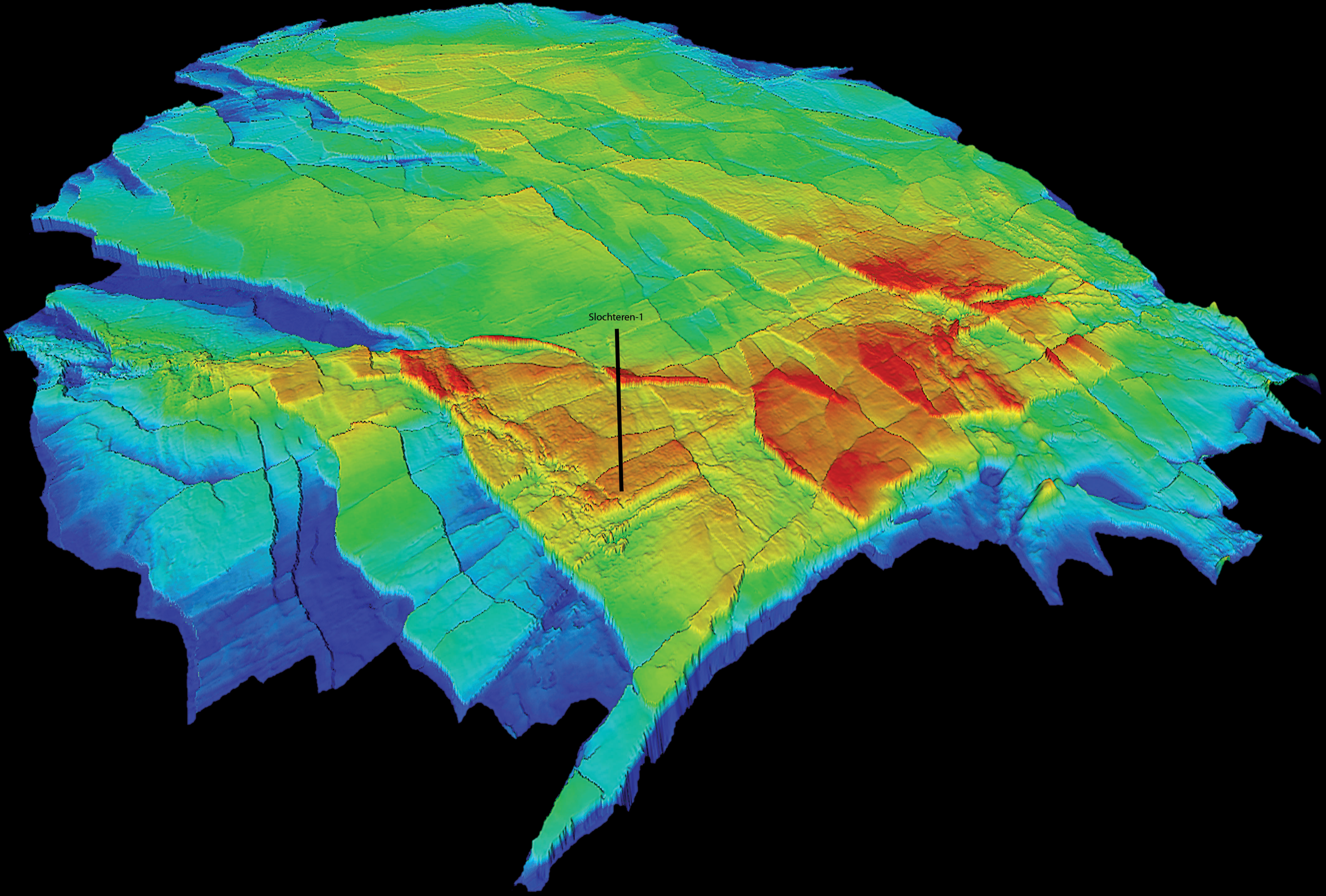

3D view of the top Rotliegend reservoir showing the depth structure of the Groningen gasfield and the Slochteren-1 exploration well. The perspective is from the SSW. Field length and width are approximately 40 km and 30 km, respectively. Colour scale: red is at 2600 m and dark blue is at 3000 m below mean sea level.

Chapter 15 Reserves and production history

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Bibliographic reference
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1 Introduction

Figures 15.1 and **15.2** show all 1392 oil and gas accumulations (grouped into 1244 fields) discovered so far within the SPB area. It is immediately apparent that the vast majority of the fields are concentrated in a relatively narrow east–west-trending corridor in the SPB. This chapter describes the history of the oil and gasfields within the SPBA and considers two key questions:
1. What are the petroleum geological controls on the location of the oil and gasfields?
2. How have the discovery of these fields and the associated hydrocarbon volumes evolved over time?

The objective is to provide some insights into the history of exploration and production (E&P) in the SPB area and offer information on E&P opportunities for the future.

2 Information and data

2.1 Geological information

The general approach has been to use a synthesis of information and interpretations on the petroleum geology found elsewhere in this Atlas and combine that with the data on the known oil and gasfields in the SPB area. **Appendix 2** provides a full list of the GIS-based maps in the Atlas, which include information on tectonic elements, source-rock facies, and reservoir facies of the SPB area.

Chapters 6-12 include maps showing the reservoir-facies distribution at the respective stratigraphic levels, together with the oil and gasfields that have been discovered within each stratigraphic level (see Chapters 6-12, Figures 6.20, 7.20, 7.21, 8.18a, 9.11, 10.11 and 11.24). The descriptions of the hydrocarbon resources in each chapter have, to some extent, already given an explanation of why fields are where they are.

Chapter 13 defines six *petroleum systems* in the SPBA area, which are characterised by a unique source-rock type and age. In addition, 13 *petroleum provinces* have been delineated, each of which hosts one or more of the petroleum systems. The provinces are listed in **Table 15.1**.

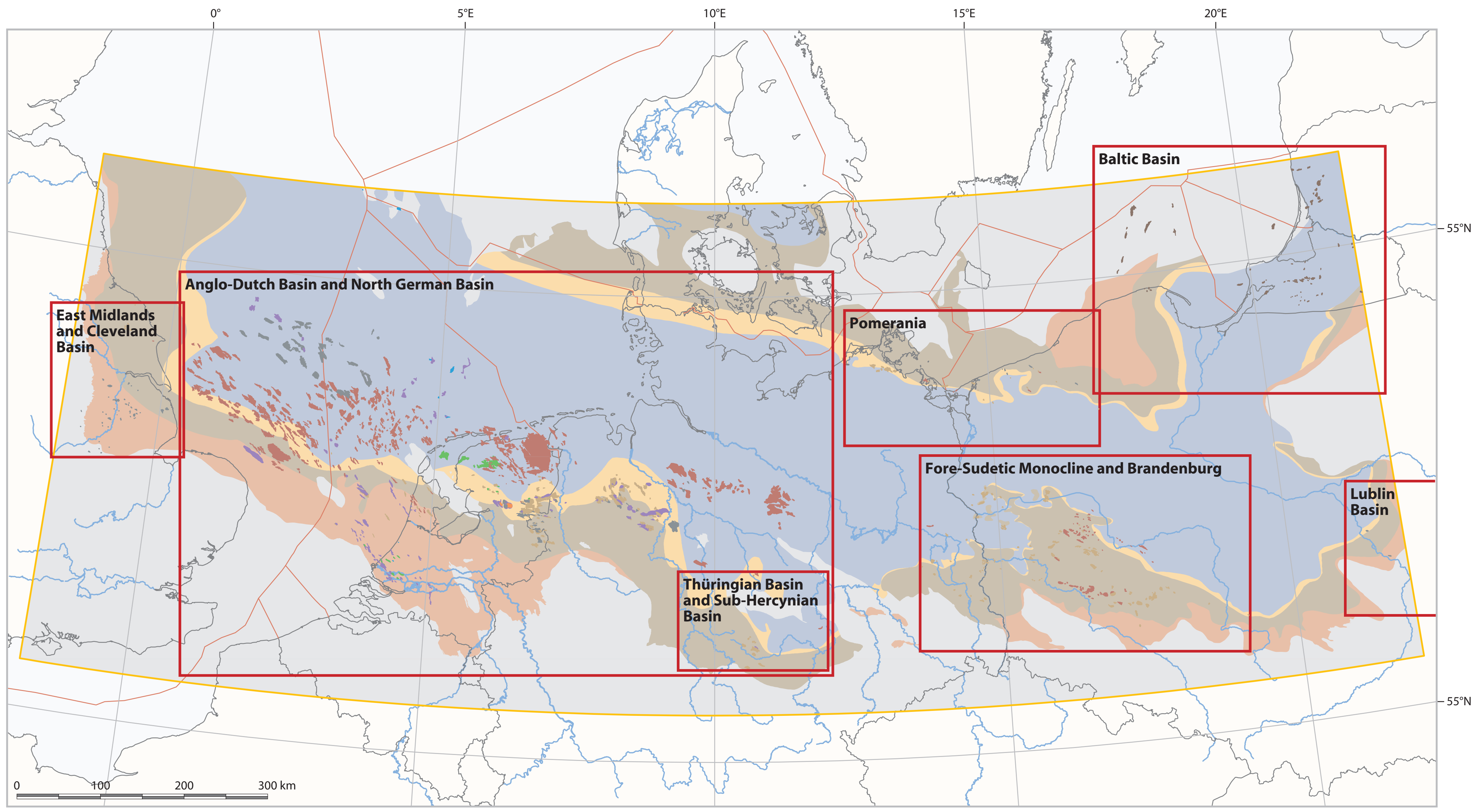


Figure 15.1 Overview of petroleum provinces related to Paleozoic source rocks.

Table 15.1 Petroleum provinces and their key characteristics.

Petroleum system / province		Main reservoir(s)	Number of accumulations	Volumes Gas (bcm) UR	Gas (bcm) Prod	Oil (mln m³) UR	Oil (mln m³) Prod	Example fields	Chapter
Pre-Devonian source									
I	Baltic Basin	Cambrian	68	10	0.9	62	44		
Carboniferous & Permian source									
II	Anglo-Dutch and North German basins	Rotliegend, Zechstein, Triassic, Cretaceous	761	6978	4848	0.11		Groningen and many others fields	6, 7, 8, 9, 10
III	East Midlands and Cleveland Basin	Carboniferous, Zechstein	55	3.3		5.9	4.7	Welton	6
IV	Thüringian and Sub-Hercynian basins	Zechstein, Triassic	18	6.4	5.6	0.13	0.04		
V	Pomerania	Carboniferous, Rotliegend, Zechstein	35	14	2.2	6	5.6	Ciechnowo	7
VI	Fore-Sudetic Monocline and Brandenburg	Rotliegend, Zechstein	175	191	92	27	5.7	BMB, Radlin, Kościan and Brońsko, LMG	7, 8
VII	Lublin Basin	Carboniferous	4	1.1		0.1		Stężyca	6
Jurassic source									
VIII	Weald Basin	Jurassic	19	0.12		3.3	2.32[1]	Palmers Wood	10
IX	Tail End Graben	Cretaceous	22	141	76	436	250	Valdemar,Tyra, Halfdan	11
X	Dutch Central Graben	Jurassic	14	21	15	22	13	F03-FB	10
XI	West Netherlands and Broad Fourteens basins	Jurassic, Cretaceous	60			109	81	Pernis-West	9
XII	Lower Saxony Basin and Dogger Troughs	Jurassic, Cretaceous	154	10	7.1	407	319	Mittelplate, Schoonebeek oilfield	10, 11
Shallow gas									
XIII	Shallow gas	Cenozoic	7	11	0	0	0	A15-A	12
Total			**1392**	**7387**	**5047**	**1079**	**725**		

1 By the end of 2005

In Chapter 14, the vast set of exploration wells drilled in the SPB area has been presented and statistically described in terms of target and success rate. For the purpose of this chapter, the well data set has been grouped into subsets for each petroleum province.

2.2 Project database

An SPBA Project Database (Chapter 1) has been compiled, from both public and industry sources of information. **Table 1.6** shows the types of attribute data in the dataset[1]. **Appendix 3** provides the full list of the 1244 oil and gasfields and their associated attributes, sorted by petroleum province.

1 All information is up-to-date as of 1st January 2007. Oil and gas volumes are treated separately, i.e. they have not been converted to Oil Equivalent units. Reserves are defined as ultimately recoverable volumes (proven and probable), according to today's estimates. Reserves are not classified in detail according to one of the many existing country or company specific classification schemes as it was beyond the scope of this Atlas to consider the subtle differences between the classifications, let alone try to standardise them. However, reserves are classified as 'developed' or 'undeveloped', depending on the development status of a field. A field that consists of more than one hydrocarbon accumulation is considered 'developed', if at least one of the accumulations has been developed.
UK operators have given permission to use their field volume data under the following disclaimer: *"All UK ultimate recoverable volumes quoted are the opinion of the operator at the time of the request to publish, and do not necessarily reflect the views of our partners in the relevant joint ventures"*.

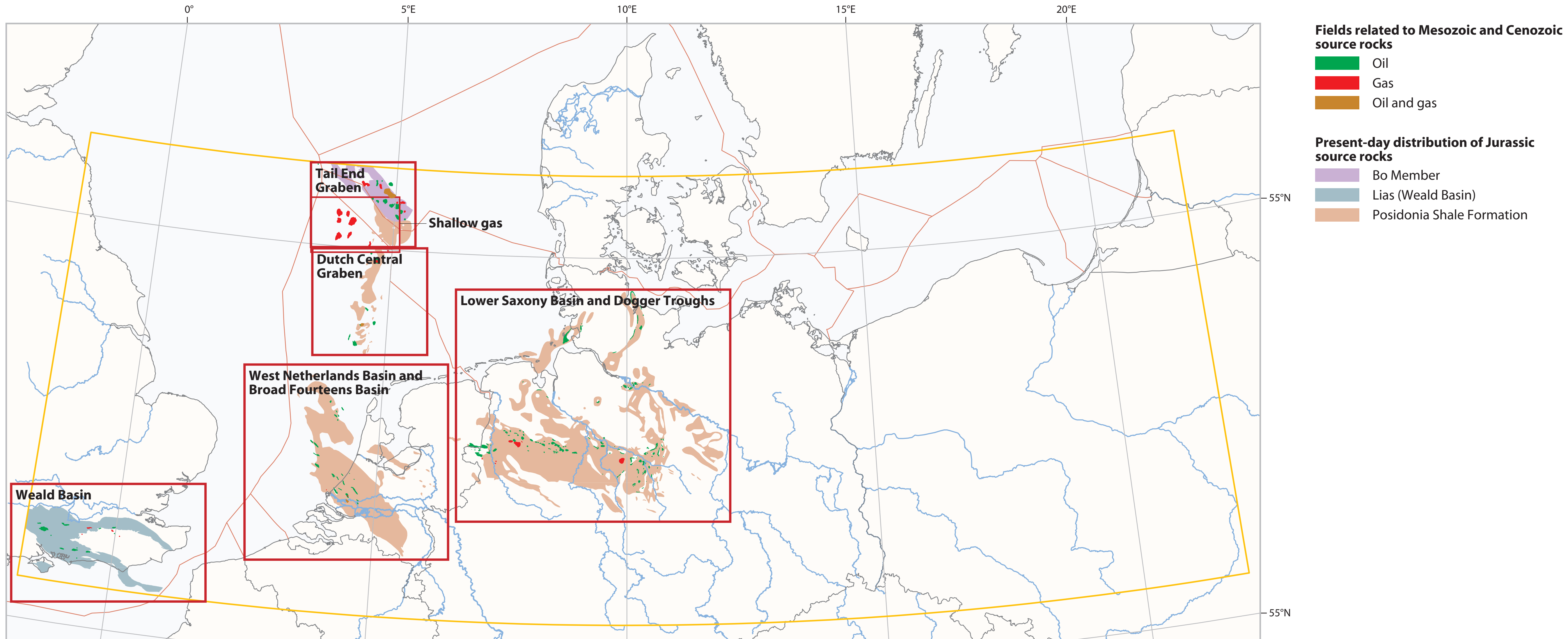


Figure 15.2 Overview of petroleum provinces related to Mesozoic and Cenozoic source rocks.

