bothamsall oilfield where at least two phases of charge can be recognised; an early charge associated with Carboniferous burial and a subsequent charge, probably coinciding with remigration 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 rarely 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 basal sands of meandering deltaic channels are locally stacked, reservoirs more than 100 m thick are possible. Oil is also found in levee and distributary mouth and 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-Beckingham, Eakring, Duke's Wood and Bothamsall), sealed by shales at the base of the Coal Measures. These are fluviodeltaic and turbiditic 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 Dinantian Carboniferous limestone, sealed by Namurian shales, which has produced small quantities of oil at Hardstoft, Eakring, Duke's Wood, Plungar and Nocturn. The basal Permian sands have not yet yielded a commercial discovery but contain a significant oil show at Nocton. The extensive syn-rift Devonian Old Red Sandstone, which underlies the Carboniferous in much of the basin, is also a prospective future target although the limited tests so far have proved fruitless, as would Dinantian patch-reefs if they could be found in the subsurface (analogous to the now-exposed Windy Knoll) exposure in Derbyshire.



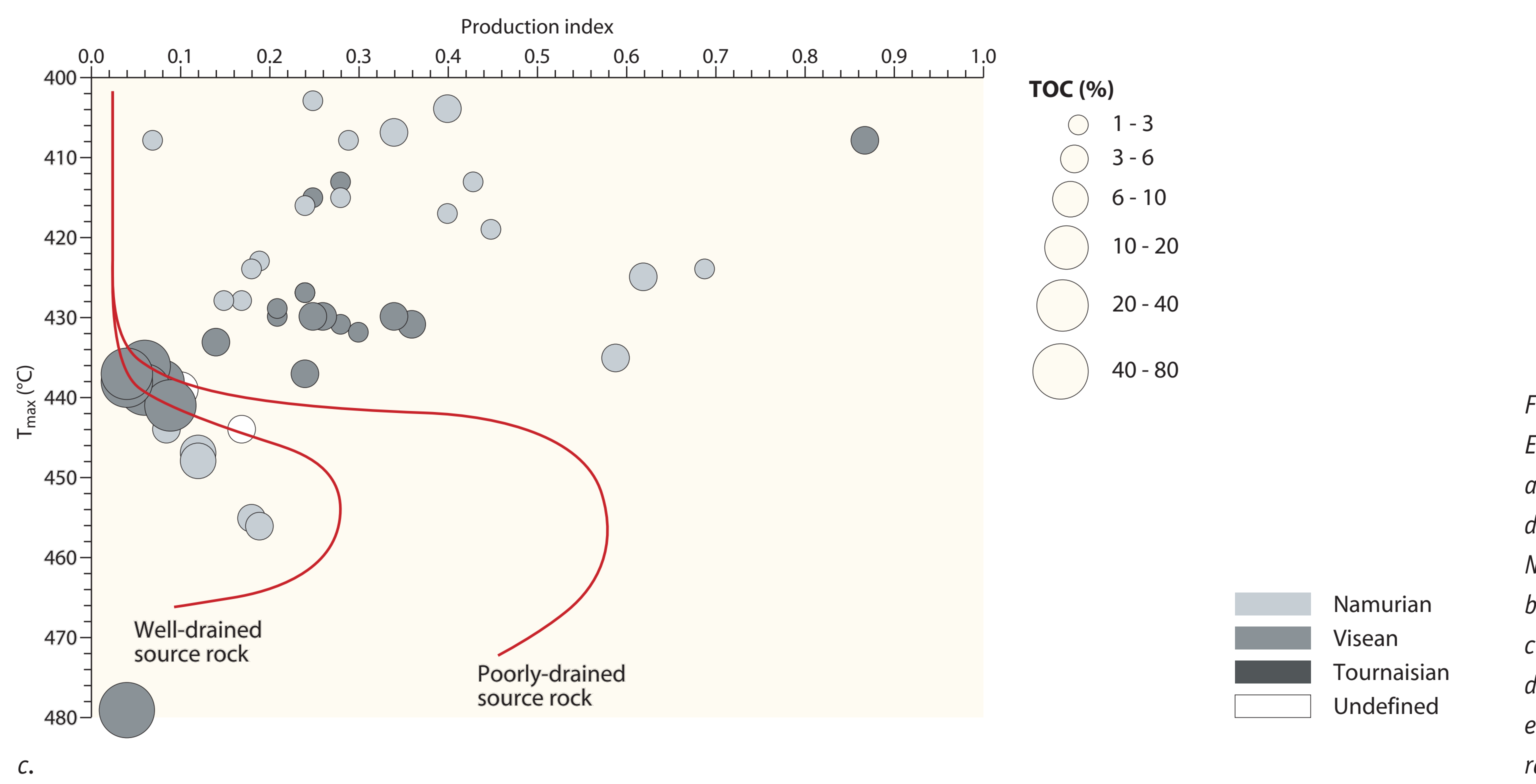


Figure 13.8 Geochemical data from Lower Carboniferous and Namurian source rocks of the central Northwest European Carboniferous Basin:
a. Pyrolytic yield (S2) versus TOC. The high-TOC samples mostly represent Visean (Yoredale Formation) coals derived from the north-western part of the basin. The data cluster near the origin comprises Visean and Namurian (black) shale samples, probably of marine origin;
b. T_{max} versus Hydrogen Index (HI);
c. T_{max} versus Production Index (PI);
d. Pr/n versus Ph/n;
e. Sterane ternary diagram. Most samples are derived from marine source rocks. Inset shows pristane/phytane ratios. Plots produced using IGI's p:IGI-3.

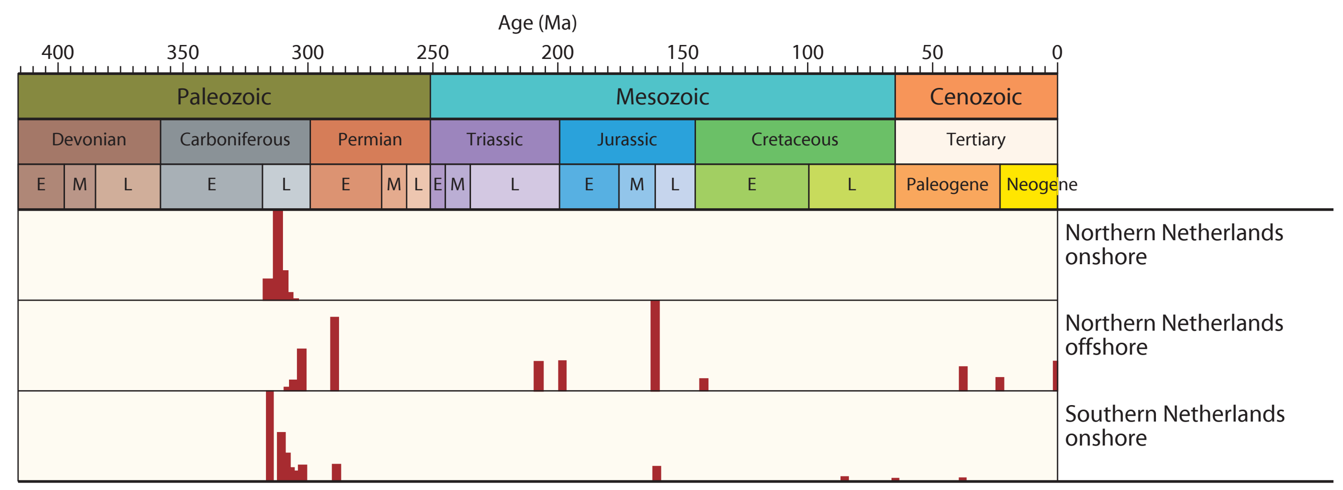


Figure 13.9 Generation and expulsion of hydrocarbons from Lower Carboniferous and Namurian source rocks in the Netherlands through time, illustrating the early generation phase for these rocks.

For further information see Hawkins (1978), Kirby & Swallow (1987), Fraser and Gawthorpe (1990) and Fraser et al. (1990).

2.2.3 *Cleveland Basin*

The Cleveland Basin forms the north-west extension of the Southern North Sea Gas Basin and shares much of its geology with the adjacent Sole Pit Trough. It is mainly a Jurassic to Early Cretaceous structure, overlying 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 (immature Westphalian) and to the south by a complex fault zone (Vale of Pickering-Flamborough Head Fault Zone) against the Market Weighton Axis and the Selby coalfield (also immature Westphalian), which separates it from the East Midlands province (see previous section, **Figure 13.15**). Seven gasfields have been discovered: Caythorpe, Eskdale, Kirby Misperton, Lockton, Malton, Marishes and Pickering (**Figure 13.14**). During the Devonian, the Cleveland area probably acted as a sediment source. Sedimentation commenced during the Tournaisian, 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 Unconformity) 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 strata were eroded and now remain only as isolated outliers (e.g. a small north-west–south-east-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, as even Middle Jurassic coals have vitrinite reflectance values between 0.82 and 0.87% Ro (**Figure 13.16**).

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 burial was mainly southwards to a postulated Market Weighton granite dome, although some northward migration would also have been possible.

Most production to date has been from fault traps along the southern fault zone. These mainly east–west-trending Jurassic and Cretaceous faults cut across the predominantly north–south-trending Permian facies belts. Consequently, the most recent discoveries (Malton, Pickering and Kirby Misperton) are located along a north–south trend within this southern fault zone. Trap breaching and remigration towards the basin axis were the key features associated with Cenozoic Alpine inversion.

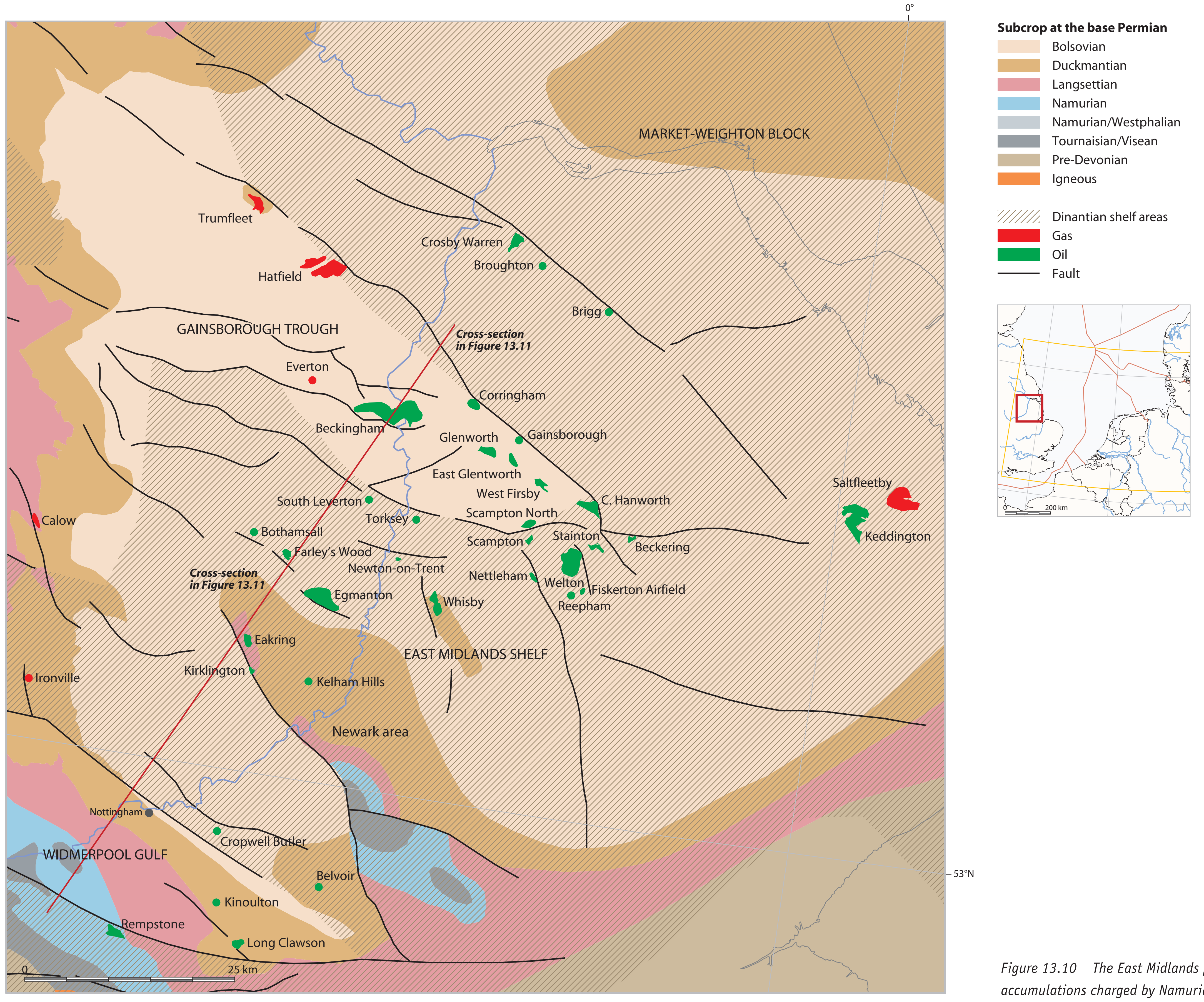


Figure 13.10 The East Midlands petroleum province with locations of fields and accumulations charged by Namurian source rocks.

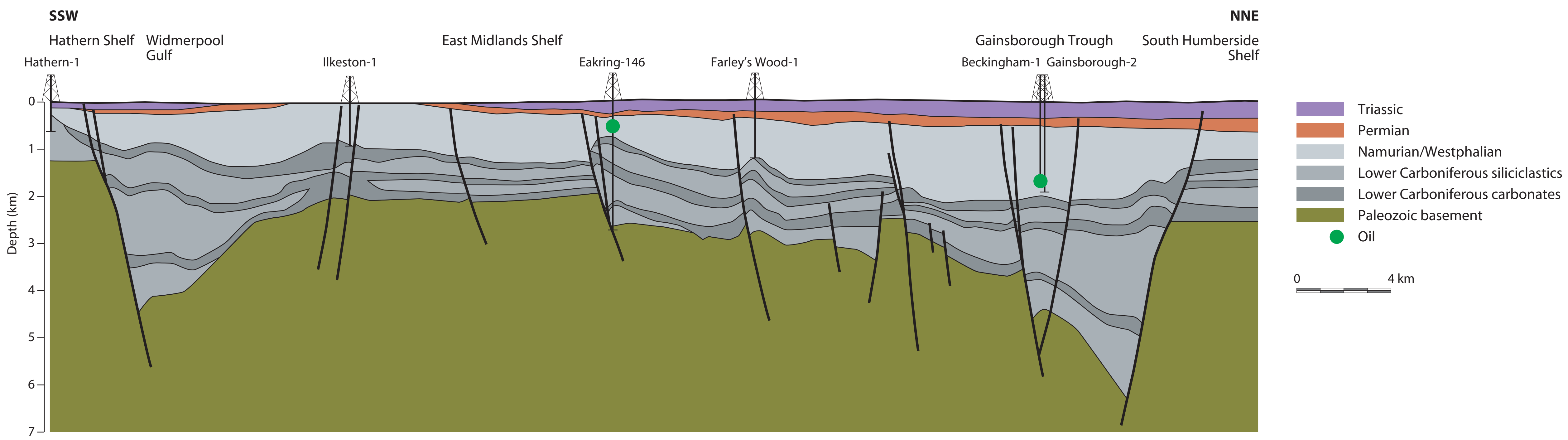


Figure 13.11 Cross-section through the East Midlands petroleum province (see Figure 13.10 for location). Based on Fraser & Gawthorpe (1990).

There are reservoir rocks in Namurian sandstones (Kirby Misperton field), basal Permian Rotliegend sandstones (Caythorpe field) and fractured Zechstein dolomites (Caythorpe, Eskdale, Malton and Marishes 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 Koszalin Fault Zone. To the south, the Variscan Deformation Front forms the transition to the folded Carboniferous rocks of the Polish Trough. Twelve Carboniferous-sourced 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, characterised by mixed siliciclastic-carbonate shallow-marine deposits (see Chapter 6, Figure 6.10). The area was uplifted during the Namurian and acted as a source of clastic material for the sedimentary basins of central and southern Poland. Sedimentation resumed during Westphalian times. The transition from deltaic to fluvial conditions only took place during the Westphalian C, in contrast to most areas in the NWECB, 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 Tournaisian, Visean and Westphalian black shales that occur across the entire Pomeranian region are the main source rocks. Uplift has largely restricted Namurian source rocks to southern Pomerania. Thin Westphalian coal seams also occur.

Tournaisian 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 streaks and interbeds are usually less than 0.5 m thick. Kerogen is mainly gas-prone type III with admixtures of type II (**Figure 13.20a** & **b**). Average Hydrogen Indices decrease upwards from the Lower Carboniferous (180 mg/g) to the Upper Carboniferous (110 mg/g), but they typically have a wide range. Stable carbon-isotope data from natural-gas samples corroborate a major contribution from Carboniferous type III kerogen. Some thin layers are characterised by significant alginite contents. The Lower Carboniferous clayey-marly Sąpolno Formation has considerable amounts of oil-prone, structureless, fluorescing sapropelic organo-mineral associations with liptinite (type II kerogen). Tournaisian samples in particular are predominantly in the type II kerogen field (**Figure 13.20a**). Saturated hydrocarbon compositions are generally homogeneous, 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-C_{17} ratio, phytane/n-C_{18} ratio and pristane/phytane ratio (Pr/Ph).

Both T_{max} and vitrinite reflectance values indicate that the Tournaisian to Westphalian source rocks are mostly marginally mature to mature (**Figure 13.20b**; Chapter 6, Figure 6.19). The highest present-day maturity varies around 1.8% Ro, indicating the gas-generating potential of Carboniferous source rocks in the southern Pomeranian petroleum province.

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 generative phases in the Triassic-Jurassic and in Late Cretaceous times, when maturities reached 1.4 to 1.8% Ro. The latter phase generated gases that probably migrated over distances that did not exceed several tens of kilometres.

Traps are both structural and stratigraphic, but are small and often accompanied by faults. Some traps have the characteristics of combined structural and stratigraphic trapping. Reservoirs include Visean limestones (Ø: 2-16%, K: 100-400 mD), Namurian (Ø: 16-23%; K: 208-274 mD), Westphalian (Ø: 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 fair porosities (Ø: 0-13%, 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. Zechstein salt and anhydrite 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 reservoirs is rich in nitrogen (39-78%) and contains 22 to 58% methane, some ethane, propane and helium. The nitrogen content increases westwards and less evidently to the south.

For further information see Karnkowski, (1996, 1999b) and Kotarba et al. (2004, 2005).

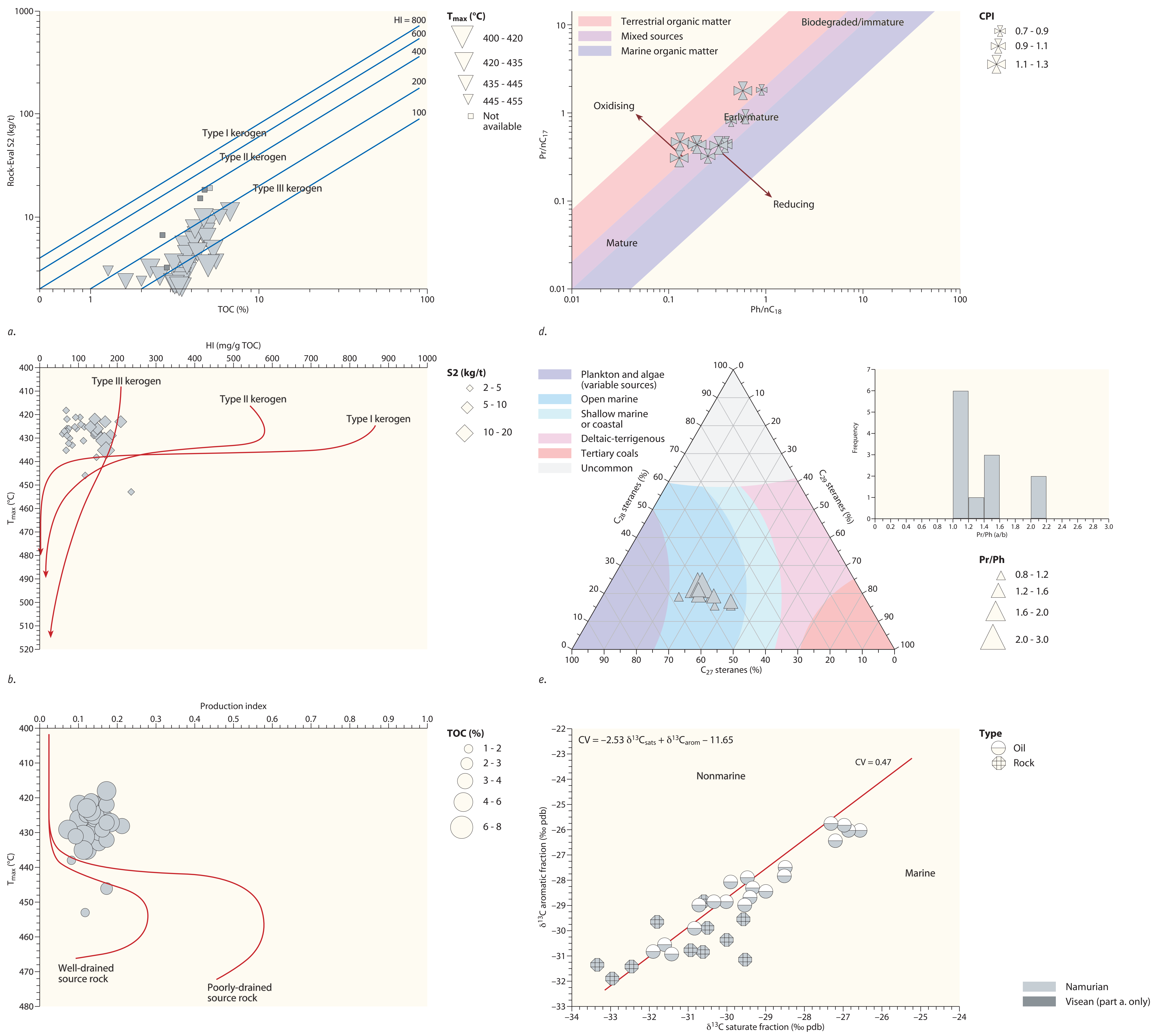


Figure 13.12 Geochemical data from Lower Carboniferous and Namurian source rocks (and oils) in the East Midland petroleum province: a. Pyrolytic yield (S2) versus TOC; b. T_{max} versus Hydrogen Index (HI); c. T_{max} versus Production Index (PI); d. Pr/n versus Ph/n; e. Sterane ternary diagram. Most samples are derived from open-marine source rocks. Inset shows pristane/phytane ratio; f. Carbon-isotope values from oils and source rocks (from Fraser et al., 1990). Plots produced using IGI's p:IGI-3.

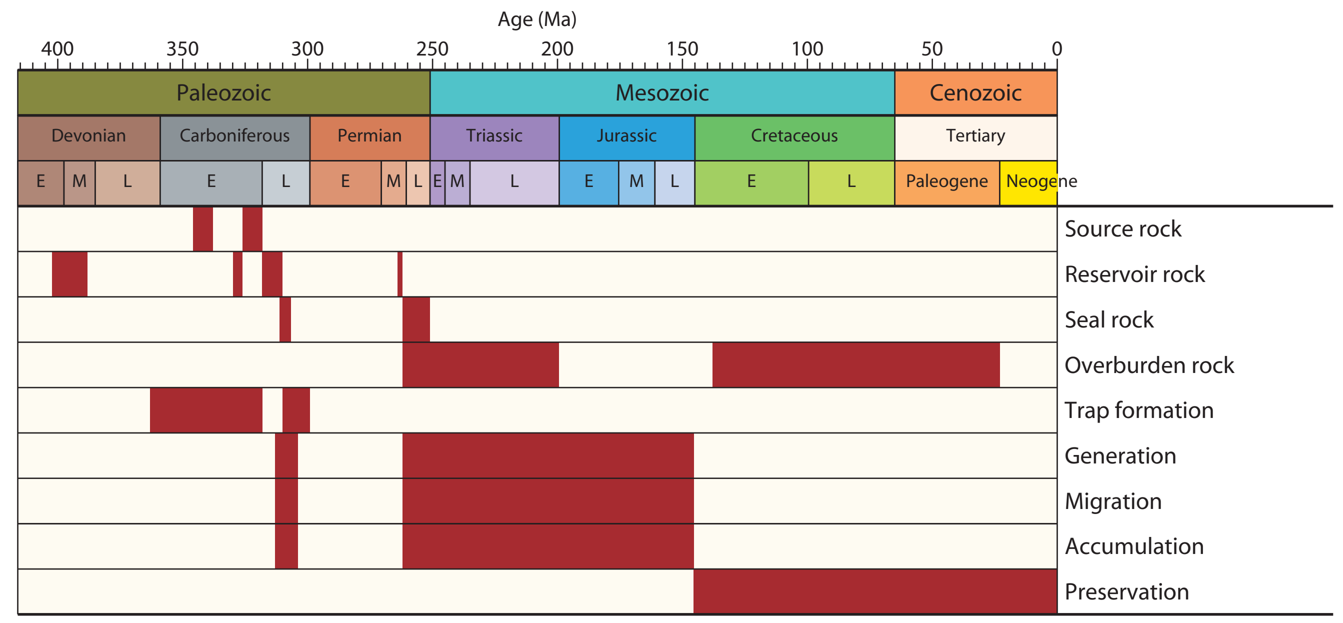


Figure 13.13 Event chart for the Early Carboniferous and Namurian petroleum system in the East Midlands petroleum province.

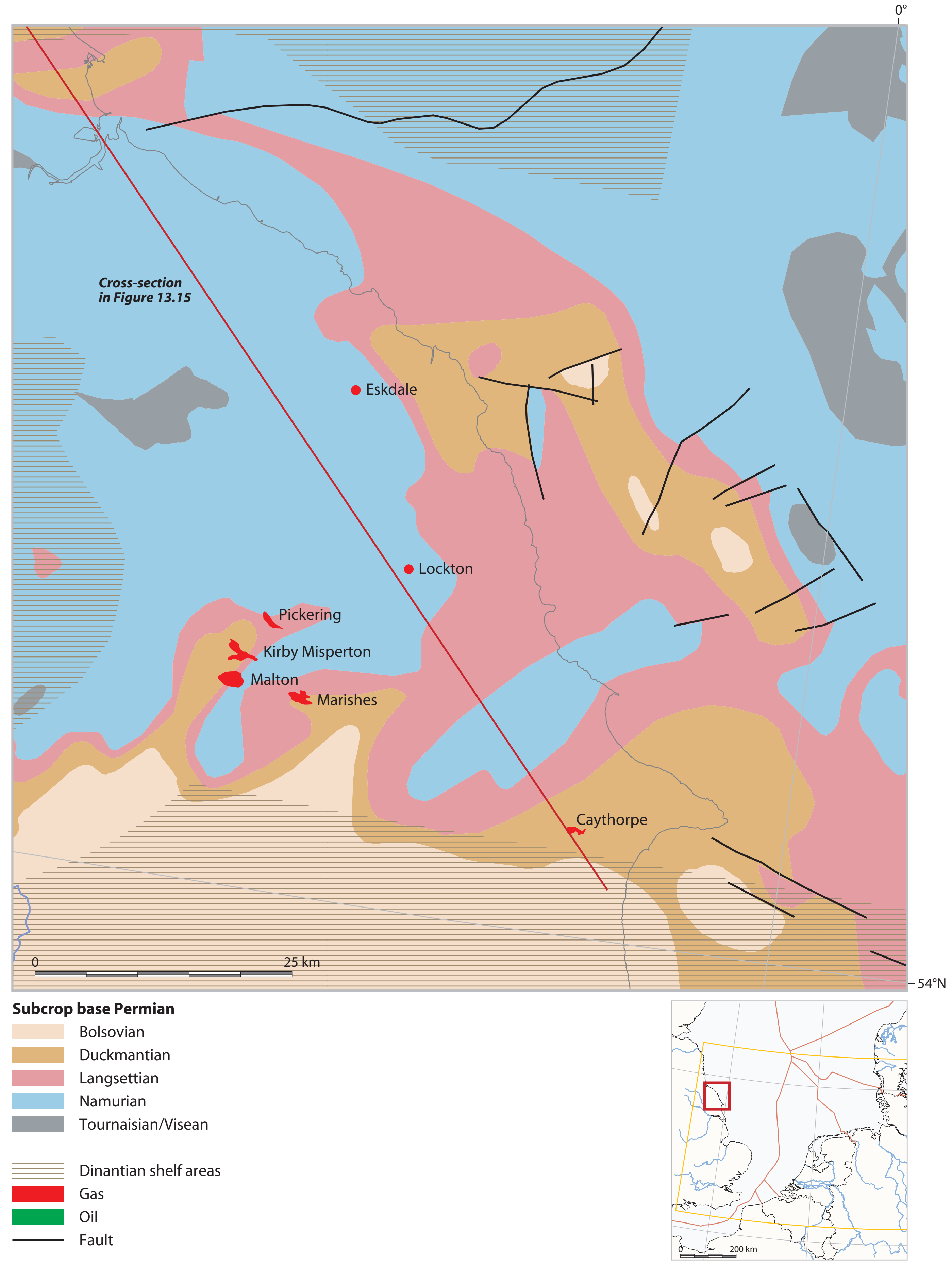


Figure 13.14 The Cleveland Basin petroleum province with locations of fields and accumulations charged by Namurian source rocks.

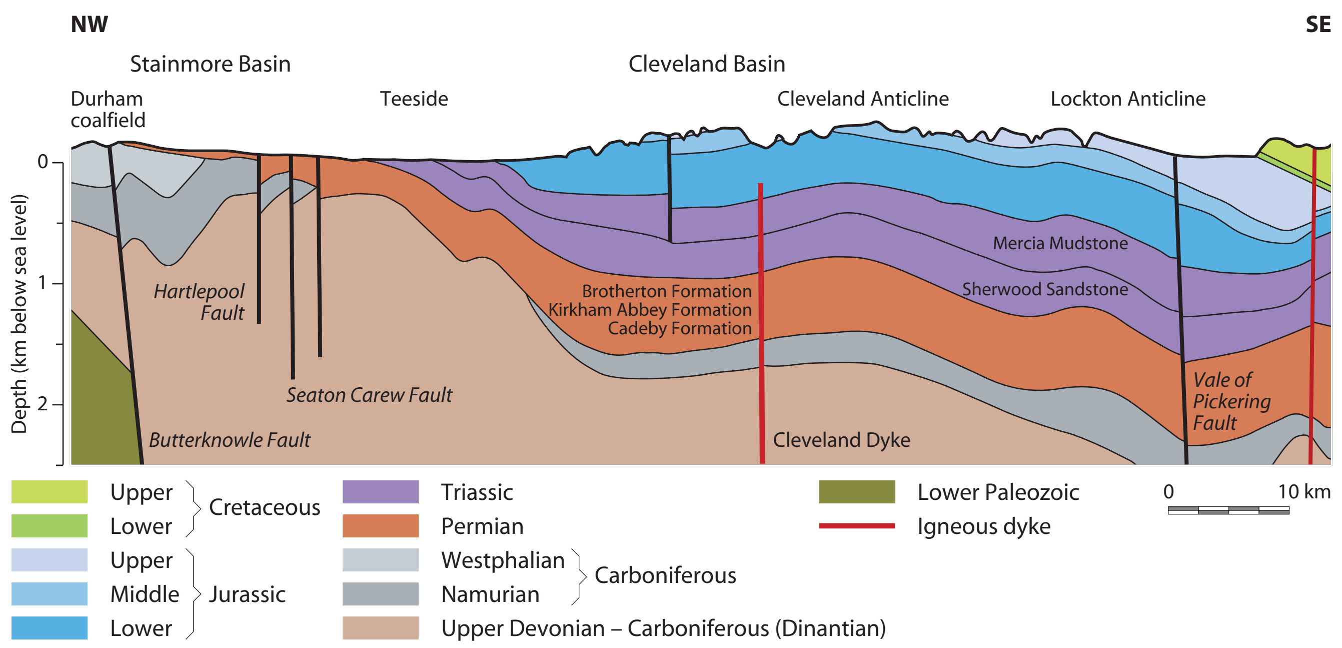


Figure 13.15 Cross-section through the Cleveland Basin petroleum province. See Figure 13.14 for location.

2.2.5 Fore-Sudetic Monocline (Wielkopolska petroleum province)

The Fore-Sudetic Monocline is bound to the north by the less-faulted Carboniferous rocks of Pomerania, and to the east and south-east by the Holy Cross Mountains and the Upper Silesian Basin. A similar setting is found westwards in eastern Germany, whereas the southern boundary is poorly defined as a result of its deep burial. Many reservoirs of various ages have been charged by Carboniferous source rocks (**Figure 13.22**). Only one Carboniferous reservoir unit has been found to date (in the Paproć C field), whereas there are abundant Rotliegend and Zechstein discoveries and fields.

Carboniferous rocks in the Fore-Sudetic Monocline are deeply buried (**Figure 13.23**) and consist mainly of Lower Carboniferous flysch sediments deposited in the Variscan foreland basin. Late Carboniferous post-orogenic deformation caused intense faulting (the area is mostly south of the Variscan Deformation Front). Uplift led to the erosion of the thick Namurian to Westphalian cover; only isolated areas of Upper Carboniferous rocks remain. From Rotliegend to Late Cretaceous times, this area was part of an extensive basin; however, Alpine inversion led to uplift, especially in the north-eastern area of the Fore-Sudetic Monocline.

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 Wolsztyn High. The Wolsztyn High is a pre-Permian ridge where Rotliegend reservoir sandstones are absent (subcrop of pre-Carboniferous rocks, **Figure 13.22**). There are six gasfields in the Zechstein Limestone of the Z1-Werra cyclothem on the Wolsztyn High. South of the high, gasfields are found in the uppermost Rotliegend sandstones, in the Zechstein Limestone, and often in both.

Lower Carboniferous and Namurian 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 vitrinite group macerals, whereas the inertinite group is subordinate and the liptinite 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 overmature in large areas due to deep burial, Early Permian magmatism and hydrothermal activity. Maturity increases towards the axis of the Mid-Polish Trough and the eastern Fore-Sudetic Monocline due to deeper burial and higher heat flow. T_{max} values range from 440 to 520°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 (80-100 mW/m^2), petroleum generation started as early as the Late Carboniferous (**Figure 13.25**) and kerogen was almost completely transformed (transformation ratio near 100%; **Figure 13.24b & c**). In the areas of the Fore-Sudetic Monocline where petroleum potential still existed after the Carboniferous, generation resumed in Mid-Triassic to Late Jurassic and in Late Cretaceous times, as it did in the Pomerania region. Peak thermal maturities locally reached 5% Ro leading to dry-gas generation and overcooking. 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 only short distances, up to some ten kilometres at most.

Major trap formation and migration probably took place during Triassic and Jurassic times. The traps are mostly stratigraphic and may be stratigraphic/structural (fault-related, e.g. Radlin field; see Chapter 7; Section 6.4.2). Unconformity-related and facies-related stratigraphic traps are common at the northern margin of the Wolsztyn High. The effects of post-Cretaceous inversion on the initiation, compartmentalisation and destruction of traps are currently being studied.

The most prominent reservoirs for the Carboniferous source rocks are quartzitic Rotliegend sandstones. There are minor accumulations in Carboniferous and Zechstein reservoirs, which are sealed by Zechstein anhydrite and halite. North of the Wolsztyn High, the Rotliegend succession consists of up to 750 m-thick aeolian sandstones (Ø: 5-21%, K: 0.1->100 mD). Farther north, their total thickness increases to almost 1000 m (Øav: 1-16%, Kav: 0-25 mD). About 100 m-thick fluvial and alluvial Rotliegend sandstones form

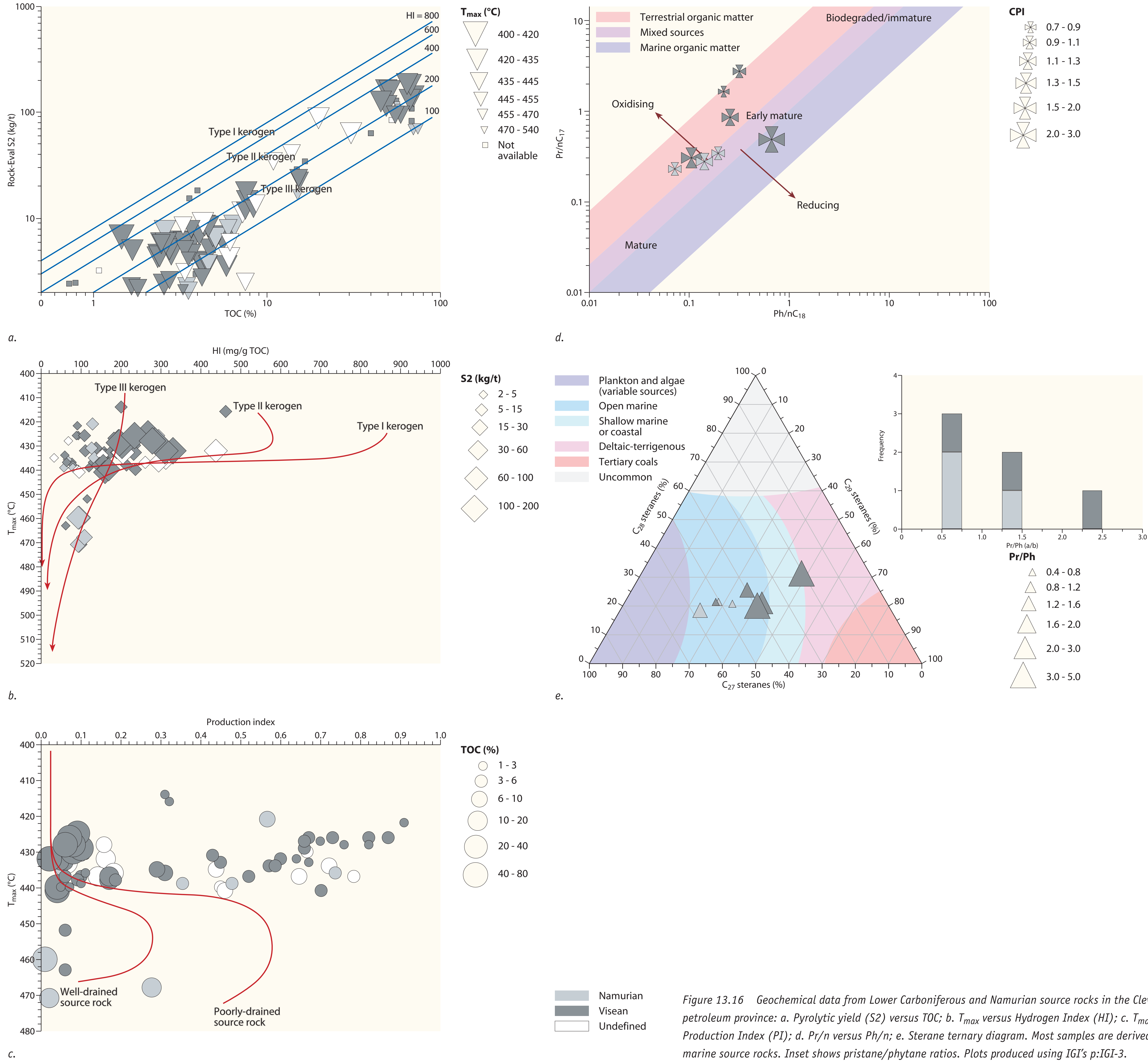


Figure 13.16 Geochemical data from Lower Carboniferous and Namurian source rocks in the Cleveland Basin petroleum province: a. Pyrolytic yield (S2) versus TOC; b. T_{max} versus Hydrogen Index (HI); c. T_{max} versus Production Index (PI); d. Pr/n versus Ph/n; e. Sterane ternary diagram. Most samples are derived from open-marine source rocks. Inset shows pristane/phytane ratios. Plots produced using IGI's p:IGI-3.

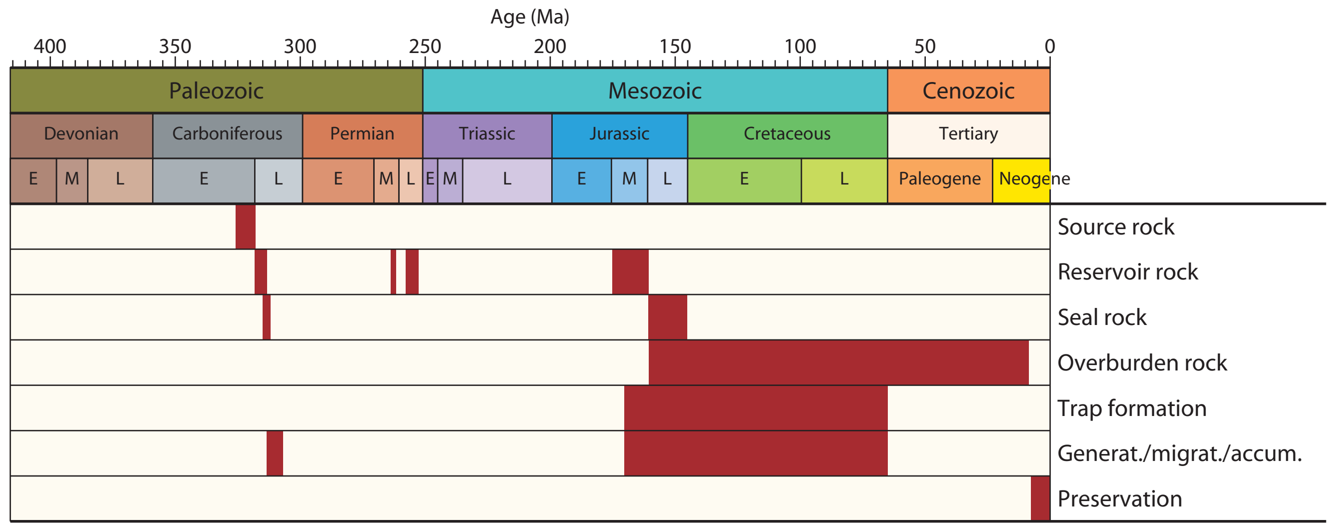


Figure 13.17 Event chart for the Early Carboniferous and Namurian petroleum system in the Cleveland Basin petroleum province.

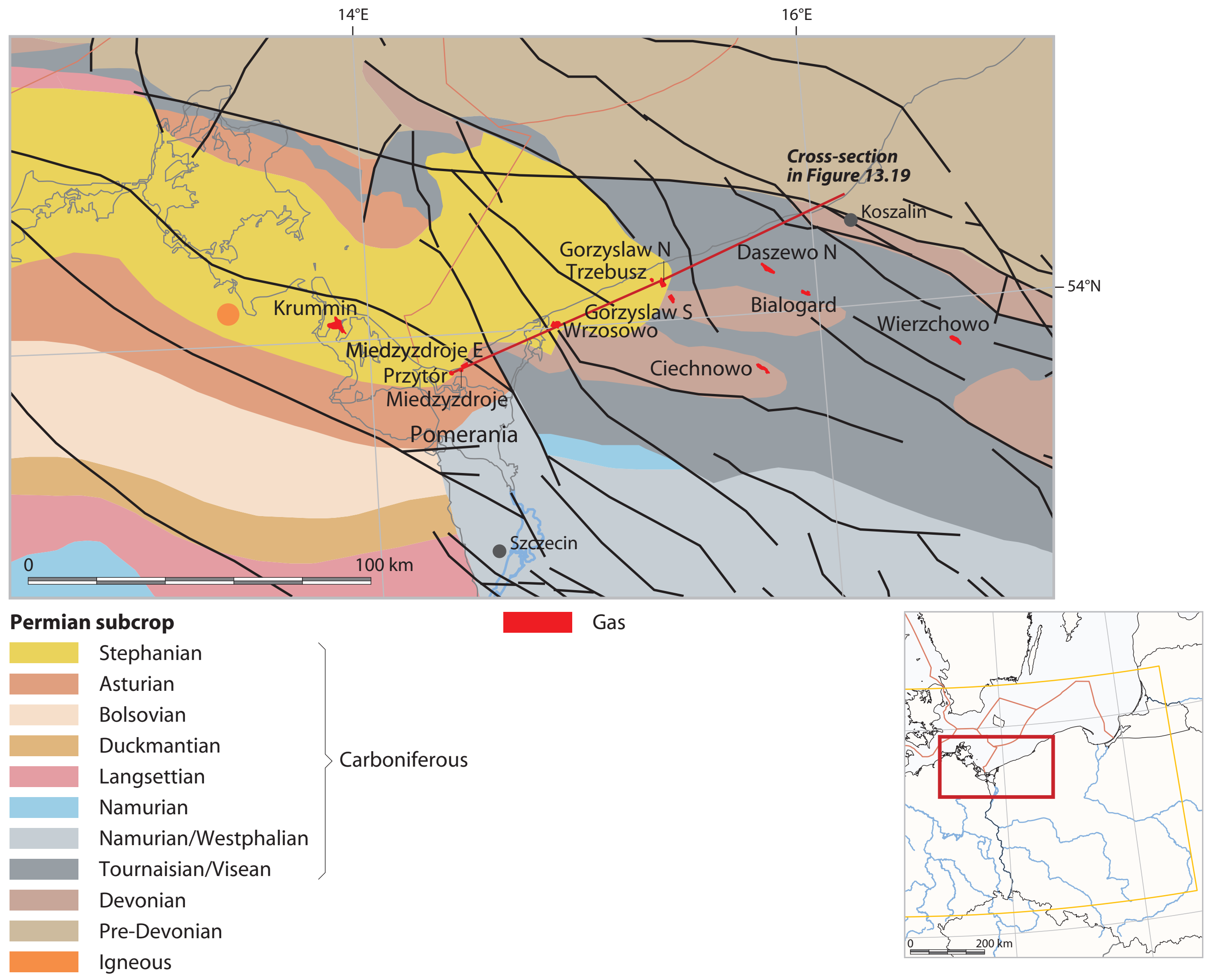


Figure 13.18 The Pomeranian petroleum province with locations of petroleum fields and accumulations charged by Early Carboniferous and/or Namurian black shales (field locations are not shown on the German side of the petroleum province).

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 illite growth. Even the areas with reduced reservoir quality are prospective for tight gas and stratigraphic traps. Zechstein reservoirs, including reefal limestones up to several tens of metres thick (Øav: <25% Kav: <40 mD) are found on the Wolsztyn High and other local basement highs. They host a number of gasfields (e.g. Kościan, Bonikowo, Paproć W and Wielichowo). 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; Ø: 3-23%, K: 0.1-100 mD). Producing reservoirs are also found in shallow-marine barrier and platform Zechstein limestones (porosities 1-13%). Both the Zechstein carbonates and Rotliegend sandstones are productive in some fields (e.g. Grabówka and Dobrzeń).

The composition of natural gas in the Fore-Sudetic Monocline is diverse. North of the Wolsztyn High, it is mostly methane (70-90%) with admixtures of nitrogen (<25%), higher hydrocarbons (<2%), CO_2 (<2%) and traces of helium. The gas quality decreases southwards and south-westwards, where fields contain 16-80% of methane, 20-78% of nitrogen, similar CO_2 and higher hydrocarbon contents, but with increased helium concentrations (up to 0.6%).

For further information see Zdanowski & Żakowa (1995), Karnkowski, (1996, 1999b), Kotarba et al. (2002, 2004, 2005) and Grotek (2004).

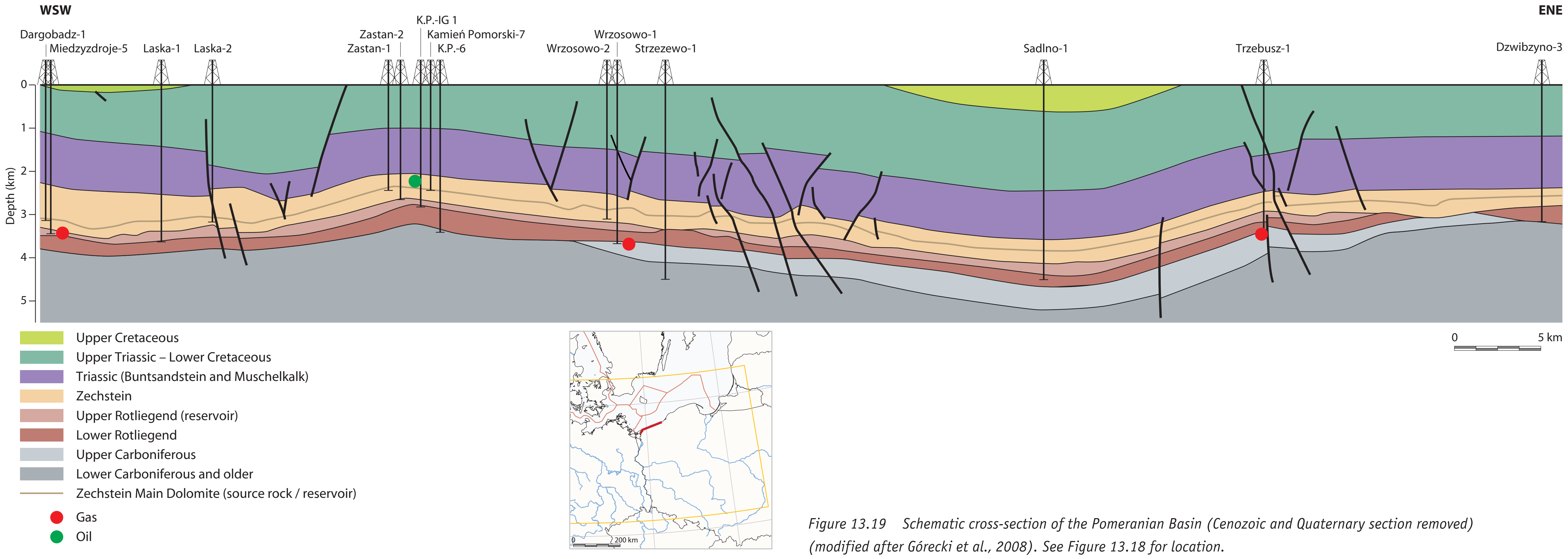


Figure 13.19 Schematic cross-section of the Pomeranian Basin (Cenozoic and Quaternary section removed) (modified after Górecki et al., 2008). See Figure 13.18 for location.

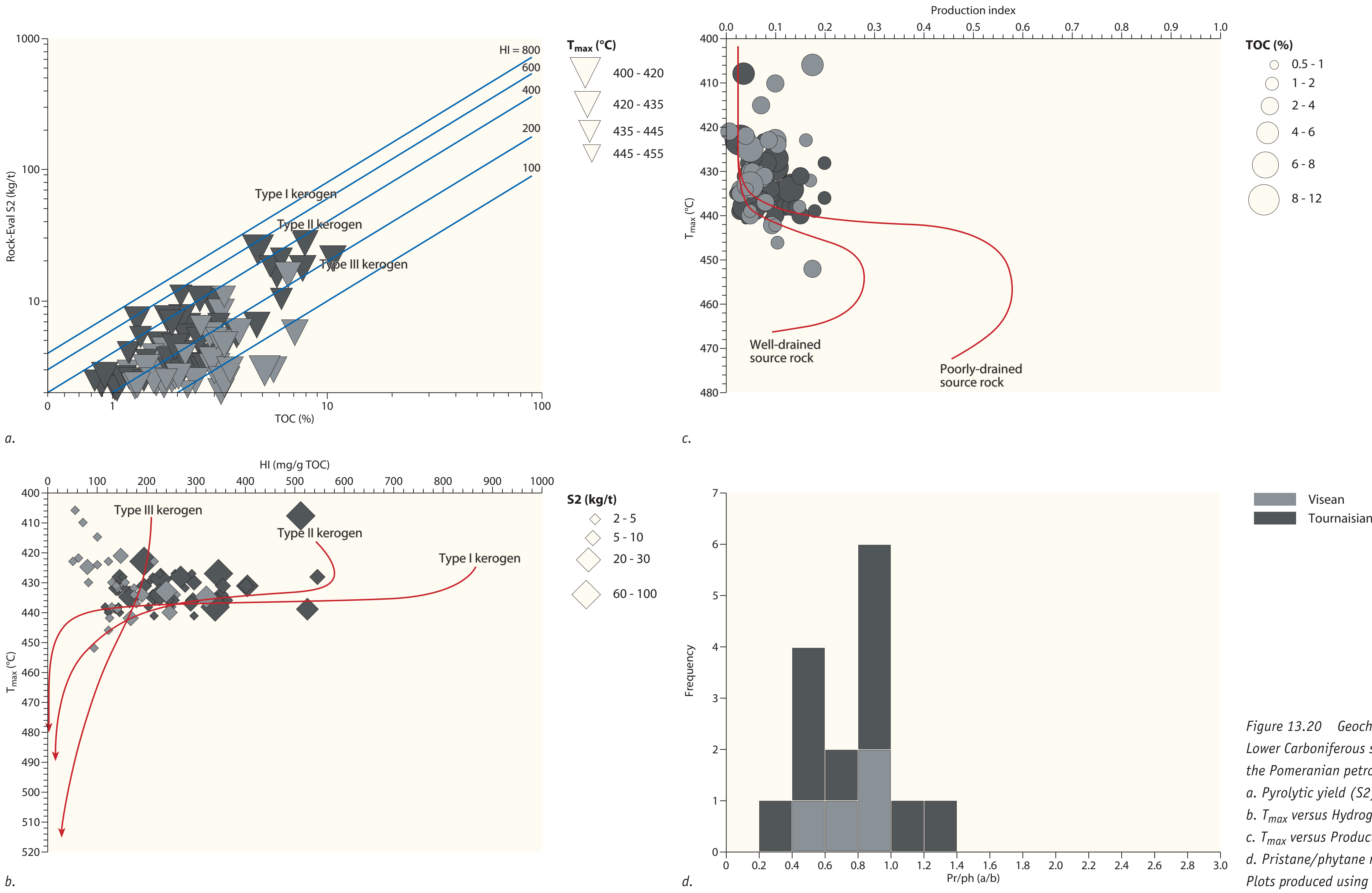


Figure 13.20 Geochemical data from Lower Carboniferous source rocks from the Pomeranian petroleum province:
a. Pyrolytic yield (S2) versus TOC;
b. T_{max} versus Hydrogen Index (HI);
c. T_{max} versus Production Index (PI);
d. Pristane/phytane ratios.
Plots produced using IGI's p:IGI-3.

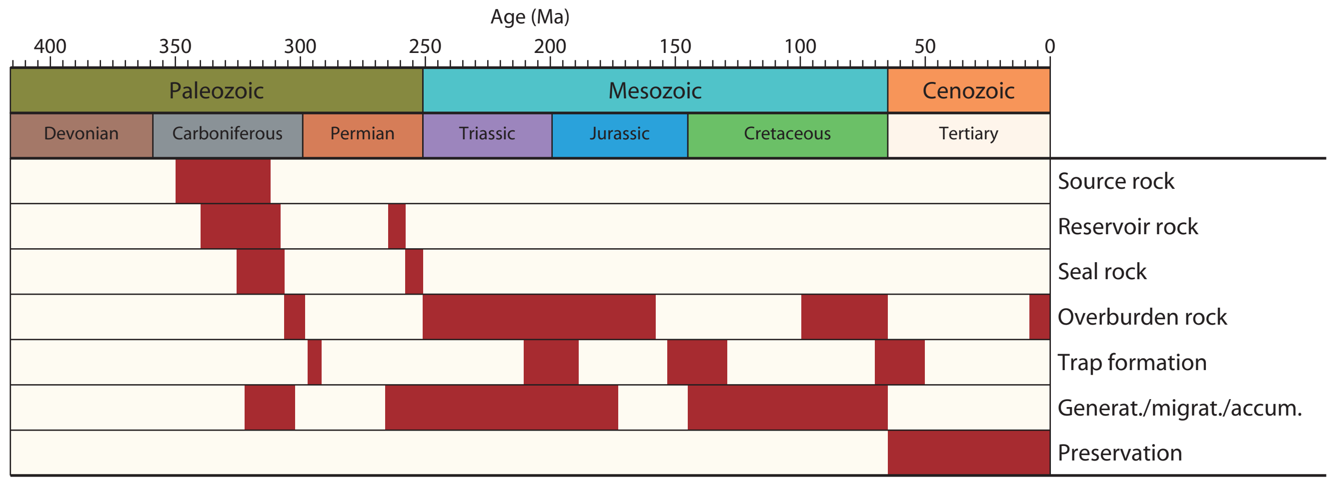


Figure 13.21 Event chart for the early Carboniferous and Namurian petroleum system in the Pomeranian petroleum province. Timescale of Harland et al. (1989).

2.2.6 Lublin Basin

The Lublin Basin is situated in the south-west of the East European Platform and is bound to the south-west by the Holy Cross Mountains and Małopolska Massif. 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 Stężyca, Świdnik (oil and gas), Wilga, and Minkowice (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 reactivation of the Teisseyre-Tornquist Zone (**Figure 13.26**).

The Carboniferous (upper Visean) succession rests unconformably on older Paleozoic formations in large areas of the Lublin Basin (**Figure 13.27**). An alternating sequence of clastics and carbonates was deposited during the Visean. In Namurian times, coal-bearing deposits were formed during cycles of shallow-shelf, 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.

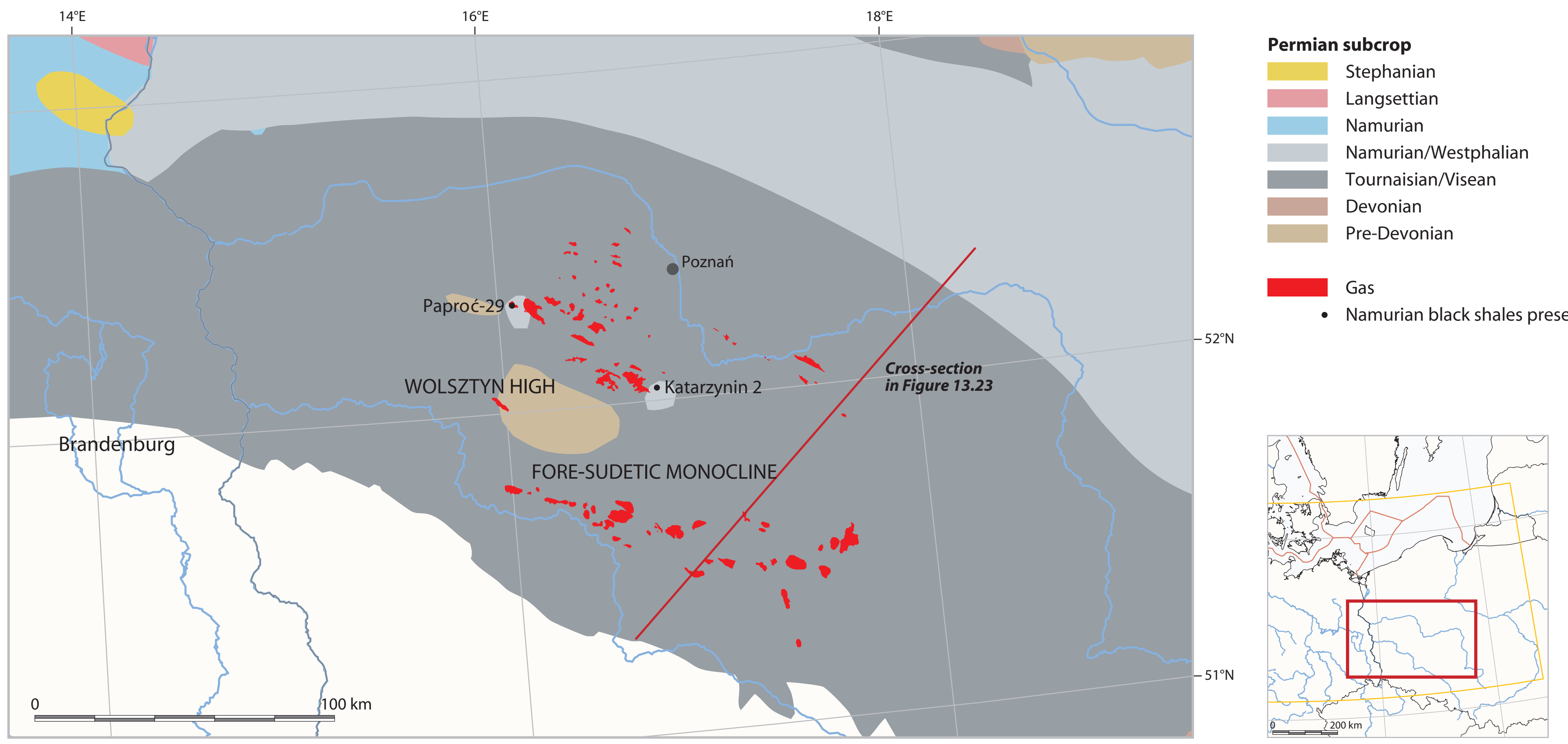


Figure 13.22 The Fore-Sudetic Monocline petroleum province with locations of fields and accumulations charged by Early Carboniferous and/or Namurian black shales (field locations not shown on the German side of the province).

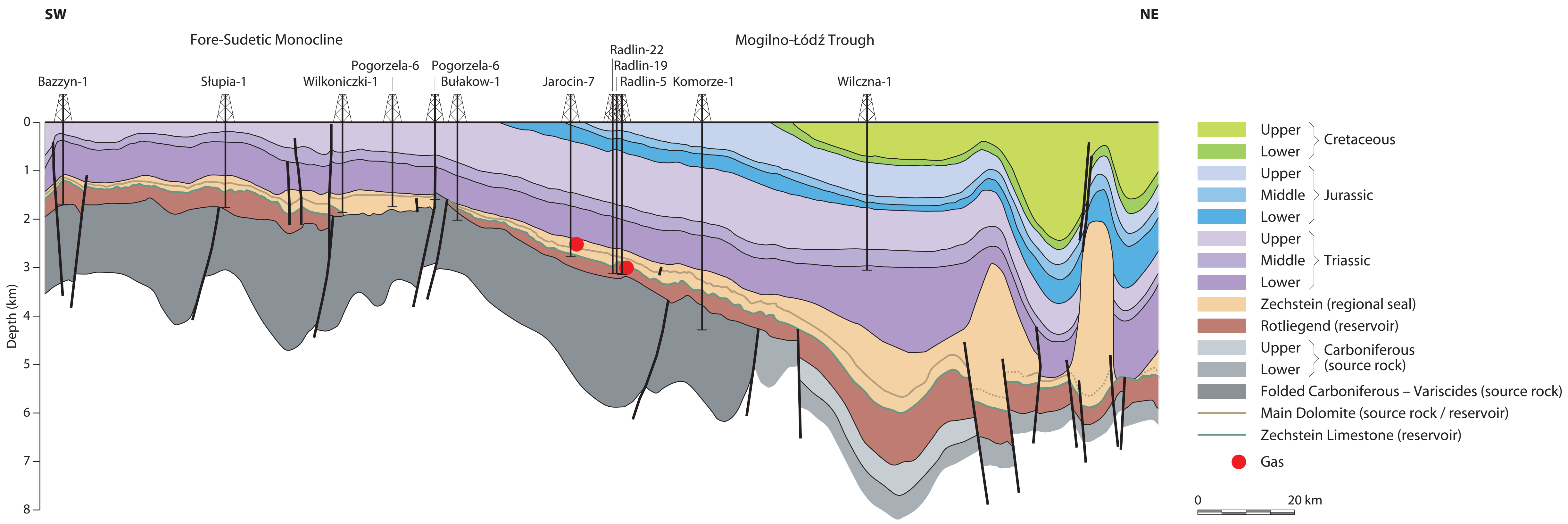


Figure 13.23 Schematic cross-section of the Fore-Sudetic Monocline (Cenozoic and Quaternary section removed) (modified after Górecki, 2006a). See Figure 13.22 for location.

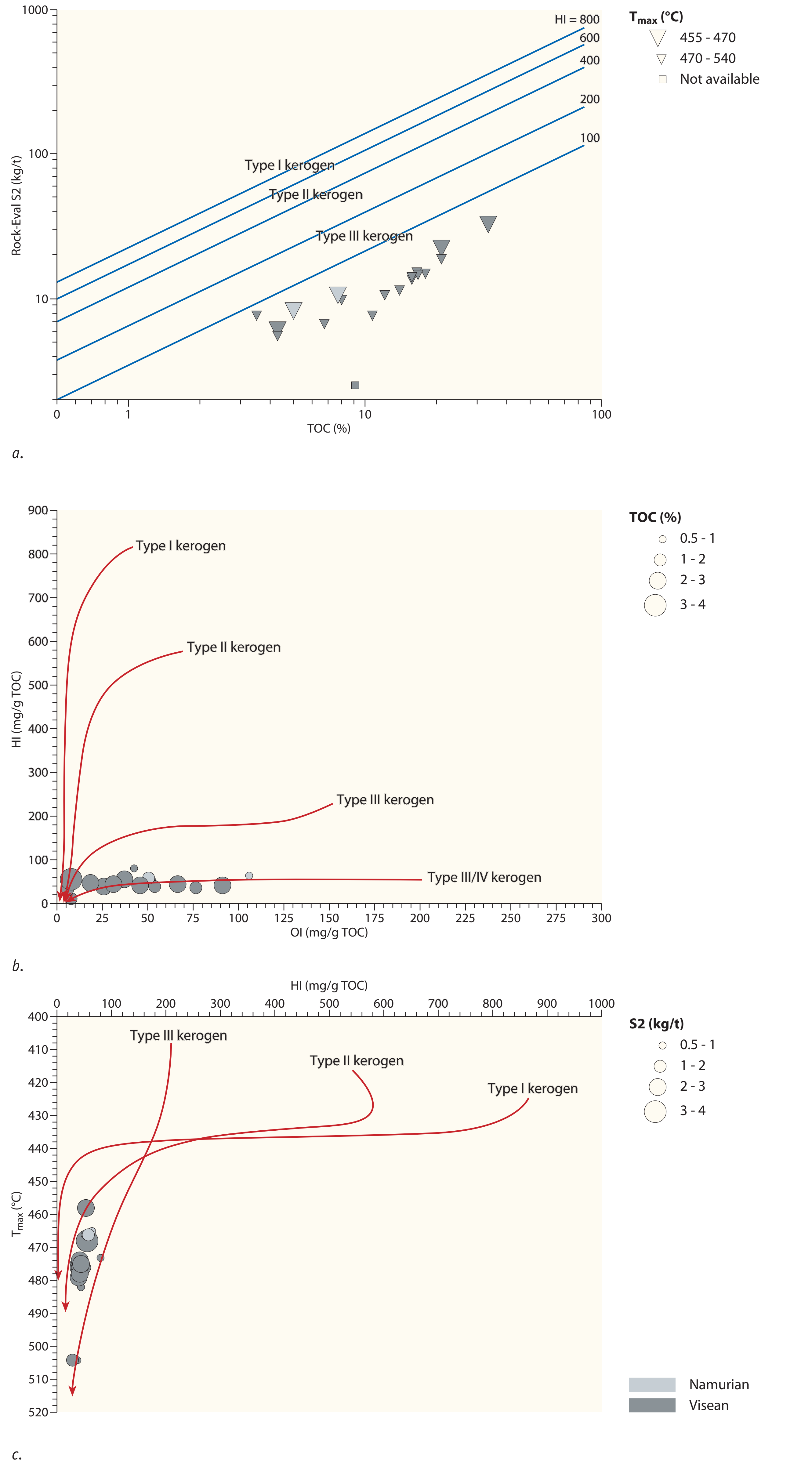


Figure 13.24 Geochemical data from different Lower Carboniferous and Namurian formations in the Fore-Sudetic Monocline: a. Pyrolytic yield (S2) versus TOC. All samples are within the type III kerogen field III kerogen; b. The pseudo-Van Krevelen plot shows that samples are aligned along the type III/IV kerogen (humic and/or recycled) trend line; c. T_{max} versus Hydrogen Index (HI). The elevated maturity of the measured samples resulted in the depletion of generative potential. Plots produced using IGI's p:IGI-3.

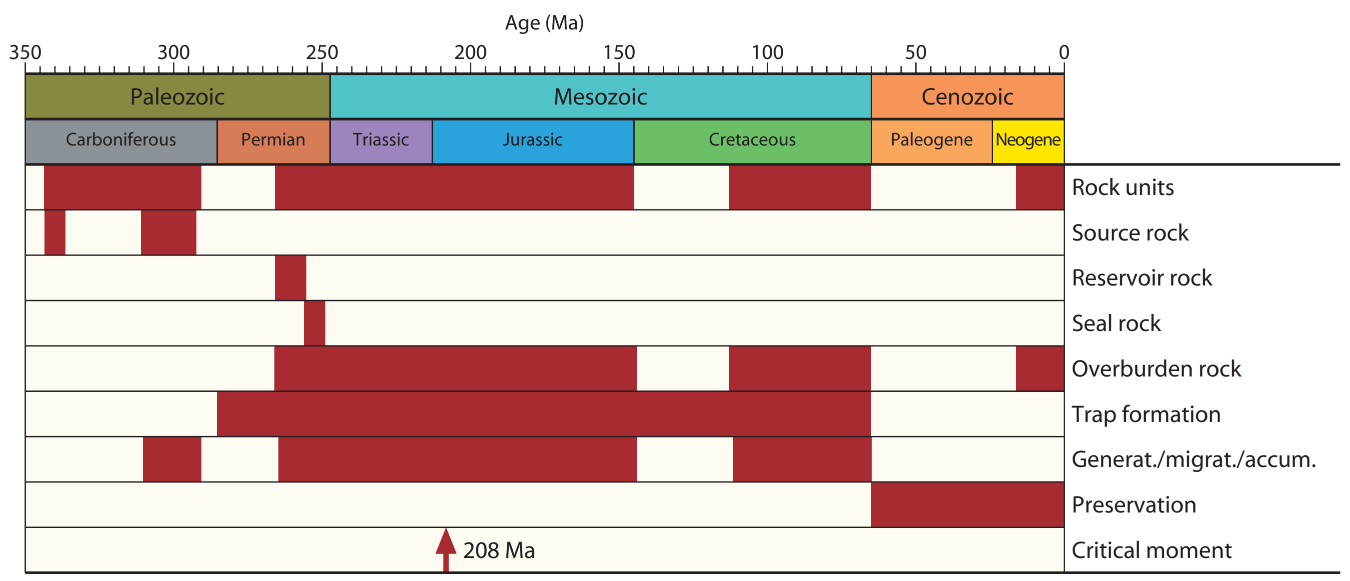


Figure 13.25 Event chart for the Early Carboniferous and Namurian petroleum system in the Fore-Sudetic Monocline petroleum province. Timescale of Harland et al. (1989).

Source rocks occur across the entire Lublin Basin except at the margins and a central north-west–south-east-trending axis where Namurian sediments were partly eroded. As seen in Pomerania and the Fore-Sudetic Monocline, the source rocks in the Lublin Basin are typically thick Visean to Westphalian siliciclastics with dispersed organic matter. Coal seams occur in the Namurian and lower Westphalian succession.

Visean shales have an average TOC content of 1.8%; the organic matter is mixed type II/III (**Figure 13.28a**). In addition to the predominantly low-TOC 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 organics are mainly terrestrial. Namurian siliciclastics have similar average TOC contents (2%) and maximum values (15.5%). Westphalian siliciclastics have an average TOC content of 1.5%. 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. The T_{max} (415-445°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 13.28b** & **c**).

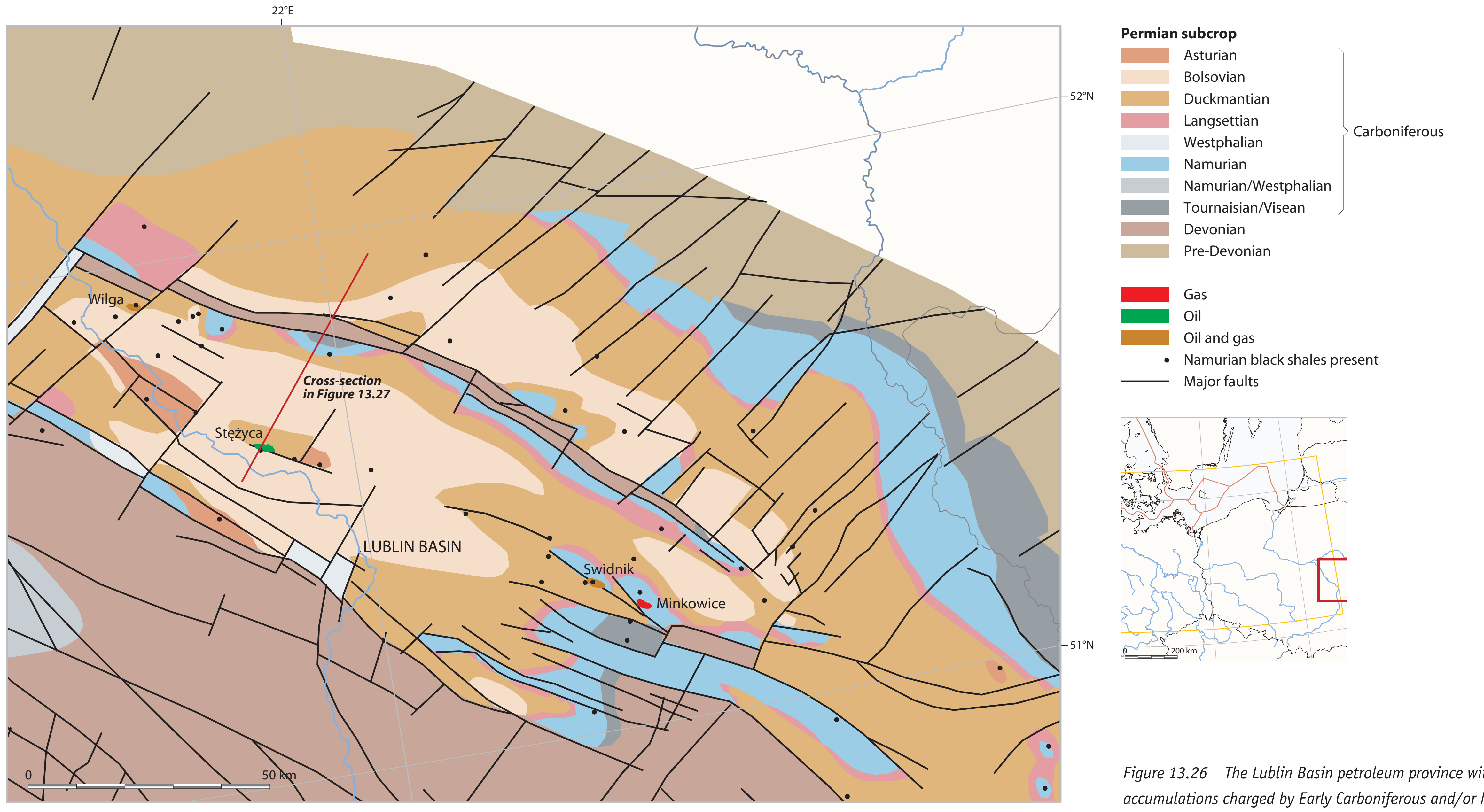


Figure 13.26 The Lublin Basin petroleum province with locations of fields and accumulations charged by Early Carboniferous and/or Namurian black shales.