3 Methodology

3.1 Controls on the distribution of hydrocarbon fields

A common feature of the petroleum provinces is that they all have accumulations of oil or gas that have been proven by drilling. This chapter reviews the specific features of these provinces and the geologically determined groups of proven oil and gasfields within them. The source-rock distribution maps show the main control on the distribution of the oil and gasfields; the reservoir-facies maps provide another control on the distribution of the fields.

The deposition of the Zechstein halite cover has had a major influence on the migration and trapping of hydrocarbons in the SPB. This is specifically dealt with in the sections describing the Anglo-Dutch and North German basins (Section 5.2.1). The pattern of exploration wells show the extent to which each petroleum province has actually been tested by drilling.

To help visualise the synthesis of information, maps have been generated for each petroleum province, in which the above-mentioned geological information and data on exploration wells and oil and gasfields have been combined. Based on these petroleum province play[1] maps, the major petroleum geological controls (source, reservoir, seal, migration) on the presently known distribution of oil and gasfields have been described by experts on the individual provinces.

3.2 Key elements of the exploration and production history

Chapter 14 gives an overview of the early discoveries and history of seismic-data acquisition and drilling (success rates). The history and efficiency of the exploration and production process in the SPBA area has been expressed in terms of the (geological) success rate of exploration drilling. This chapter focusses on the fields and associated hydrocarbon volumes that have been discovered by exploration drilling.

The historical discovery process of oil and gasfields may have been influenced by non-geological factors that are country-specific, for example, national regulations and infrastructure (distance to market) or to onshore compared to offshore conditions. It is very difficult, if not impossible, to disassociate non-geological factors from the main petroleum-geological factors. The assumption in this chapter is that a petroleum province has been explored in a consistent way (albeit by various operators and/or in more than one regulatory regime) and that information on discoveries has been shared by industry to a certain extent. As a result, the approach is based on petroleum-geological factors, rather than a country-by-country assessment.

Whenever the data permit, the discovery history is expressed as a *creaming curve*. In a creaming curve, the cumulative growth of discovered volumes (in this case ultimately recoverable volumes) is plotted against the cumulative exploration effort (number of exploration wells) required to make the discoveries. To this end, only the relevant exploration wells in a particular province have been selected.

The creaming curves provide valuable historical information, but their interpretation has to be treated with caution. In cases where there are only a small number of discovered fields, a creaming curve does not provide statistically significant information on the creaming effect. Moreover, history shows that even when a creaming curve seems to have shown a statistically significant creaming off, another creaming cycle may occur when previously overlooked play elements are proven and successfully drilled.

1 White (1988) describes a 'play' as 'a group of geologically related prospects having similar conditions of source, reservoir and trap'. This concept can be extended to a 'play area', which delineates a coherent geological unit with similar conditions of source, reservoir and trap or regional top seal. We have restricted the analysis to proven play concepts, since only discoveries are considered as the basis for a play (area). The 'yet to prove' plays and 'yet to find' fields are not treated here.

4 Petroleum provinces and their oil and gasfields

4.1 Petroleum provinces

Table 15.1 lists the petroleum provinces considered in this chapter, together with the ages of their main source and reservoir rocks. The provinces fall into two groups based on the age of the main source rock for the oil and gas accumulations:
1. Paleozoic source (Pre-Devonian, Carboniferous and Permian source rocks).
2. Mesozoic and Cenozoic (Jurassic and 'shallow-gas' source).

The locations of the petroleum provinces are shown in **Figure 15.1** (Paleozoic source) and **Figure 15.2** (Mesozoic and Cenozoic sources). Drilling has so far proved that the oldest pre-Devonian play is restricted to the Baltic Basin in the north-easternmost corner of the SPBA area, whereas the youngest shallow-gas play seems to be restricted to the northern Dutch offshore sector. In contrast, the other plays are widespread and contain several petroleum provinces.

4.2 Oil and gasfields

Table 15.1 summarises the exploration and production (E&P) results for each of the 13 petroleum provinces, the number of fields discovered, and the associated recovered and recoverable oil and gas volumes. Reference is also made to the hydrocarbon field examples, which have been individually described in detail in the stratigraphic chapters (Chapter 6, Carboniferous to Chapter 12, Cenozoic). These fields were chosen because they are typical of the petroleum-geological setting for a particular petroleum province.

Detailed information on each of the oil and gasfields in the SPBA area is presented in **Appendix 3**. Although the focus of the remainder of this chapter is on the discovery history of the various petroleum provinces, information on the development and production history can be found in **Appendix 3** on a per field (or even reservoir) basis in terms of:
- development status (as of 1st January 2007);
- year of production start (if applicable);
- cumulative production (as of 1st January 2007).

The upstream oil and gas infrastructure in the SPB area is shown in Chapter 1 (see Figure 1.4). Together with the development status information in **Appendix 3**, this provides an insight into the present areal development of oil and gasfields in the SPB area.

5 Discovery history of each petroleum province

5.1 Pre-Devonian sourced fields

5.1.1 Baltic Basin

The fields discovered in the Baltic Basin are shown in **Figure 15.3** and their most important attribute data are given in **Appendix 3.1**. A condensed display of the discovery history is shown in **Figure 15.4**. Note that the facies and seal control in this area has not yet been mapped. There is therefore a lack of knowledge on the factors that control the distribution of the fields.

Source
The main hydrocarbon source rock is the Upper Cambrian and/or Tremadocian black bituminous shale, an equivalent of the Alum Shale Formation. This formation is only a few metres thick onshore, but thickens north and westwards to reach a few tens of metres in the Polish offshore area. Total organic carbon (TOC) content is relatively high, usually a few to several percent (Kanev et al., 1994). Maturation changes laterally from oil window in the east to gas window and overmature in the west. Results of geochemical analysis and organic petrology studies indicate the type II oil-prone kerogen (Kanev et al., 1994). Another source-rock complex is recognised higher up the sections; the Upper Ordovician (mainly Caradoc) and Silurian (mainly Llandovery and Wenlock) black graptolitic shale (Klimuszko, 2002). This complex is several tens to a few hundred metres thick, much thicker than the Alum Shale Formation. TOC content of the Upper Ordovician to Lower Silurian source rock is commonly within a range of a few percent in a relatively thick interval of the complex; the highest TOC values reach several percent. Like the Alum Shale Formation, thermal maturity of the Upper Ordovician to lower Silurian source rocks varies from oil window in the east to gas window and overmature in the west, and they contain the oil-prone type II kerogen.

Generation
Hydrocarbon generation from the Lower Paleozoic source rock is not clearly understood. According to Botor et al. (2002) and Karnkowski (2003a, 2003b), the Paleozoic source rocks of the East European Platform generated oil and gas mainly during maximum Carboniferous burial accompanied by elevated heat flow. However, analysis of maturity profiles across the Baltic and Lublin-Podlasie basins by Poprawa & Grotek (2005) and Poprawa et al. (2005) suggests two phases of hydrocarbon generation; the first as described above, whereas the second would be related to a Mesozoic (Jurassic and/or Cretaceous) positive thermal event. The proportions of hydrocarbons generated at each stage would vary laterally. However, in some parts of the East European Platform the second phase may have been more important than the first. In the case of the relatively thick Upper Ordovician to lower Silurian source-rock complex, hydrocarbons may not have been expelled from the shale complex, but might have accumulated within the source rock as shale gas, as indicated by gas shows.

Reservoirs
The main reservoir formation in the pre-Devonian of the East European Platform is the Middle Cambrian shallow-marine sandstone (Kanev et al., 1994; Jaworowski, 1997). In the Baltic Basin, this formation contains oil and gas condensate fields. However, in the Lublin-Podlasie Basin, only hydrocarbon shows

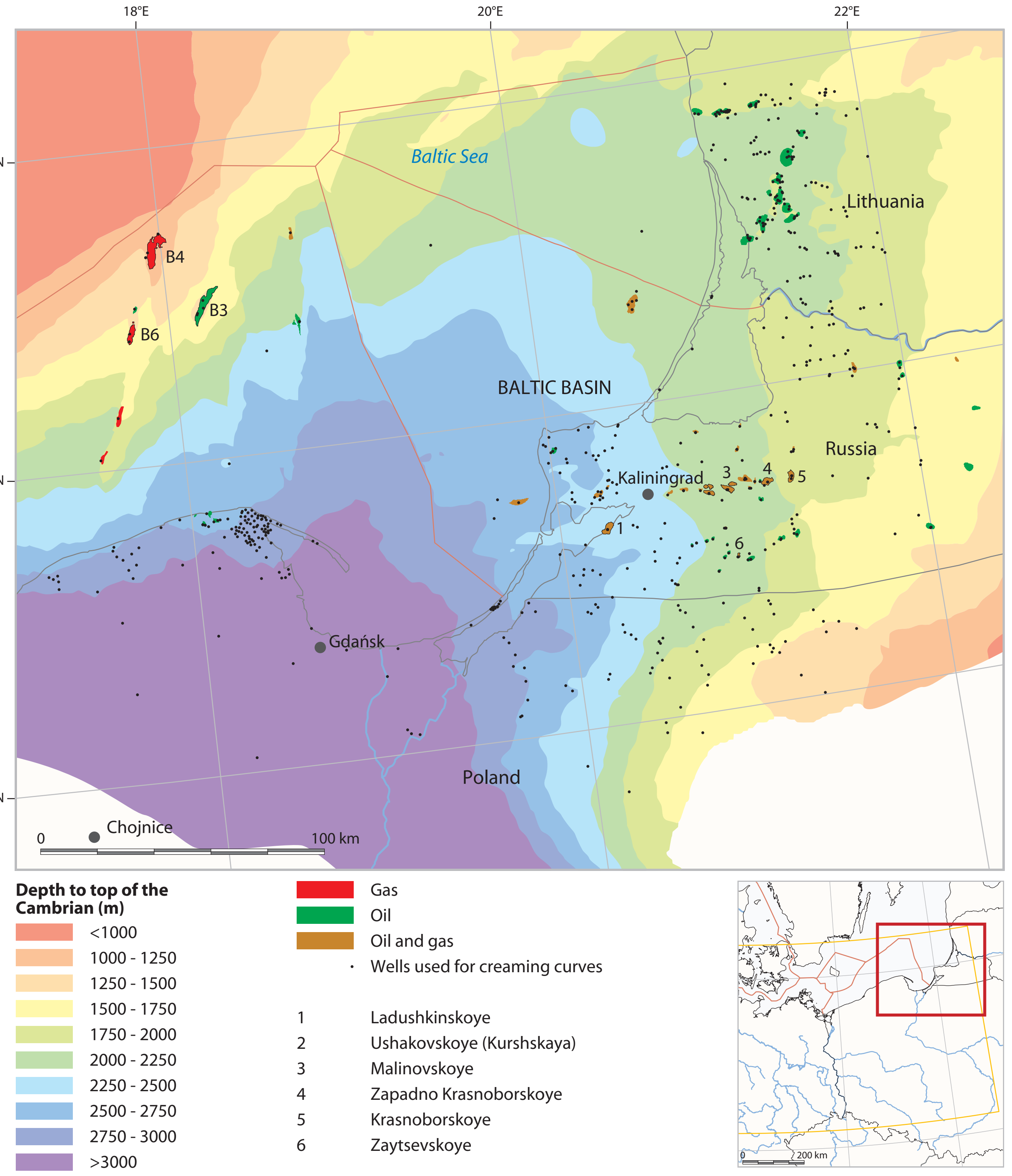


Figure 15.3 The Baltic Basin petroleum province. Fields charged by pre-Devonian source rocks. Main reservoir: Cambrian.

have been documented and no oil and gasfields have been discovered so far. The quality of the Middle Cambrian reservoirs depends mainly on the intensity of quartz cementation, which is dependant on its maximum depth of burial (Sikorska, 1998; Molenaar et al., 2007). Small oilfields are also present in Ordovician and Silurian limestones, mainly carbonate buildups that developed in marginal zones of the basin (Brangulis et al., 1992; Kanev at al., 1994).

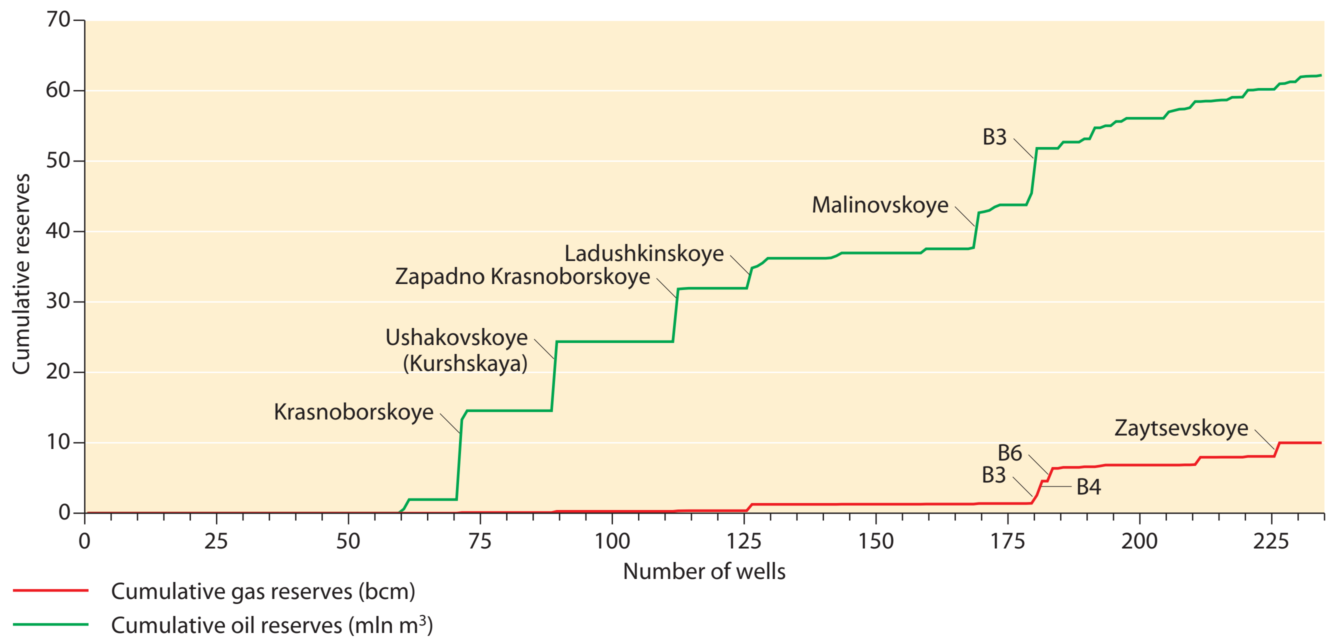


Figure 15.4 Creaming curve for the Baltic Basin petroleum province.

5.2 *Carboniferous and Permian-sourced fields*

5.2.1 *Anglo-Dutch and North German basins*

The Carboniferous, in particular the Westphalian Coal Measures, provides the principal source-rock interval in the Anglo-Dutch and North German basins. Distribution of these coals and their maturity largely dictates the distribution of hydrocarbon accumulations. To date, an estimated total of 7000 bcm of recoverable gas have been discovered in reservoirs that are inferred to have been sourced by the Carboniferous petroleum system. Oil generated from Carboniferous source rocks is of minor importance in the area. The extent of this petroleum province and the hydrocarbon fields are shown in **Figure 15.5**. Details on the fields are given in **Appendix 3.2**.

Factors controlling the distribution of hydrocarbon fields

A major controlling factor is the presence of Upper Permian Zechstein evaporites, the principal seal to the Lower Permian Rotliegend and Zechstein reservoirs (pre-salt reservoirs). Zechstein salt also commonly prevents gas from migrating into Triassic and younger reservoirs (post-salt reservoirs). The majority of the fields in the Anglo-Dutch Basin (78% of all fields) contain reserves in Rotliegend reservoirs. Most of the fields (341 out of 407) are located beneath the Zechstein, where its thick evaporite successions form the primary seal. The rest of the fields (66) are located at the Zechstein Basin margin, where slope and lagoonal/platform facies are found. The evaporites in these marginal Zechstein deposits apparently still provide an effective seal to the Rotliegend reservoirs. No Rotliegend fields are located in the so-called 'Fringe' Zechstein, where there are insufficient evaporites to form a seal and so gas has migrated to the next seal in place, the shales and evaporites of the Triassic Solling and Rot formations and the Lower Cretaceous Vlieland Claystone Formation. A unique occurrence in the area is the Harlingen field, an Upper Cretaceous Chalk reservoir beneath Tertiary claystones charged by the Carboniferous.

Development of reservoir-quality sandstones in the Rotliegend is another key factor controlling field distribution in the region. Aeolian sandstones are preserved in a wide belt around the southern part of the area and, to a more limited extent, around the northern margin, and pass basinward into contemporary non-reservoir playa-lake mudstones and evaporites.

Ongoing exploration has gradually expanded the Rotliegend play area to the north; the discovery of the Markham field in 1984 pushed the so-called 'Rotliegend Feather-Edge' considerably northwards. Increased knowledge of the depositional system and better seismic-imaging techniques have further extended the Rotliegend play, proof of which is given by the recent F16-E (2001) discovery in the Lower Slochteren Sandstone.

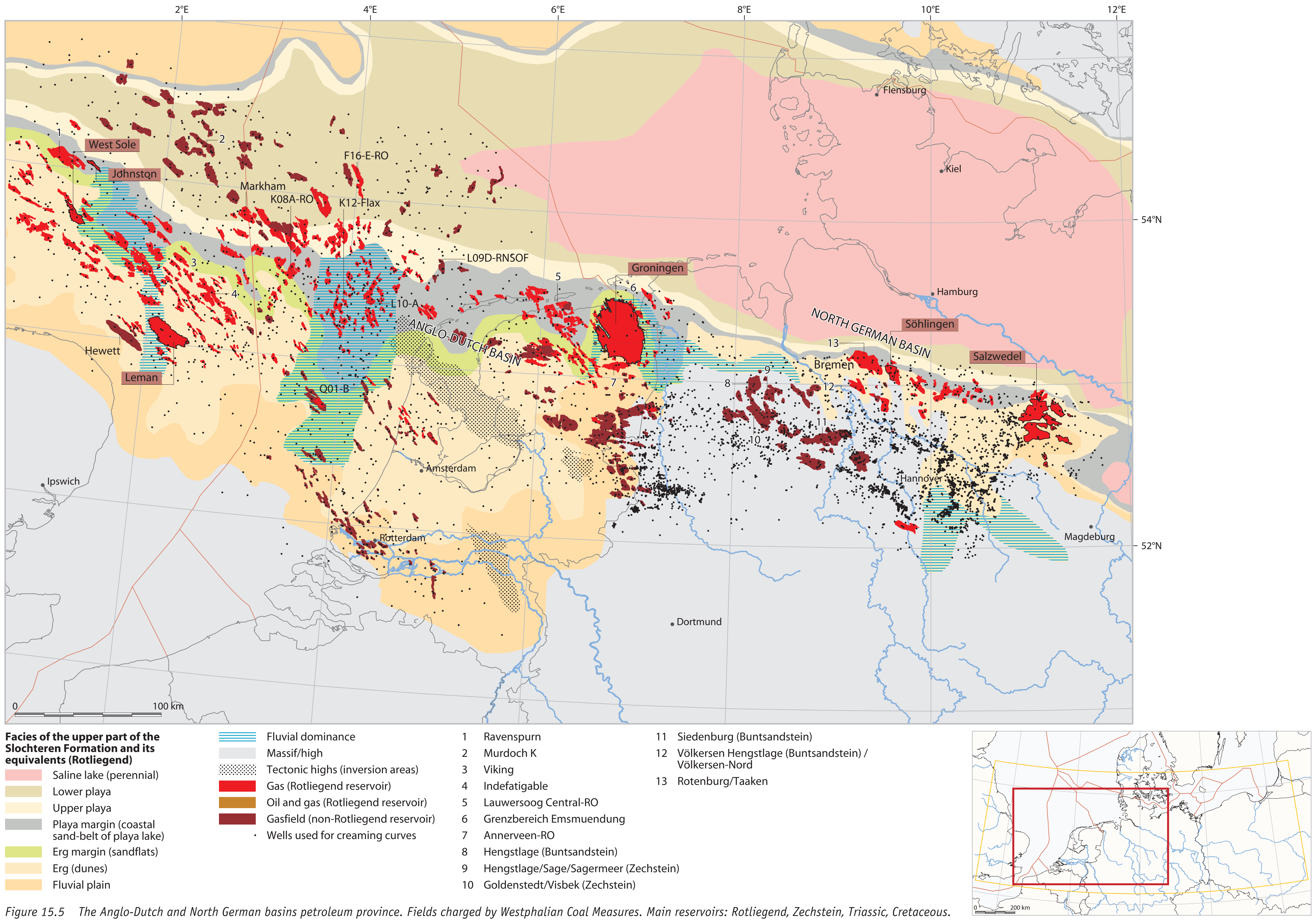


Figure 15.5 The Anglo-Dutch and North German basins petroleum province. Fields charged by Westphalian Coal Measures. Main reservoirs: Rotliegend, Zechstein, Triassic, Cretaceous.

Almost all gas-bearing reservoirs (95 out of 105) in the Zechstein Z2 and Z3 carbonates are located in a relatively narrow band of platform, lagoonal and slope facies located between the evaporite basin and the fringe facies. Stacked Zechstein and Rotliegend reservoirs are found in eight fields within the Anglo-Dutch and North German basins.

Post-salt producing reservoirs are more often located at either the fringe of the Zechstein Basin, such as the Triassic, Jurassic and Cretaceous fields in the West Netherlands and Broad Fourteens basins, or are related to inverted basins such as the Dutch Central Graben, the Texel-IJsselmeer High or Broad Fourteens Basin. The lack of sealing Zechstein evaporites and migration along fault-plane conduits in these areas are inferred to be the mechanisms by which Carboniferous gas has migrated into post-salt reservoirs. In the UK sector, Triassic fields in the northern part of the basin (Forbes, Esmond, Gordon, Caister, Hunter) owe their charge to migration routes opening up where the Triassic has locally grounded upon the Lower Permian due to complete salt evacuation into adjacent diapirs.

Similarly, the success of the post-salt play in the Dutch sector is primarily dependent on gas migration through the above-mentioned 'grounded' Triassic series due to extreme salt-withdrawal, existence of conductive faults, and in cases where there is a thick Silverpit series, deep-seated fault-zones. Proof of such long and potentially tortuous migration paths was made by the first discovery of a Carboniferous-charged Triassic reservoir in the core of the area at the L02-FA field. The F15-A field (see Chapter 9) is an example of the many Triassic discoveries that followed. It is inferred that the Triassic fields in the Dutch G and M Quadrants were charged by gas migration through main basin-bounding faults such as the Rifgronden and Hantum Fault zones and the eastern fault zone of the Central Graben. Jurassic and Cretaceous reservoirs sourced by the Carboniferous require even longer migration paths than the Triassic. The F03-FA field is one of the early discoveries of such a reservoir.

Some 16% of all fields in the Anglo-Dutch and North German basins have Triassic reservoirs; Jurassic and younger reservoirs make up only 6% of the fields. In combination, these fields contain less than 10% of the total gas ultimate recovery in the region.

The distribution of Carboniferous fields is controlled by the presence of reservoir sands and of a mudstone top-seal at the Base Permian Unconformity, or by internal seals within the Westphalian and Stephanian sections. The fields are located in three areas: the offshore Silverpit / Cleaver Bank area, the Dutch-German border area (Coevorden) and the northern edge of the Lower Saxony Basin in Germany. Carboniferous discoveries in the Dutch sector in the 1980s and 1990s followed the successes on the UK side of the median line, and are related to truncated Westphalian reservoirs below the Base Permian Unconformity. These discoveries remained undeveloped for a long time due to uneconomic conditions. A significant component of the gas found in the Silverpit / Cleaver Bank area has been generated from Namurian marine source rocks (Gerling et al., 1999c), which should extend the geographic area of exploration for Carboniferous plays beyond the limit of the Westphalian Coal Measures.

Exploration history

Before the discovery of the Groningen gasfield (Slochteren-1 well; see introductory-page image) in 1959, discoveries in the Anglo-Dutch and North German basins were mainly confined to Permian Zechstein and Triassic Buntsandstein reservoirs onshore of northern Germany and the eastern Netherlands, with some small discoveries in the younger Jurassic and Cretaceous sections in the West Netherlands Basin. In Germany, the discovery of the Bentheim gasfield near the Dutch border in 1938 led to further Zechstein exploration in the area during the 1950s. Exploration for Zechstein targets in Germany culminated with the discovery of the Goldenstedt/Visbek structure in 1959, which produced about 50 bcm of gas up until the end of 2005 (16% of the total Zechstein production in Germany). In the same year, economic quantities of gas were discovered in the Triassic Main Buntsandstein reservoir in wells Adorf Z-7 and Goldenstedt T-1. The discovery of the Hengstlage field in 1963 marked the height of Buntsandstein exploration in Germany; by the end of 2005 the field had produced some 80 bcm of gas.

The discovery of gas in the Permian Rotliegend by the Slochteren-1 well in 1959 led to a new era of intensified exploration for deeper targets. Rotliegend exploration was initially concentrated onshore of the Netherlands and Germany. The first Rotliegend discovery in Germany (Groothusen Z3) was made in 1965, followed by the discovery of the Salzwedel gasfield in 1969, the largest field in Germany, with initial reserves exceeding 200 bcm. Although the Rotliegend had become a new target in the 1960s, discoveries have continued to be made in the Zechstein, Triassic and to a minor extent the Cretaceous.

These successes triggered interest in offshore exploration. However, exploration outside territorial waters could not start until ratification of the Geneva Treaty on the Continental Shelf by the UK in 1964 and by the Netherlands in 1968, which divided the continental shelf into the sectors as we know them today (Figure 1.4). After three dry holes, the first offshore Rotliegend discovery was made in the UK sector in the Sole Pit Basin at the West Sole gasfield during 1965 (Section 6.1.3 in Chapter 6). This discovery was rapidly followed by many more in the southern North Sea. The large Leman (ultimate recovery 328 bcm; Section 6.1.1 in Chapter 6) and Indefatigable (81 bcm) gasfields were discovered in 1966. The first discovery in the Dutch sector (L02A-RBM) was made in a Triassic reservoir in 1968, followed a year later by the Rotliegend discovery at L12A-RO.

Carboniferous gasfields had already been discovered onshore in the Netherlands and Germany during the 1950s. The reservoirs in many of these fields were discovered by drilling deeper wells on existing fields producing from Permian, Triassic and Cretaceous reservoirs. An example is the Rehden field in Germany (Section 4.1.5 in Chapter 9), originally discovered as a Zechstein structure in 1953. Gas shows beneath the Zechstein led to deeper drilling, and commercial quantities of gas were found in the Carboniferous in 1961. To date, the Rehden field has produced more than 8 bcm of gas from the Carboniferous. Another interesting Carboniferous discovery is the Husum Schneeren field (Section 6.3.5 in Chapter 6), which has produced some 7.5 bcm of gas from tight, fractured sandstones since its discovery in 1986. The first offshore Carboniferous discovery was K04-Z in Dutch waters in 1974. Most of the Carboniferous offshore fields were discovered in the mid-1980s and 1990s and are located in UK quadrants 43, 44 and 49, extending into the Dutch D, E and northern K quadrants.

Although the discovery of Carboniferous-charged reservoirs in the Netherlands and northern Germany in the early stage of exploration has directed exploration within the region, leading to the discovery of the giant Groningen gasfield in 1959, it is the continuous series of discoveries in the offshore sector since 1965 that have been largely responsible for its success. Most of the simple structural gas-bearing traps in the area were discovered using 2D-seismic data. The introduction of regular 3D-seismic surveys, and more enhanced processing techniques such as AVO analysis in the 1990s, led to the recognition of more subtle traps, for example downthrown fault blocks and stratigraphic traps. This generated interest in searching for similar traps onshore, leading to discoveries such as the Weissenmoor field in Germany during 1996, a stratigraphic trap at a depth of 4700 m. However, the estimated ultimate recovery in fields discovered since 1990 accounts for only 7% of the total in the Anglo-Dutch and North German basins.