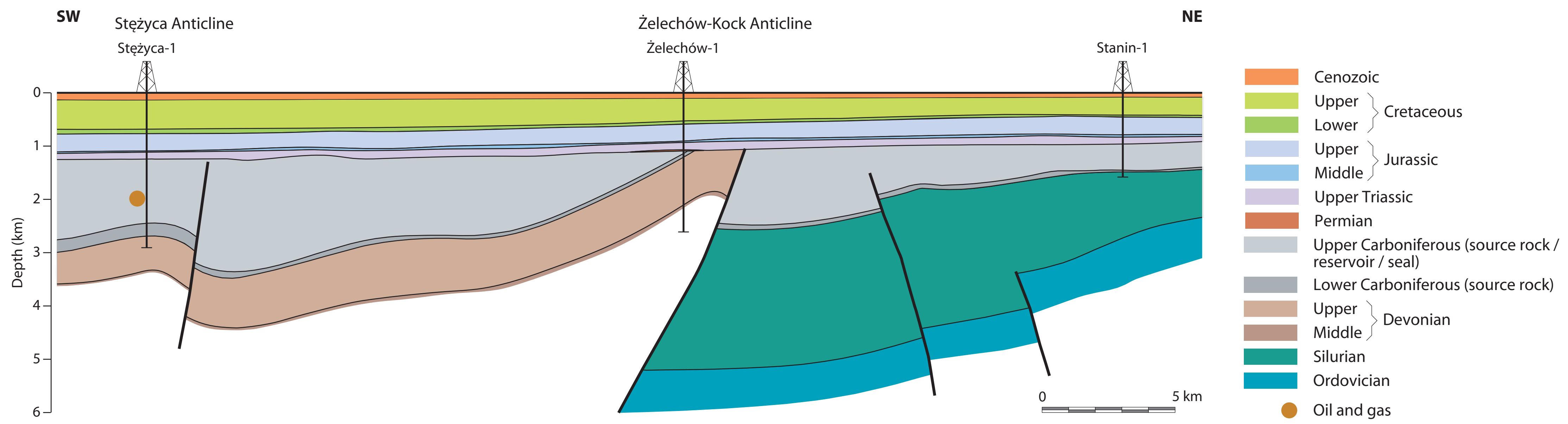


Figure 13.27 Schematic cross-section of the Lublin Basin (modified after Górecki, 2006a).

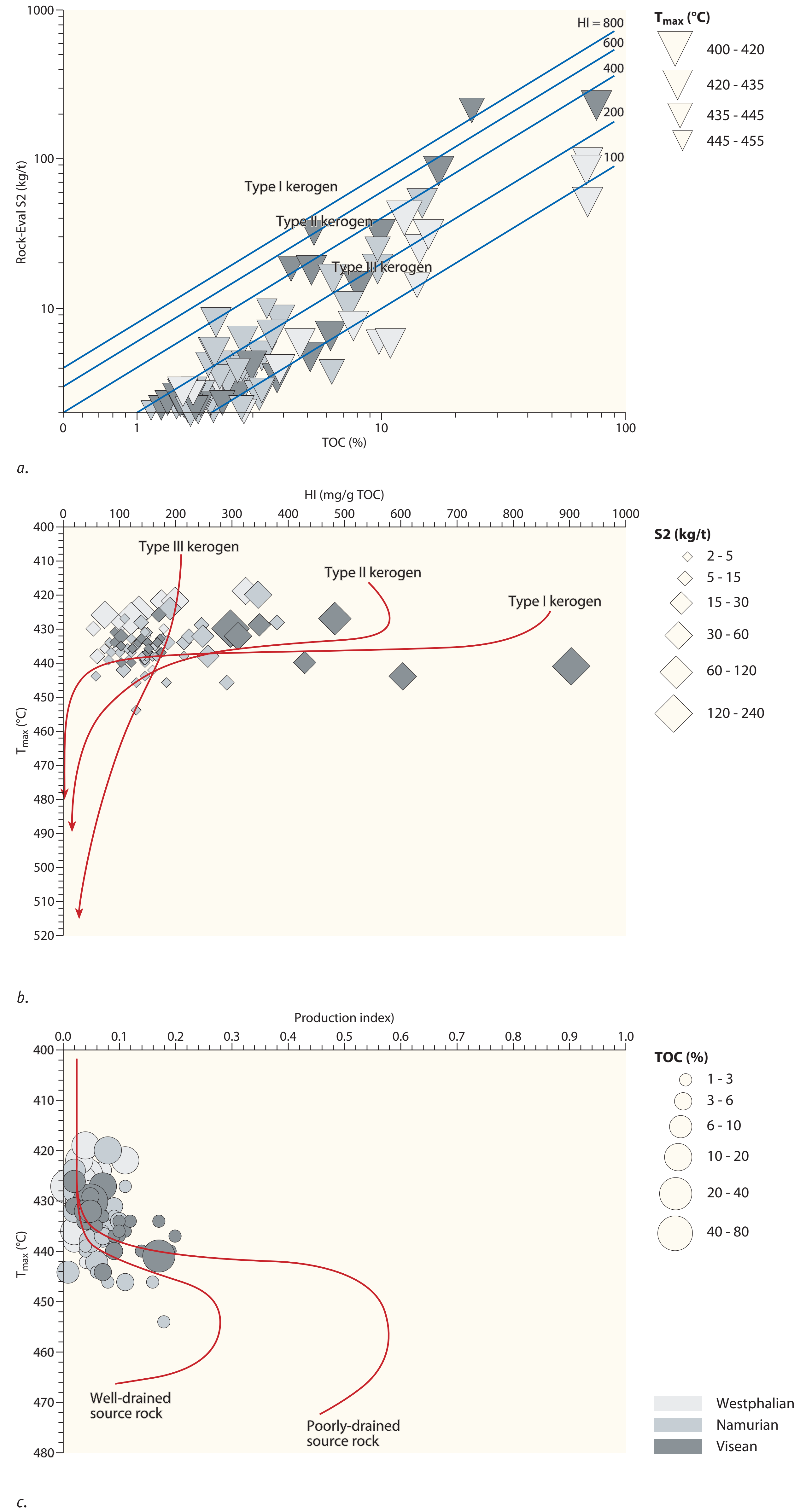


Figure 13.28 Geochemical data of samples from different lower Carboniferous and Namurian formations of the Lublin Basin: a. Pyrolytic yield (S2) versus TOC. In addition to many mature and non-source rock samples and a few immature coal samples with type III kerogen there are a number of atypical samples with hydrogen-rich kerogen; b. T_{max} versus Hydrogen Index (HI). Samples are mostly marginally mature to mature and comprise some unusual samples with type I kerogen; c. T_{max} versus Production Index (PI). Maturity-induced depletion has led to well-drained source-rock conditions. Plots produced using IGI's p:IGI-3.

The timing of petroleum generation and migration in the Lublin Basin, as well as reservoir and seal stratigraphy, differs significantly from the Pomeranian and Fore-Sudetic Monocline petroleum province (**Figure 13.29**). Generation started during the Westphalian in most of the area (transformation ratio mainly ~25%, reaching up to 60%) and had ended by the time of the Asturian inversion (300 Ma). In the north-western Lublin Basin, petroleum generation continued until the end of the Cretaceous (65 Ma), with transformation ratios never exceeding 11% 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 Pomerania. The main reservoirs are Namurian fluvial sandstones (Ø: 1-22%, K: 1-400 mD), which are sealed by interdistributary fine-grained sediments, prodelta shales and marine bands. The Carboniferous rocks in the north-western Lublin Basin are covered by mainly carbonate and anhydrite Zechstein deposits. The Stężyca oilfield is the most important in the region and comprises six reservoirs that range in age from lower Namurian A to Westphalian B (Chapter 6).

For further information see Botor et al. (2002), Kotarba et al. (2002), Karnkowski (2003a) and Grotek (2004).

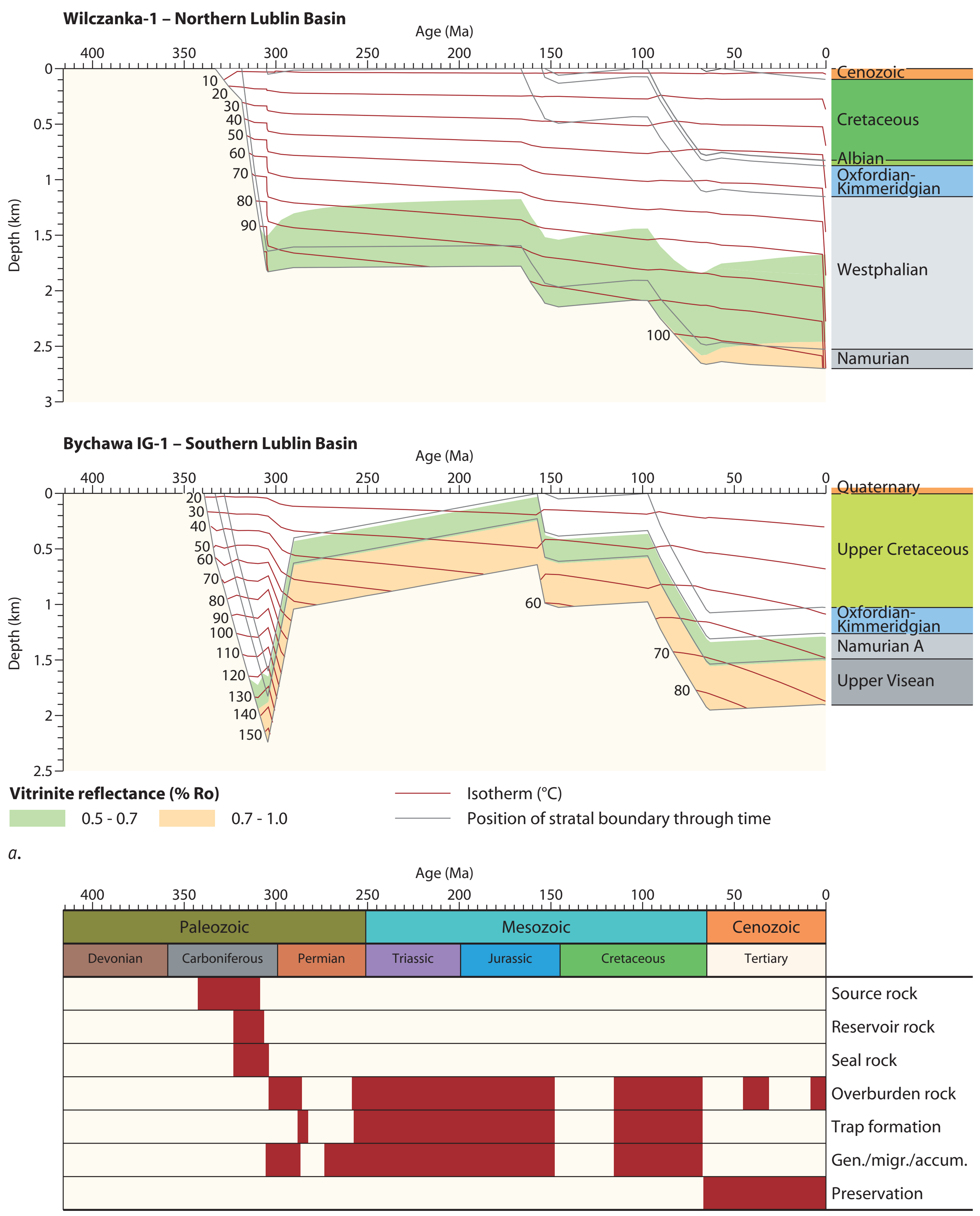


Figure 13.29 a. Burial and thermal history of wells Wilczanka-1 and Bychawa IG-1, which are typical for the northern and southern parts of the Lublin Basin respectively (modified after Botor et al. 2002). Timescale of Harland et al. (1989). The main phase of hydrocarbon generation when upper Visean and Namurian source rocks reached the oil window over much of the basin was during the Late Carboniferous and ended with Asturian inversion (~304 Ma). Only in the NW Lublin Basin did hydrocarbon generation continue until the end of the Cretaceous (~65 Ma). Maturities and transformation ratios of organic matter in Westphalian rocks are low. Most coals did not generate significant amounts of hydrocarbons; b. Event chart for the early Carboniferous and Namurian petroleum system in the Lublin Basin petroleum province.

2.3 Westphalian

2.3.1 Anglo-Dutch and North German basins

The largest Carboniferous petroleum (mainly gas) system in the SPB is sourced from Westphalian Coal Measures in an area extending from the UK offshore sector to western Germany (**Figure 13.30**). Despite the widespread distribution of the Coal Measures, their depositional environment and related source-rock properties are very similar throughout the area. However, 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 discoveries and fields of the region from Lower Carboniferous and Namurian source rocks.

The region was 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 Coal Measures, along with a wide range of post-Carboniferous reservoir rocks 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 (Yoredale Formation; Section 2.2.1), the most important coal-bearing deposits, the Westphalian Coal Measures, are Langsettian to Bolsovian. The deposits are up to 3000 m thick. The coals can form up to 6% of the section after compaction. The thickness of individual coal seams rarely exceeds a few metres and is mostly less than a metre. In most areas, the coals have a cumulative thickness of several tens of metres. The swamps in which these peat layers developed were part of an extensive lower-delta plain that covered large areas of the NWECB.

The Coal Measures (Chapter 6, 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. Elsewhere, tectonic inversion, especially during the late Carboniferous, has resulted in partial or locally complete removal of the Coal Measures.

Rock-Eval pyrolysis results from both coals and samples with no coals indicate the predominance of kerogens that straddle the boundary between oil-prone type II and gas-prone type III over a large range of TOC contents (**Figure 13.31a**). Oil staining is found above some of the shale layers overlying the coal seams, especially in the bands formed during marine incursions, which indicates their oil-generation potential.

Within a wide 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 coalification 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**). Farther east in the North German Basin, Westphalian organic matter is mostly in the gas window or overmature. The anomalously high coalification of gas-prone Westphalian source rocks in the Ems Low is a matter of ongoing research. Until a few years ago the localised coalification maxima were attributed to magmatic intrusion of the Bramsche and Apeldorn offshoots to the south-east. More recent studies suggest very pronounced deep burial of the sedimentary sequence prior to Late Cretaceous inversion.

Generation from Westphalian coals was widespread until Mid-Jurassic 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 accelerated within the rift basins as a result of increased subsidence and increased basal heat flow. As a consequence, the kerogen in these graben areas was almost completely transformed. In the Lower Saxony and Broad Fourteens 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 caused temperatures at the Westphalian source-rock levels to exceed the maximum temperatures reached earlier, gas generation resumed and eventually filled traps that formed after the uplift and inversion events.

Generation from Westphalian coals resumed during enhanced Neogene subsidence on the Pompeckj Block, where generation was most intense during Triassic to Jurassic burial. Generation in the Jurassic graben areas halted during the Late Cretaceous due to inversion-related uplift and declining heat flow. At the basin margins, where inversion had been limited and was followed by strong Cenozoic subsidence such as at the south-west margin of the West Netherlands Basin, charge from the Westphalian resumed during the Cenozoic and continued to the present day.

Widespread charge of Rotliegend reservoirs took place until Jurassic times (**Figure 13.32**). Gas was lost from some accumulations due to Late Jurassic and Late Cretaceous tectonic breaching of the existing traps. Renewed generation and migration during the Neogene resulted in some of these reservoirs being refilled. Consequently, the gas generated from deeper sources was largely replaced by gas derived from Westphalian sources with concurrent changes in gas composition. This type of evolution is envisaged for the Lauwerszee Trough to the west of the Groningen field, where low nitrogen contents are attributed to a more recent charge from Westphalian coals. Falling temperatures and hydrostatic pressures of the uplifted Coal Measures due to late Cretaceous inversion may have brought about additional gas desorption from these gas-prone source rocks and so adding to the pool of free gas.

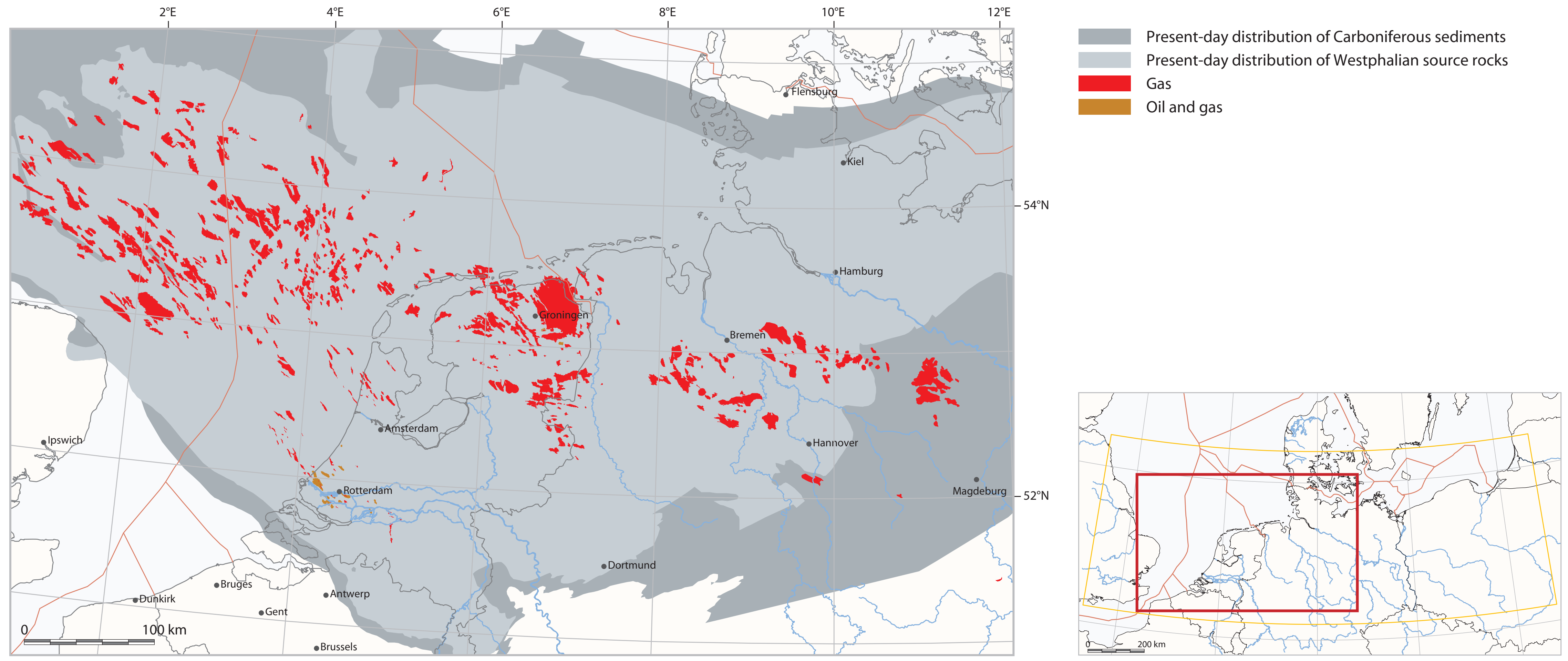


Figure 13.30 The Anglo-Dutch and North German basins petroleum province with locations of fields and accumulations charged by the Westphalian Coal Measures.

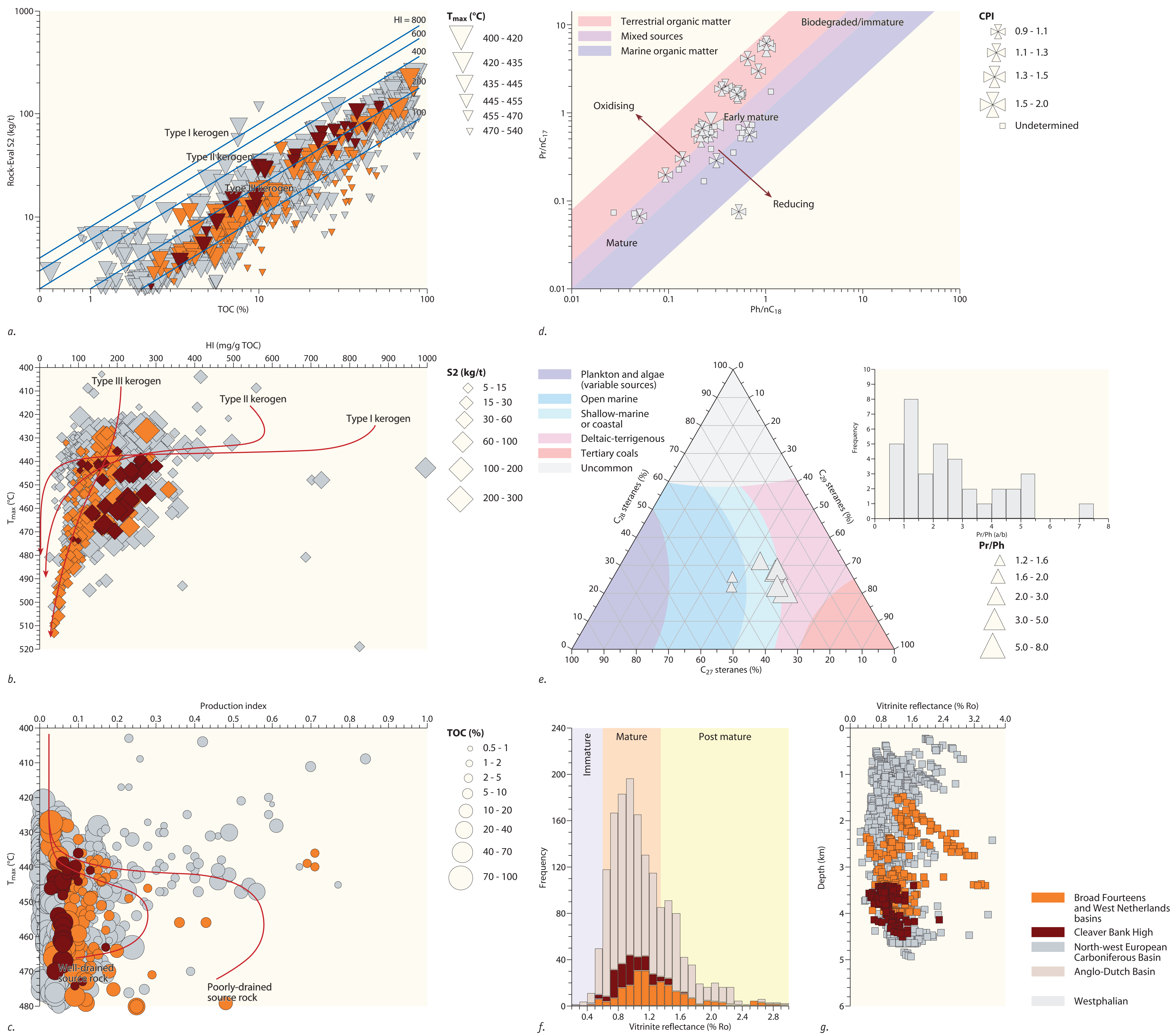


Figure 13.31 Geochemical data from Westphalian formations in the Anglo-Dutch and North German basins: a. Pyrolitic yield (S2) versus TOC. Coals with a Hydrogen Index (HI) of 200 or more would actually be oil-prone. However, maturity acts to depress the HI, as the pyrolytic yield is more rapidly depleted than organic richness (TOC), therefore lowering the HI;
b. T_{max} versus Hydrogen Index (HI);
c. T_{max} versus Production Index (PI);
d. Pr/n versus Ph/n;
e. Sterane ternary diagram. The sterane composition indicates the expected strong terrestrial component in the coal samples. However other samples reveal a distinct marine organic-matter influence. Inset shows pristane/phytane ratio, which covers a range that comprises both humic and sapropelic kerogen;
f. Vitrinite reflectance histogram. Differences in the maturity distribution of the Broad Fourteens and West Netherlands basins are related to different burial depths. Inset shows vitrinite reflectance versus sub-bottom depth;
g. Vitrinite reflectance versus sub-bottom depth. Plots produced using IGI's p:IGI-3.

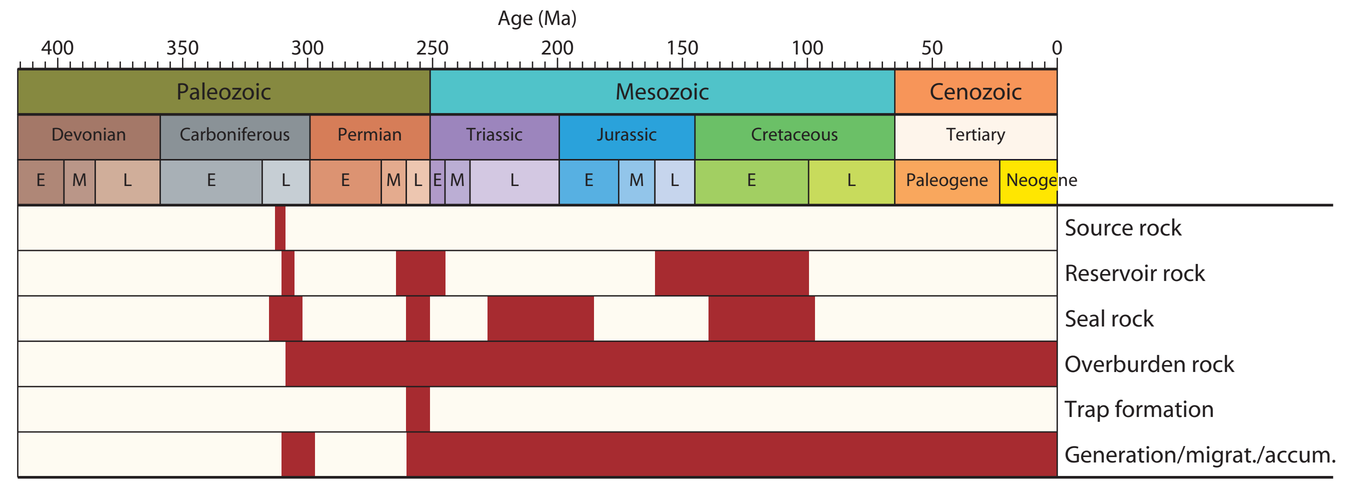


Figure 13.32 Event chart for the Westphalian petroleum system in the Anglo-Dutch and North German basins petroleum province.

Hydrocarbons generated from the Coal Measures accumulated in reservoirs at almost all stratigraphic levels. The major control appears to be the presence or absence of sealing units in the overburden. Traps in combination with Carboniferous reservoirs are mostly dip-fault closures at the Base Permian Unconformity. Stratigraphic traps also occur in places such as the Weissenmoor 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 Groningen field. In the area from Groningen southwards to offshore blocks K and L, gas in Rotliegend reservoirs is mostly trapped in simple horst blocks. Zechstein traps are predominantly fault-dip 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 turtle-back anticlines, salt-wall bounded or fault-dip closures related to halokinesis of the Zechstein salt.

The seals in the Silverpit / Cleaver Bank High area are formed by claystones and evaporites of the Silverpit Formation and locally by intra-Westphalian shales and tight faults. Zechstein evaporites form the most important seal in the eastern Netherlands and neighbouring Germany.

The majority of fields in the Anglo-Dutch Basin (78%) have reserves in Rotliegend sandstones. Most of the fields are located in the basin axial areas where thick Zechstein evaporites were deposited and which form the major seal. A minority are located on the basin margin with slope and lagoonal/platform Zechstein facies. Evaporites 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 facies dependent and therefore they do not occur in the shaly deposits 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 fair to good poro-perm properties in the UK and the Netherlands (Ø average: 9%, Ø max: 20%; K average: 1-2 mD, locally >100 mD). However in the Ems Low, the reservoir properties of Carboniferous sandstones are generally poor and although gas-bearing they rarely warrant commercial production due to their low porosity and permeability.

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 Coevorden field; see Section 6.3.4 in Chapter 6). Sealing is provided by Zechstein salts and anhydrites. Fractured Stassfurt carbonates are the most important reservoirs in the Ems area as the Rotliegend deposits are much thinner and have suffered severe reservoir deterioration due to illite growth.

Triassic reservoirs occur in a variety of trap styles at locations where the Zechstein seal is absent or breached. The distribution of Buntsandstein fields can be correlated with the underlying Rotliegend gasfields or the productive Zechstein Stassfurt Carbonate. There is a direct relationship between the migration barriers and migration pathways in the Zechstein. The Upper Triassic evaporitic shales generally form the top seal of the reservoirs with sporadic sealing by Lower Cretaceous shales in places where the Triassic succession is truncated by the Base Cretaceous Unconformity. Side seals are provided by juxtaposed Upper Triassic to Lower Jurassic shales in the horst structure.

Some of the Upper Jurassic and Lower Cretaceous hydrocarbon fields have a varying contribution (major to minor) from Westphalian source rocks. The distribution of these fields is restricted to the Cimmerian rift basins. This contribution is also limited by an unfavourable 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-derived gas are found in the Chalk Group and the Cenozoic (e.g. the Harlingen field in the northern Netherlands).

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

2.4 Zechstein

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

Oil source rocks such as the basal Zechstein Kupferschiefer (Copper Shale) Member and the Stinkschiefer Member of the lower Hauptdolomit / Main Dolomite Formation are widely distributed across the SPB (**Figure 13.33**). The dark-coloured Copper Shale Member is a metal-enriched basinal deposit characterised by increased organic-carbon contents. During deposition of the basinal Stinkschiefer Member (fetid shale), the correlative Stinkkalk and Stinkdolomit members were deposited as isolated pods on the arid platforms and slopes around the Zechstein Basin (Chapter 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 1950s. However, most Zechstein discoveries in the western SPB are sourced from Carboniferous deposits and only a few have a Zechstein source (**Figure 13.33**). This is partly related to the limited thickness (minor petroleum yields) of the Zechstein source rocks and to later flushing of many Zechstein-sourced accumulations by Westphalian gas.

Another reason for the patchy distribution of major Zechstein-sourced petroleum accumulations is that the widespread basinal sediments often have limited source-rock qualities. Organic-carbon contents and generative potential within the Stinkschiefer Member are therefore generally low. Permeabilities are also low and reservoir facies are scarce in the typical carbonate mudstones of the basinal palaeoenvironments. There is usually sufficient type II kerogen for petroleum generation in sediments on the toe and on the middle slope, where there are also adequate reservoir facies.

There are notable contributions from lower Zechstein source rocks in Rotliegend and Buntsandstein accumulations between the south-eastern North Sea and the Ems Low, where oil-prone Zechstein source rocks are often correlated with high condensate contents in Rotliegend gas. Residual oil in the Slochteren sandstone suggests an early oil charge from lower Zechstein source rocks. However, the composition of condensates from Upper Carboniferous to Bunter reservoirs in the Ems Low differs significantly from that of typical lower Zechstein oils. Apart from these few fields, and contributions to oil accumulations, most of the economically interesting discoveries from Zechstein sources are concentrated in the eastern SPB.

The Zechstein petroleum system in the central and eastern SPB is distinguished by the following characteristics:

- the palaeoenvironmental diversity of its source rocks, including carbonate-evaporite facies;
- very short migration pathways from shallow-water algal laminites to the adjacent carbonate sandstones;
- complex post-trapping histories with widespread flushing of existing accumulations, mostly by Westphalian-sourced gas.

Although slope and basinal facies have been invoked as sources for a number of deposits, the most characteristic source rocks in the central/eastern Zechstein petroleum provinces are the laminated carbonate mudstones and boundstones that were laid down in low-energy evaporitic lagoons on the platform or on detached platforms (also called 'off-platform high' or 'peninsula'). They locally contain abundant (>20% TOC), hydrogen-rich type I kerogen and botryococcene, a remnant of botryococcus algae that is commonly detected in these oil-prone source rocks.

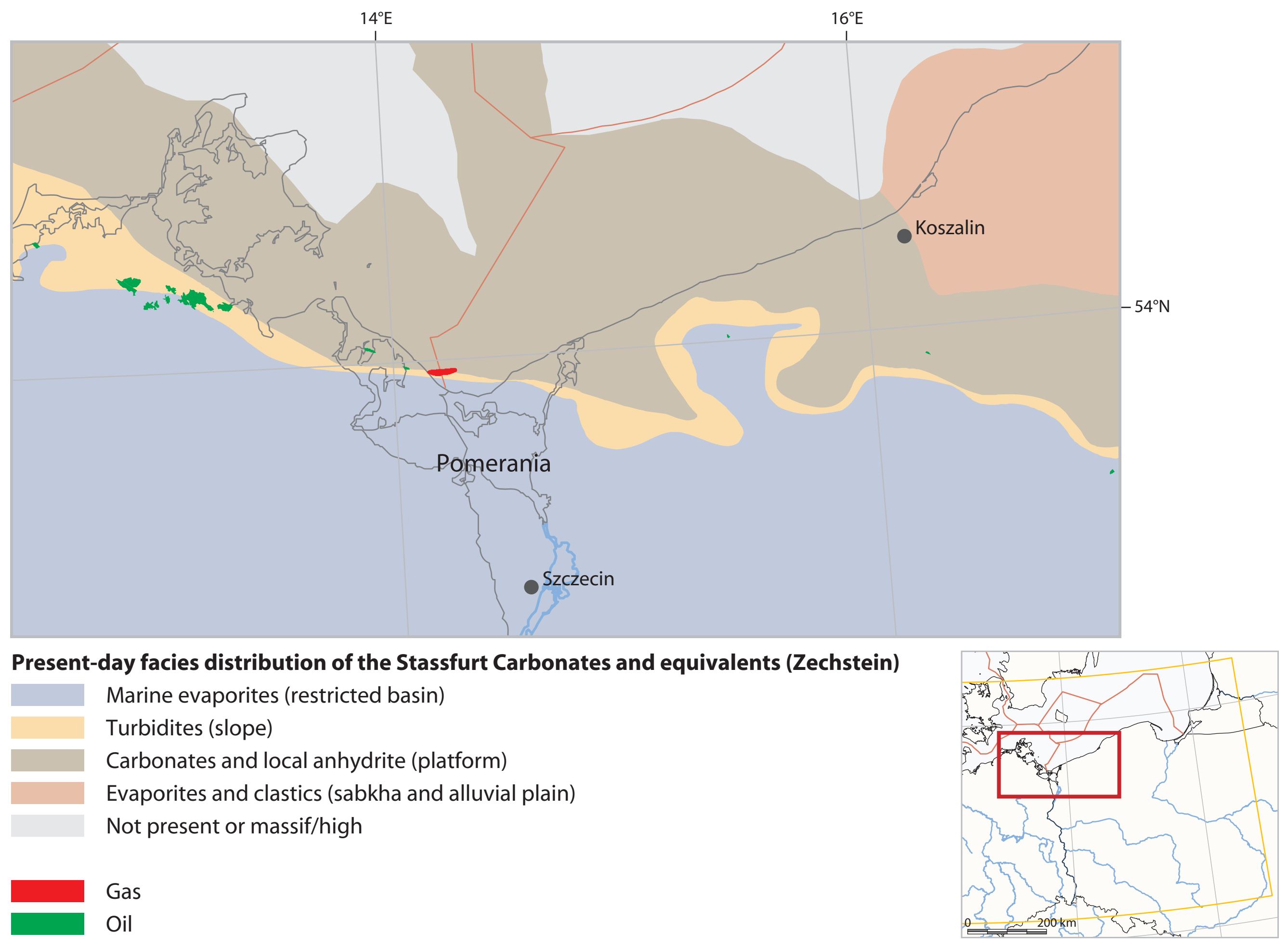


Figure 13.33 The Pomeranian petroleum province with locations of fields and accumulations charged by Zechstein source rocks. Note the striking coincidence of fields with the carbonate-platform facies belt in the eastern SPB. In the western part of the basin only a few, isolated fields occur within the area of basinal palaeoenvironments (i.e. Stadskanaal, Gieterveen, and E13-1).