Analysis of ultimate recovery

The exploration and discovery history of the region has been analysed by constructing creaming curves based on data compiled from various sources. For the UK and the Netherlands, sufficient information was available from national databases. In Germany, ultimate recovery statistics for each field are confidential and so data had to be compiled from different sources, principally the IHS database, resulting in interpretation of different definitions of well classification and of estimates of ultimate recovery. The data for Germany in particular should therefore be used with caution as estimates could deviate from official values. However, data coverage is sufficient for statistical analysis and allows the following general conclusions on the distribution and history of discoveries and ultimate recovery.

The creaming curve for the Anglo-Dutch and North German basins shows the cumulative amount of ultimate recovery on the Y-axis against the number of exploration wells drilled in the area on the X-axis. The curve indicates that only minor discoveries were made in the initial exploration phase before 1958. The discovery of the Groningen gasfield heralded a new phase of exploration, resulting in the discovery of important large gasfields in the area during the 1960s and early 1970s (**Figure 15.6a**).

The vast reserves of the Groningen gasfield, with estimated ultimate recovery of 2820 bcm of gas forming 45% of the entire ultimate recovery for the area, give a conspicuous anomaly on the creaming curve. In the following 'normalised' curve (**Figure 15.6b**), the component associated with the Groningen gasfield has been removed to provide a clearer picture of the exploration history of the region. This curve shows a rapid increase in cumulative ultimate recovery during the mid-1960s, with the discoveries of major offshore gasfields in the UK including Leman and Indefatigable. Another sharp step in the creaming curve during the late 1960s is due to the discovery of gasfields including Salzwedel in northern Germany and Viking in the UK offshore. After this initial steep incline, the growth rate per well rate in cumulative ultimate recovery has been gradually declining. Several smaller sharp increases in cumulative ultimate recovery are recorded throughout the early 1980s due to the discovery of fields such as Söhlingen and Hemmelte/Kneheim/Vahren (onshore Germany, 1980), Ravenspurn (UK offshore, 1983) and Rotenburg/Taaken (onshore Germany, 1984). A slight increase is again noted in the mid-1990s as better 3D-seismic imaging became available to detect more subtle traps beneath the Zechstein. The reserves have been added to at a relatively steady pace at almost 7 bcm/well during the last ten years, which is very encouraging for the future of such a mature province.

Analysis of production

As of the end of 2005, approximately 3400 bcm of gas had been produced from fields originating from Carboniferous source rocks within the Anglo-Dutch and North German basins. Since the majority of the estimated ultimate recovery is within pre-Zechstein reservoirs (90%), it is not surprising that the majority of the produced gas (about 70%) has come from these reservoirs. Triassic reservoirs have contributed almost 30% of the total gas production.

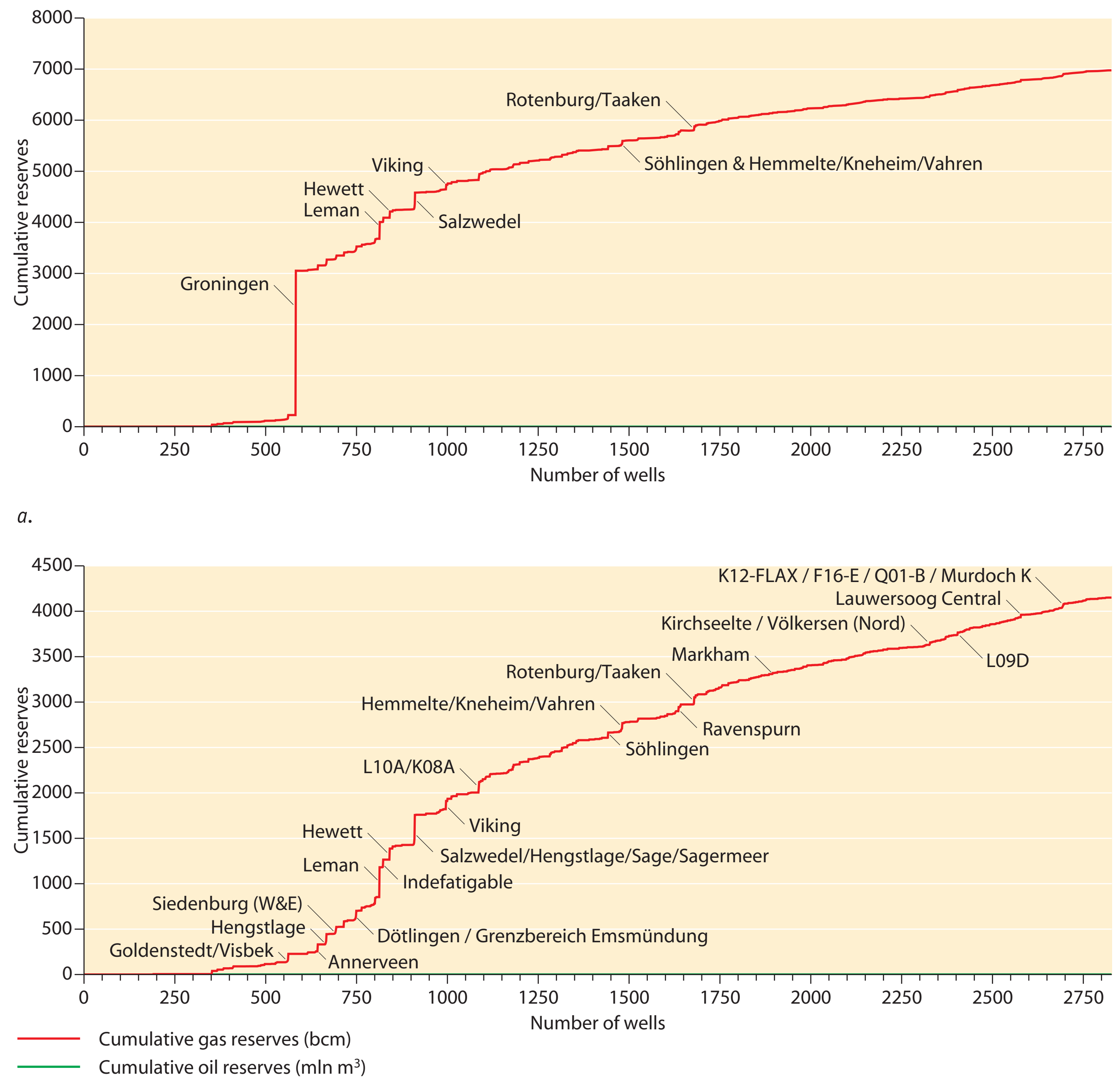


Figure 15.6 a. Creaming curve for the Anglo-Dutch and North German basins petroleum province; and b. creaming curve for the Anglo-Dutch and North German basins petroleum province, excluding the Groningen field.

Almost all of the discovered fields are currently in production or under development, which indicates the mature stage of development of the region. Of the total gas produced, 42% has been from the Netherlands (29% offshore, 13% onshore), 33% has been from offshore UK, and 25% has been from Germany.

5.2.2 East Midlands and Cleveland Basin

The UK onshore Carboniferous petroleum province spans two discrete areas within the Northwest European Carboniferous Basin, the East Midlands area and the Cleveland Basin (Chapter 6). The principal source rocks are Namurian marine shales, locally supplemented by late Dinantian (Visean) marine shales (Bowland Shale Formation). Westphalian Coal Measures may constitute an additional source rock, for although these strata are immature across the region, migration from the more deeply-buried mature rocks in the adjacent offshore Anglo-Dutch Basin can not be discounted.

The area contains 41 oilfields and discoveries plus 25 gasfields and discoveries (**Figure 15.7**; 13 fields are not shown). Eighteen of the oilfields are currently producing, all of which occur in the East Midlands; nine gasfields are producing, four in the East Midlands and five in the Cleveland Basin. A full list of the oil and gasfields is given in **Appendix 3.3**.

Factors controlling the distribution of hydrocarbon fields

East Midlands

The East Midlands comprises several north-west–south-east-trending concealed Carboniferous sub-basins. Potential reservoir rocks are abundant in the Devonian to Carboniferous succession; however, the main oil reservoirs are Namurian sandstones of the Millstone Grit, and Westphalian sandstones within the lower and middle Coal Measures (Section 2.2.2 of Chapter 13). Small quantities of oil have also been produced from the top of the Dinantian Carboniferous Limestone (e.g. Hardstoft, Eakring-Duke's Wood; Gale et al. 1984). Namurian and Westphalian mudstones are also abundant, and these form effective intraformational seals. All of the commercial hydrocarbon accumulations in the East Midlands are trapped in structural closures such as faulted anticlines, closed rollovers against faults, and horst blocks (DECC, 2003). Most

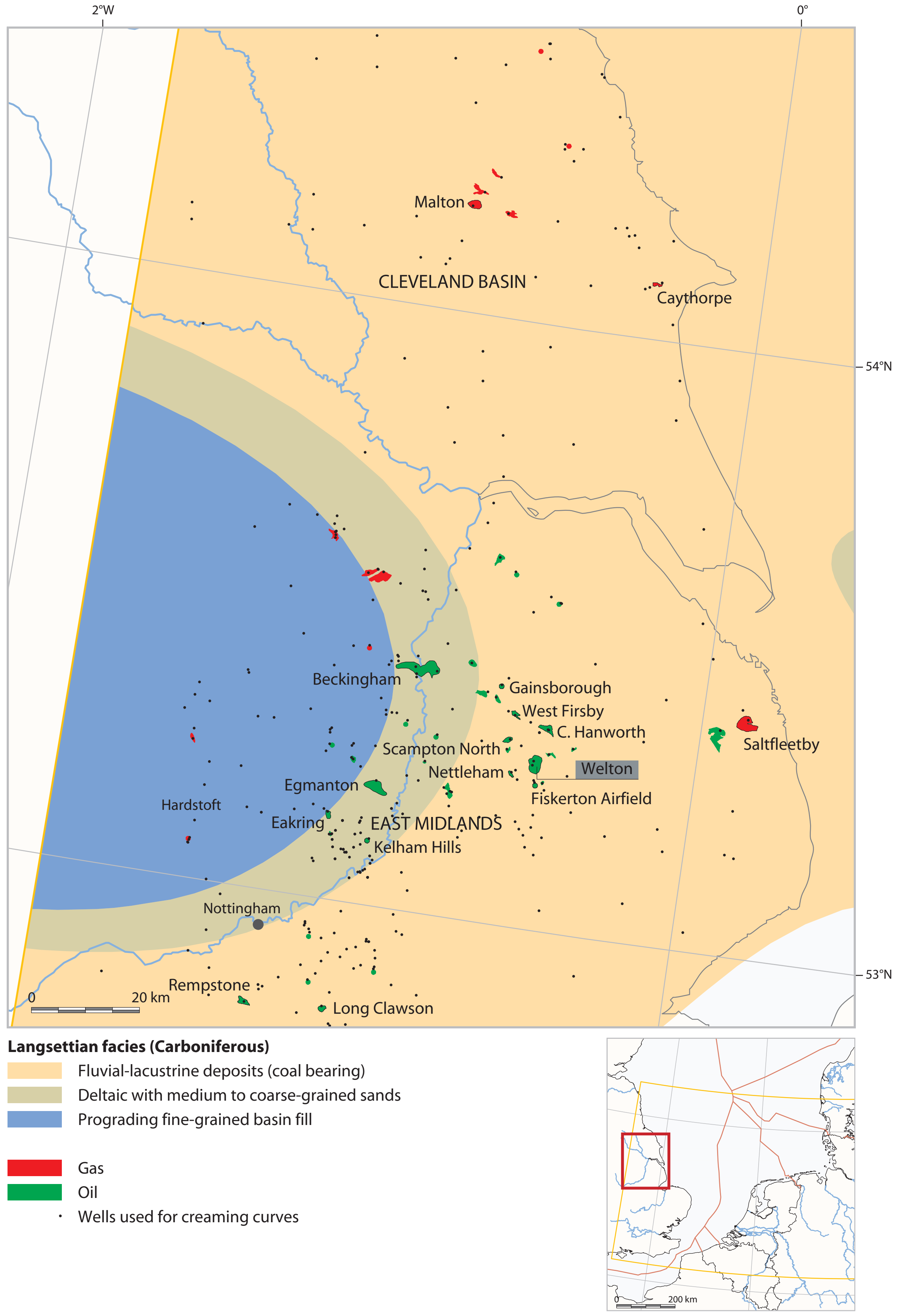


Figure 15.7 The East Midlands and Cleveland Basin petroleum province. Fields charged by Namurian source rocks. Main reservoirs: Carboniferous, Zechstein.

traps also have an element of stratigraphic control; for example, many of the producing reservoirs at the Gainsborough oilfield are either lenticular channel sandstones (Westphalian) or exhibit lateral facies variation (Namurian sheet sands). The principal source rocks are early Namurian distal prodelta shales (Fraser et al., 1990), possibly supplemented by local Dinantian shales and limestones. Oil generated during the Carboniferous would have migrated up-dip towards the basin margins. However, this generally easterly migration would have been reversed following Variscan uplift of the Pennines inversion axis. Hydrocarbons generated during the Mesozoic would generally be expected to have migrated westwards since the Permian and Mesozoic cover is thickest in the north-east of the area. Gas accumulations (e.g. Calow, Ironville, and Hatfield Moors) are most common in the west of the area, with the significant exception of the Saltfleetby gasfield at the eastern margin of the East Midlands region.

Cleveland Basin

The Jurassic to Early Cretaceous Cleveland Basin is an onshore component of the Anglo-Dutch Basin, specifically of the Sole Pit Trough, located in north-east England. It was inverted during the Tertiary Alpine Orogeny, and it overlies a Carboniferous basin that was itself inverted by the end-Carboniferous Variscan Orogeny (Kent, 1980). It is likely that faults on the northern margin were dominant during both phases of Early Carboniferous and Early Jurassic extension. These faults were reactivated as reverse faults during the end-Carboniferous Variscan inversion. The Carboniferous source rocks of the Cleveland Basin lie beyond the wet-gas window, although Westphalian gas-prone source rocks are largely absent due to pre-Permian erosion from the basin, except at the Robin's Hood Bay borehole where a north-west–south-east-trending outlier terminates nearby offshore.

The main reservoirs are Upper Permian (Zechstein) limestones, basal Permian sandstones (Rotliegend Yellow Sandstone Formation) and Namurian sandstones. Jurassic and Early Cretaceous migration of hydrocarbons from deeply buried Namurian shales was mainly towards the southern margin of the basin. Some re-migration may have taken place northwards towards the axis of the basin following Tertiary inversion. Although most of the discoveries made in the basin lie along the faulted southern margin, prospects along the northern faulted margin of the basin offer future potential.

Exploration

There have been 364 exploration wells aimed at predominantly Carboniferous plays in the East Midlands and the Cleveland Basin since 1919 (**Figure 15.8**).

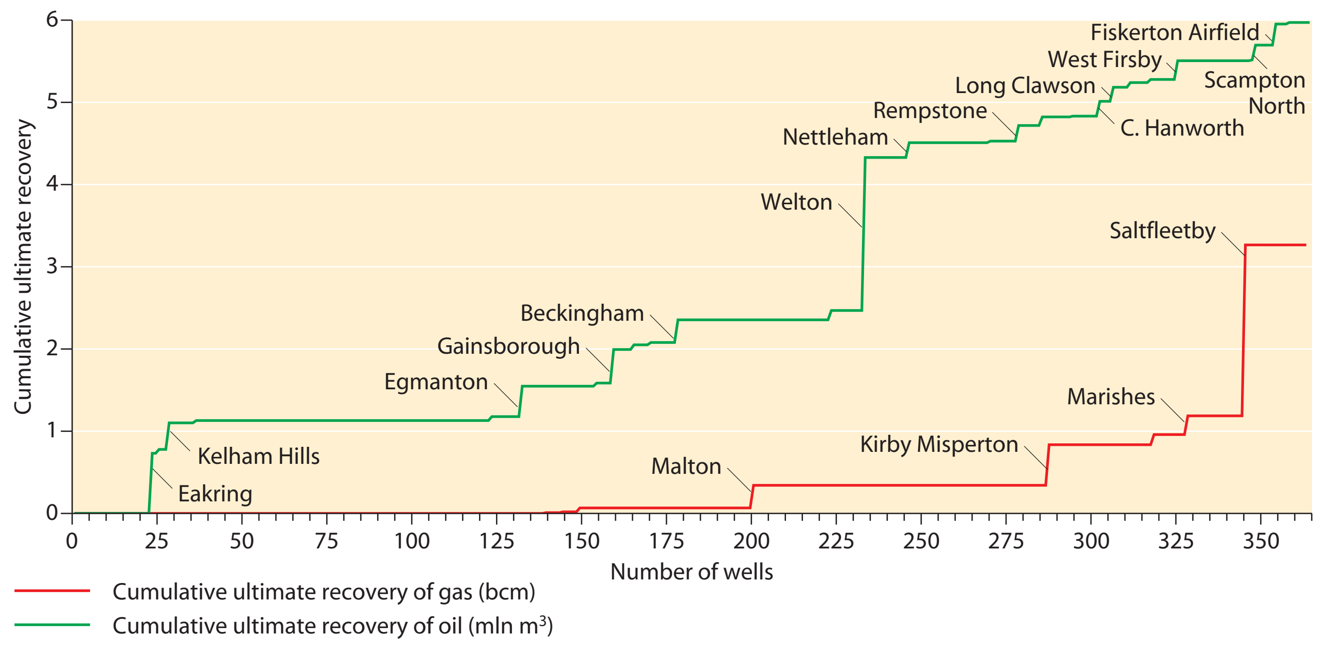


Figure 15.8 Creaming curve for the East Midlands and Cleveland Basin petroleum province.

East Midlands

The first East Midlands oil discovery was made in 1919 by the Dinantian Hardstoft well (**Figure 15.7**); production was from Carboniferous Limestone beds in an anticlinal trap. A major oil-exploration effort started just before World War II, which led to the discovery of the Eakring-Duke's Wood oilfield in 1940, closely followed by Kelham Hills and Farley's Wood oilfields in 1941 and 1943 respectively. Important oil discoveries were made between 1953 and 1964 including Plungar, Egmanton, Bothamsall, Corringham, Gainsborough and Beckingham, Apleyhead, South Leverton, Glentworth and Torksey, plus several minor accumulations (**Figure 15.8**). The first gas discovery in the East Midlands area was at Ironville in 1956 within Namurian Kinderscoutian grits (Brunstrom, 1966). This was closely followed by discovery of the Trumfleet gasfield in 1957 and the Calow gasfield one year later. Exploration activities increased in line with rising oil prices following the Middle East war in 1973. The largest oil discovery in the region was made at Welton in 1981; at 1.86 mln m^3 ultimate recovery, this constitutes the second largest oilfield in the UK onshore after the Wytch Farm oilfield of the Wessex-Channel Basin in southern England. After the mostly unsuccessful drilling of another 40 to 50 wildcats, a series of important oil discoveries were made between 1982 and 1998, including Cold Hanworth (1997), Long Clawson (1986), West Firsby (1988), Rempstone (1995), Scampton North (1985), Nettleham (1982), Fiskerton Airfield (1997) and Reepham (1998).

Cleveland Basin

The Eskdale gasfield was discovered in the Cleveland Basin in 1939, followed by the Robin's Hood Bay gas discovery in 1957 within Permian (Zechstein) carbonates, and the Lockton gasfield in 1966. Improved seismic-reflection profiling led to further prospects being drilled along the southern, faulted basin margin (Vale of Pickering-Flamborough Head Fault Zone; Kirby & Swallow, 1987), with success at Kirby Misperton in 1985 in Namurian sandstone reservoirs. The Caythorpe (1987) and Marishes (1988) gasfields preceded the discovery of the UK's largest onshore gasfield (2.08 bcm) at Saltfleetby during 1996.

Ultimate recovery

Estimated ultimate recovery from the fields and discoveries of the UK onshore Carboniferous province is 5.88 mln m^3 oil and 3.26 bcm gas (excluding 34 fields and discoveries for which the ultimate recovery is not available) (**Figure 15.8**).

Development history

The Hardstoft field continued to produce oil for about 25 years following its discovery in 1919. Development of the Eakring-Duke's Wood field followed during the 1940s. Although the Farley's Wood oilfield was discovered in 1943 it did not come onstream until 1985; however, it continues to produce to the present day. The Welton oilfield started producing in 1984, 3 years after it was discovered. The Nettleham, Stainton, Crosby Warren and Scampton North oilfields began production between 1985 and 1989. A further 11 oilfields were developed during the 1990s, all of which were onstream as of the end of 2007.

The Eskdale gasfield was the first to be developed in the Cleveland Basin. Production began in 1960 and continued until 1966. It was followed by the Lockton gasfield, which came onstream in 1971, but produced for only 3 years (Huxley, 1983). The Hatfield Moors gasfield has been in production from 1986 to the present day. The Caythorpe, Kirby Misperton, Marishes, Malton, Trumfleet and Saltfleetby fields came onstream between 1992 and 1999, and the Pickering and Ironville gasfields began production in 2001 and 2002 respectively. All of these more recent developments remain onstream at present.

In the East Midlands, there are 11 oilfields which have ceased production, 18 are currently producing and one oilfield (Reepham) is under development. Three gasfields have ceased production (two in the Cleveland Basin) and nine fields (five in the Cleveland Basin) were producing gas at the end of 2005.

The producing oilfields of the East Midlands had yielded 6.53 mln m^3 oil by the end of 2005. Note that this figure includes production from six fields for which no estimate of ultimate recovery is known. The total gas production by the end of 2005 for the fields in the East Midlands and the Cleveland Basin is not known.

5.2.3 *Thüringian and Sub-Hercynian basins*

Field characteristics and volumes

The location of oil and gas accumulations/fields is shown in **Figure 15.9** and the main field attributes are listed in **Appendix 3.4** (from: Karnin et al., 1998b; Piske & Rasch, 1998; Schwark et al., 1998; Pasternak et al., 1999; Bleschert et al., 2000; Franke, 2008). **Table 15.1** shows the produced oil and gas volumes in fields discovered in the Thüringian and Sub-Hercynian basins (Müller et al., 1993; Karnin et. al., 1998b; Pasternak et al., 1998, 2006). Some of the gasfields in the Thüringian Basin also contain condensate, of which 32 657 t had been produced by the end of 2007.

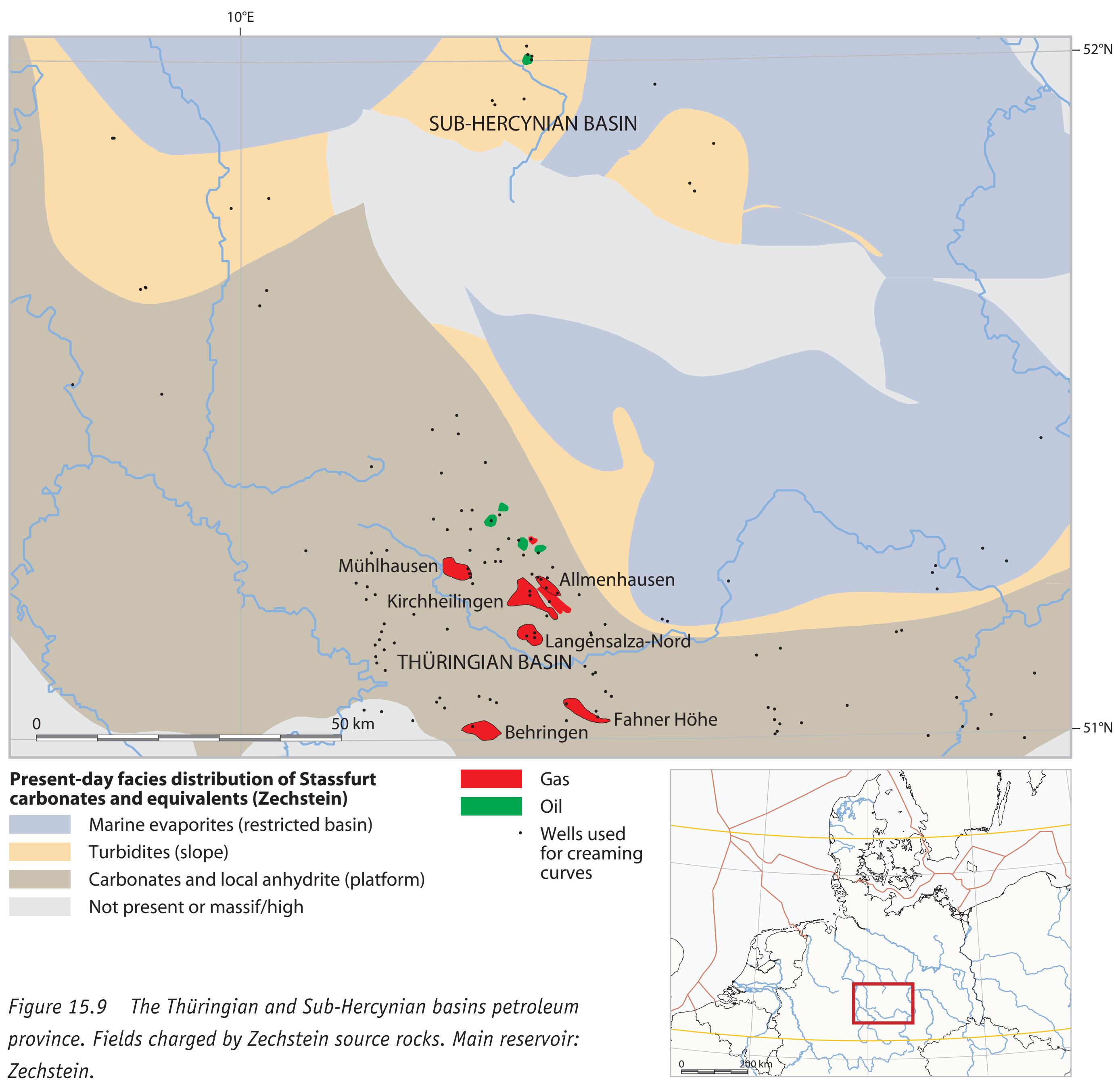


Figure 15.9 The Thüringian and Sub-Hercynian basins petroleum province. Fields charged by Zechstein source rocks. Main reservoir: Zechstein.

The Thüringian Basin is located in central Germany. It is bordered to the south by the Thüringian Forest and by the Harz Mountains in the north. The Sub-Hercynian Basin is a small depression to the north of the Harz Mountains. Both basins are part of a large embayment that started to develop during the Werra Cycle of the Zechstein. They contain small oil and gas accumulations in carbonate reservoirs of the Upper Permian Zechstein Stassfurt Carbonate (Z2Ca) and gas accumulations in the Lower Triassic sandstone reservoirs (Middle Buntsandstein). One field has been discovered in Rotliegend clastics. Both groups belong to the same hydrocarbon system. The oil and most of the gas were generated from mudstones of the basinal and slope facies of the Zechstein Stassfurt Carbonate (Z2Ca). A smaller amount of gas that accumulated in some of the fields originates from pre-Permian source rocks. The oil and gas commonly accumulated in structural traps of the 4-way dip closure type, i.e. in anticlines, half anticlines and faulted blocks of Middle Buntsandstein, Stassfurt Carbonate and Rotliegend reservoirs. Combined and stratigraphic traps with changes of porosity and permeability are known only in the Stassfurt Carbonate Formation. Trap seals are formed by the evaporitic intervals of the Zechstein and Upper Buntsandstein (Röt).

History

Exploration

The exploration history of the Thüringian and Sub-Hercynian basins is shown in **Figure 15.10**. The creaming curve for these basins is based on data presented in **Appendix 3.4**. Following an oil and gas inflow in the potassium mine at Volkenroda in 1930, hydrocarbon exploration took place in several phases within the Thüringian and Sub-Hercynian basins. The next discoveries were made at the Mühlhausen gasfield in the Thüringian Basin and the small Kleiner Fallstein oilfield in the Sub-Hercynian Basin. After World War II, there was extensive drilling from the mid-1950s to mid-1960s and from the late 1960s to early 1970s. The most recent exploration phase started at the end of the 1970s and continued into the 1980s based on new geological concepts regarding the location of the Stassfurt Carbonate barrier zone. After a period of inactivity, a new exploration programme started in 1991 when modern high-resolution 2-D seismic surveys, which had not previously been used, were carried out on Stassfurt Carbonate targets (Behla et al., 1998) within both the Thüringian and Sub-Hercynian basins. Potential off-platform hydrocarbon traps were identified in both basins (Behla et al., 1998; Piske et al., 1998). In 1995, prospects were tested at the Harsleben Z1 well in the Sub-Hercynian Basin and at Sprötau Z1 in the Thüringian Basin; however, neither contained hydrocarbons in economic amounts. The creaming curve shows two main discovery phases. The first relatively large discoveries were made during the early stage of exploration, and the second discovery phase correlates with the main drilling phase.