Charges 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, but its contribution to the overall charge is difficult to assess due to its great loss of mass during generation. Petroleum generated from the algal source rocks had extremely short migration pathways because the lagoonal deposits are often fringed, underlain or overstepped by high-energy carbonate grainstone and packstone with excellent reservoir properties.

The downside of these peculiar carbonate-evaporite source rocks is their tendency to generate undesirable non-hydrocarbon gases, such as H_2S, CO_2, and N_2. Furthermore, because lower Zechstein source rocks were formed only under regionally restricted environmental conditions, the structures were charged with petroleum generated within limited areas at high rates along short migration pathways, and so volumes tend to be low.

Fields and economically interesting discoveries sourced from carbonate-evaporite facies are found along the northern (Pomerania) and southern (Fore-Sudetic Monocline, Thüringian Basin) margins of the Zechstein Sea. Whereas production on the German side of these provinces (Vorpommern, Lusatia and Thüringian Basin) is relatively minor, oil accumulations charged from Zechstein source rocks are the mainstay of the Polish oil industry.

Regional maturity trends are controlled mainly by burial depth. As burial depth is in turn commonly concordant with the zonal palaeoenvironmental and facies pattern of the Zechstein Sea, the maturity trends grossly follow the different facies belts. Organic matter deposited in the platform environments, commonly buried to 1000 m depth, is therefore generally at an early mature stage (0.5-1% Rr). Maturity gradually increases up to the late condensate and dry-gas phases (>1% Rr) in source rocks deposited in slope and basinal palaeoenvironments that were typically buried to depths greater than 1800 m; overmaturity prevails in the deepest parts of the basin.

Crude oils attributed to Zechstein sources share a number of compositional properties (even-numbered *n*-alkane predominance, high triterpane and sterane content, low diasterane concentration, pristane/phytane ratio <1) which suggest a moderately mature carbonate source rock. Geochemical differences in the oils and source rocks of Pomerania and the Fore-Sudetic Monocline and adjacent regions are described in the regional sections below.

Natural gas is derived from either lower Zechstein or pre-Zechstein sources. Autochthonous gas mostly consists of microbial methane with minor thermocatalysed methane and higher hydrocarbon homologues. Nitrogen is possibly derived from ammonium (NH_4^+)-enriched formation water. Allochthonous gas is coal-derived methane and nitrogen from pre-Zechstein sources.

For further information see Gerling et al. (1996a, 1996b) and De Jager & Geluk (2007).

2.4.1 Pomerania

On the north-eastern margin of the Zechstein Sea, Stassfurt Carbonate and Main Dolomite sediments were laid down on Werra evaporites on a narrow, poorly differentiated north-west–south-east-trending platform. Most Zechstein petroleum discoveries and fields in Pomerania contain oil, although gasfields also occur (**Figures 13.33** & **13.34**). Average reservoir porosities in the Zechstein carbonates / Main Dolomite members vary widely (0-10%; 6% on the Kamień Pomorski Platform) and average permeabilities rarely exceed 10 mD.

Zechstein source rocks in Pomerania reached the early generation phase (>10% transformation ratio) during the Early Triassic in the axial part of the basin and the Late Triassic on the platform (**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 entering the expulsion window (25-65% 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 in the basin to the Late Cretaceous on the slope and platform, when 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 render these properties highly variable, both laterally and vertically, even within individual discoveries, and may lead to severe reservoir deterioration. For example, in the Kamień Pomorski oilfield, zero-porosity and zero-permeability zones within the reservoir considerably constrain the migration pathways. The directly overlying Basal Anhydrite (A2) and Older Salt (Na2) members, and other Zechstein evaporites, form efficient seals for the Main Dolomite reservoirs.

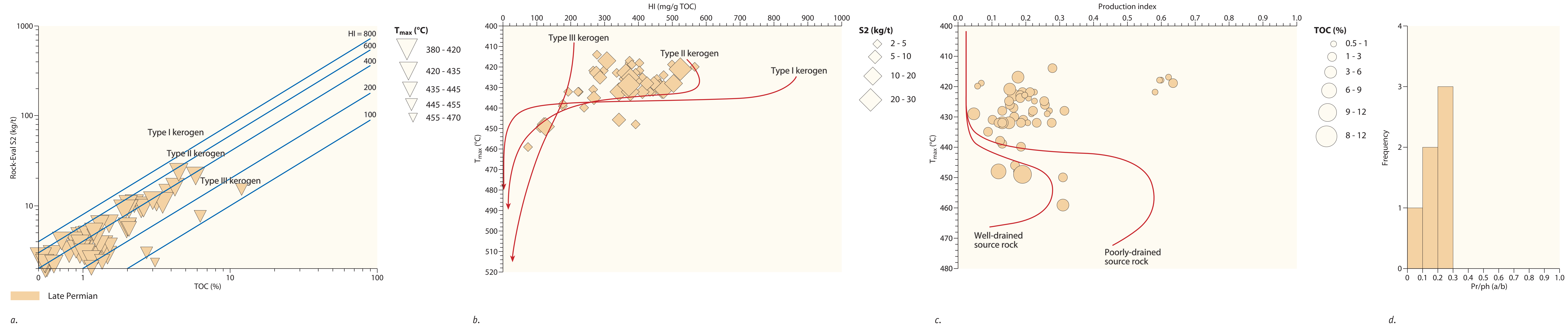
Pomeranian Zechstein-sourced crude oils have densities higher than 0.8 g/cm^3 (lower than 45° API). The heaviest oils occur in slope accumulations (Wysoka Kamieńska) and the lightest oils are found in basinal deposits. Organic-sulphur content (0.18-1.32 wt.%) is positively correlated with oil density throughout the region. Oil composition is relatively homogeneous across the palaeogeographic zones of the province. Oils mostly consist of saturated hydrocarbons (> 57 wt.%), which have low saturated versus aromatic hydrocarbon concentrations (3.6-8.3) that suggest short migration distances. The composition of *n*-alkanes and isoprenoids (CPI, Pr/n-C_{17}, Ph/n-C_{18} and Pr/Ph) indicates a marine origin. Such an environment is marked by CPI values lower than 1, increased relative concentration of the C_{12} alkylbenzene, the presence of isoprenbenzene and isoprentoluene (C_{27} iso) and CPI of alkylcyclohexanes markedly higher than 1. Pr/Ph ratios lower than unity in all oils indicates anoxic conditions during deposition of the organic matter. Gammacerane, isorenieratane and acrylic isoprenoids in most platform oils, and their higher-than-unity homohopane index, point to their generation in a photic-zone anoxia and to deposition in a carbonate environment under reducing conditions. The lack of these latter compounds in the basin suggests suboxic deposition and attendant decomposition, leading to lower hydrocarbon accumulation in this area. Particularly increased diasterane concentrations, the presence of secohopanes and the absence of gammacerane in crude oils from the basin, testify to their derivation from clayey deposits. Thermal maturity of the crude oils corresponds to the trend of increasing organic-matter transformation towards the axial parts of the basin and ranges from the top to the middle oil window.

Hydrogen sulphide in natural gas from the Kamień Pomorski, Rekowo and Brzozówka-1A fields was mostly formed through microbial reduction, whereas thermochemical sulphate reduction accounts for about half of the H_2S in the Błotno field. The predominance of the microbial component is evidence for early trapping and efficient sealing by the Stassfurt evaporites.

Further reading: Głogoczowski & Jędrychowska (1974), Głogoczowski et al. (1977), Kosakowski & Kotarba (2002), Kotarba et al. (2000a), Kotarba et al. (2003), Kosakowski et al. (2003), Kowalski (2006), Kotarba & Wagner (2007).

2.4.2 Fore-Sudetic Monocline and Brandenburg

In contrast to the north-eastern Pomeranian margin, the bathymetry of the south-western Zechstein Sea was highly variable (**Figure 13.36**). Platform lagoons were separated from the slope by carbonate sand bars and the platform margin was dissected by large-scale deep embayments and intervening salients. The latter are referred to as 'peninsulas' or 'off-platform highs' with isolated carbonate platforms on top (e.g. the Grotów 'peninsula'; **Figure 13.37**). These bays, salients and off-platform highs produced a complex lateral facies pattern in the developing carbonate-dominated deposits of the Stassfurt Formation. Deposition of the Stassfurt Carbonate is characterised by facies belts that are broadly parallel to the margin. The facies consist of coastal sabkhas and neritic carbonate sand shoals on the platform margin and off-platform highs to thin-bedded carbonate mudstones on the slope and in the basin.



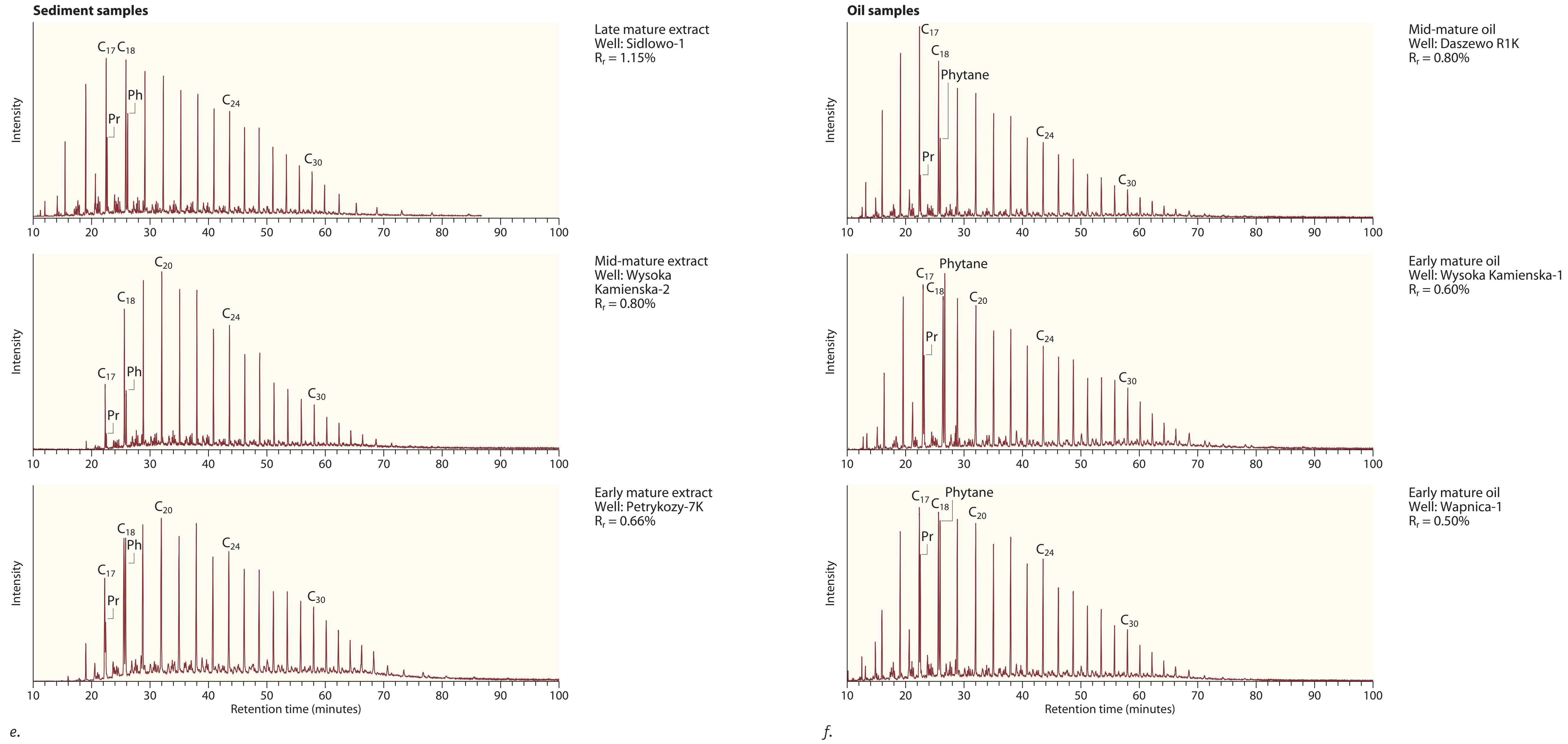


Figure 13.34 Geochemical data from lower Zechstein samples of the Pomeranian petroleum province:
a. Pyrolytic yield (S2) versus TOC. Most samples are immature and contain type II kerogen. The presence of some samples with type III kerogen is probably unrelated to input of higher plant remains, but likely 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 labile than standard type II kerogen;
c. T_{max} versus Production Index (PI). Unusually elevated PI values are likely related to the presence of migrated hydrocarbons;
d. Pr/nC_{17} versus Ph/nC_{18};
e. Chromatograms of n-alkanes and isopreonoid distribution in Zechstein Main Dolomite carbonate sediment samples;
f. Chromatograms of n-alkanes and isopreonoid distribution in Zechstein Main Dolomite oil samples.
Plots produced using IGI's p:IGI-3.

Slightly restricted conditions developed in the lagoons along the Thüringian margin; however, more pronounced restriction influenced the environments on the Fore-Sudetic Slope, including its Lusatian segment (Brandenburg Slope). The Brandenburg Slope developed much like the Fore-Sudetic Monocline with concentric facies belts around the Zechstein Basin. In contrast to the open slopes of the Fore Sudetic Monocline and Lower Lusatia, Stassfurt deposits of the Thüringian Basin were deposited in an originally north-north-east-trending extension of the central European Zechstein Sea. Before it was flooded by the Zechstein Sea, the Thüringian Basin was part of the Saar-Saale Trough that accumulated up to several hundred metres of Westphalian and Rotliegend siliciclastics 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 Grotów salient (**Figure 13.37**) is an excellent example of variability in lithofacies, palaeogeography, petrophysics 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 basinal, slope and platform environments. Carbonates deposited on the platform, and within oolite barriers, commonly consist of grainstones and packstones with porosities up to 26%. However, deposits with average permeabilities greater than 10 mD are only found in limited areas (e.g. the Barnówko-Mostno-Buszewo oilfield and the Lubiatów-Międzychód-Grotów oil and gasfield.)

As seen in Pomerania, petroleum generation in the Fore-Sudetic Monocline basinal deposits started during earliest Triassic times, with burial depth greater than 1700 m (**Figure 13.38**). The Main Dolomite source rocks entered the oil window in the Late Triassic (basinal deposits) with burial to approximately 2000 m, and in the Early Jurassic (platform deposits) with burial to about 1800 to 2200 m. After the Early Jurassic, generation spread across the entire carbonate platform of the Fore-Sudetic – Silesian region. Generation ended during the Late Triassic (basin) and in the Middle Jurassic (platform). The source rocks on the Brandenburg Slope entered the oil window during the Jurassic and reached peak generation (0.8-1.2% vitrinite reflectance equivalent) prior to the Late Cretaceous inversion.

Crude oils that accumulated in the Main Dolomite rocks of the Fore-Sudetic Monocline were generated from type II kerogen, as indicated by the distribution of *n*-alkanes and isoprenoids, and values of the Pr/Ph, Pr/n-C_{17} and Ph/n-C_{18} indicators. The indicators are evidence of algal-source matter (CPI values and Pr/Ph less than 1), principally in the middle and final phases of low-temperature thermocatalytic processes (the oil window). They are also evidence for the absence of secondary processes of biodegradation. These oils are characterised by densities of 0.736 to 0.896 g/cm^3 and sulphur contents ranging from 0.08 to 1.67 wt.%. The sulphur contents increase with increasing densities. Analysis of relative concentrations of aromatic sulphur compounds (methyl-dibenzotiophenes) allows the estimation of the thermal maturity. In the north, vitrinite reflectance ranges from 0.6 to 1.25% and increases from the west to the east. In the south, values range from 0.6 to 0.98%. The ratio of saturated to aromatic hydrocarbons in these zones is less than 25, which confirms the short migration routes from the source rocks.

Natural-gas composition in the Fore-Sudetic Monocline is more variable than in Pomerania. It usually contains negligible microbial components, but thermochemical sulphate reduction has produced considerable H_2S (Mostno, Zielin fields, Stanowice-2 well). There may be a substantial admixture of gas from highly mature type III kerogen from probable Carboniferous source rocks in wells Chlebowo-10, Sučcin-21, Kościan-9, Kościan-11, and Wierzchowice-20.

In addition to the Zechstein hydrocarbons, nitrogen probably entered several reservoirs on the Brandenburg Slope and in the Thüringian Basin after the reservoirs became hydrocarbon-charged. The nitrogen is derived from deeply buried Paleozoic sediments. High CO_2 contents in the gasfields of Thüringia correlate with Cenozoic basaltic volcanism. The H_2S can be explained by either bacterial or thermochemical sulphate reduction. The methane content in the larger deposits (Behringen, Mühlhausen) is about 50%.

For further information see Głogoczowski & Jędrychowska (1974), Głogoczowski et al. (1977), Botz et al. (1981), Gerling et al. (1996a,1996b), Wehner (1997), Behla et al. (1998), Karnin et al. (1998), Merkel et al.

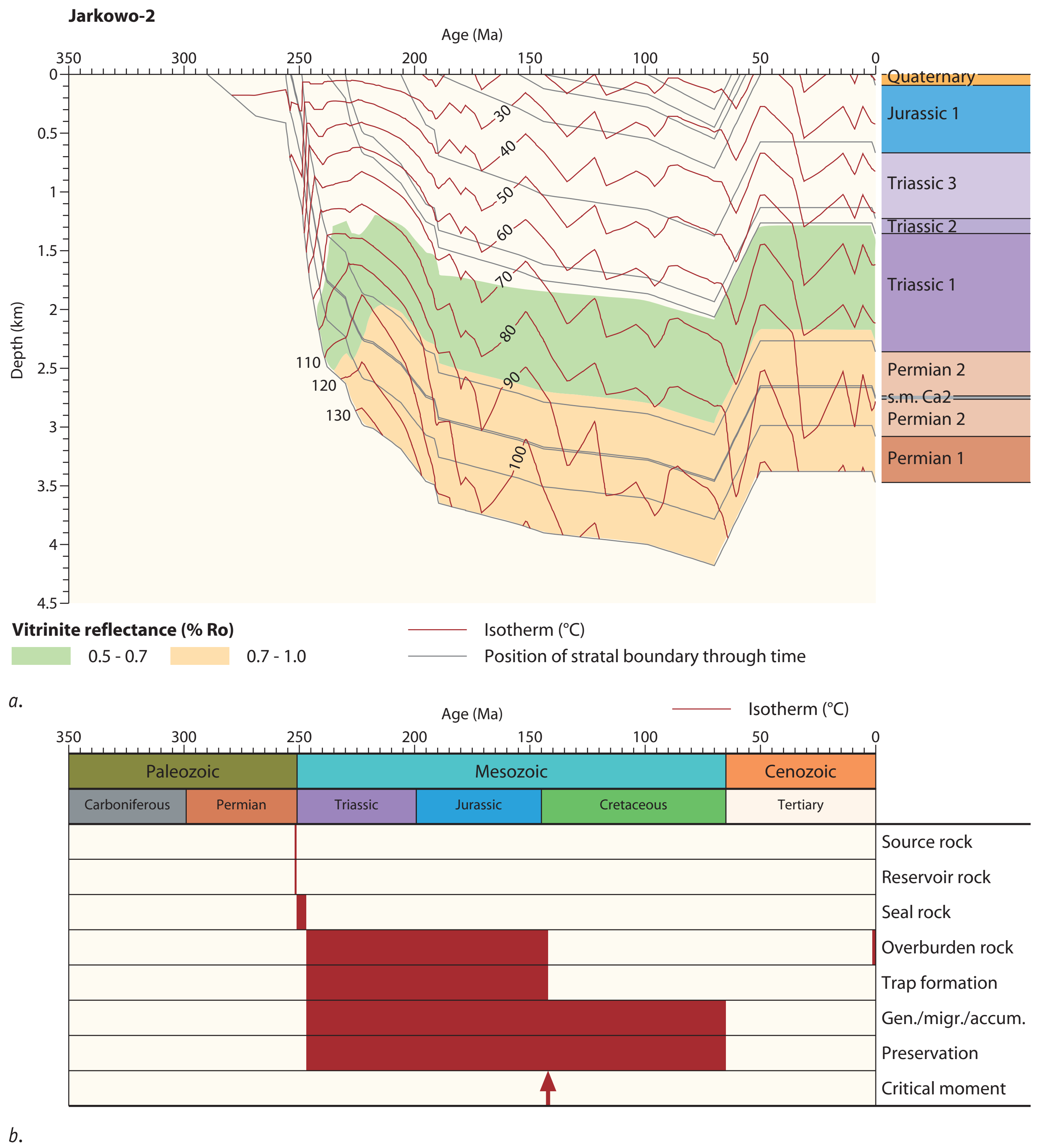


Figure 13.35 a. Burial history and modelled vitrinite reflectance history for well Jarkowo-2. Timescale of Harland et al. (1989); b. Event chart for the Zechstein / Main Dolomite petroleum system in the Pomeranian petroleum province.

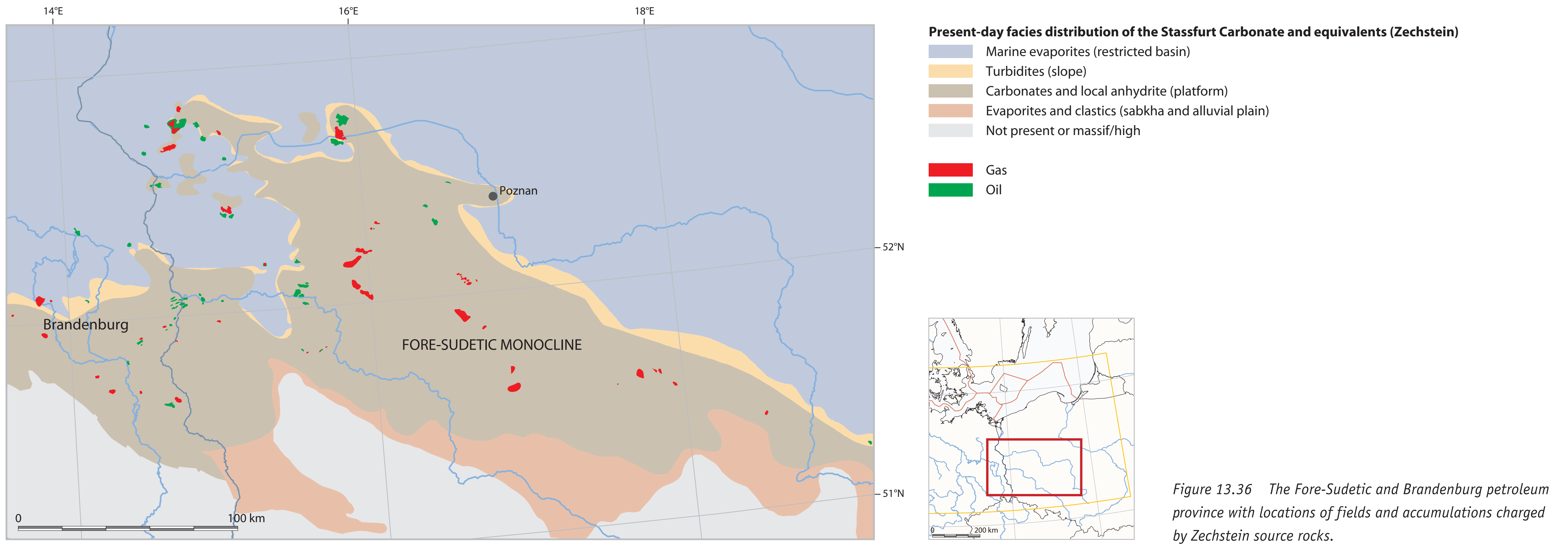
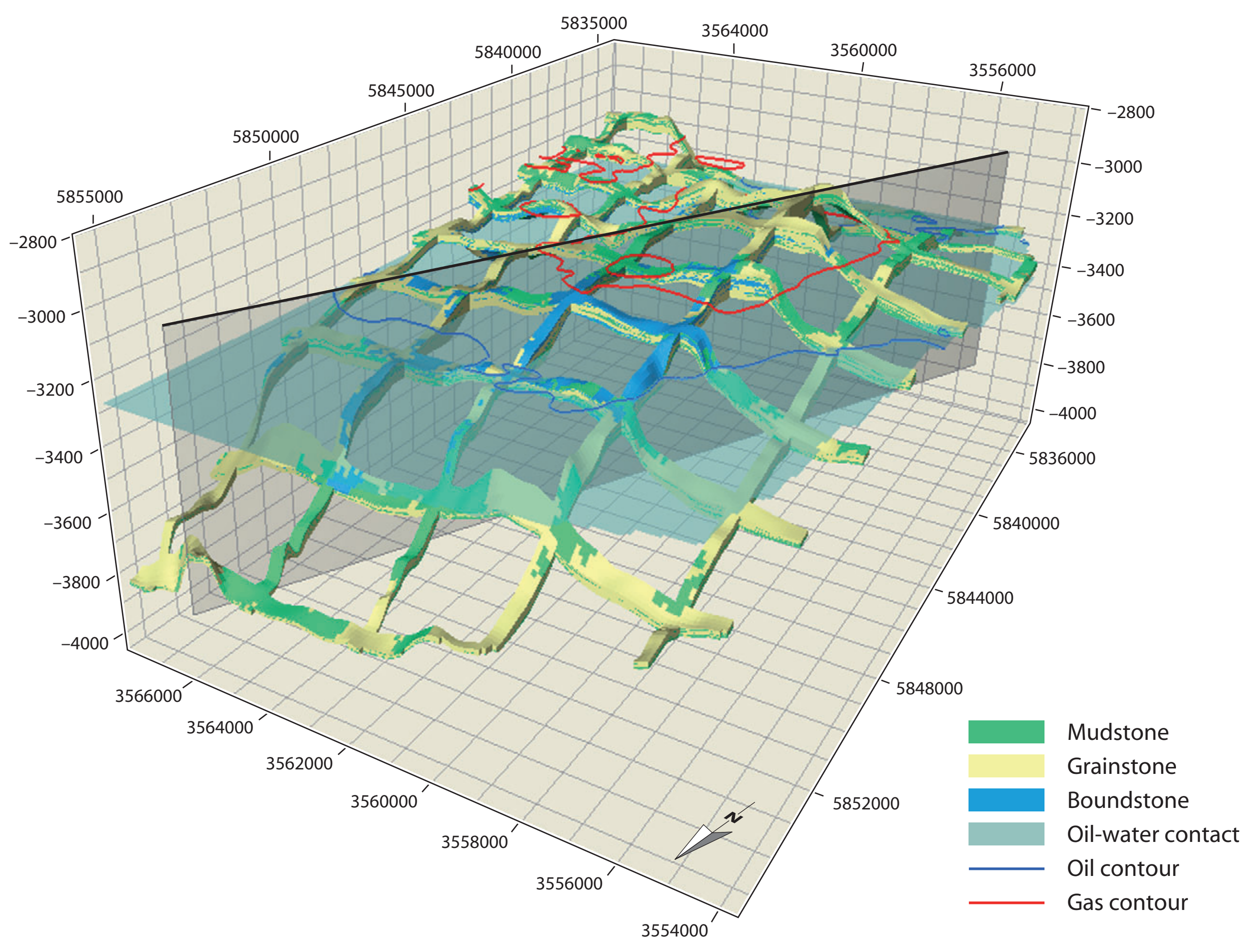


Figure 13.36 The Fore-Sudetic and Brandenburg petroleum province with locations of fields and accumulations charged by Zechstein source rocks.



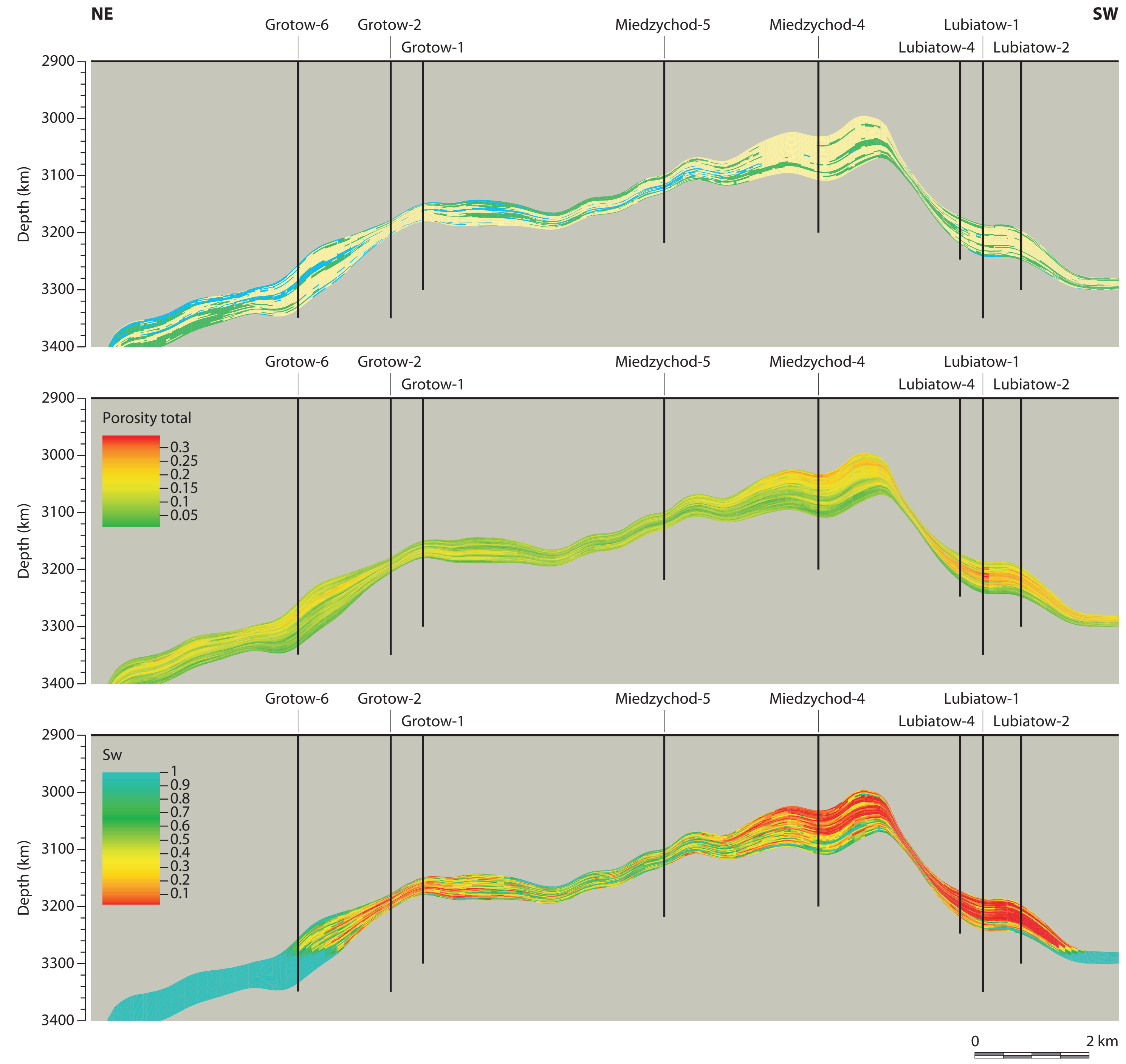


Figure 13.37 Fence diagram of the Zechstein Main Dolomite in the western part of the Grotów 'peninsula' of the Fore-Sudetic Monocline in western Poland (left panel; view from the NW). The panels on the right show the microfacies, total effective porosity (matrix pore space and fractures), and water saturation of the pore space. The best reservoir properties with permeabilities up to 40 mD occur within grainstones of the oolite barriers and grainstones on the toe-of-slope.

(1998), Piske & Rasch (1998), Piske et al. (1998), Rasch et al. (1998), Schwark et al. (1998), Strohmenger et al. (1998), Kotarba et al. (2000a), Kosakowski & Kotarba (2002), Kosakowski et al. (2003), Kotarba et al. (2003), Kowalski (2006) and Kotarba & Wagner (2007).

2.5 Jurassic

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

The Posidonia Shale is a very distinctive interval throughout the western SPB area 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 Broad Fourteens basins, Dutch Central Graben, Lower Saxony Basin and Dogger Troughs). Given the uniform character and thickness (mostly around 30 m of dark-grey to brownish-black, bituminous, fissile claystones) across these basins, the Posidonia 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 Posidonia Shale from the UK (Jet Rock Member) to Germany (Posidonienschiefer, or Ölschiefer) 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-grey mudstones with calcareous concretions in the lower part. Farther east and into Poland, source-rock quality deteriorates with the common intercalation of siltstones and fine-grained sandstones in the progressively organic-poor mudstones (Chapter 10, Figure 10.13).

2.5.1 Weald Basin

The Weald 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 Weald Basin itself forms an asymmetric east–west-trending structure (**Figure 13.40**). Triassic strata in the Wessex Basin are initially conglomerates followed by sandstones (the Sherwood Sandstone Group) overlain by marls and clays of the Mercia Mudstone

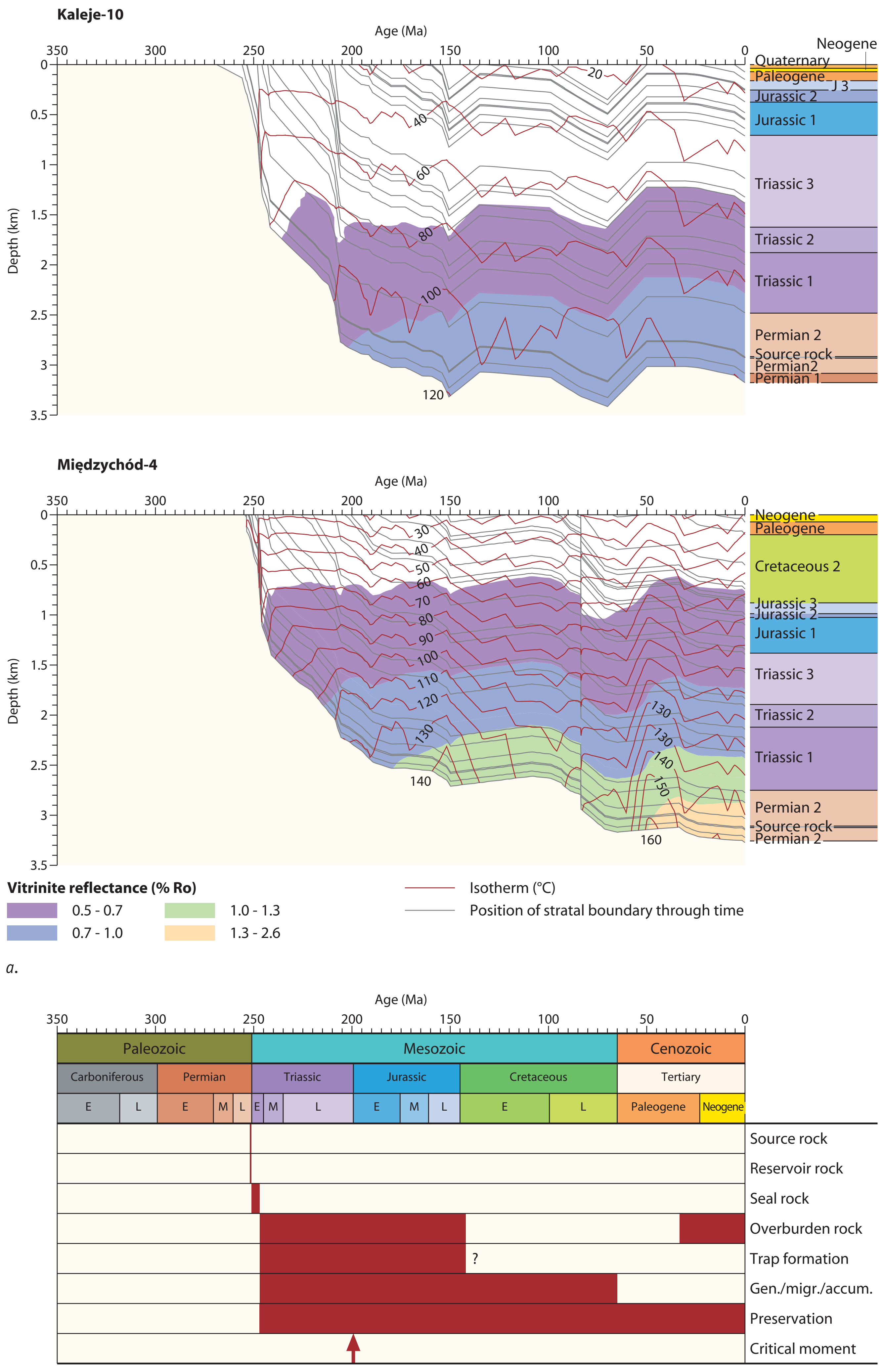


Figure 13.38 a. Burial history and modelled vitrinite reflectance history for Kaleje-10 and Międzychód-4 wells. Timescale of Harland et al. (1989); b. Event chart for the Zechstein / Main Dolomite petroleum system in the Fore-Sudetic Monocline petroleum province.

Group, although their distribution is largely restricted to the west of the Weald Basin. Early Jurassic transgression resulted in a thick cyclic sequence of variably thick shales 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. By mid-Cretaceous (Late Cimmerian Unconformity) 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 faults was associated with Alpine movements to the south. During this time, the whole Wealden area was uplifted to form the present-day 'Wealden Anticlinorium' (**Figure 13.41**).

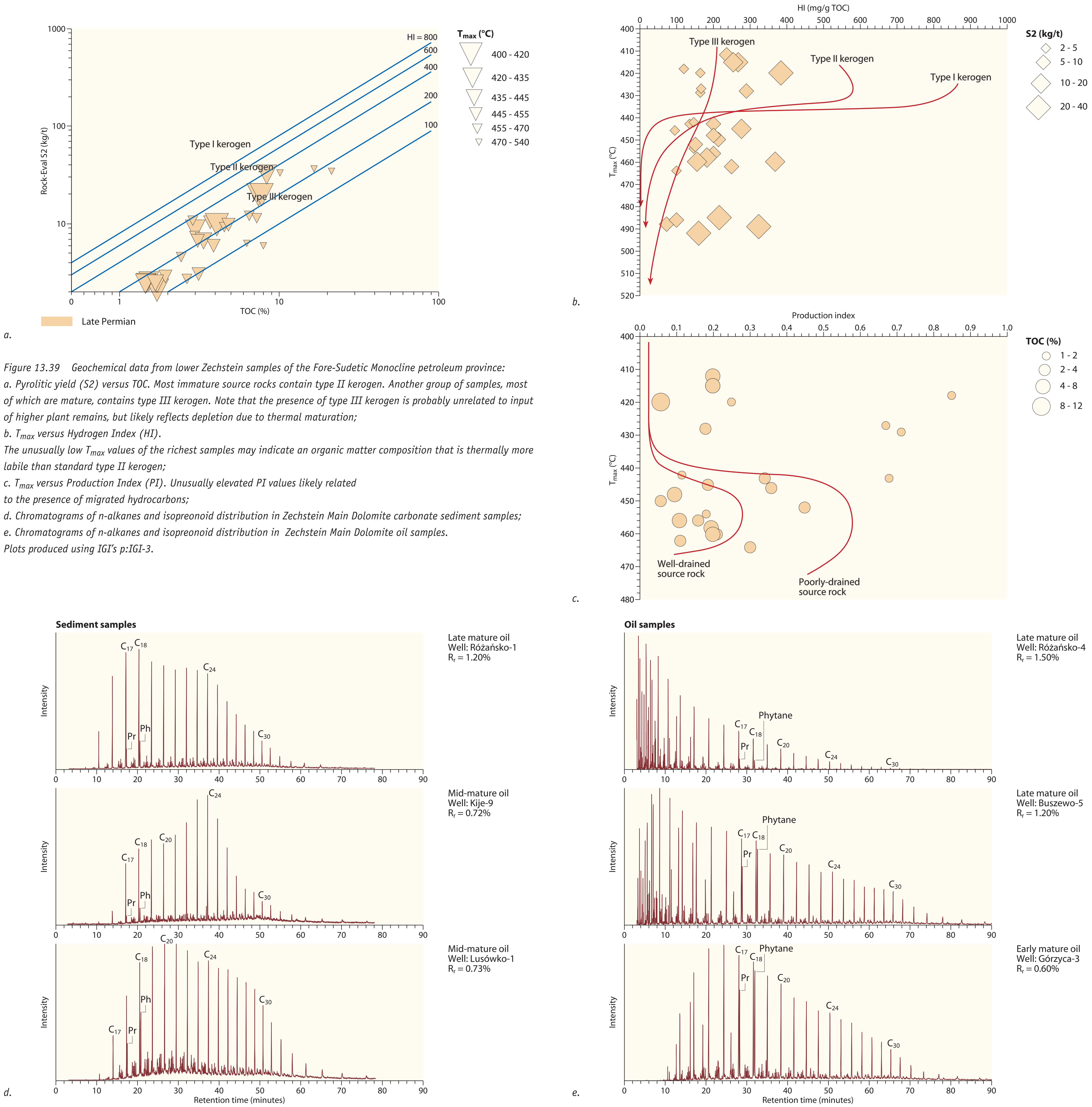


Figure 13.39 Geochemical data from lower Zechstein samples of the Fore-Sudetic Monocline petroleum province:
a. Pyrolitic yield (S2) versus TOC. Most immature source rocks contain type II kerogen. Another group of samples, most of which are mature, contains type III kerogen. Note that the presence of type III 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 labile than standard type II kerogen;
c. T_{max} versus Production Index (PI). Unusually elevated PI values likely related to the presence of migrated hydrocarbons;
d. Chromatograms of n-alkanes and isopreonoid distribution in Zechstein Main Dolomite carbonate sediment samples;
e. Chromatograms of n-alkanes and isopreonoid distribution in Zechstein Main Dolomite oil samples.
Plots produced using IGI's p:IGI-3.

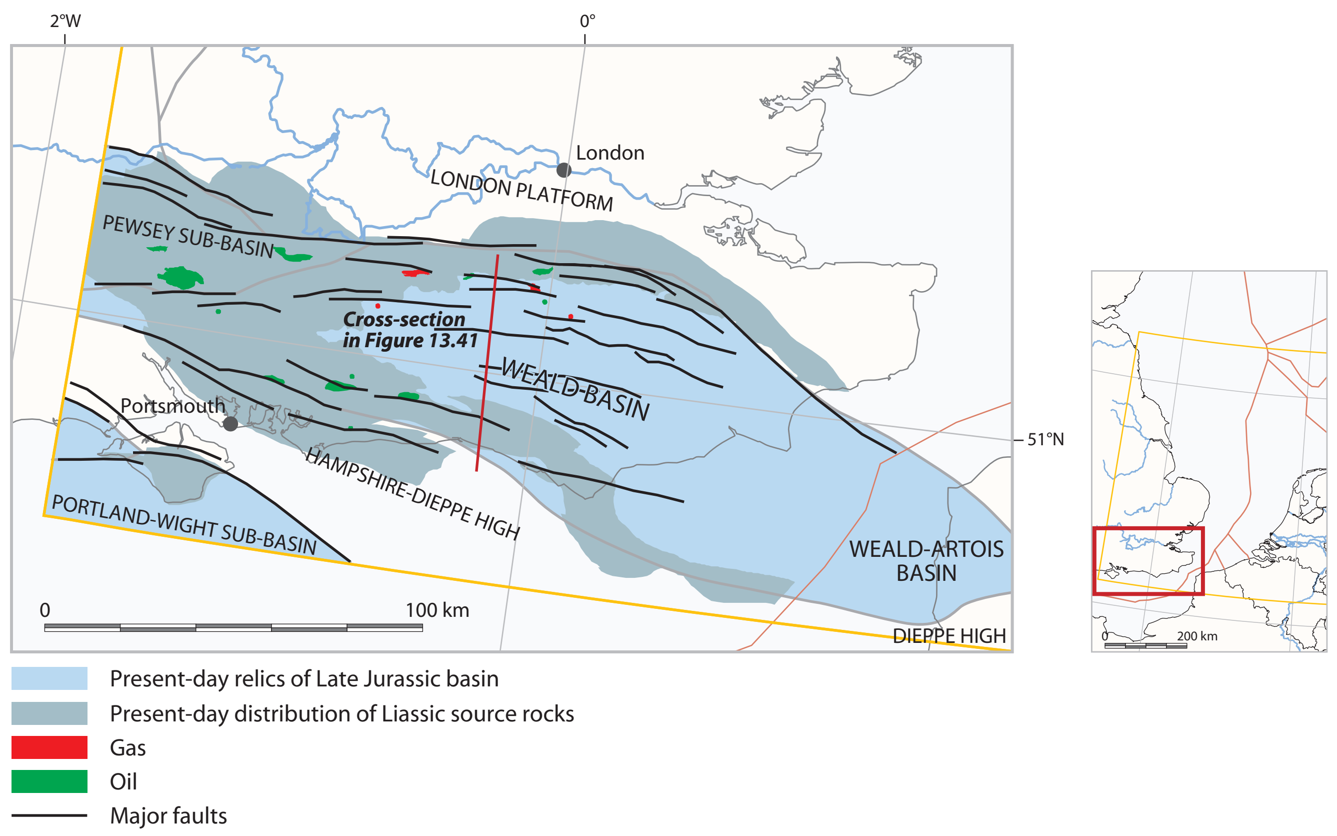


Figure 13.40 The Weald Basin petroleum province with locations of fields and accumulations charged by Lower Jurassic source rocks.

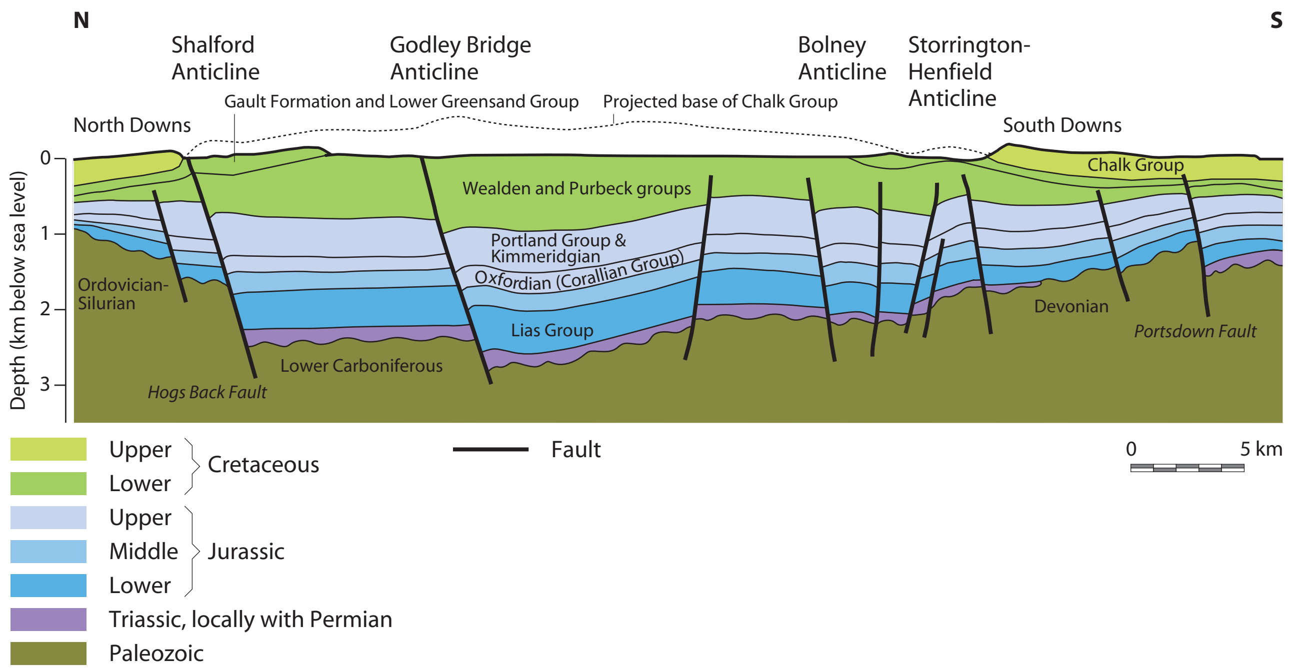
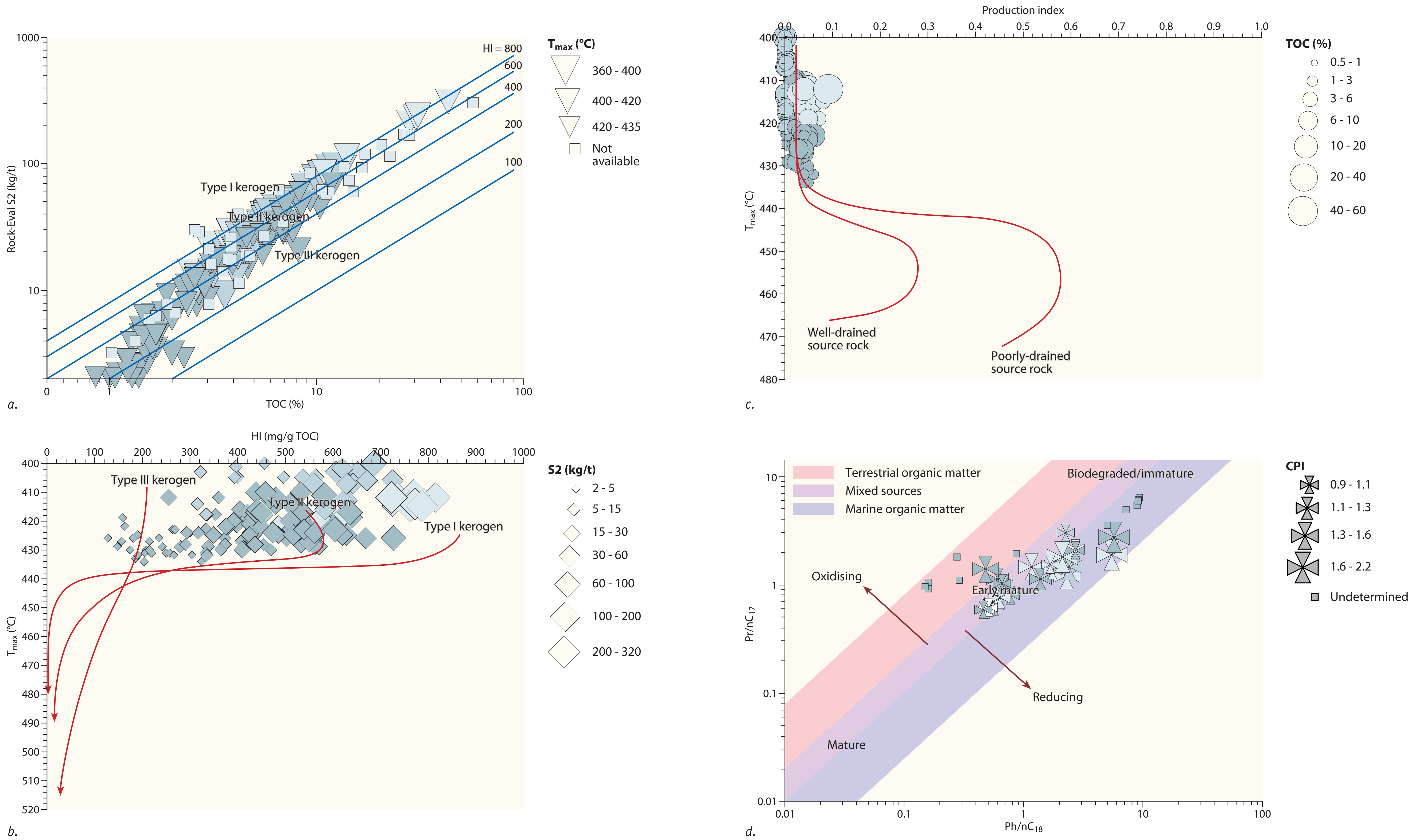


Figure 13.41 Cross-section of the Weald Basin. See Figure 13.40 for location.

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 Toarcian Posidonia 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 Hettangian to Sinemurian section. These rocks have a distinct small-scale rhythmicity of organic-rich shales and intervening organic-poor limestones attributed to periodic influxes 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 local values up to 7% have been reported; however, source-rock quality deteriorates eastwards. The organic matter is dominantly type II with low background levels of type III (**Figure 13.42**). The Lias shales are at least marginally mature in almost all of the Weald Basin and reach well into peak-oil generation in the depocentre with vitrinite reflectance values up to 0.85%. Oil generation probably commenced during the Early Cretaceous and peaked around mid-Late Cretaceous times when the Lias in the basin centre may have just reached the gas window (**Figure 13.43**).

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 local intervals of mixed type II and 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 from Penshurst in the basin centre, roughly corresponding to peak-oil generation, although the Oxford Clay is either immature or only marginally mature in much of the area. This is supported by thermal modelling that also suggests oil expulsion may have commenced in Early to mid-Cretaceous times and continued until basin inversion in the Miocene (**Figure 13.43**).



Differentiation of the relative contribution of Liassic-sourced and Oxford Clay-sourced oils to the known accumulations is problematic, as both source rocks supply oils with essentially identical geochemical characteristics. However, there is a subtle difference in the carbon-isotopic ratio of the two, which may be of potential use.

The Upper Jurassic Kimmeridge Clay is the richest source rock with typically more than 10% TOC contents and type II oil-prone kerogen with a variable but low terrestrial type III kerogen component (**Figure 13.42**). Organic richness in the Kimmeridge Clay has been attributed to freshwater capping associated with very 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 Rhaetic beds at Humbly Grove. The most important reservoir is the Bathonian Great Oolite, sealed by the Oxford Clay (Storrington-1 well, Humbly Grove, Horndean, Goodworth, Singleton, Stockridge, Lidsey and Baxters Copse). There are minor accumulations in other units such as Upper Jurassic Corallian limestone reservoirs sealed by Kimmeridge Clay (Palmers Wood; see Section 3.6.1 in Chapter 10), or Upper Jurassic Portland beds sealed by the Purbeck anhydrite (Godley Bridge). The Triassic Sherwood Sandstone Group is a potential reservoir in the west of the region, sealed by the Mercia Mudstone Group, which has proven successful in the Lias-sourced Wytch Farm field.

The three major clay-rich intervals in the sequence (Lias, Oxford Clay and Kimmeridge) had a profound influence on migration patterns by partitioning the sequence into vertically constrained Triassic, Middle Jurassic and Upper Jurassic. migration cells. Lateral migration was extensive within these cells, starting from Liassic source rocks in the Early Cretaceous. For example, the Stockridge field lies 30 km from the

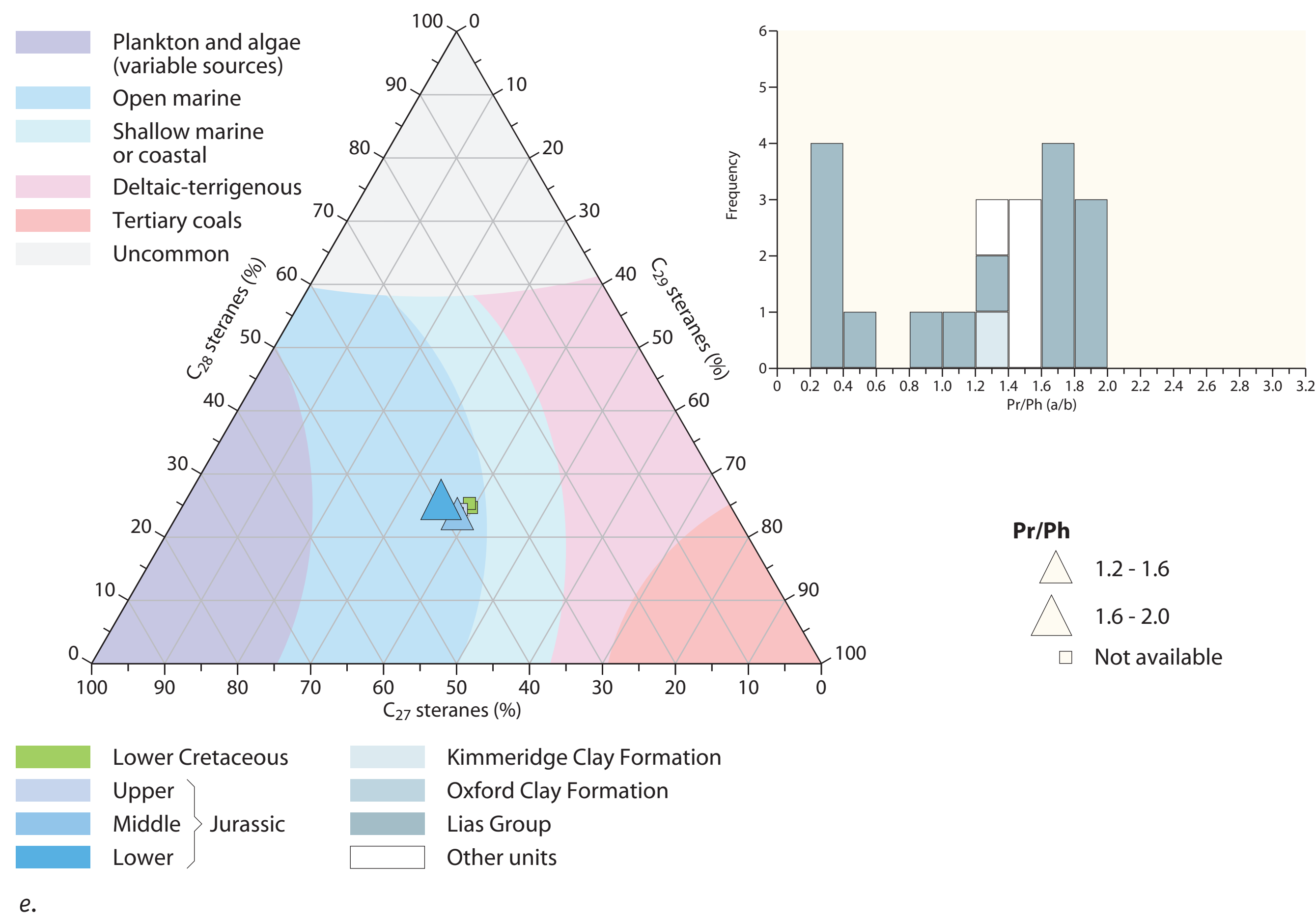


Figure 13.42 Geochemical data from different Lower Jurassic formations of the Weald Basin: a. Pyrolytic yield (S2) versus TOC; b. T_{max} versus Hydrogen Index (HI); c. T_{max} versus Production Index (PI); d. Pr/nC_{17} versus Ph/nC_{18}; e. Sterane ternary diagram. Inset shows pristane/phytane ratios. Plots produced using IGI's p:IGI-3.

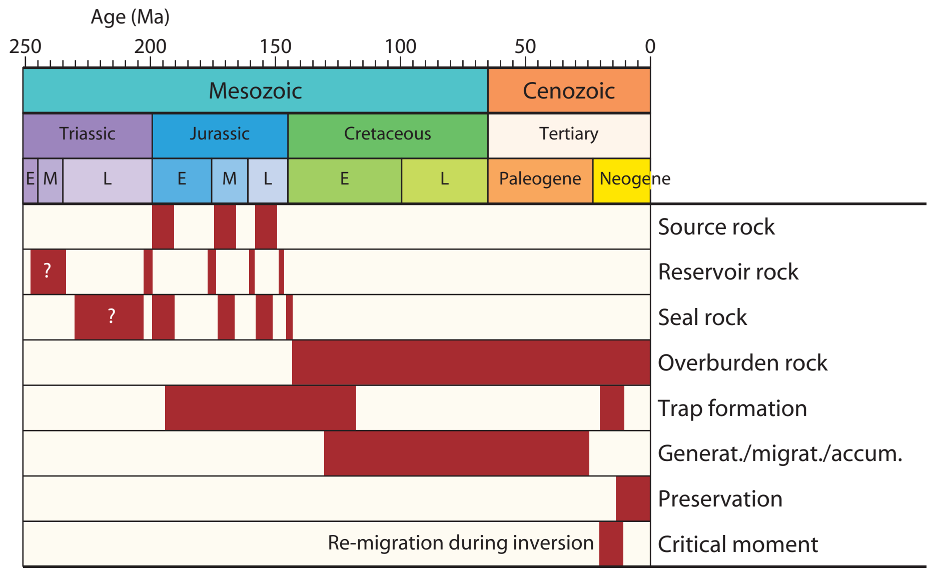


Figure 13.43 Event chart for the Lower Jurassic petroleum system in the Weald Basin petroleum province.

probable limit of mature Liassic 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-reservoir 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 footwall of extensional faults or in isolated horsts. Potential also exists in original rollover anticline structures, albeit tightened during inversion, but these have not 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; a number of present-day accumulations are probably the result of re-migration at this time.

For further information see Ebukanson & Kinghorn (1985, 1986a), Fleet & Brooks (1987), Penn et al. (1987) and Butler & Pullen (1990).

2.5.2 Dutch Central Graben

The thickness of Upper Triassic to Lower Jurassic deposits varies considerably across the Dutch Central Graben as a result of synsedimentary movements of the Zechstein salt (**Figure 13.44** & **13.45**). In contrast, the Posidonia Shale Formation is uniformly thick, indicating relative tectonic quiescence during deposition.

The Posidonia Shale in the Dutch Central Graben is a marine bituminous source rock with common type II kerogen, although some analyses indicate type III (**Figure 13.46**). The average TOC content is about 8% (up to 15%), with HI values up to 850 mg/g. The Posidonia Shale can be recognised on wireline logs by its high gamma-ray and resistivity readings (**Figure 13.47**). Log evaluation shows a gradual increase in TOC contents and HI values from bottom to top ending with an abrupt decline. This abrupt change seems to correspond to a temporary flooding event and the initiation of an anoxic environment with evidence of maximum flooding in the middle of the formation. Type II kerogen is probably prevalent in the middle part of the formation and less common at its top and bottom.

The timing of oil generation from the Posidonia Shale depends on the location within the basin (**Figure 13.48**). The southern sector of the Dutch Central Graben has been strongly inverted and there is currently no oil generation as present-day temperatures in the Posidonia Shale are lower than those reached before inversion. In the north, the Posidonia Shale has reached its deepest burial and is still generating oil. Several oil discoveries were made in Upper Jurassic and Lower Cretaceous sandstones, which may be attributed to charge from the Posidonia Shale, with minor contributions from the Upper Triassic Sleen and Lower Jurassic Aalburg formations.

Traps are structural and include 4-way dip closures (turtle-back structures) and tilted fault blocks. The southern sector of the graben is structurally more complex and compartmentalised due to strong inversion. Oil shows that are probably derived from the Posidonia Shale have been encountered in the Chalk Group in this southern area. The Hanze field in the northern Dutch Central Graben was discovered in 1996 in block F2 and was the first, and so far the only, economic oil accumulation offshore (**Figure 13.49**).

For further information see Wong et al. (1989), Wong (1991), Van Adrichem Boogaert & Kouwe (1993) and De Jager & Geluk (2007).

2.5.3 West Netherlands and Broad Fourteens basins

Whereas salt tectonics are dominant in the Dutch Central Graben, the West Netherlands and Broad Fourteens basins and the Roer Valley Graben are characterised by a horst and graben configuration related to Jurassic rift and Cretaceous inversion events (**Figure 13.50** & **13.51**). The Posidonia Shale

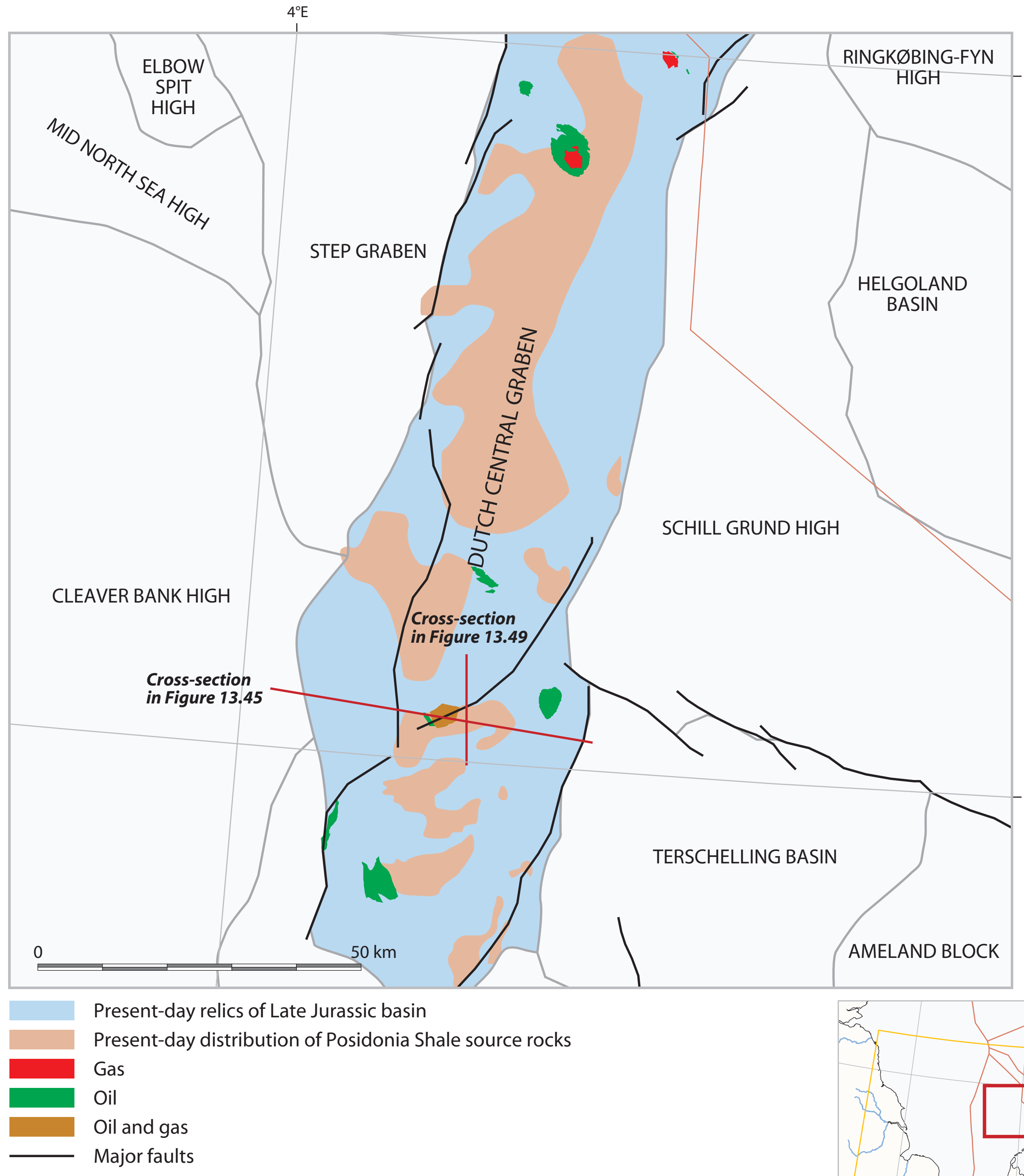


Figure 13.44 The Dutch Central Graben petroleum province with locations of fields and accumulations charged by the Posidonia Shale Formation.

Formation has remarkably uniform thickness, whereas there are large thickness variations in the underlying Aalburg Formation in the Broad Fourteens and West Netherlands basins. Tectonic activity was limited during the Toarcian.

Source-rock characterisation of the Posidonia Shale indicates type II kerogen, with an average TOC content of about 7% and increased HI values (**Figure 13.52a** & **b**). Biomarker analyses indicate early mature marine organic matter (**Figure 13.52d**). Log evaluation in the Posidonia Shale shows the highest TOC contents related to maximum flooding at the base of the formation, gradually decreasing upwards. The dissimilar log pattern to that seen in the Dutch Central Graben indicates the different depositional conditions during the Toarcian.

Both the West Netherlands and Broad Fourteens basins were inverted at the end of the Cretaceous (**Figure 13.51**). Depending on burial after inversion, which varied throughout the basins, generation either ceased before the inversion or continued into the Cenozoic. Generation continued where post-inversion burial was deeper (i.e. where temperatures are higher) than pre-inversion burial. Erosion took place in the most inverted areas. Present-day oil accumulations are found at locations where suitable reservoir deposits were preserved. The Posidonia Shale is immature for oil at some well locations on the horst structures in the West Netherlands Basin (**Figure 13.52e** & **f**). As oil occurs in proximity to these immature areas, there is an implication that main oil generation took place in adjacent grabens and oil migrated into the structural traps. In places where the Posidonia Shale is highly mature, it may have contributed gas to Jurassic and Cretaceous reservoirs.

Oil has been encountered in several Triassic reservoirs that are attributed to a Posidonia Shale source, where the oil migrated across faults from downthrown blocks into the older reservoirs. However, most oil reservoirs were found in Upper Jurassic and Lower Cretaceous sandstone reservoirs. The reservoirs occur in clastic Upper Jurassic to Lower Cretaceous syn-rift deposits and early post-rift deposits of Early Cretaceous age that show rapid facies variations from continental to marine (**Figure 13.53**).

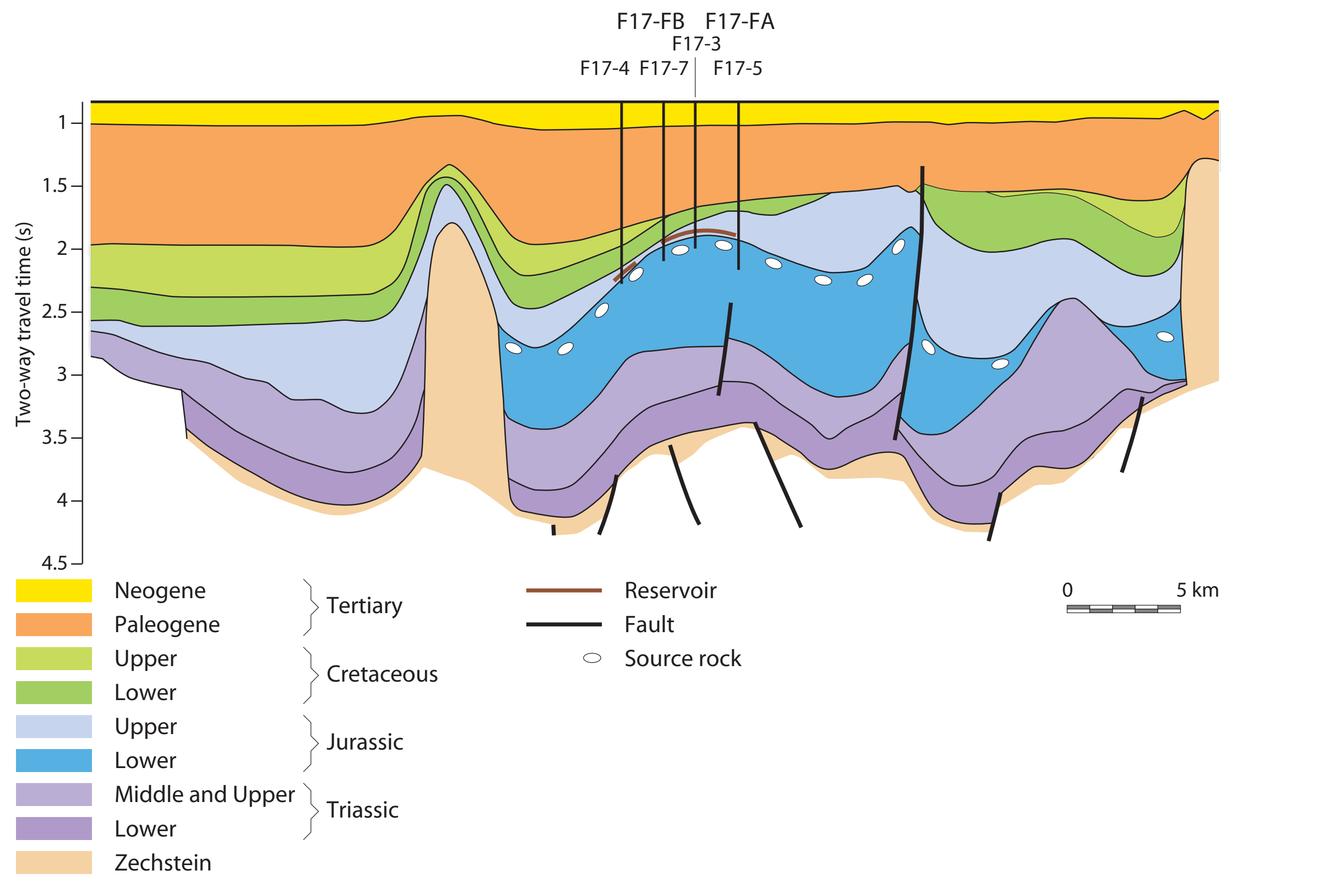


Figure 13.45 Cross-section of the Dutch Central Graben. Hydrocarbons generated from the Posidonia Shale Formation migrate upwards to reservoirs associated with salt diapirs. See Figure 13.44 for location.

The best reservoirs are the post-rift Rijswijk, Berkel and IJsselmonde sandstones that were deposited as coastal barrier complexes overlying the Late Cimmerian Unconformity. Traps occur mainly as 4-way dip closures along anticlinal trends that formed in response to the Late Cretaceous and Paleogene inversion along the south-western basin margin. In some fields in the West Netherlands Basin, the oil was biodegraded at the onset of the Cenozoic. Due to tectonic inversion, reservoirs were then at or near the surface where bacteria had access to fresh meteoric waters. The Posidonia Shale source rock also shows signs of biodegradation in places within the West Netherlands Basin. Fields in the Broad Fourteens Basin are located along the north-eastern margin of the inverted basin in Q1, K18 and L16.

For further information see Bodenhausen & Ott (1981), (Wong et al., 1989), Roelofsen & De Boer (1991), Wong (1991), De Jong & Laker (1992), Goh (1994), Van Adrichem Boogaert & Kouwe (1993-1997), De Jager et al. (1996), Den Hartog Jager (1996), Racero-Baena & Drake (1996), Van Balen et al. (2000), Verweij (2003), De Jager & Geluk (2007) and Nelskamp et al. (2008).