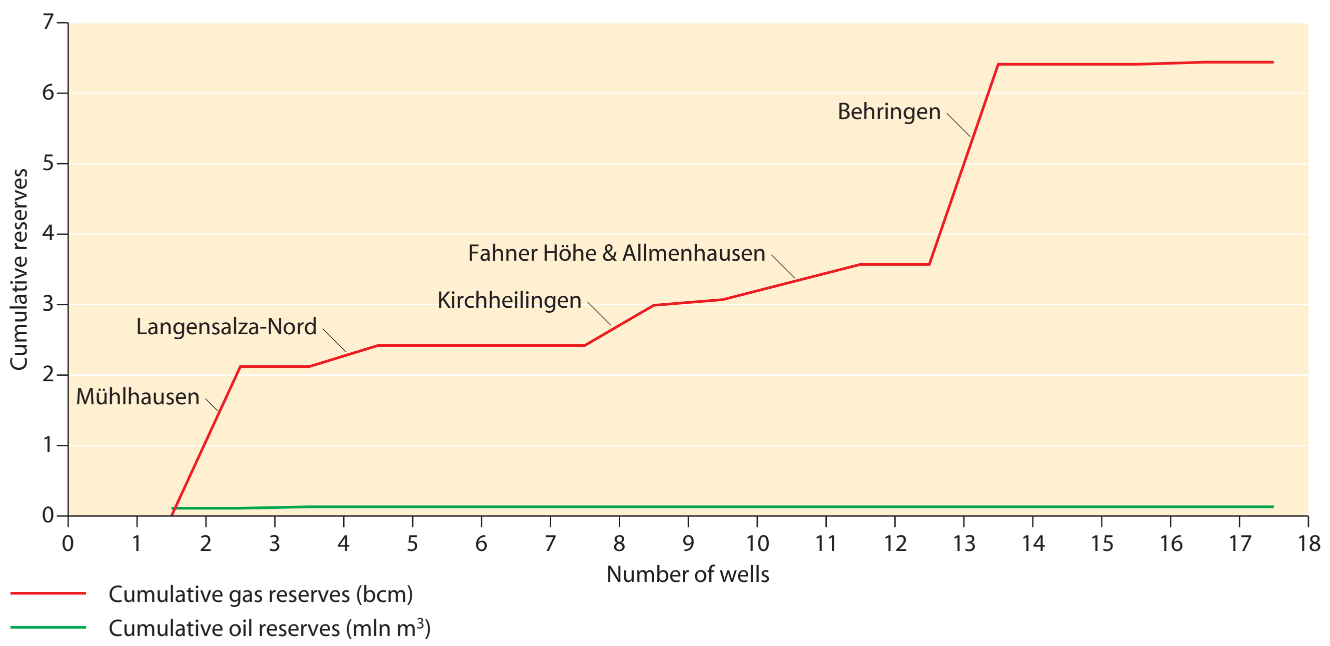


Figure 15.10 Creaming curve for the Thüringian and Sub-Hercynian basins petroleum province.

Development and production

Most of the oil and gas accumulations have been developed. Today, only four fields at Mühlhausen, Langensalza, Kirchheilingen SW and Fahner Höhe are still producing gas. Three fields at Kirchheilingen, Almenhausen and Bad Lauchstädt are used as underground gas-storage sites (see Chapter 16).

5.2.4 Pomerania

Carboniferous-sourced fields

Figure 15.11a gives an overview of this petroleum province and the fields discovered. The region of Pomerania in the north-western Polish Lowlands was considered to have hydrocarbon potential from the 1930s as it was analogous to the Hannover region in Germany where many oilfields had been discovered in Mesozoic deposits. Immediately after World War II, the Petroleum Institute in Kraków started to explore for hydrocarbons in the Polish Lowlands, and on the 1st January 1946 the oil company 'North' was founded.

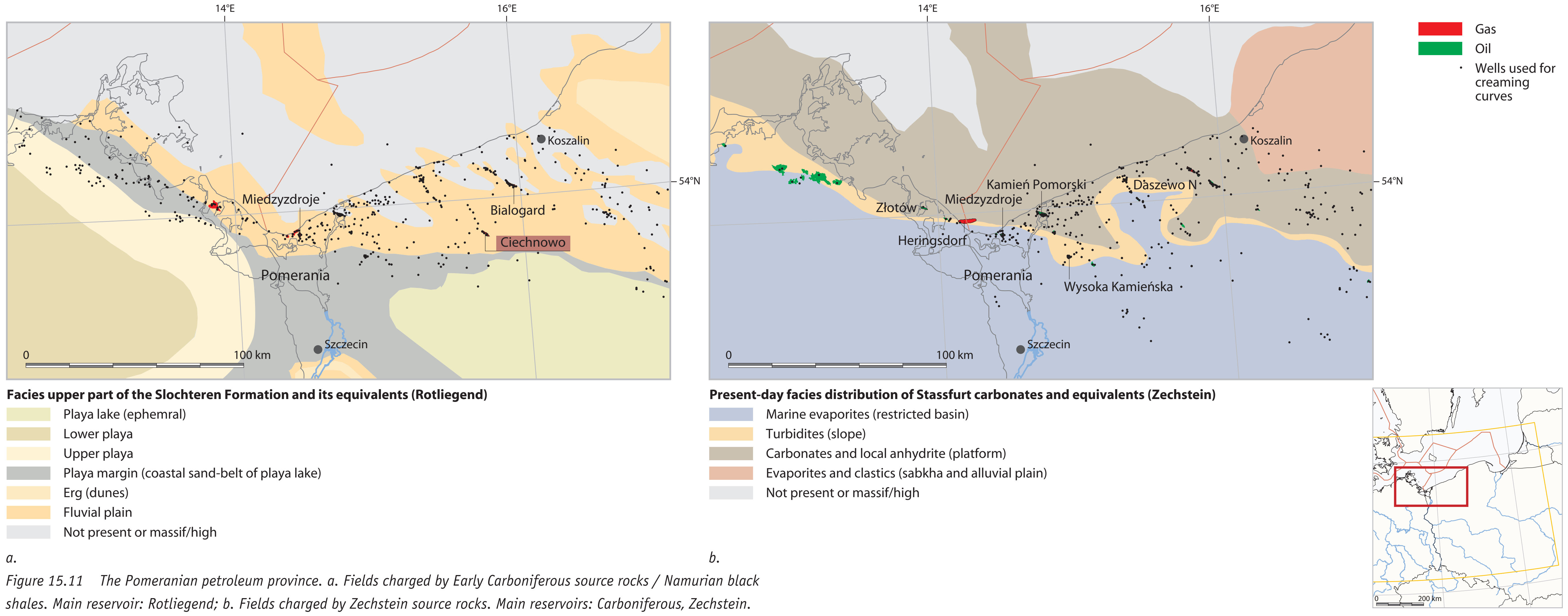


Figure 15.11 The Pomeranian petroleum province. a. Fields charged by Early Carboniferous source rocks / Namurian black shales. Main reservoir: Rotliegend; b. Fields charged by Zechstein source rocks. Main reservoirs: Carboniferous, Zechstein.

The scientific basis for exploration was the available geophysical (gravimetric) and geological expertise and the information that was available in German and Polish publications. The first drillsites were planned in the Kujawy region (Kłodawa-1) where geophysical surveys indicated the presence of a salt diapir. Drilling started in 1946 and salt was encountered at a depth of 325 m; however, the suspected oil accumulations in the area around the salt diapir were not confirmed.

Systematic studies of the Polish Lowland structural units were started in 1955 by the Petroleum Geological Survey in collaboration with the Polish Geological Institute. The first deep borehole was drilled in 1955 (Złotów-1, depth 1539 m) and reached the Upper Triassic. New boreholes were drilled throughout the following years and the present number of deep drillsites (more than 1000 m) stands at 374. During that period the main exploration activity took place in the area of the Fore-Sudetic Monocline. The first oil discovery in the Polish Lowlands was made in 1961 (at the Rybaki-1 well) in carbonates of the Zechstein Main Dolomite Formation at a depth of about 1800 m. The initial output was more than 100 t/day. About 130 000 t of oil was produced from the field. In 1964, the first gasfield was discovered in Rotliegend sandstones and Zechstein limestones (Bogdaj-Uciechów gasfield). The discovery of these fields had a considerable influence on the intense exploration that followed in the Polish Lowlands.

In western Pomerania, the first important discovery was made in 1972 at the Kamień Pomorski oilfield in the Main Dolomite carbonates. Despite considerable attempts, no major oil accumulations were found in the Fore-Sudetic Monocline, although a few economic oil and gasfields have been documented (**Appendix 3.5a**) In addition to the Kamień Pomorski field, which was the largest oilfield in the Polish Lowlands at the time, the Wierzchowo gasfield (also discovered in 1972) was the first to be found in the Lower Carboniferous deposits of the area. Other important fields include the Gorzysław North field (1976) with an Upper Carboniferous reservoir and reserves of 1.3 bcm gas; the Wysoka Kamieńska (1978) oil and gasfield at depths of about 3050 m in a Main Dolomite reservoir, with reserves of 0.49 mln m^3 of oil; the Daszewo (Karlino) (1980) oil and gasfield at depths of about 3200 m, also with a Main Dolomite reservoir (the field is well-known for the huge fire that burned for more than a month from December 1980 to January 1981); the Daszewo N gasfield has an Upper Carboniferous reservoir with reserves of 1.4 bcm of gas with a methane content of 65%.

A significant increase in resources in the Pomerania region took place from 1970 to 1980 (**Appendix 3.5a**), which is clearly shown on the creaming curve (**Figure 15.12**). Oilfields were quickly developed in the region and almost all oil reserves were exploited (**Table 15.1**). Gas in the region normally contains 50 to 60% methane. Not all gasfields were developed and only half of the resource was produced. The last 25 years of exploration has resulted in very few significant successes.

Zechstein-sourced fields

Figure 15.11b gives an overview of the Zechstein-sourced petroleum province. The discovery history is summarised in **Figure 15.12**. Details on the fields are given in **Appendix 3.5b**.

The petroleum system of Zechstein deposits in the Pomerania region is focussed on the Main Dolomite carbonates (Ca2). The Zechstein deposits in Poland are mainly evaporates subdivided into four cyclothems (Chapter 8). The first cyclothem (Werra, PZ1) starts with the development of the Zechstein Limestones (Ca1) (Peryt, 1978c; Peryt & Ważny, 1978). The second cyclothem (Stassfurt, PZ2) has a similar sedimentological history, but is smaller in extent. Carbonates (Main Dolomite, Ca2) were deposited in all basins, but only carbonate-platform facies have suitable thickness, organic matter content and petrophysical properties to be exploration targets. The Main Dolomite was generally deposited in a shallow-water environment with increased salinity, which influenced the development of organisms. In particular, algae and cyanosis developed to form a huge biomass that played an important role in the source rock for the hydrocarbon deposits. The system is a closed hydrodynamic type that is sealed by evaporites at both the top and bottom. The Main Dolomite (Ca2) is the series of carbonates at the base of the Zechstein Stassfurt cyclothem (Depowski et al., 1978; Antonowicz & Knieszner, 1984; Głowacki, 1986; Wagner, 1988, 1994; Górecki et al., 1995) where the source rocks and reservoirs also occur. Reservoirs in the Main Dolomite are easily recognised. The burial and thermal history of the Main Dolomite (Ca2) of Pomerania shows that oil generation had started in the Late Jurassic although the main phase took place during the Cretaceous (Karnkowski, 1999b; Karnkowski, P.H., 2007). Oil generation was later here than in other parts of the Polish Basin. It is notable that there are no gasfields in the Zechstein Main Dolomite (Ca2) of Pomerania. This is largely due to the thermal history of the region, which led to many areas of the carbonate platform (Ca2) being below the oil window and so most are still immature. Northern Pomerania has the most potential for exploration in the Main Dolomite (Ca2).

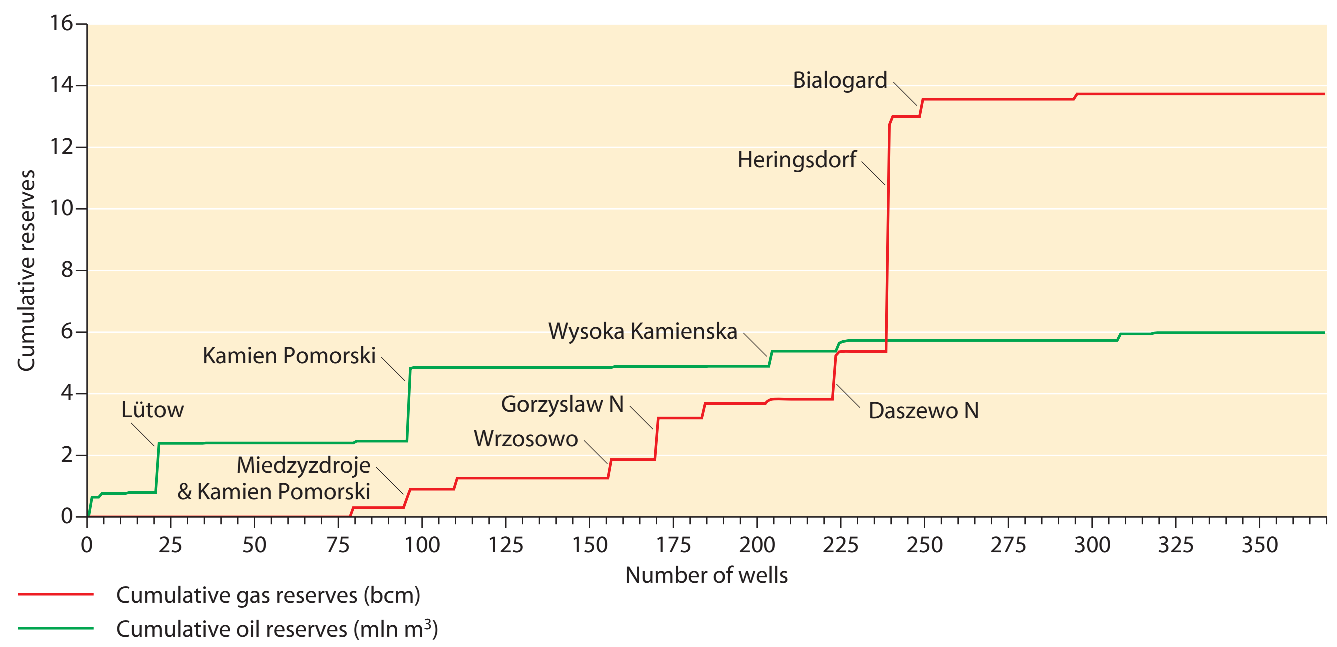


Figure 15.12 Creaming curve for the Pomerania petroleum province.

5.2.5 Fore-Sudetic Monocline and Brandenburg

Carboniferous-sourced fields

Source

The Carboniferous is the source rock for hydrocarbons (natural gas) in the area of the Fore-Sudetic Monocline. The monocline corresponds to the folded and thrusted Carboniferous rocks of the south-western Polish Variscan Externides, which extend into eastern Germany. The Variscan Externides consist of Lower Carboniferous (Tournaisian to Visean and lower Namurian) thick siliciclastic and carbonate rocks with high organic content. The younger coalified Westphalian to Stephanian strata are absent or occur in restricted areas as erosional remnants of the former sedimentary cover. Older hydrocarbon sources in the Variscan Externides area are hypothetical. However, in places, the high helium content of the total gas volume suggests deeper gas sources (Karnkowski, 1999b).

Generation

Carboniferous sediments in the major part of south-west Poland attained thermal maturity prior to the Late Permian (Poprawa et al., 2005). There is a significant difference in maturity development between the top of the Variscan succession and the lower part of the Permian to Mesozoic section. Poprawa et al. (2005) confirmed that the maturity profiles are not dependent on tectonic dipping or thrust sheets (i.e. rapid burial processes), but resulted from Late Carboniferous heat flow in the external zone of the Variscan Orogen. The heat flow varied laterally, although it was relatively high (Majorowicz et al. 1984; Speczik & Kozłowski, 1987). Poprawa et al. (2005) also noted the impact of Lower Permian volcanic traps on the thermal maturity of the Carboniferous succession beneath, as well as by migration of hot fluids related to the volcanic activity. This maturity was high enough to generate hydrocarbons. A second stage of hydrocarbon generation (mainly dry gas) took place during latest Triassic and Jurassic times due to burial of Carboniferous strata during subsidence and the development of the Mesozoic sedimentary cover. A special attribute of the gas produced is the nitrogen content derived from organic matter and NH_4 fixed in minerals. The nitrogen content can reach more than 90% of the gas volume (Lokhorst et al., 1998) and generally increases to the west of the Fore-Sudetic Monocline area.

Reservoirs

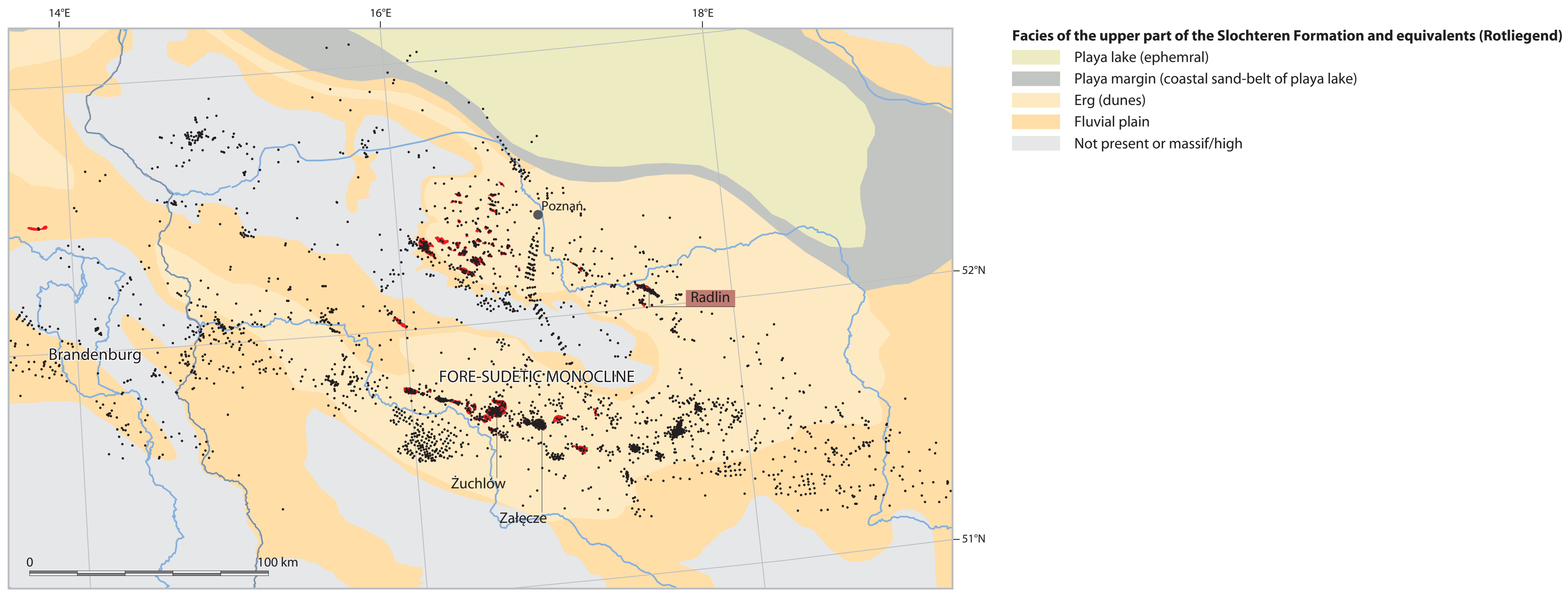
The gasfields in the Fore-Sudetic Monocline petroleum province are sourced from Carboniferous rocks. The reservoir rocks are mainly upper Rotliegend aeolian and fluvial porous sandstones and Weissliegend marine (reworked aeolian) sandstones. The reservoir is formed locally by the uppermost, fractured Carboniferous rocks and the fractured Zechstein Limestone (Ca1) succession where it overlies Rotliegend sands. The Ca1 succession is locally more porous than the Rotliegend sandstones. The Rotliegend sandstones have excellent porosity and permeability (especially those of aeolian origin), although permeabilities may be very low locally. However, recent discoveries indicate the presence of potentially tight gasfields in the deeper Rotliegend sandstones (Buniak et al, 2008a; 2008b; Poprawa & Kiersnowski, 2008).

The reservoir sandstones are separated locally from the Carboniferous source rocks by the thick Lower Permian volcanic cover. The reservoir seal is formed by lower Zechstein anhydrite and halite. Most gasfields originated in structural traps, although there are some palaeogeomorphological traps (as dune fields) and stratigraphic traps. Towards the eastern Fore-Sudetic Monocline and easternmost Germany (Brandenburg area), the prospects of finding gasfields are poor due to the lack of good reservoir rocks and the predominance of nitrogen in the total gas volume (Lokhorst et al., 1998). The most promising area is in north-west Poland (western Pomerania) and north-east Germany (Mecklenburg-Vorpommern) (Pasternak, 2008).

Field characteristics

In the Fore-Sudetic Monocline, the largest gasfields were discovered between the late 1960s and late 1980s (e.g. Bogdaj Uciechów (16.4 bcm); Borzęcin (4.5 bcm); Brzostowo (2.79 bcm); Tarchały (2.45 bcm); Wierzchowice (11.6 bcm); Załęcze (22.1 bcm); Żuchlów (24.5 bcm); Paproć (4.53 bcm) and Radlin (6.18 bcm). Gasfields such as Załęcze-Wewierz and Wierzchowice are characteristic of Rotliegend-Zechstein Limestone reservoirs (Depowski et al., 1993; Karnkowski, 1993). **Figure 15.13a** shows the Rotliegend and Rotliegend-Zechstein Limestone (Ca1) gasfields in the Fore-Sudetic Monocline (after Buniak, 2008). The map shows gasfields in production, developed and exhausted, and demonstrates the discovery history and the diverse gas-trap origins. The gasfields are clearly defined in groups with tectonic, palaeogeomorphological or mixed gas traps.

There are no Rotliegend gasfields in westernmost Poland, apart from those in the Pomerania region. Similarly, in easternmost Germany there are no Rotliegend gasfields other than the exhausted gasfield at Rüdersdorf in eastern Brandenburg and gasfields in Mecklenburg-Vorpommern, where the gas is associated with the Zechstein Main Dolomite oilfields (Pasternak, 2008).



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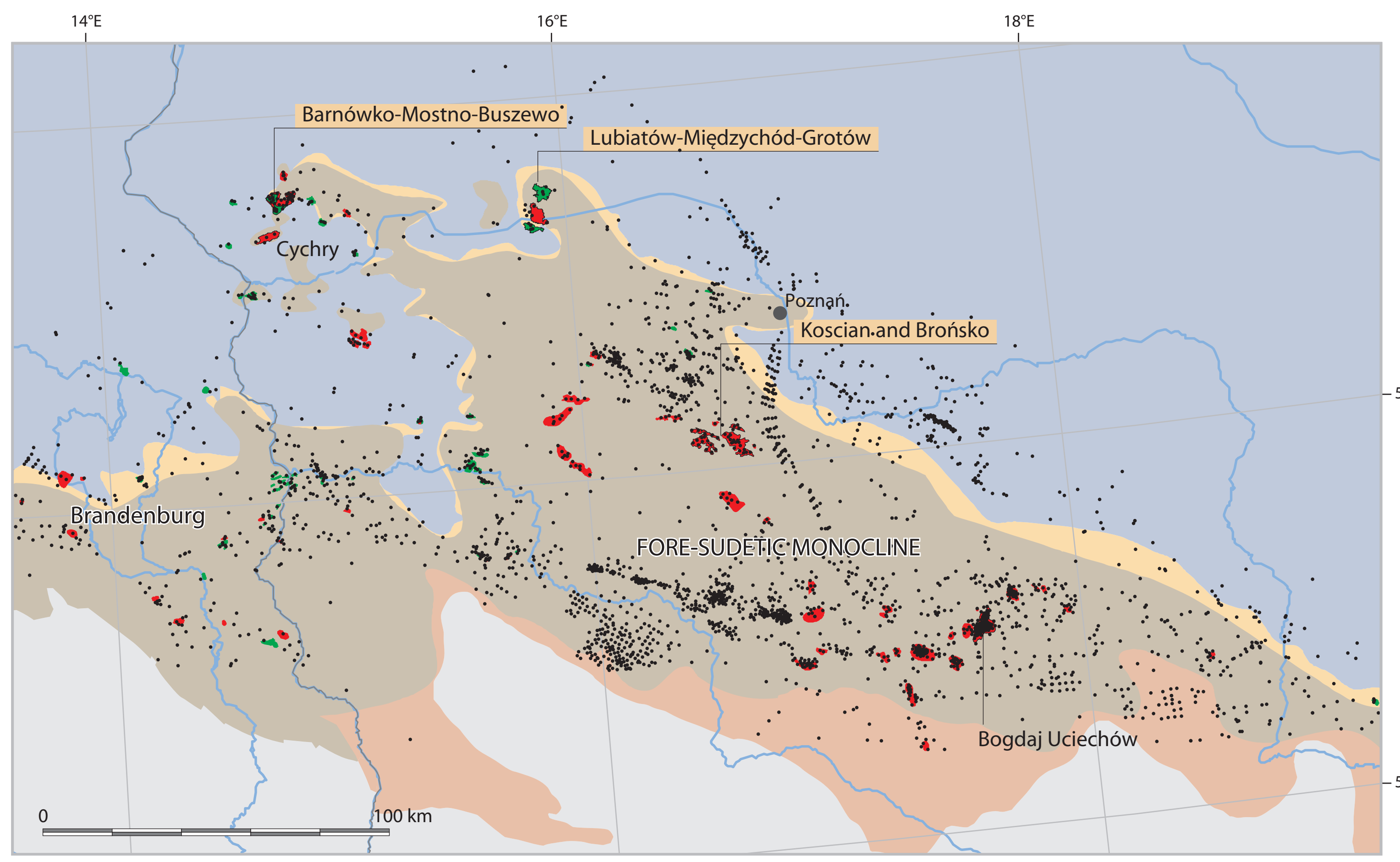
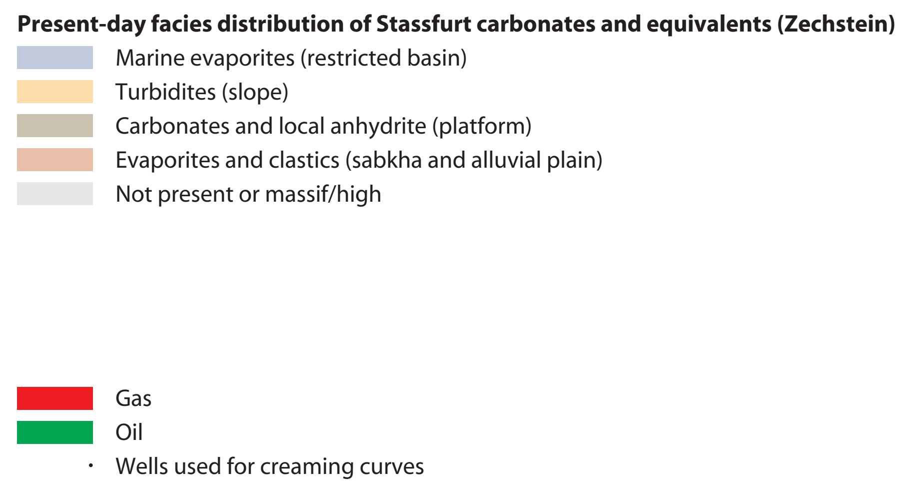
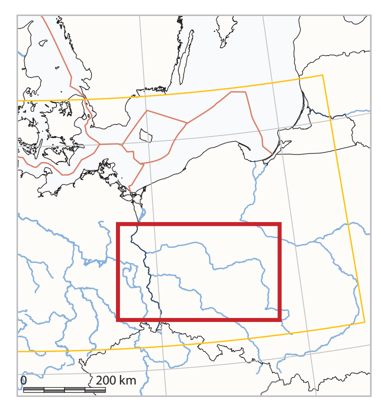






b.

Figure 15.13 The Fore-Sudetic Monocline and Brandenburg petroleum province. a. Fields charged by Early Carboniferous source rocks / Namurian black shales. Main reservoir: Rotliegend; b. Fields charged by Zechstein source rocks. Main reservoir: Zechstein.

Analysis of gas production

The creaming curves shown in **Figure 15.14** provide details on the exploration and discovery history of the Fore-Sudetic Monocline gasfields (Karnkowski, 1993, 1999b; Polish Geological Instytute, 1993). However, the left side of the curve does not explain the pure Rotliegend gas recovery from the Fore-Sudetic Monocline area. The curves show the productive period of gas recovery from the late 1970s to late 1980s. They also clearly show the gradual decrease in gas production in the area, although the recent Rotliegend tight-gas discovery may result in a change in this trend.

Permian (Zechstein)-sourced fields

Field characteristics and volumes

The locations of oil and gas accumulations/fields are shown in **Figure 15.13b** and the main field attributes are listed in **Appendix 3.6b** (after Karnkowski, 1999; Pasternak, 2008). **Table 15.1** shows the produced volumes of oil and gas from fields in the Fore-Sudetic Monocline and Brandenburg. Some of these gasfields may also contain condensate.