2.5.4 Lower Saxony Basin and Dogger Troughs

A sequence of fine-grained marine sediments was deposited during the Early Jurassic within the incipient Lower Saxony Basin and the Dogger Troughs (**Figures 13.54** & **13.55**). The gradual transition from the mainly grey claystones and marlstones west of the Weser River to more frequent sandstone beds and sedimentary iron ores 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 lower water column; palynomorph data have been interpreted as invoking reduced salinities in the surface-water layer. This interval is the main source rock for hydrocarbons within the Lower Saxony Basin east of the Ems River.

The Dogger Troughs include the West and East Holstein troughs on the eastern and western flanks of the Glückstadt Graben, and the Jadeberger Trough in the North German Basin. The Glückstadt Graben formed during Late Permian to Early Triassic rifting and rapidly filled with several kilometres of Upper Triassic siliciclastics. After the Late Triassic, rising Zechstein salt formed north-north-west-trending diapiric plug and wall structures. Marginal basins (rim-synclines) subsided around the periphery of the diapirs. The rim-synclines include the Holstein Trough, which subsided in Early to Mid-Jurassic 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 varied strongly within the individual rim-synclines.

The source rock has an average thickness of 25 m, but may be up to 50 m thick in the Gifhorn 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 Weser. The organic matter consists mainly of alginite and bituminite with increasing, but still subordinate, vitrinite contents to the east (**Figure 13.56f**). In addition to the organic petrographic observations, the available Rock-Eval data (**Figure 13.56a** to **c**) with an average HI value of 520 for the

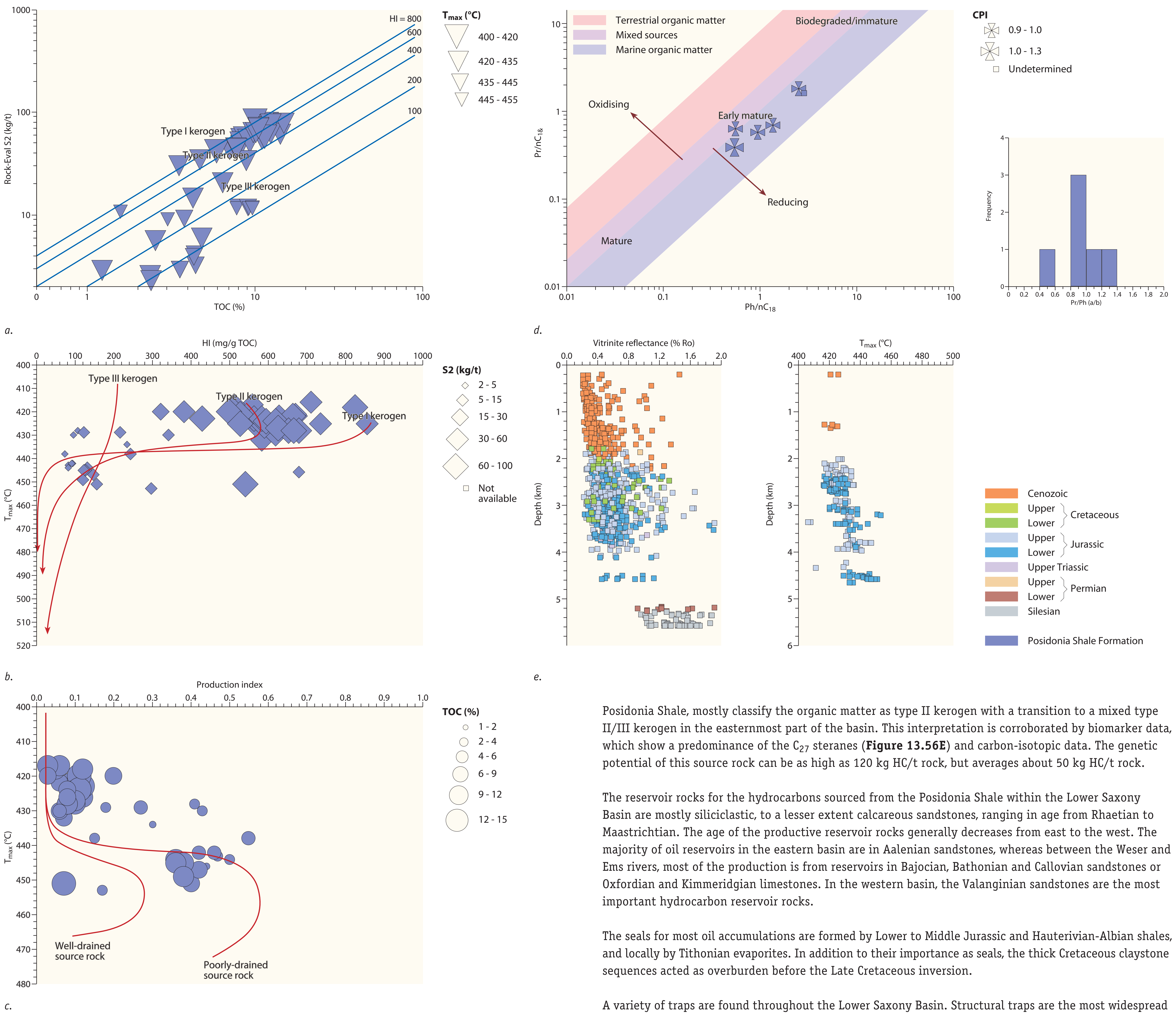


Figure 13.46 Geochemical data from the Posidonia Shale Formation in the Dutch Central Graben:
a. Pyrolytic yield (S2) versus TOC;
b T_{max} versus Hydrogen Index (HI);
c. T_{max} versus Production Index (PI);
d. Pr/nC_{17} versus Ph/nC_{18}. Inset shows pristane/phytane ratios;
e. Vitrinite reflectance and Rock-Eval T_{max} parameters of Silesian to Cenozoic samples plotted against sub-bottom depth. Plots produced using IGI's p:IGI-3.

Posidonia Shale, mostly classify the organic matter as type II kerogen with a transition to a mixed type II/III kerogen in the easternmost part of the basin. This interpretation is corroborated by biomarker data, which show a predominance of the C_{27} steranes (**Figure 13.56E**) and carbon-isotopic data. The genetic potential of this source rock can be as high as 120 kg HC/t rock, but averages about 50 kg HC/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 Maastrichtian. 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 Ems 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 Hauterivian-Albian shales, and locally by Tithonian evaporites. In addition to their importance as seals, the thick Cretaceous claystone sequences acted 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 diapirism (e.g. **Figure 13.55**), rollover structures or anticlines. Both facies and unconformity-related stratigraphic traps are common in the easternmost Lower Saxony Basin. Unconformity traps predominate in areas where transgressive Valanginian to Albian sedimentary rocks truncate the Jurassic reservoirs rocks.

Thermal maturation of the Posidonia Shale source-rock interval occurred mainly during pre-Turonian subsidence, but continued after Late Cretaceous inversion into Cenozoic times (**Figure 13.57**). There is an ongoing debate about the relative importance of additional extreme heating by magmatic intrusions

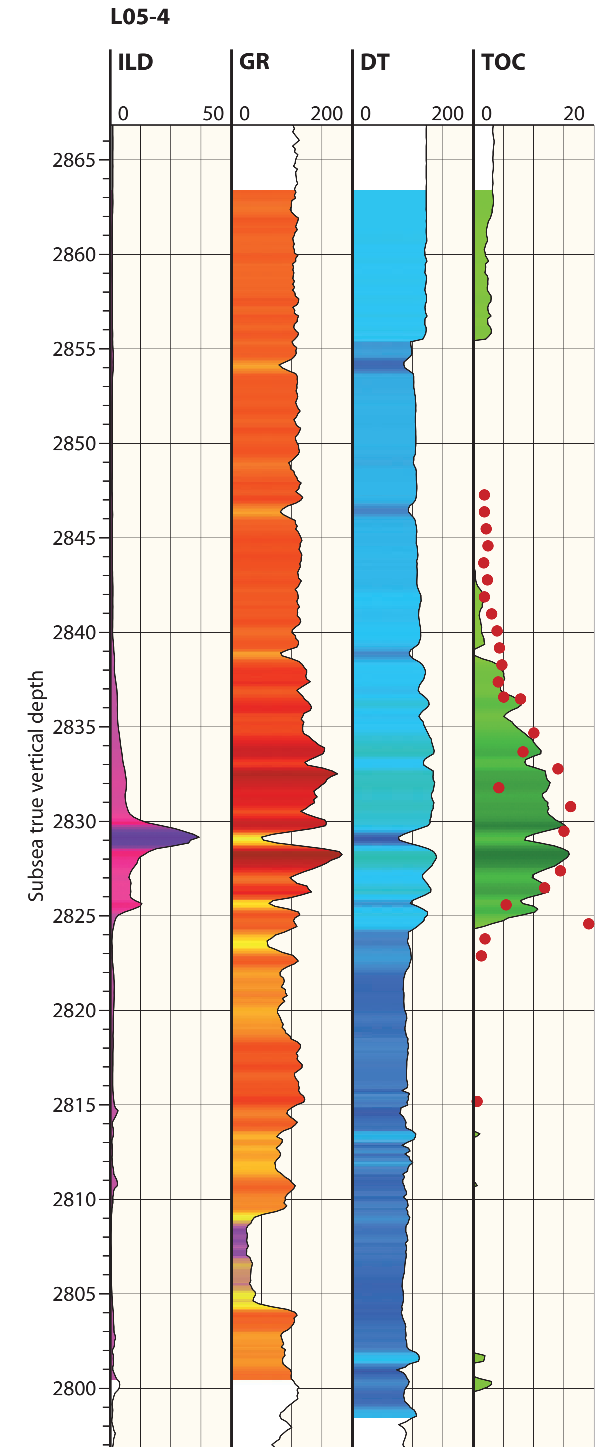


Figure 13.47 Log response of Posidonia Shale Formation in well L05-4 in the Dutch offshore sector including a calculated TOC log with measured TOC plotted for comparison. The calculation method makes use of the gamma-ray (GR), sonic (DT), and deep resistivity logs (ILD). A shaly interval consists of a shale matrix (by gamma ray), some porosity (by sonic), and possibly (light) hydrocarbons (also sonic). The deep-reading resistivity responds strongly to the presence of hydrocarbons, i.e. the resistivity will increase. If there are no hydrocarbons and there is only (saline) water present in the shale pores, the sonic and resistivity logs will overlay if they are properly scaled. In an organic-rich section, there will be a distinct separation between the sonic and resistivity logs. The amount of separation indicates the amount of organic material.

at the beginning of the inversion in contrast to pronounced pre-Santonian subsidence, especially west of the Ems. In most areas of the basin, the Posidonia Shale had already reached the oil window during the Early Cretaceous and entered the gas window, at least in the southern and western areas of the basin, during the Cenozoic. Differing subsidence/uplift histories locally resulted in the preservation of immature Posidonia Shales, for example, in the southern Hils Syncline where the maturity sequence is within a short distance. Maturity in the Dogger Troughs is usually lower than in Posidonia Shale-sourced accumulations of the Lower Saxony Basin, with most fields showing less than 0.7% Ro.

Asphalt relics and the results of basin-modelling 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 represents the critical moment in the evolution of the Posidonia Shale petroleum system in the Lower Saxony Basin.

The second phase of oil generation and migration started in the Early Cenozoic and 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

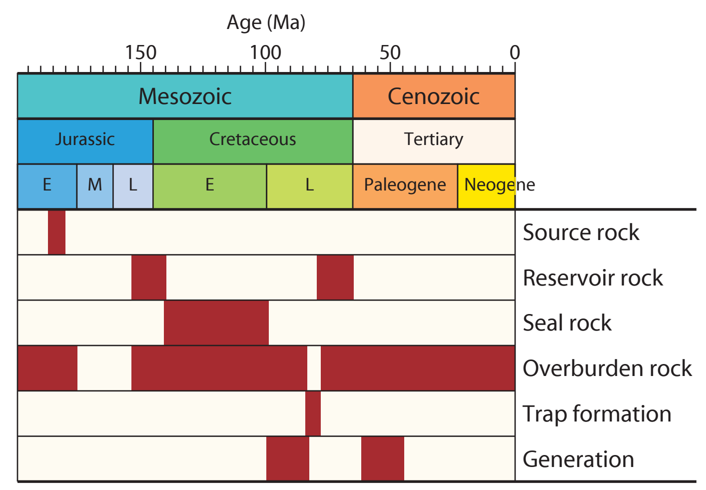


Figure 13.48 Event chart of the southern part of the Dutch Central Graben, based on basin modelling.

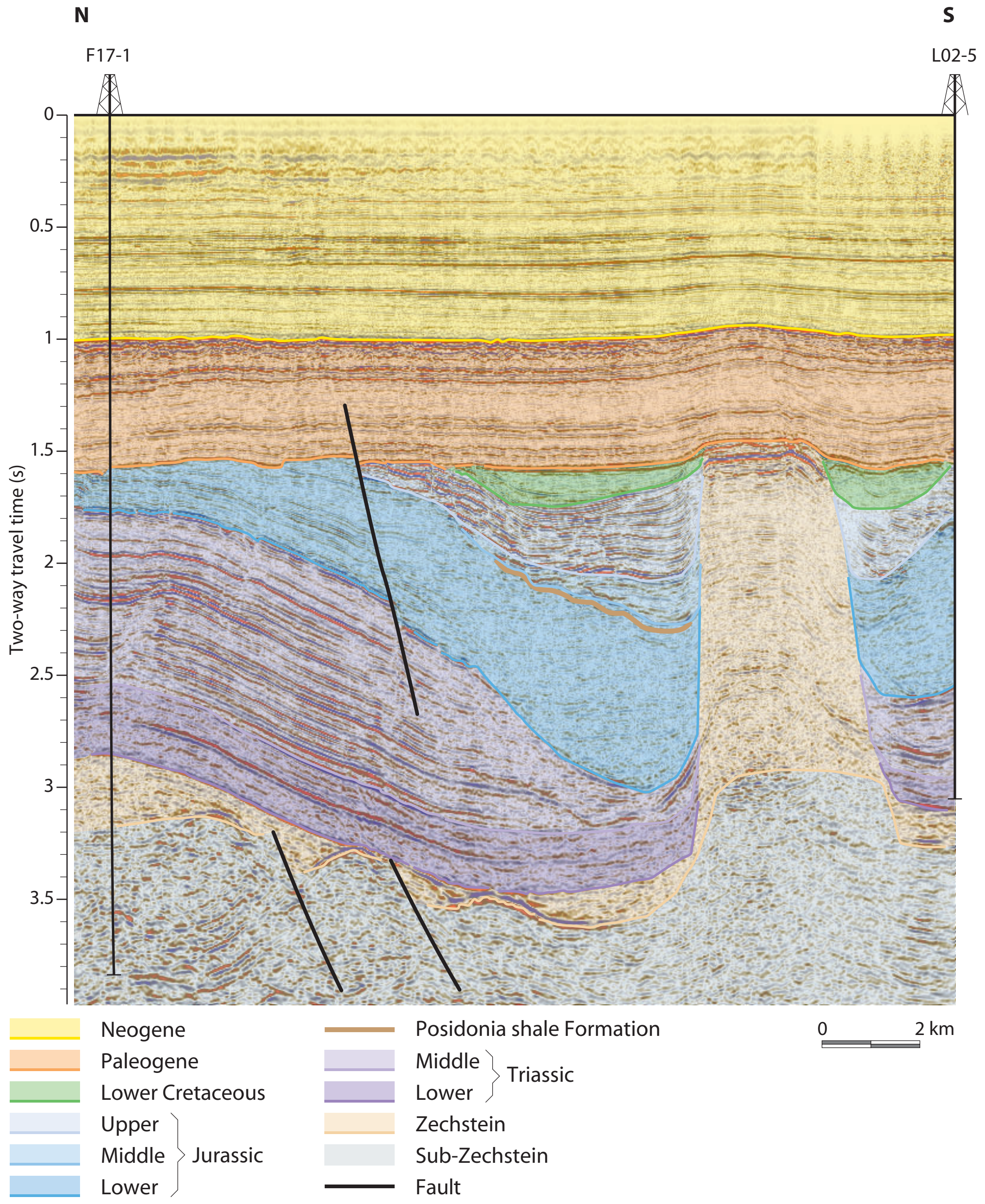


Figure 13.49 Seismic cross-section through the Dutch Central Graben. Petroleum generated from the Posidonia Shale Formation migrates upward to reservoirs associated with salt tectonics. See Figure 13.44 for location.

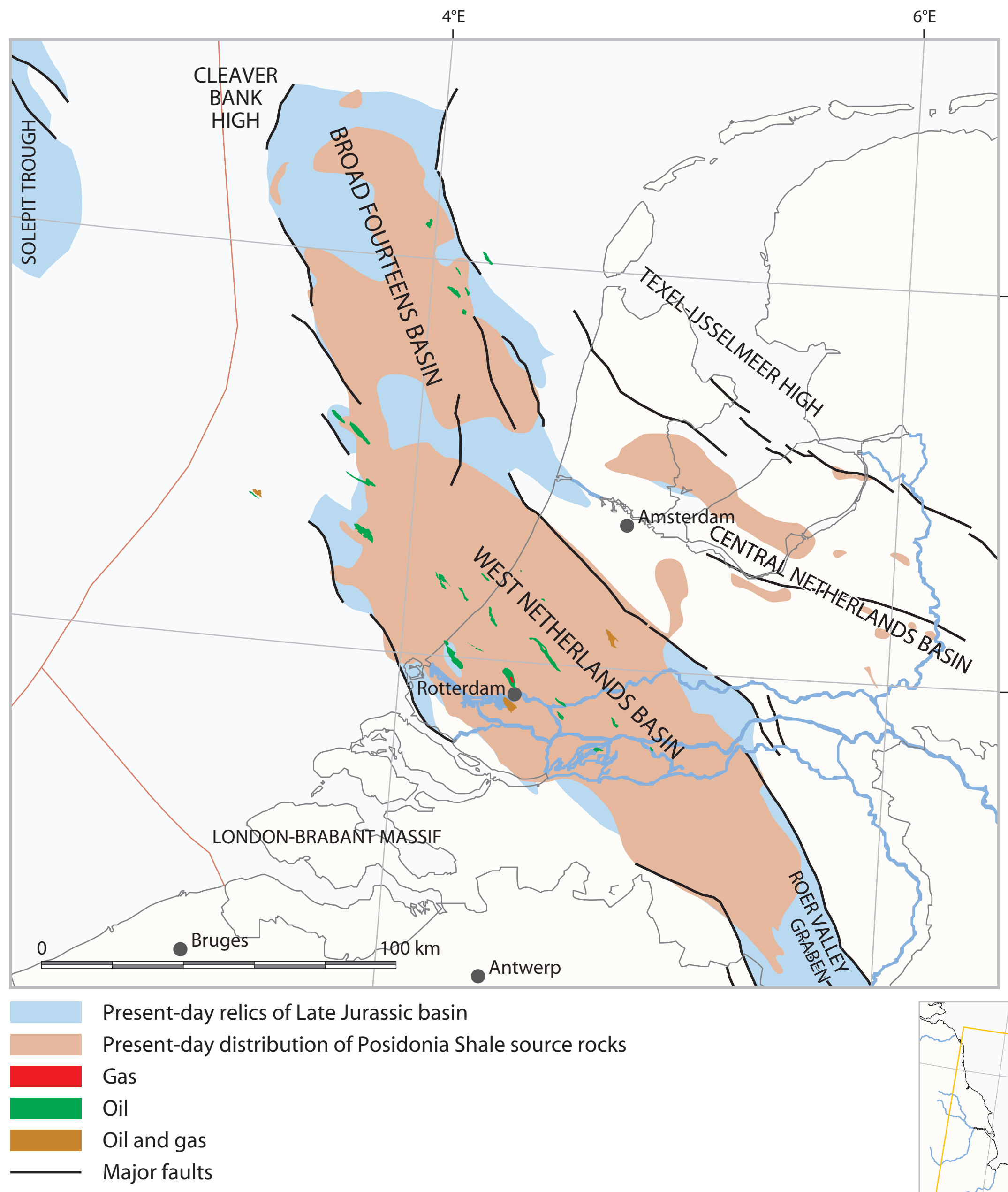
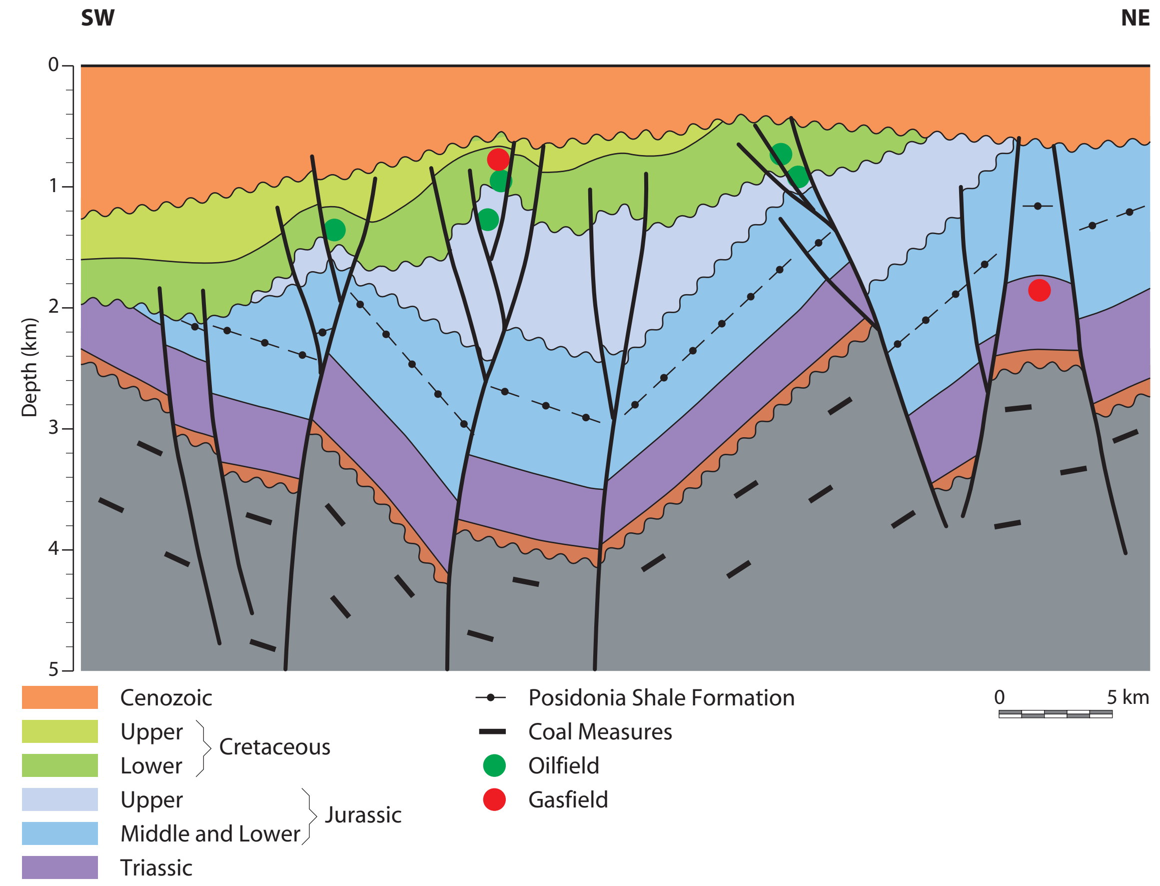


Figure 13.50 The West Netherlands and Broad Fourteens basins petroleum province with locations of fields and accumulations charged by the Posidonia Shale Formation.



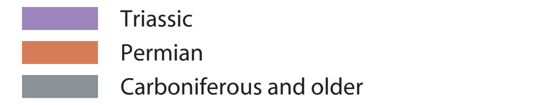


Figure 13.51 Schematic section through the West Netherlands Basin (after De Jager et al., 1996).

vertical migration path of less than 5 km. Several oilfields exhibit high gas:oil ratios with stable isotopic compositions of the gases invoking their thermal generation. This may point to either admixture of thermogenic gas or to oils already in place. East of the Weser, the generation-accumulation efficiency is 5%, indicating that most of the hydrocarbons have been lost during Late Cretaceous inversion or later due to missing traps. Petroleum generation in the Holstein Troughs reached its peak at 55-35 Ma when subsidence increased around some of the diapirs leading to a maturity of up to 0.8% Rr in the structurally deeper parts of the Heide Trough; lateral migration was up to 5 km. Numerical modelling of the thermal history successfully reproduces the present-day reservoir temperature when a basal heat flow of 50 mW/m^2 is assumed.

Severe biodegradation reduced the oil quality in a number of shallower fields, especially in the eastern Lower Saxony Basin. Interestingly, the risk of microbial degradation is strongly reduced where sealing Middle Jurassic shales are preserved above the Aalenian reservoir. In unconformity traps, where the transgression locally truncated this seal such that Cretaceous shales acted as the seal, biodegradation has frequently affected the quality of the organic matter. The petroleum in several reservoirs, especially in fields west of the Ems, was generated from both the Posidonia Shale and Wealden source rocks (see Section 2.6.1).

In contrast to the Lower Saxony Basin, where admixtures of Wealden-sourced oil and pre-Jurassic-sourced gas is common, oil compositions in the Dogger Troughs are remarkably homogenous and point to a Posidonia Shale source. Contributions from other potential source rocks are either minor or non-existent. Notably, the analyses of oils from different Mittelplate reservoirs corroborated their derivation from a compositionally and thermally uniform Posidonia Shale source. They are products of the early to peak generation phases. Systematic depth trends of maturity-related geochemical parameters correlate with oil quality and point to the dominant control of oil (and source-rock) maturity on oil quality. Oil quality improves with increasing oil maturity. Lower maturity oils occur at greater depths, which excludes gravitational segregation as the cause of the quality trend. The least mature oils are found in the structurally deepest reservoirs. There are no indications for major alteration, biodegradation or water washing. However, there is a deterioration in oil quality (increasing density and sulphur contents) with increasing structural depth. Deterioration with depth and moderate reservoir temperatures (<100°C) preclude thermal cracking as a mechanism.

The compositions and carbon-isotopic signatures of associated gases revealed different types. The associated gases, most of which are microbially generated methane in the Jaderberger Trough (Elsfleth and Varel fields), indicate a source-rock maturity of about 0.6%. Associated gases of the East Holstein Trough are progressively intermixed northwards with gases generated from a Zechstein source. For further information see Adriasola-Muñoz et al. (2007), Baldschuhn et al. (1996), Binot et al. (1993), Buntebarth & Teichmüller (1979), Grassmann et al. (2005), Kockel et al. (1994), Maystrenko et al. (2005), Petmecky et al. (1999), Rodon & Littke (2005), Rullkötter & Marzi (1988), Schwarzkopf & Leythaeuser (1988) and Wehner et al. (1979).

2.5.5 Tail End Graben

The Danish Central Graben is generally considered to be a mature region with 91 exploration wells (**Figure 13.58**). The exploration focus was on reservoirs within the Chalk Group, which hosts the majority of currently proven reserves. Prior to 1995, the targets were primarily Jurassic, Triassic and Zechstein reservoirs, but the discovery of the Upper Paleocene Siri field turned the focus towards Paleogene plays (see Chapters 14 and 15). Oil and gas/condensate in Middle and Upper Jurassic sandstones is the main secondary exploration objective in the Danish Central Graben after the Chalk Group (**Figure 13.59**). The majority of exploration wells in the 1980s were drilled on either a primary or secondary target in the Jurassic. Many of these wells did find hydrocarbons, demonstrating the existence of active petroleum systems in the sector. However, the quantity and quality of the reservoirs was often highly variable and so to date only a few discoveries have been declared economic.

The major and most prolific oil and gas source rock in the Tail End Graben of the Danish Central Graben is the marine, type II Upper Jurassic Farsund Formation (Kimmeridge Clay Formation equivalent, Ryazanian; Ineson et al., 2003). The Farsund Formation covers the entire Danish Central Graben except for major highs such as the Inge-Mads High in the Outer Rough Basin towards the west (**Figure 13.58**). Large thickness variations are evident, with more than 3000 m-thick deposits in the Tail End Graben. The thickest are found towards the Coffee Soil Fault, and are 1500 to 2250 m thick in the Feda Graben farther north (**Figure 13.60**).

The TOC content generally increases upwards in the formation, along with a shift from generally gas-prone to generally oil-prone characteristics. The richest interval, the Bo Member (former 'Hot Unit'), is in the upper part of the Farsund Formation. Source-rock quality decreases towards the Salt Dome Province reflecting both the thinning of the prolific upper part of the formation and shallower and more oxygenated conditions during deposition.

The Jurassic discoveries in the Danish Central Graben have all been drilled where significant structural components in the plays 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 long been on Jurassic stratigraphic traps. In the Feda Graben, the basal Farsund Formation also has good oil-generating properties, as indicated by the Gert-2 well north of 56°N. Similarly good source potential is expected 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 terrestrially influenced, oil-prone source-rock intervals are found in the lower part of the Upper Jurassic (Lola Formation) and may constitute additional sources for liquid petroleum. In many areas, the uppermost 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 (Danish and German sectors), but have not developed as source rocks. In contrast, the Middle Jurassic Bryne Formation contains coals and organic-rich lacustrine shales with good to excellent type III kerogen source rocks (**Figure 13.61**). The Lower to Middle Jurassic coals formed in a humid, warm-temperate to subtropical, weakly seasonal climate. The Bryne Formation is best known from the Søgne Basin north of 56°N. The Middle Jurassic coals in the Søgne Basin are mostly found at depths between about 3400 to 3800 m (VR from 0.75-0.89% Ro) although they may be buried to around 5000 m towards the Tail End Graben. Nine coal seams 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**).

For further information see Damtoft et al. (1992), Hemmet (2005), Ineson et al. (2003), Megson & Hardman (2001), Møller et al. (2003), Petersen (2006), Petersen et al. (1998) and Petersen & Nytoft (2006, 2007b).

2.6 Early Cretaceous

2.6.1 Lower Saxony Basin

The restricted shallow-water conditions that prevailed during the Late Jurassic culminated in the deposition of Tithonian rock-salt layers and time-equivalent lacustrine sediments. Increased vertical movements resulted in a complex, small-scale pattern of rapidly subsiding graben structures next to sediment-starved horsts. In the Early Cretaceous, most of the basin was occupied by swamp areas in front

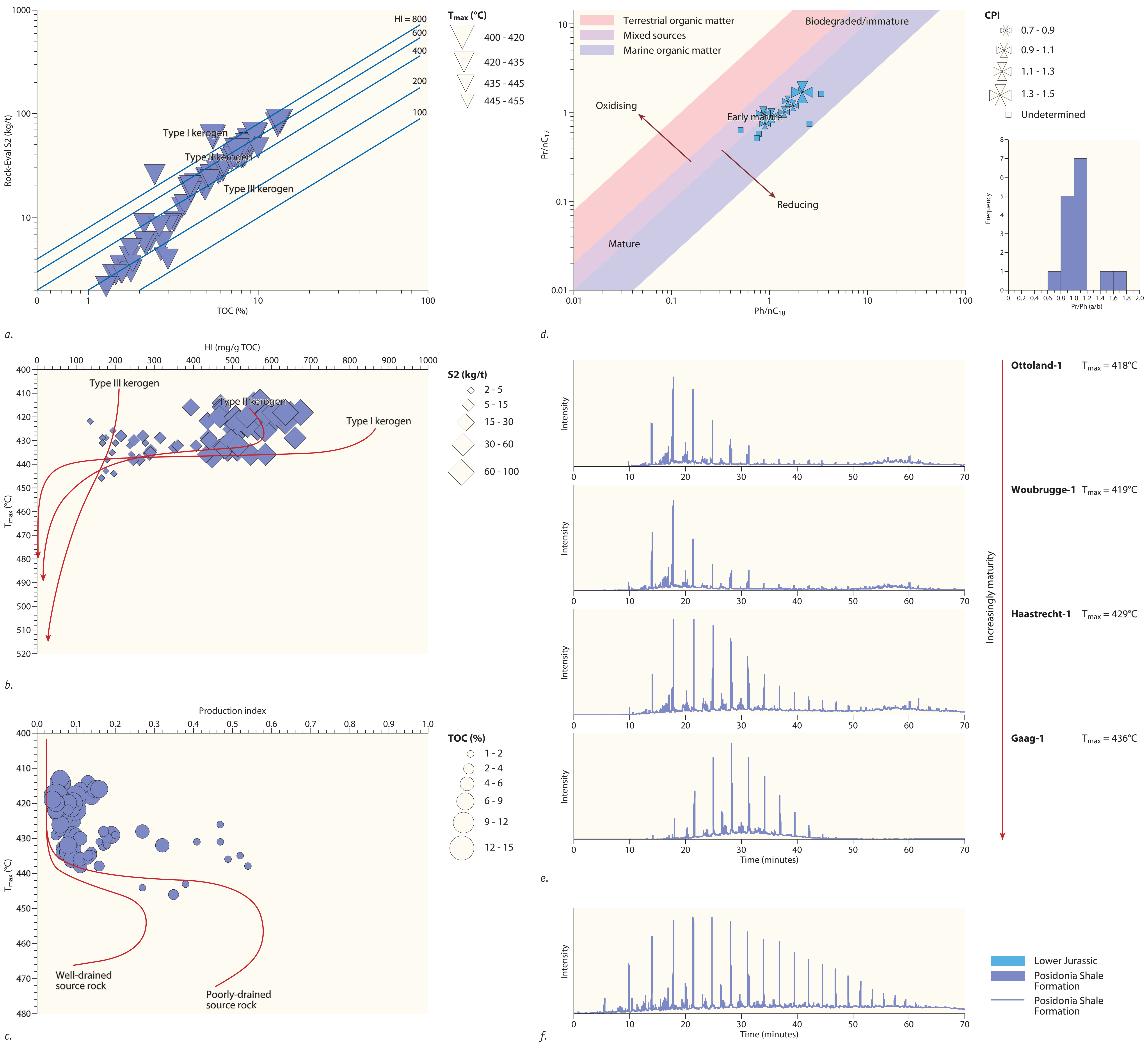


Figure 13.52 Geochemical data from the Posidonia Shale Formation in the Broad Fourteens and West Netherlands basins: a. Pyrolytic yield (S2) versus TOC; b. T_{max} versus Hydrogen Index (HI); c. T_{max} versus Production Index (PI); d. Pr/nC_{17} versus Ph/nC_{18}. Early mature Posidonia samples with the highest TOC plot in the field indicating marine deposits in a reduced environment suggesting restricted water circulation. Inset shows pristane/phytane ratios; e. n-alkane distribution in source-rock extracts from samples of the Posidonia Shale Formation, showing the effect of maturity; f. n-alkane pattern of oil with a Posidonia Shale Formation source. Plots produced using IGI's p:IGI-3.

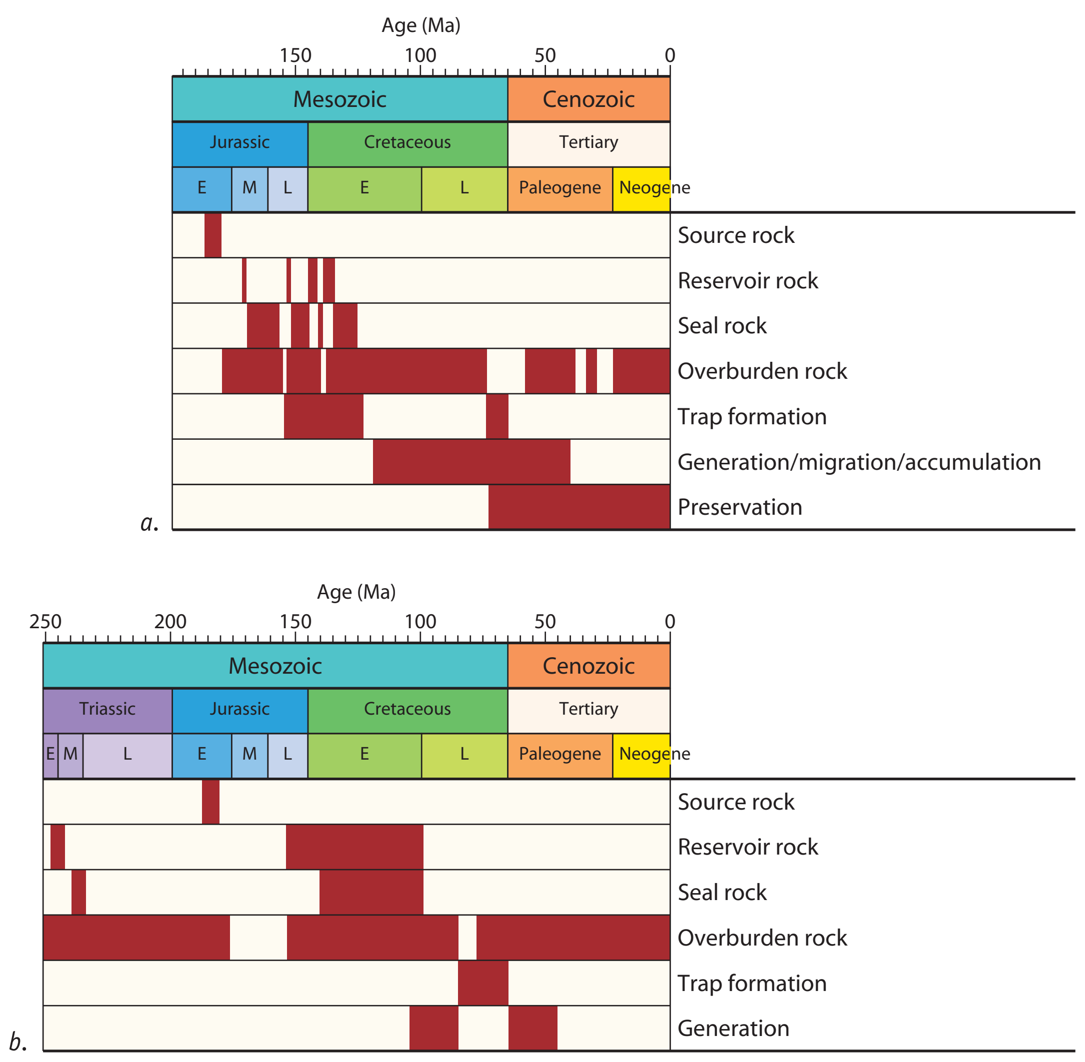
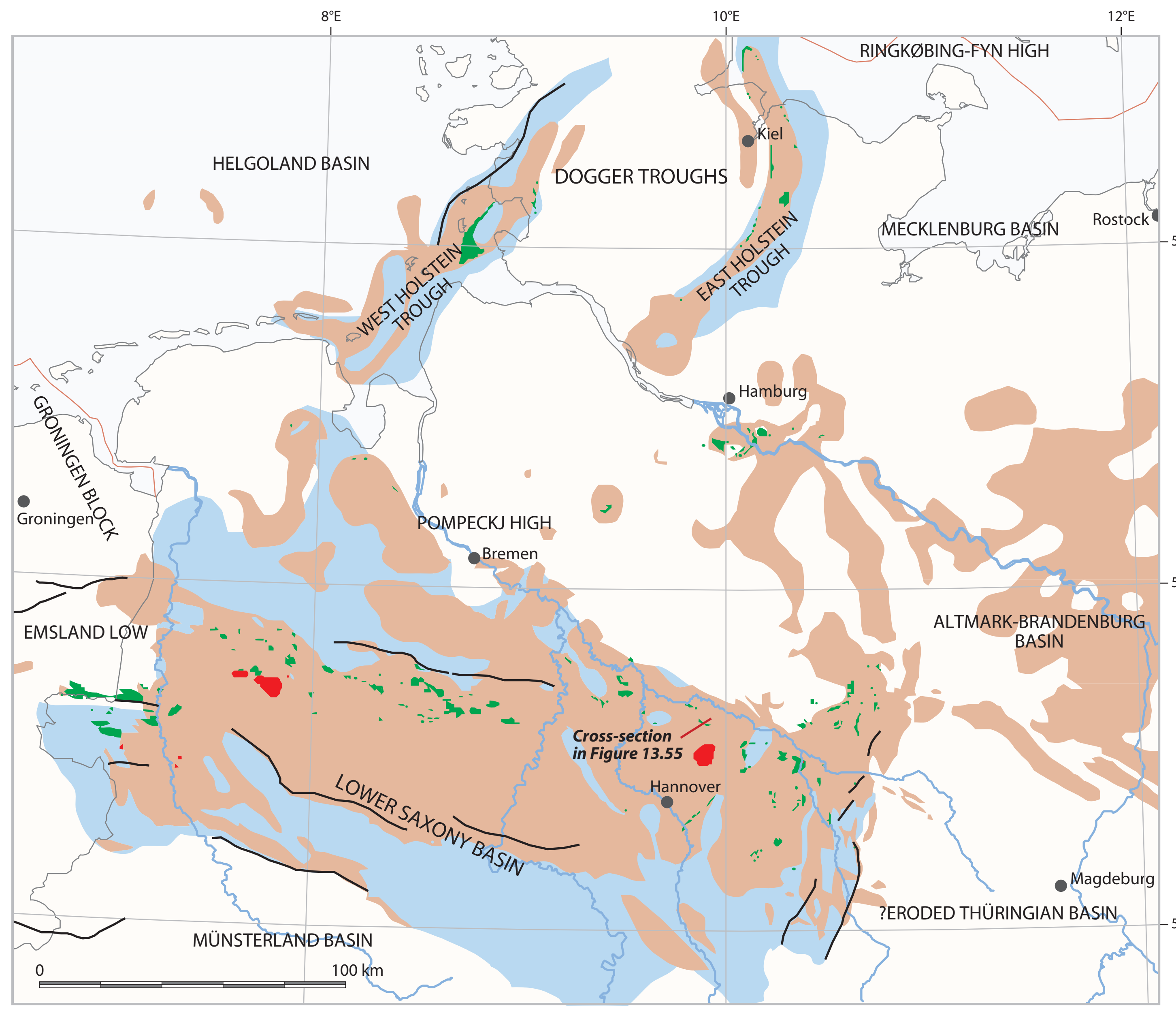


Figure 13.53 Event charts of: a. the Broad Fourteens Basin; and b. the West Netherlands Basin.



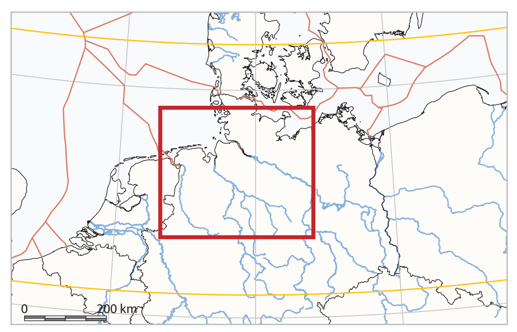


Figure 13.54 The Lower Saxony Basin and Dogger Troughs petroleum province with locations of fields and accumulations charged by the Posidonia Shale Formation.

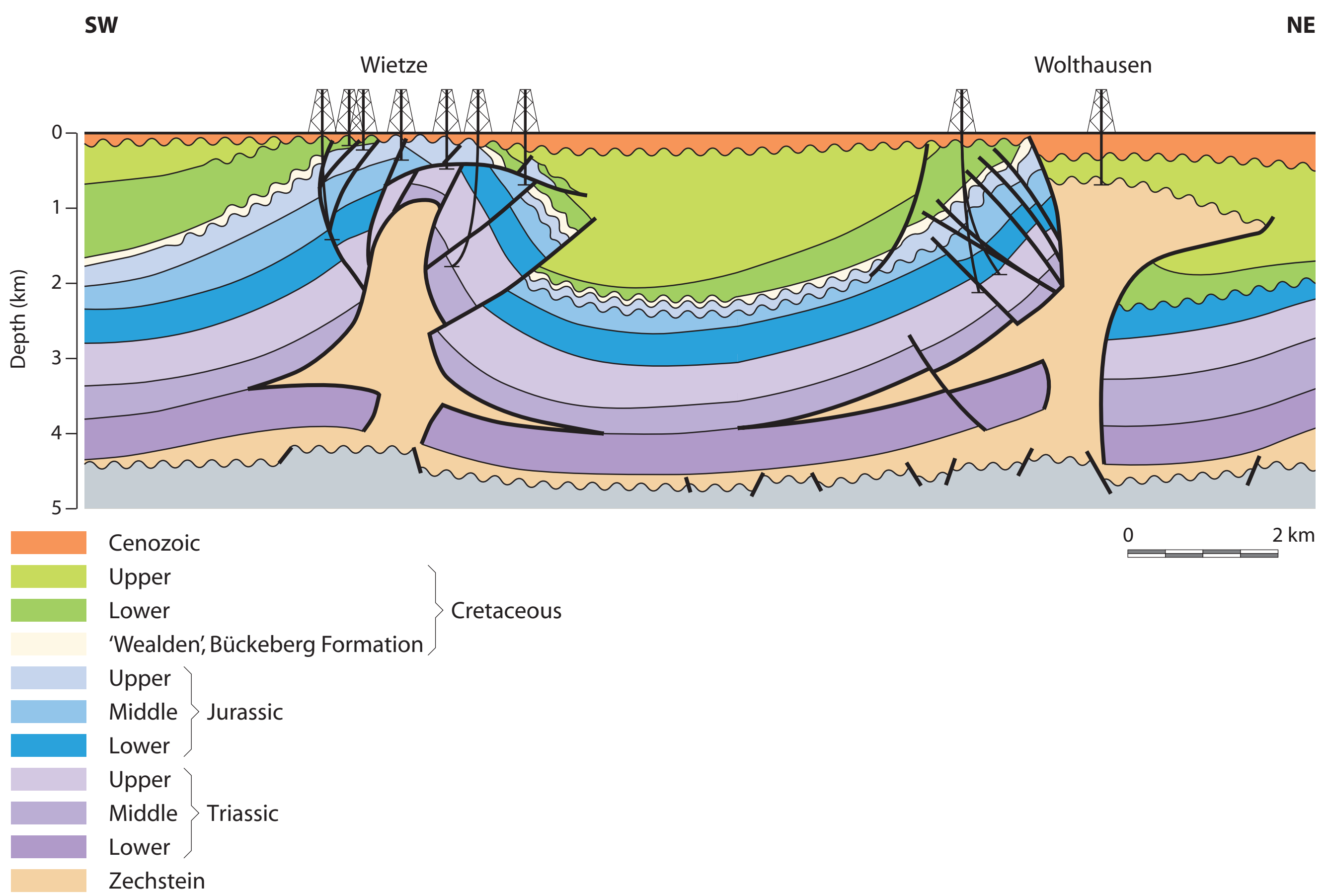


Figure 13.55 Cross-section through the Lower Saxony Basin. Example of a structural trap created by salt diapirism in the eastern Lower Saxony Basin (after Baldschuhn et al., 1996). See Figure 13.54 for location.

of the deltas in the east and more-or-less continuous lake systems to the west. Sediments deposited in these palaeoenvironments are referred to as the widespread Bückeburg or 'Wealden' Formation in Germany and as the regionally more limited Coevorden Formation in the Netherlands (**Figure 13.63**). East of the Weser River, coaly deposits are intercalated in mainly siliciclastic successions. Thick sequences of dark claystones, bituminous 'paper shale', and intercalated *Cyrena* shell horizons accumulated in a large lake system between the present-day Weser and Ems rivers.

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 sediment in the rapidly subsiding grabens at the southern basin margin (**Figure 13.64**: Chapter 11). The organic-carbon content is up to 14% with an average of about 5% west of the Weser. The organic matter in the Wealden paper shales in the lake areas consists mainly of alginite (**Figure 13.65**) with some bituminite. Admixtures of terrigenous organic particles are more pronounced towards the east and the south, building up local coal seams in the delta areas. Rock-Eval 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 II/III mixture. The biomarker data support the latter conclusion by the higher percentages of C_{29} steranes (**Figure 13.65**) in source-rock samples from the area. The genetic potential of this source-rock interval may be as high as 125 kg HC/t rock, but it is highly variable as mentioned above. The Wealden paper shale between the Weser and Ems has genetic potential averages of about 40 kg HC/t rock.

The most important reservoir rock for the hydrocarbons sourced from the Wealden paper shale within the Lower Saxony Basin are Valanginian sandstones. Intraformational sandstones and coquinites, and Hauterivian and Aptian reservoir rocks, also yield minor production mainly to the west of the Ems River.

Seals for most of the oil accumulations sourced or co-sourced from Wealden paper shale are formed by Hauterivian to Albian shales. In addition to their importance as seals, the thick Cretaceous claystone sequences acted as overburden before Coniacian 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 Cenozoic. The importance of extreme heating by magmatic 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 southernmost part of the basin, it entered the gas window in the Cenozoic. The strong variations in overburden and the possible local influence of deep magmatic intrusions led to sharp maturity gradients between different tectonic blocks in the Lower Saxony Basin.

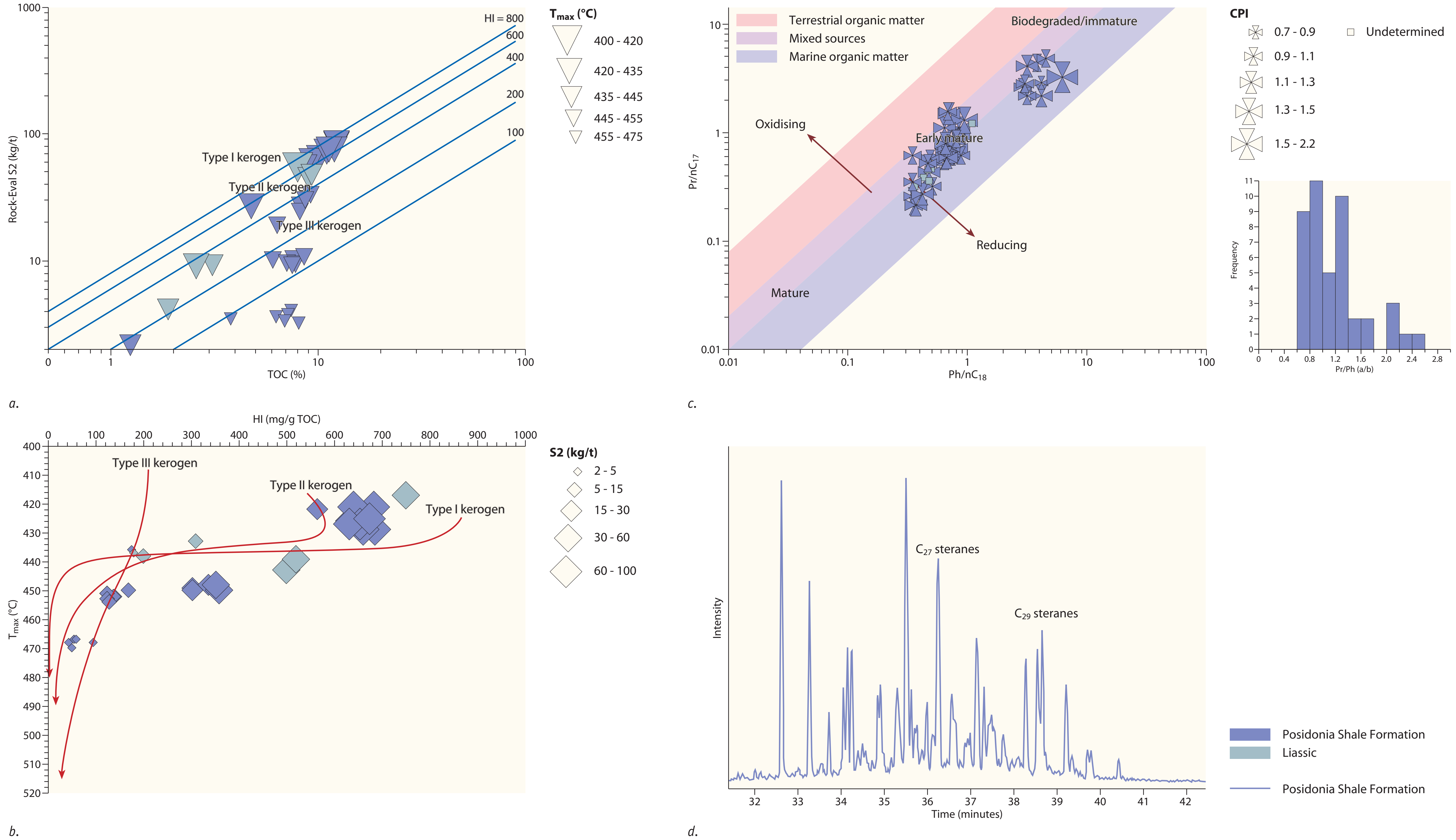
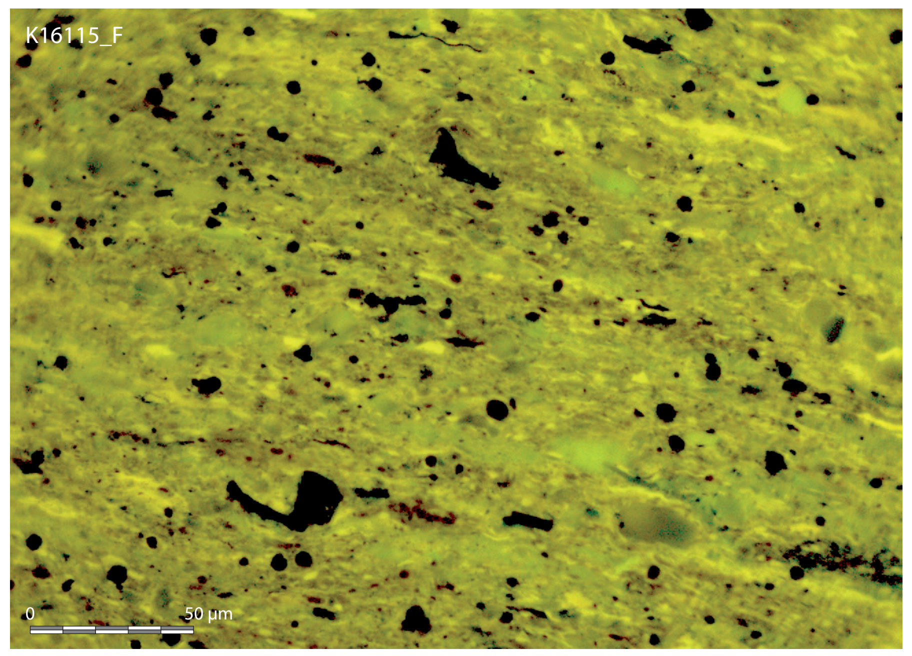


Figure 13.56 Geochemical data from the Posidonia Shale Formation and other Liassic samples from the Lower Saxony Basin and the Dogger Troughs:
a. Pyrolytic yield (S2) versus TOC. In addition to many mature and non-source rock samples and a few immature coal samples with type III kerogen there are a number of atypical samples with hydrogen-rich kerogen;
b. T_{max} versus Hydrogen Index (HI). Samples are mostly marginally mature to mature and comprise unusual type-I kerogen samples;
c. Pr/nC_{17} versus Ph/nC_{18}. Inset shows pristane/phytane ratios;
d. Molecular biomarker characteristics of a typical Posidonia Shale sample from the Lower Saxony Basin. The depicted m/z 217 trace was reconstructed from the single parent-daughter transitions from the metastable reaction monitoring measurement. The predominance of the C_{27} steranes over C_{28} and C_{29} steranes points to the dominance of algal remains in the organic matter;
e. Reflected-light micrograph (blue fluorescence excitation) of particulate organic matter in typical Posidonia Shale sample. Note the bright background fluorescence due to dispersed organic material in addition to the small yellow alginite particles.
Plots produced using IGI's p:IGI-3.

e.



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 survived 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, geochemical maturity data from the oils are comparable to the maturity of the Wealden paper shale in the vicinity, implying short migration distances. Several oilfields near the Ems exhibit increased gas:oil ratios, with stable isotopic compositions of the gases invoking their thermal generation, perhaps from deep-seated Carboniferous coals. 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.

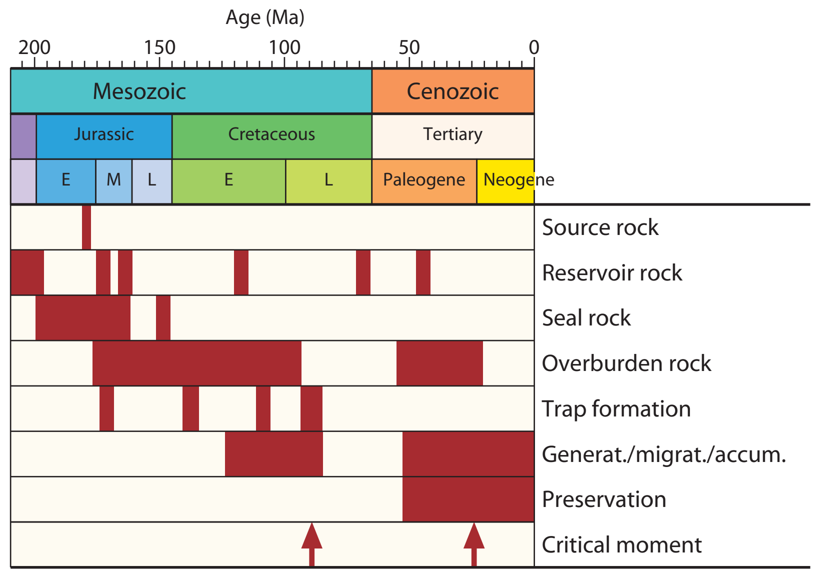


Figure 13.57 Event chart of the Posidonia Shale petroleum system in the Lower Saxony Basin (after Kockel et al., 1994).

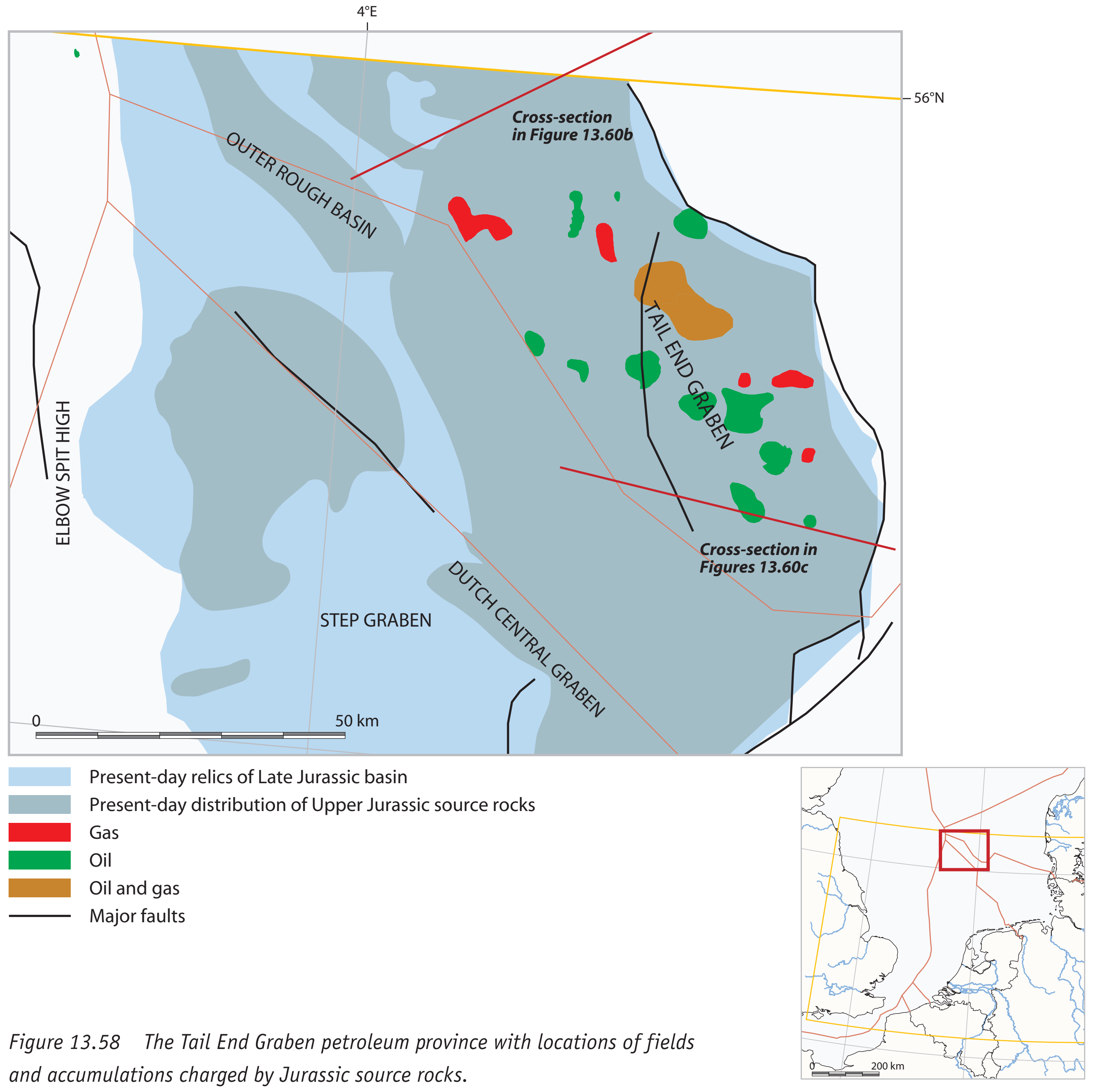


Figure 13.58 The Tail End Graben petroleum province with locations of fields and accumulations charged by Jurassic source rocks.

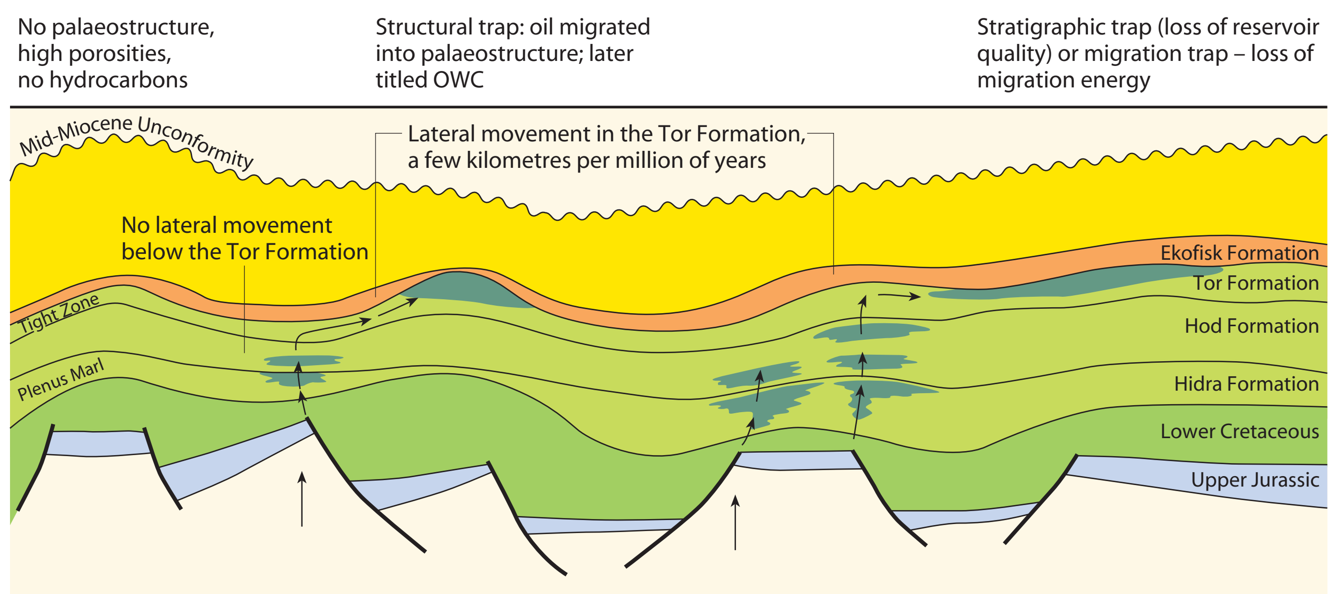


Figure 13.59 Schematic model illustrating the entry points and various oil-migration paths in the complex Chalk Group of the Tail End Graben (modified after Megson & Hardman, 2001).

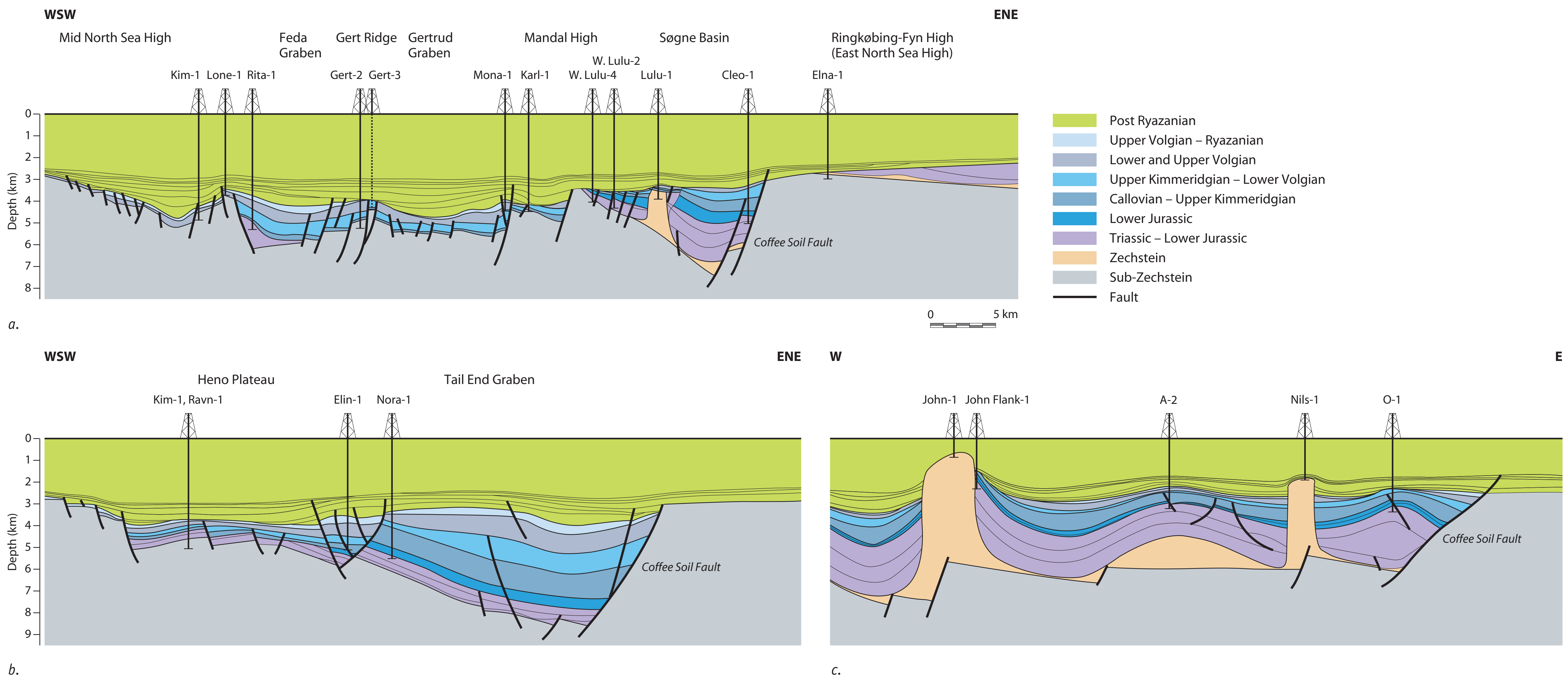


Figure 13.60 Cross-sections through the Tail End Graben petroleum province and adjacent areas: a. Northern Danish Central Graben; b. Tail End Graben and Heno Plateau; c. Salt Dome Province (modified after Møller & Rasmussen, 2003). See Figure 13.58 for locations.

The Schoonebeek oilfield in the Netherlands and its extension into Germany (where it is still producing) is the most prominent oilfield in the SPB area that was charged from Lower Cretaceous deposits (Section 4.1 in Chapter 11). It is the largest onshore oilfield in western Europe, with an initial in-place volume of about 1 bln barrels of which 25% had been produced before it was closed in 1996. The source rocks of the oil are lacustrine shales with algal, type I source rocks of the Coevorden Formation. Geochemical data indicate that the oil is an early expulsion product of a source rock with low maturity, consistent with the high viscosity of the oil (25° API). There are no signs of biodegradation. However, a contribution from the Posidonia Shale source rocks that occur west of the field can not be excluded. The oil from the Schoonebeek field is produced from the Lower Cretaceous Bentheim Sandstone at a depth of about 800 m.

For further information see Binot et al. (1993), Kockel et al. (1994), Baldschuhn et al. (1996), Mutterlose & Bornemann (2000), NITG (2000), Adriasola-Muñoz et al. (2007) and De Jager & Geluk (2007).

3 Shallow gas and bright spots in the southern North Sea

The SPB, 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 occurrences 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 hydrocarbon 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 a separate, ancient species of organisms.

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 breaking of carbon bonds of complex kerogen molecules at higher temperatures. Hydrocarbons can accumulate in traps during buoyancy-driven secondary migration. Leakage from these traps leads to preferential dismigration 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 origin. Other sources of gas (destabilised gas hydrates, volcanic/hydrothermal emanations) are thought to be irrelevant in the southern North Sea.

Major incentives to investigate seismic shallow-gas indicators include risk and hazard prevention associated with drilling into unknown gas-bearing sediments. A blow-out is the most dangerous of these drilling hazards. Another aspect is the effect shallow gas has on the engineering behaviour (particularly the shear strength and consolidation characteristics) of unlithified sediments; the construction of petroleum infrastructure or windfarms may be impaired on these potentially unstable substrates. Natural-gas seeps may be indicated by methane-derived authigenic carbonates (MDAC) at the sea bed. As well as providing uneven sea-bed foundations and obstacles to sea-bed structures such as cables and pipelines, MDAC structures are identified by the European Commission's Habitats Directive as sensitive habitats that should be avoided by offshore operations.

Pockmarks (sea-bed depressions formed by the erosion of soft, fine-grained seabed sediment by escaping fluids) may also indicate current or former migration of gas (either microbial or thermogenic). Although common in large parts of the northern North Sea in the SPB, they seem to be restricted to parts of the Dutch sector. Freak sandwaves, also thought to be attributable to gas seepage, have also been described from the southern North Sea. Knowledge and understanding of the distribution, size and extent of shallow gas and associated features is therefore crucial to safe drilling, construction and other offshore operations.

The presence of gas in the shallow subsurface can be an indication of deeper hydrocarbon fields. Further motivation 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 extension 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. Gases in the pore space of rocks, even at concentrations as low as 0.5%, can change both their 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.

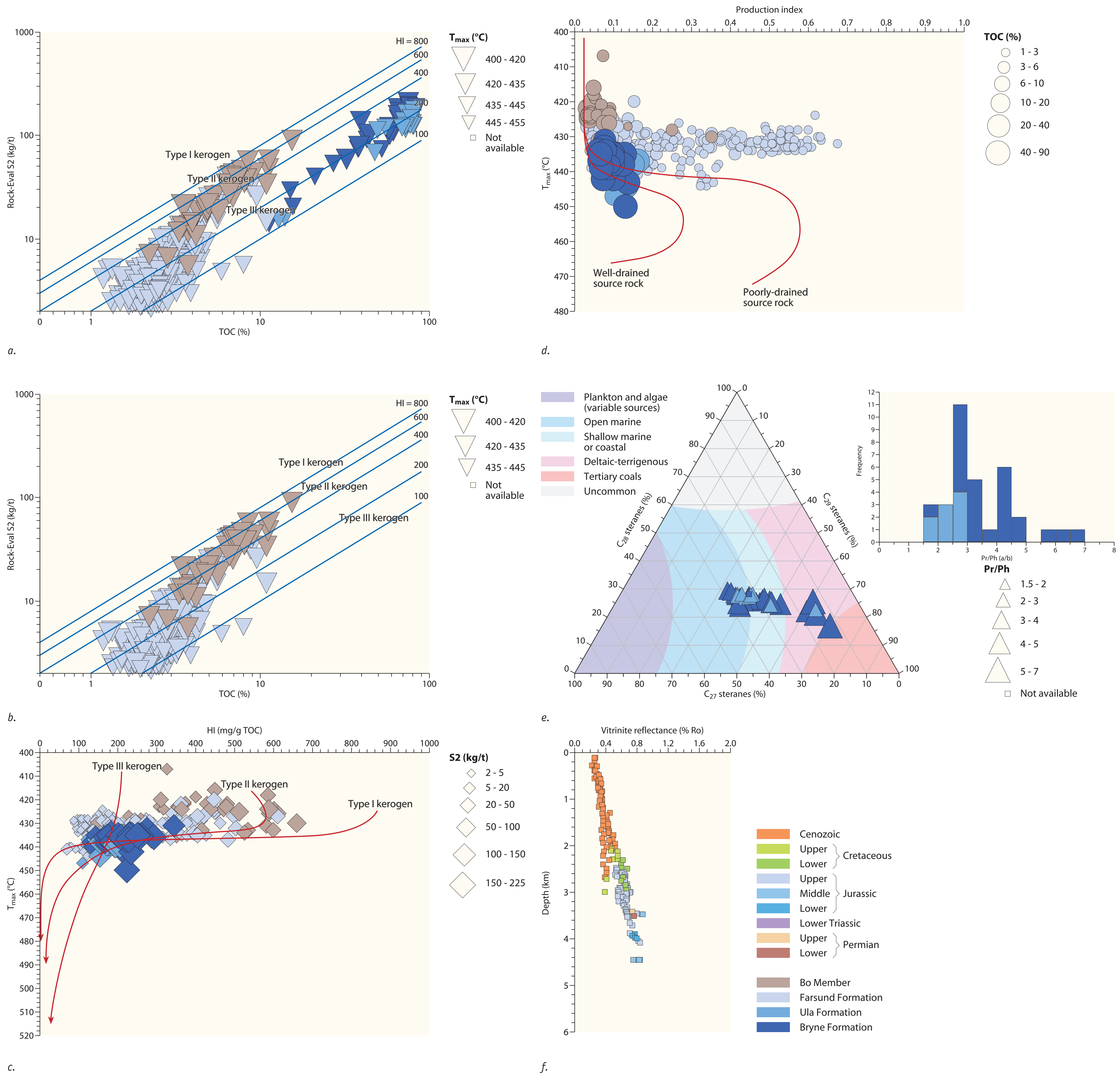


Figure 13.61 Geochemical data of samples from different Jurassic formations of the Tail End Graben:
a. Pyrolytic yield (S2) versus TOC. In addition to many mature and non-source rock samples and a few immature coal samples with type III kerogen there are a number of atypical samples with hydrogen-rich kerogen;
b. T_{max} versus Hydrogen Index (HI). Samples are mostly marginally mature to mature and comprise unusual type I kerogen samples;
c. T_{max} versus Production Index (PI). Maturity-induced depletion has led to well-drained source rock conditions;
d. Pr/nC_{17} versus Ph/nC_{18};
e. Sterane ternary diagram;
f. Vitrinite reflectance plotted against sub-bottom depth.
Plots produced using IGI's p:IGI-3.

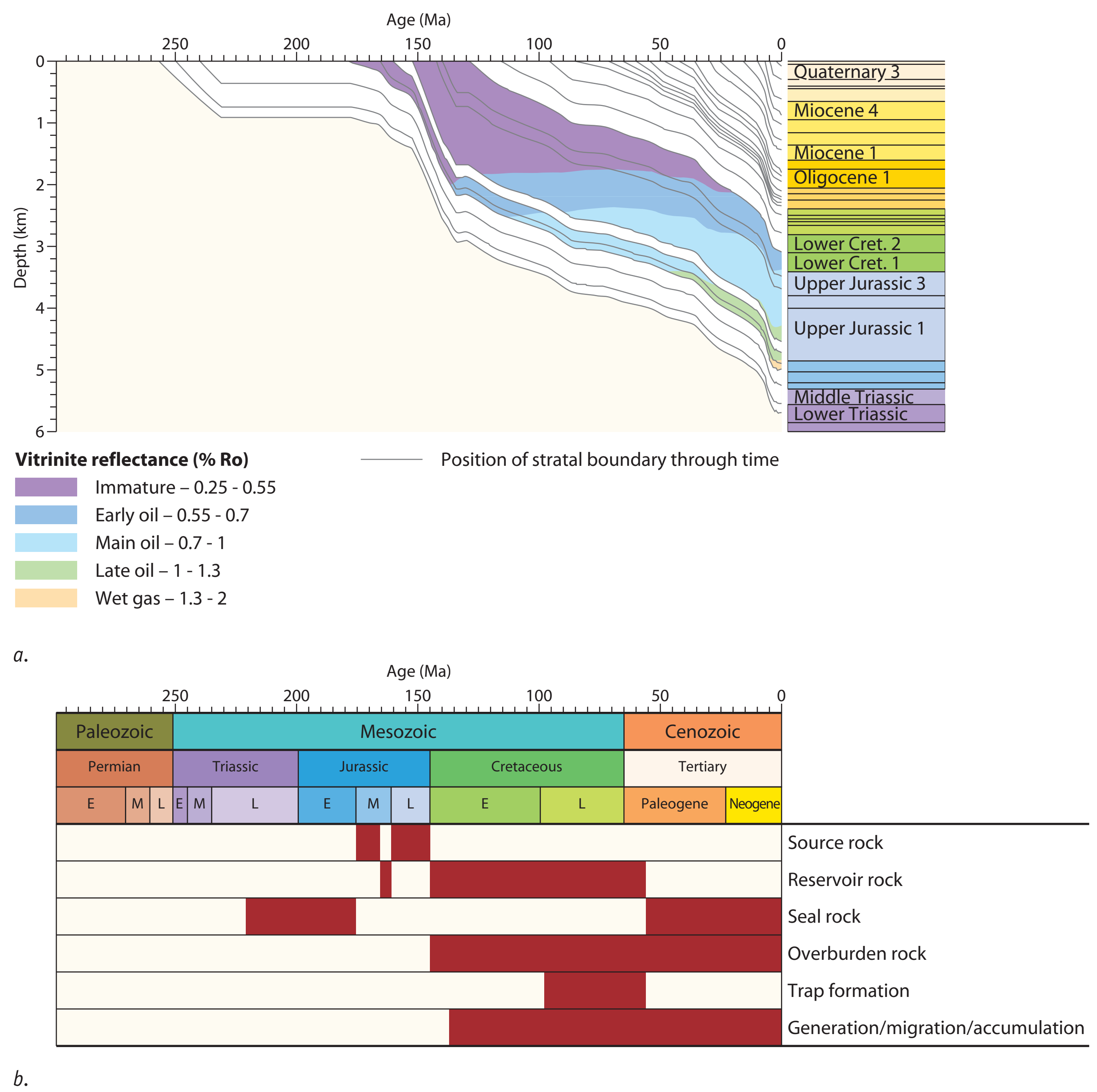


Figure 13.62 a. Burial history and modelled vitrinite reflectance history for well in the Tail End Graben; b. Event chart for the Upper Jurassic Farsund Formation and the Middle Jurassic Bryne Formation in the Tail End Graben.

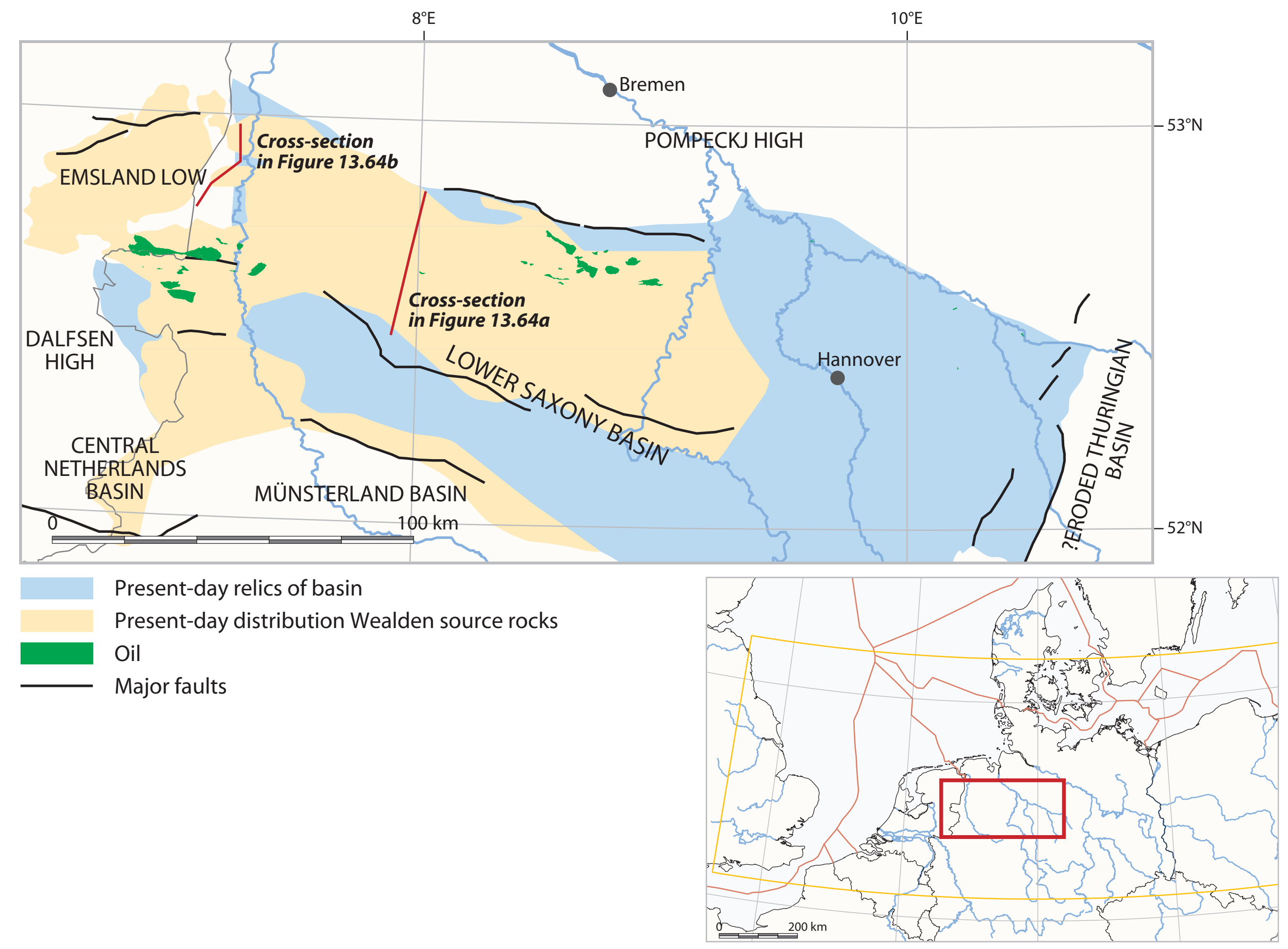


Figure 13.63 The Lower Saxony Basin petroleum province with locations of fields and accumulations charged by Wealden source rocks.

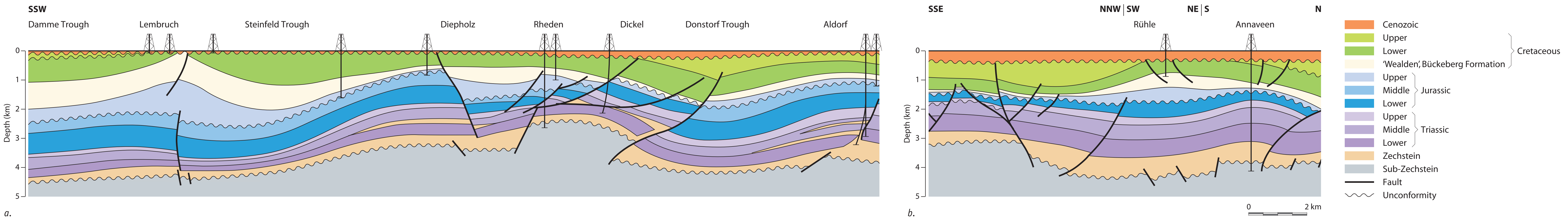


Figure 13.64 Cross-sections through the Lower Saxony Basin (after Baldschuhn et al., 1996): a. Variability in thickness of the Wealden shale caused by variable subsidence rates; b. dominating structural traps in large anticlines in the area west of the Ems River. See Figure 13.63 for locations.

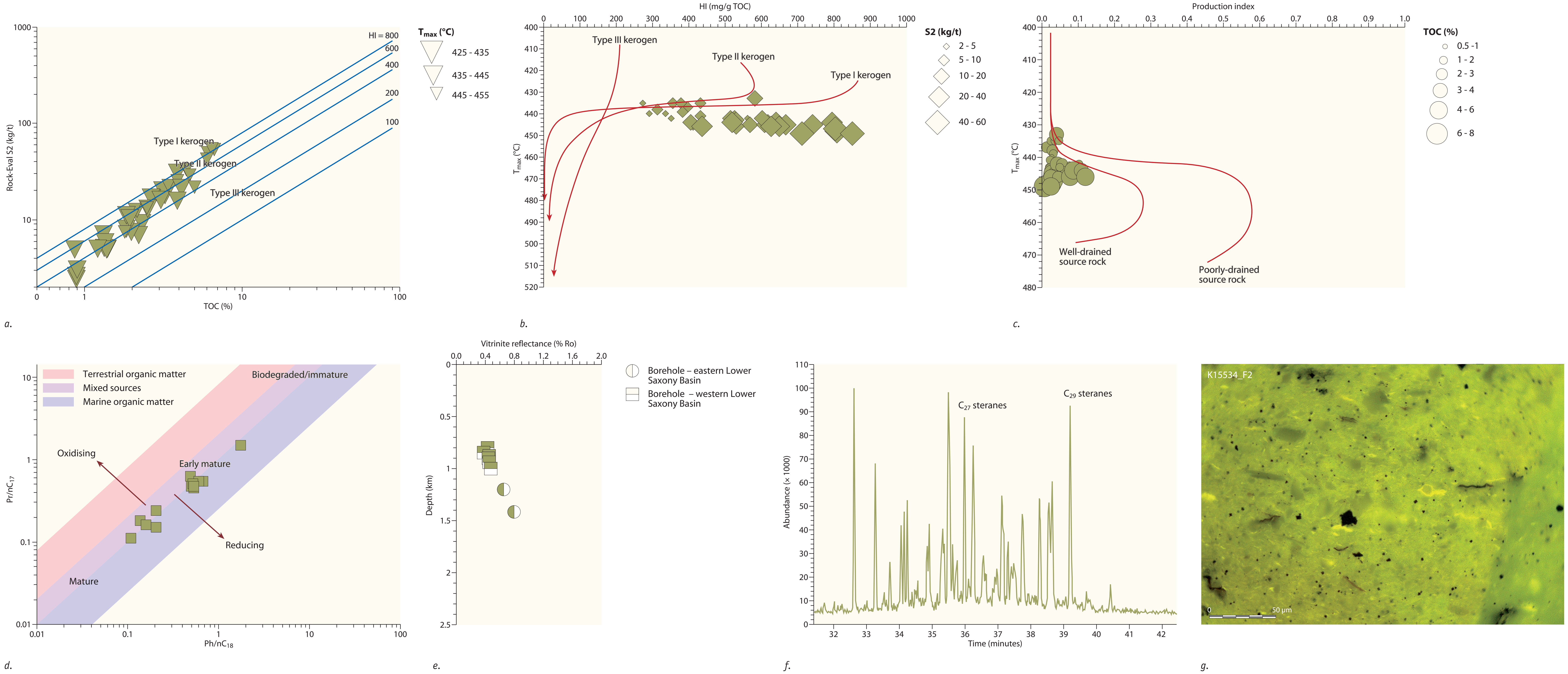


Figure 13.65 Geochemical data from Wealden Shale formations in the Lower Saxony Basin:
a. Pyrolytic yield (S2) versus TOC;
b. T_{max} versus Hydrogen Index (HI);
c. T_{max} versus Production Index (PI);
d. Pr/nC_{17} versus Ph/nC_{18};
e. Vitrinite reflectance and Rock-Eval T_{max} parameters plotted against sub-bottom depth;
f. Molecular biomarker characteristics of a Wealden Shale sample from the centre of the basin. The depicted m/z 217 trace was reconstructed from the single parent-daughter transitions from the metastable reaction monitoring measurement. The similar abundance of the C_{27} and C_{29} steranes depicts a sedimentary environment with mixtures of algal and land plant derived material;
g. Reflected-light micrograph (blue fluorescence excitation) of particulate organic matter in a Wealden paper shale sample. Note the bright background fluorescence due to dispersed organic material in addition to the small yellow alginite particles.
Plots produced using IGI's p:IGI-3.

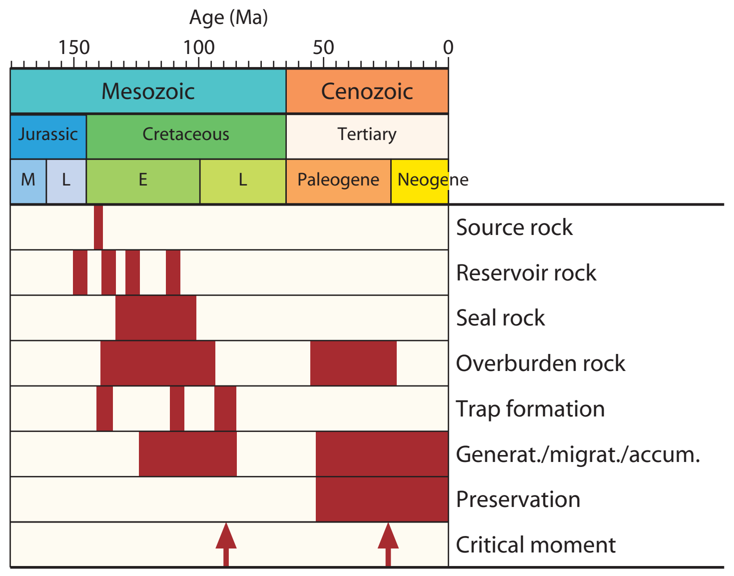


Figure 13.66 Event chart for the Wealden petroleum system in the Lower Saxony Basin (after Kockel et al., 1994). Lower Cretaceous traps are stratigraphic (facies and unconformity traps) whereas the predominant Upper Cretaceous traps are mostly structural.

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 sharp 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 igneous intrusions. Coal beds, peat, gas-charged or over-pressured sediments lead to decreasing velocity (**Figure 13.68**). 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 Step grabens. In most cases, the bright spots agglomerate 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 lying source rocks, i.e. the gas is of thermogenic origin. First analyses 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 erosionally truncated and terminate against a seal (**Figure 13.71**). Pinch-out traps are common in fluvial and delta foresets or beneath unconformities. The Baltic River System, which developed from mid-Miocene times and occupied a large area of the southern North Sea (Chapter 12), offers appropriate conditions for this trap type due to the common development of inclined horizons. Negative polarity ('soft kick') of the bright spots is considered to be an indicator of gas beneath the pertinent interface.

Gas chimneys are characterised by a zone or column of reflections that are discontinuous, chaotic, and/or attenuated in comparison with the adjacent sediment (**Figure 13.72**). This type of amplitude anomaly is indicative of the leakage of fluids, including hydrocarbon gas, from a deeper reservoir. Many of the seismic anomalies indicating leakage 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.

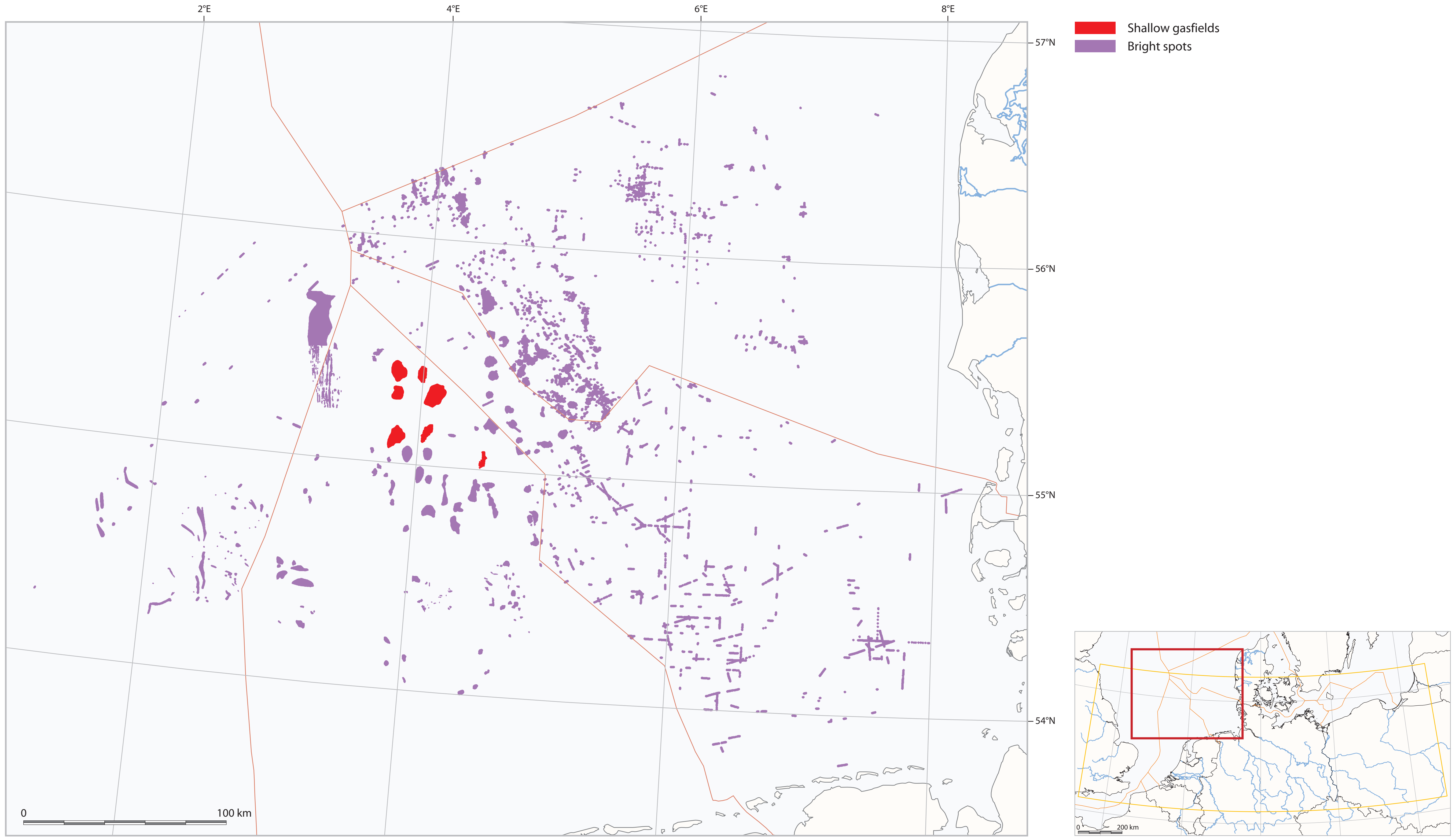


Figure 13.67 Distribution of bright spots and amplitude anomalies in the southern North Sea. Bright spots are observed on 2D- and 3D-seismic data as high amplitudes, probably caused by microbial or thermogenic gas in the pore fluid. Most bright spots were found at the top of Pliocene sands. Linear alignments of some bright spots in the English and German North Sea sectors are related to the locations of the 2D-seismic lines used rather than to geological structures.

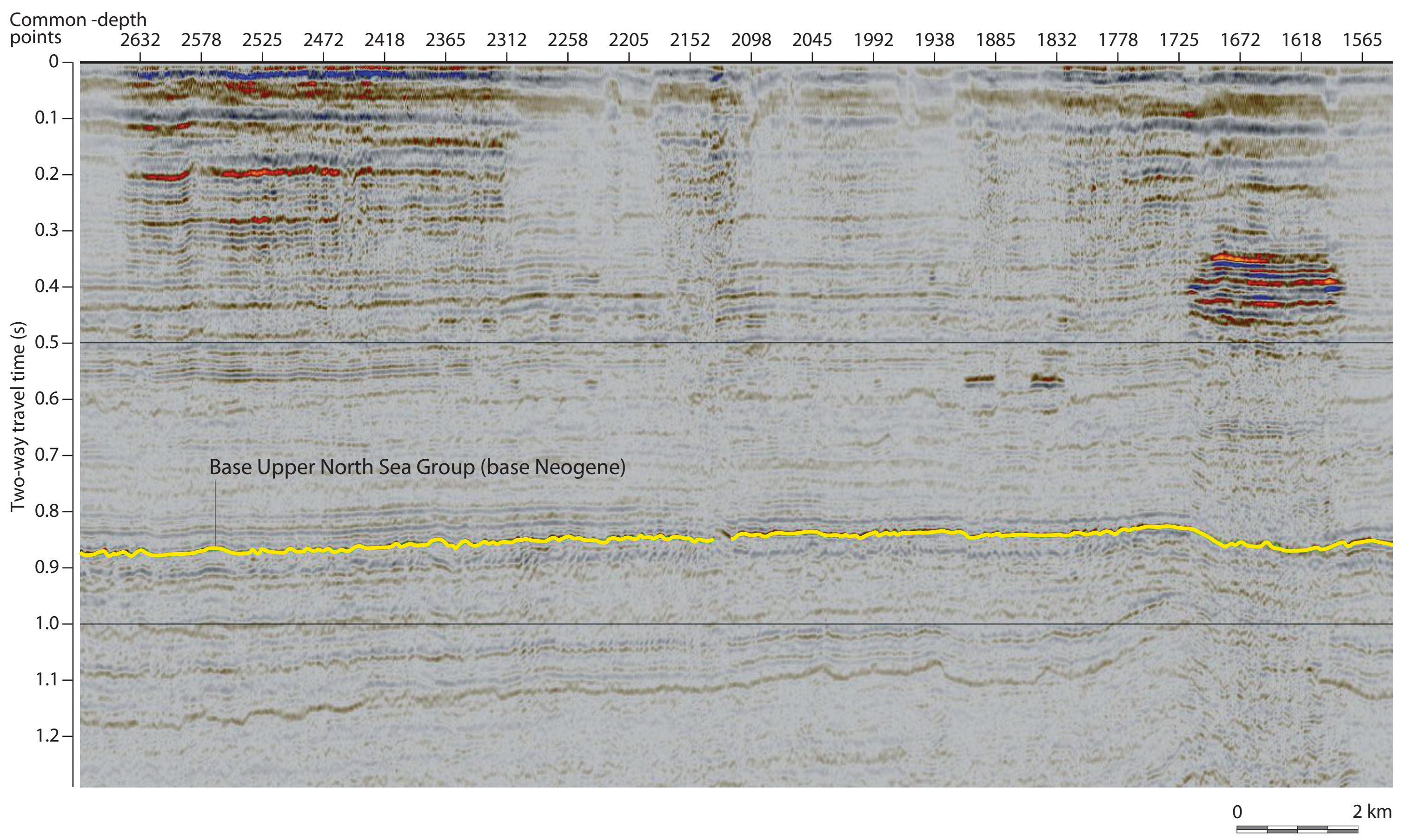


Figure 13.68 Bright spots caused by peat and shallow gas in the Dutch North Sea sector. The interpreted horizon is the Mid-Miocene Unconformity. High amplitudes between the common depth point (CDP) 2300 and 2600 are probably caused by a peat layer close to the sea floor. The associated high amplitudes in the subsurface are sea level and inter-bed multiples. The bright spot between CDP 1600 and 1700 at about 0.4 s two-way travel time on top of a salt diapir is from an unconsolidated gas-charged Pliocene sand layer. The gas is probably thermogenic and comes from a deeper source. A push-down effect occurs at about 0.9 s beneath the gas reservoir. There are indications of a gas chimney at around CDP 2100.

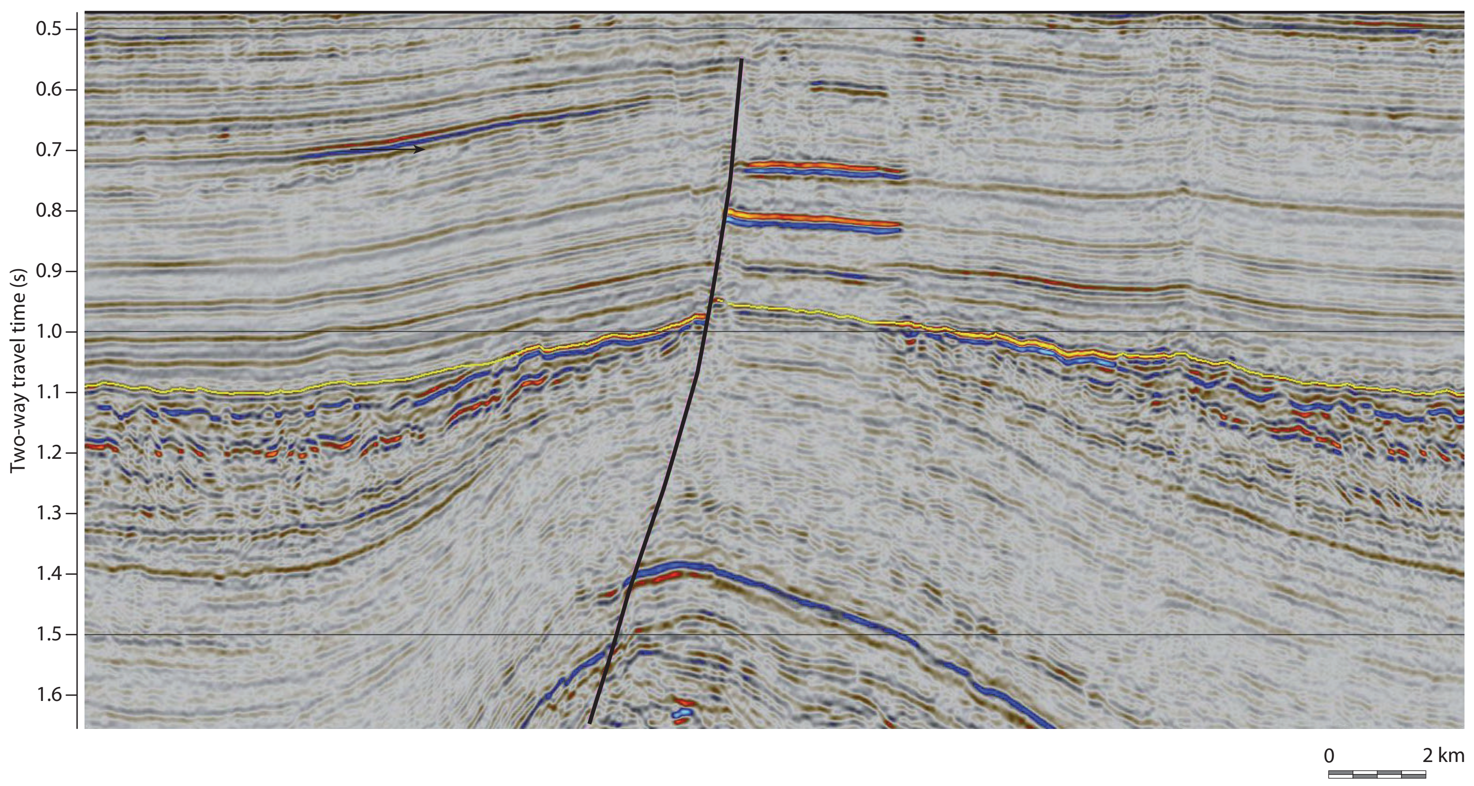


Figure 13.69 Fault-related bright spot in the Dutch North Sea sector. The gas-charged Pliocene sediments are located on top of a salt diapir. The fault probably acted as a conduit for thermogenic gas from a deep-seated source. The interpreted horizon is the Mid-Miocene unconformity.

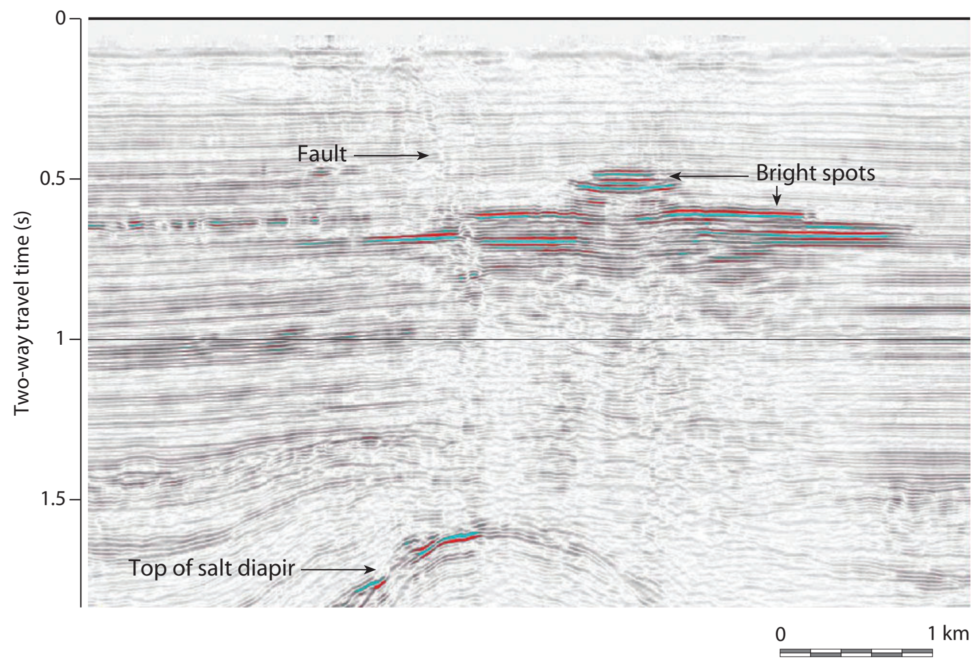


Figure 13.70 Bright spots above a diapir in the German North Sea sector. Bright spots between 0.4 to 0.8 s two-way travel time are probably related to gas-charged sediments. The bright spot around 1.6 s TWT is interpreted as amplitude anomalies induced by well-cemented caprocks at the top of the diapir.

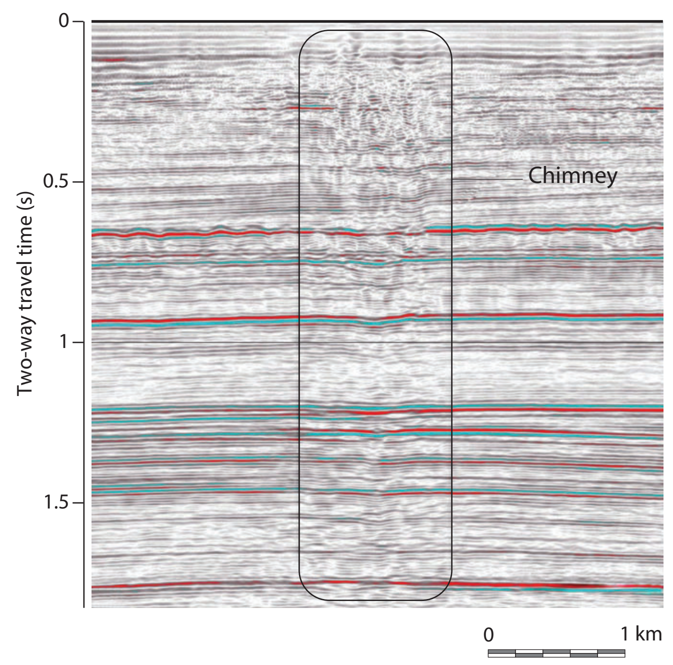


Figure 13.72 Chimney induced by gas-rich pore fluids, where gas is rising from deeper sources vertically or diagonally along faults towards the sea bed and locally increases the gas content of the sediment. Note the chaotic reflection pattern in the upper 0.3 s TWT and the push-down effect of reflections at about 0.9 s and 1.25 s.

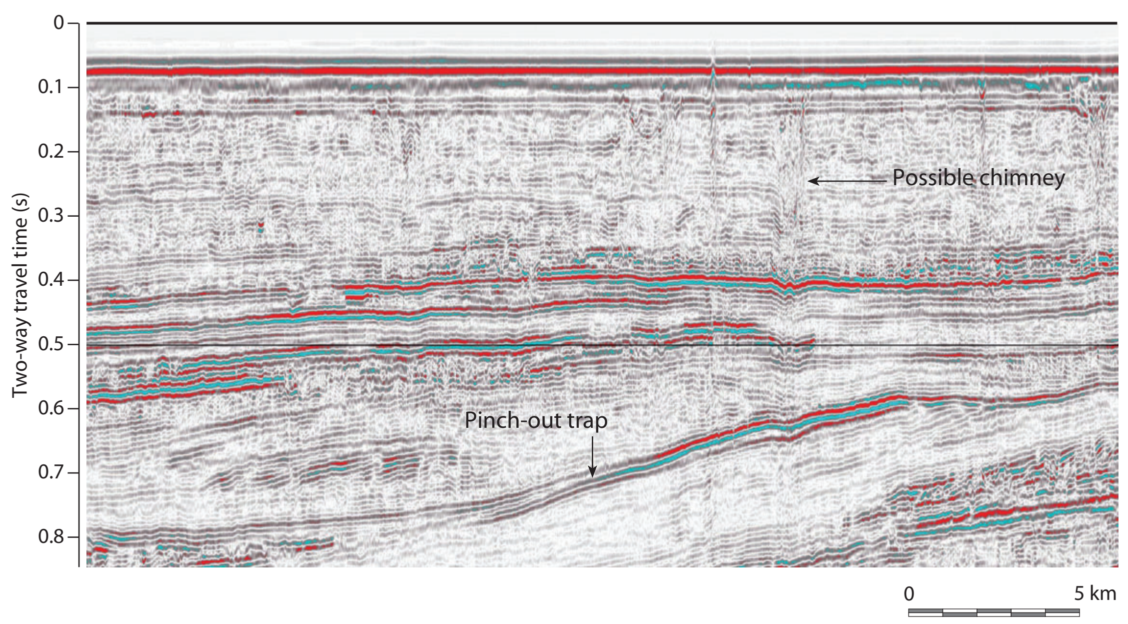


Figure 13.71 Bright spot in a pinch-out trap in the German North Sea sector. The amplitude of the marked anomaly increases updip. This may be related to the presence of gas in the layer, which accumulates in the upper part of the structure where it increases the acoustic impedance contrast at its top interface.

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 overlie the blanked zone and reduce 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. Reflectors within these zones appear weakened and/or chaotic. This may result from the disruption of the sedimentary reflectors 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 Schroot & Schüttenhelm (2003), Schroot et al. (2005), Judd & Hovland (2007) and Kuhlmann & Wong (2008).

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