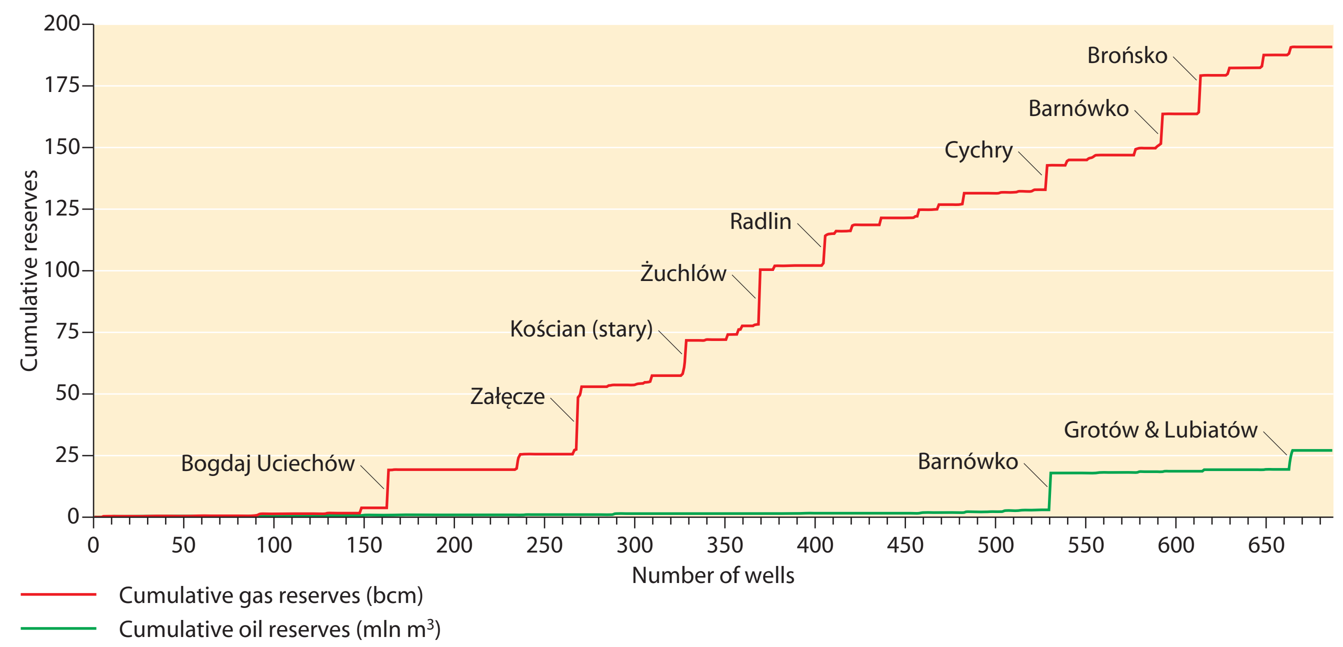


Figure 15.14 Creaming curve for the Fore-Sudetic Monocline and Brandenburg petroleum province.

Both the Fore-Sudetic Monocline and the neighbouring Brandenburg region are located to south-west of the Mid-Polish Trough and developed similarly during Permian times when the most distinctive structural elements in terms of basin palaeomorphology were the Brandenburg-Wolsztyn-Pogorzela series of palaeohighs. These highs were formed by Carboniferous to Permian volcanic rocks and subordinate Lower Carboniferous and possibly Devonian sedimentary rocks. The highs had a major influence on deposition of the Zechstein Werra and Stassfurt cycles as they were the places where the mostly sulphate platforms of the Werra and carbonate platforms of the Main Dolomite were formed. The Main Dolomite hosts many oil and gasfields, and is both a source rock (in addition to the basinal and slope facies, the platform facies of the Main Dolomite are regarded as source rocks in the region) and reservoir. The oil that accumulated in the Main Dolomite is autochthonous, and gas is partly autochthonous, syngenetic with oil, and partly allochthonous, source rocks being localised in deeper parts of the Zechstein and older Carboniferous successions. The oil and gas commonly accumulated in structural, combined and stratigraphic traps. The seals are formed by Zechstein evaporites.

History

Exploration

The exploration history of the region is shown in **Figure 15.14**. The first oil deposit in the Fore-Sudetic Monocline, and in the entire Polish Lowland area, was discovered in 1961, in the Rybaki-1 well. This discovery had a considerable influence on the intense exploration that followed in the Fore-Sudetic area (Depowski et al., 1978). Exploration was based on the concept that there were new discovery prospects in practically every structural uplift of the Main Dolomite as long as the potential trap had sufficient capacity (Karnkowski, 1999). A total of 36 oil and gasfields have so far been found in the Fore-Sudetic area and 24 oil and gas deposits in Brandenburg. A full list of discoveries is given in **Appendix 3.6b**.

The largest deposit in the area, and in Poland, is the Barnówko-Mostno-Buszewo oil and gas deposit (Section 3.4 in Chapter 8); its discovery well reflects the exploration history in the Fore-Sudetic area. The earliest exploration was the 2-D seismic surveys that were run intermittently between 1968 and 1992 (Karnkowski, 1999c). Three of the structures identified by these surveys were drilled between 1992 and 1994, and in the Mostno-1 well gas inflow was obtained. Oil and gas were found in the Barnówko-1 well and oil inflow was obtained in the Buszewo-1 well. Subsequent 3-D seismic analysis proved the presence of a single oil and gas accumulation, which allowed the location of subsequent wells to be optimised (Karnkowski, 1999c).

Development and production

Most of the oil and gas discoveries have been developed. There are 14 fields in the Fore-Sudetic Basin producing oil and gas, 11 of which have been developed during the last two decades. The first oil deposit discovered in the Fore-Sudetic Basin (Rybaki) is still producing.

5.2.6 *Lublin Basin*

Figure 15.15 gives an overview of the Lublin Basin petroleum province. The fields discovered are listed in **Appendix 3.7** and the discovery history is summarised in **Figure 15.16**.

Hydrocarbon accumulations discovered in Carboniferous deposits of the Lublin Basin occur within north-west–south-east-trending anticlinal structures along the basin axis (Chapter 6, Figure 6.4). Namurian and Westphalian sandstones, especially geophysical complexes D, H, I and L, have the highest hydrocarbon potential which increases north-westwards with increasing thickness, porosity and permeability of the sandstone bodies.

According to Grotek (2005), the potential oil and gas source rocks are the Visean and Namurian shale/mudstones (Chapter 6, Figures 6.3 & 6.18) and local limestones (the Huczwa, Terebin and Dęblin formations). Westphalian A and B deposits (Lublin Formation) can also be considered as potential gas-type source rocks, whereas the Westphalian C and D deposits (Magnuszew Formation) do not have any source-rock potential. The degree of organic-matter alteration generally increases southwards and north-westwards with increase in burial depth (Chapter 6, Figure 6.19).

To date, hydrocarbon fields have been discovered in the Minkowice, Świdnik, Stężyca and Wilga regions (Chapter 6, Figure 6.20). The main field attributes, reservoir parameters and resources are shown in **Appendix 3.7**. There are eight producing wells in the Stężyca field (Chapter 6, Figure 6.28a); the Stężyca-7 well produces about 10 t/day of oil and gas, Stężyca-3k well produces 13.73 m^3/day of oil and Stężyca-5k well produces 317 Nm^3/min. One well in the Wilga (Wilga 2) field currently produces about 1 MMcfD of high methane gas and ten barrels of light crude oil per day.

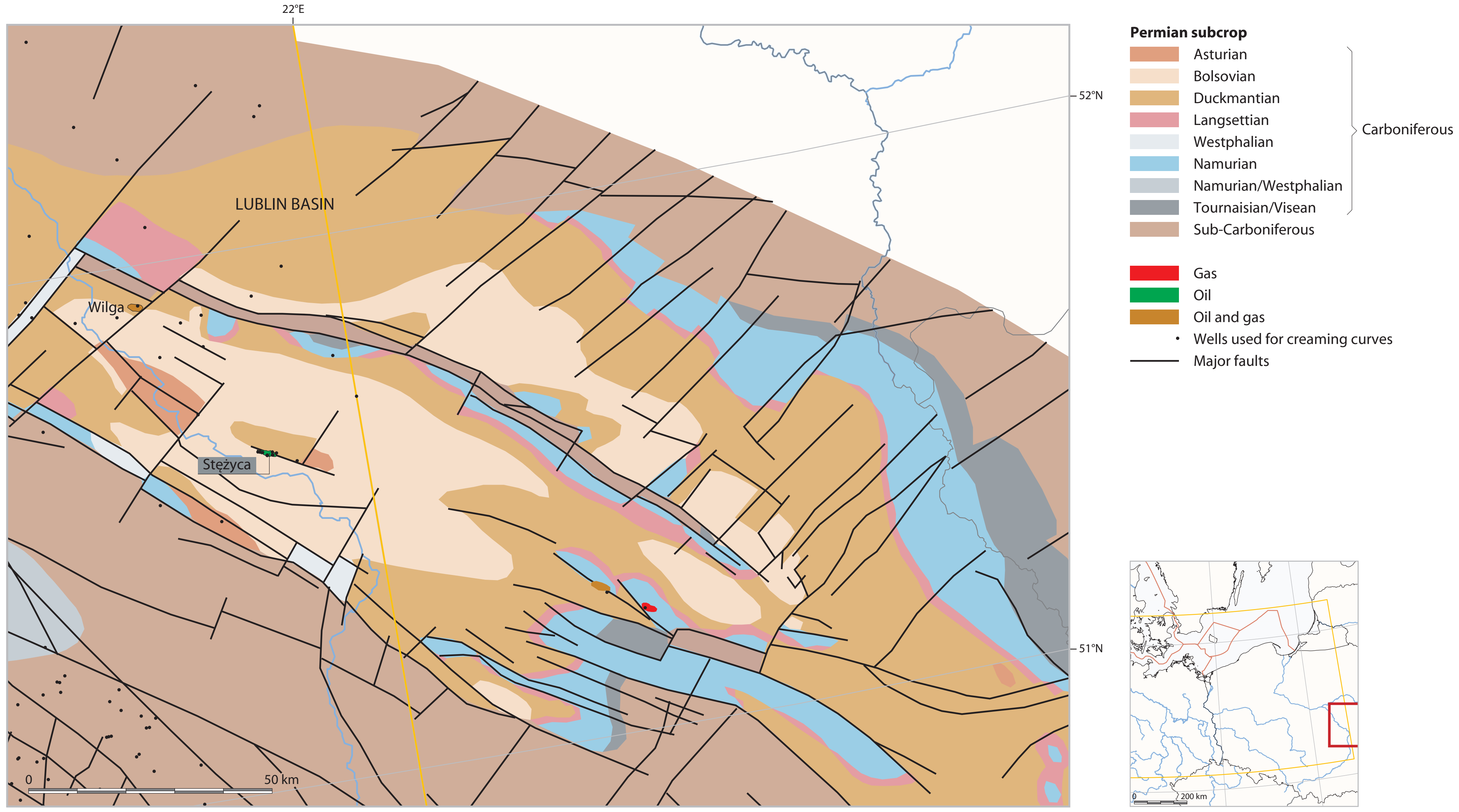


Figure 15.15 The Lublin Basin petroleum province. Fields charged by Early Carboniferous source rocks / Namurian black shales. Main reservoir: Carboniferous.

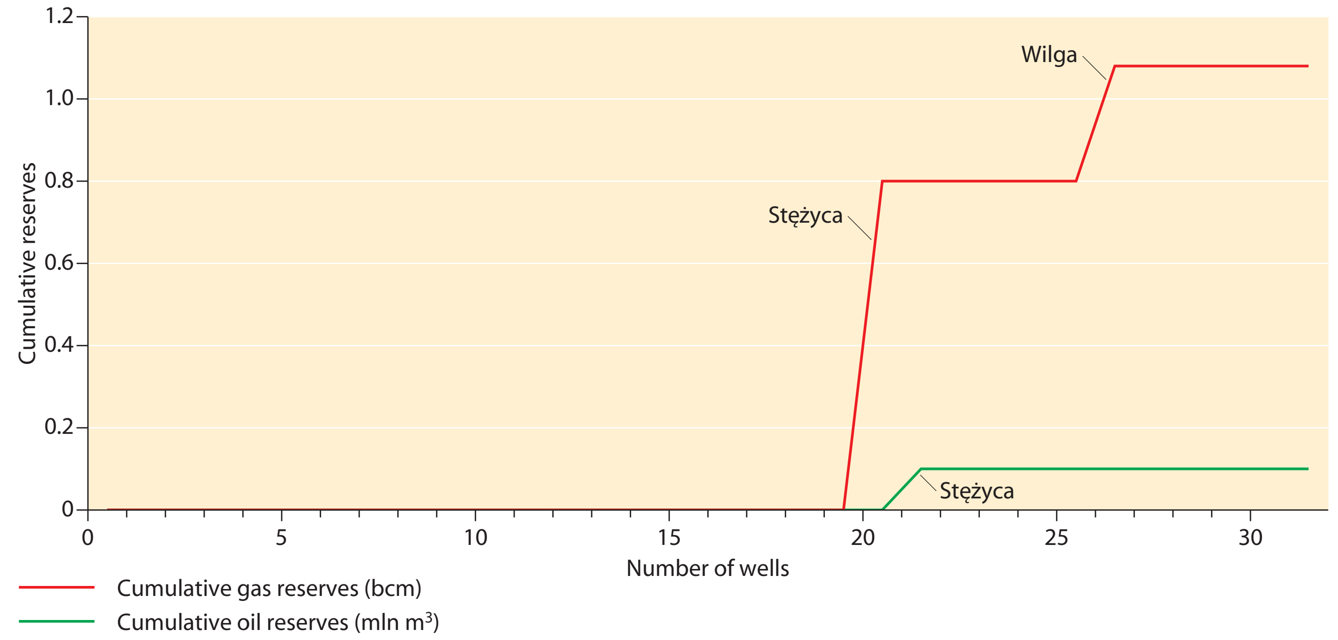


Figure 15.16 Creaming curve for the Lublin Basin petroleum province.

5.3 *Jurassic-sourced fields*

5.3.1 *Weald Basin*

The Weald Basin is in southern England to the north-east of the Wessex-Channel Basin hydrocarbon province. It falls within the Jurassic petroleum system, as the oil and gasfields and discoveries are considered to have been sourced from Jurassic mudstones within the Lias, the Oxford Clay, and the Kimmeridge Clay formations.

The Weald Basin contains 13 oil and 6 gas discoveries (**Figure 15.17**). There are eight oilfields and one gasfield currently producing (see below). A full list of the oil and gasfields is given in **Appendix 3.8**.

Factors controlling the distribution of hydrocarbon fields

The presence of three major widespread sealing mudstone sections created three vertically separated fluid regimes in reservoir intervals within the Triassic, the Middle Jurassic and the Upper Jurassic. The Middle Jurassic Great Oolite Group is the principal reservoir for the majority of fields and discoveries in the Weald Basin, and is sealed by the Oxford Clay. Upper Jurassic strata, including Corallian Group sands, the Portland Sandstone and Purbeck Beds, form the reservoirs at the Palmers Wood (Section 3.6.1 of Chapter 10) and Brockham oilfields, the Albury gasfield, and at the Godley Bridge, Balcombe and Bletchingley undeveloped discoveries. The Corallian reservoirs are sealed by the Kimmeridge Clay Formation, and the Purbeck Anhydrite forms an effective seal to the Portland Sandstone at Godley Bridge (Butler & Pullan, 1990). The highest quality Jurassic reservoir facies are found at the margins of the Weald Basin (Penn et al., 1987; Butler & Pullan, 1990), which is strongly reflected in the distribution of oil and gas discoveries in the province. Stockbridge, Goodworth, Humbly Grove, Godley Bridge, Albury, Brockham, Palmers Wood, Bletchingley, Lingfield and Cowden all lie along the northern margin of the basin, whereas Horndean, Baxters Copse, Singleton and Storrington lie along its southern margin (**Figure 15.17**).

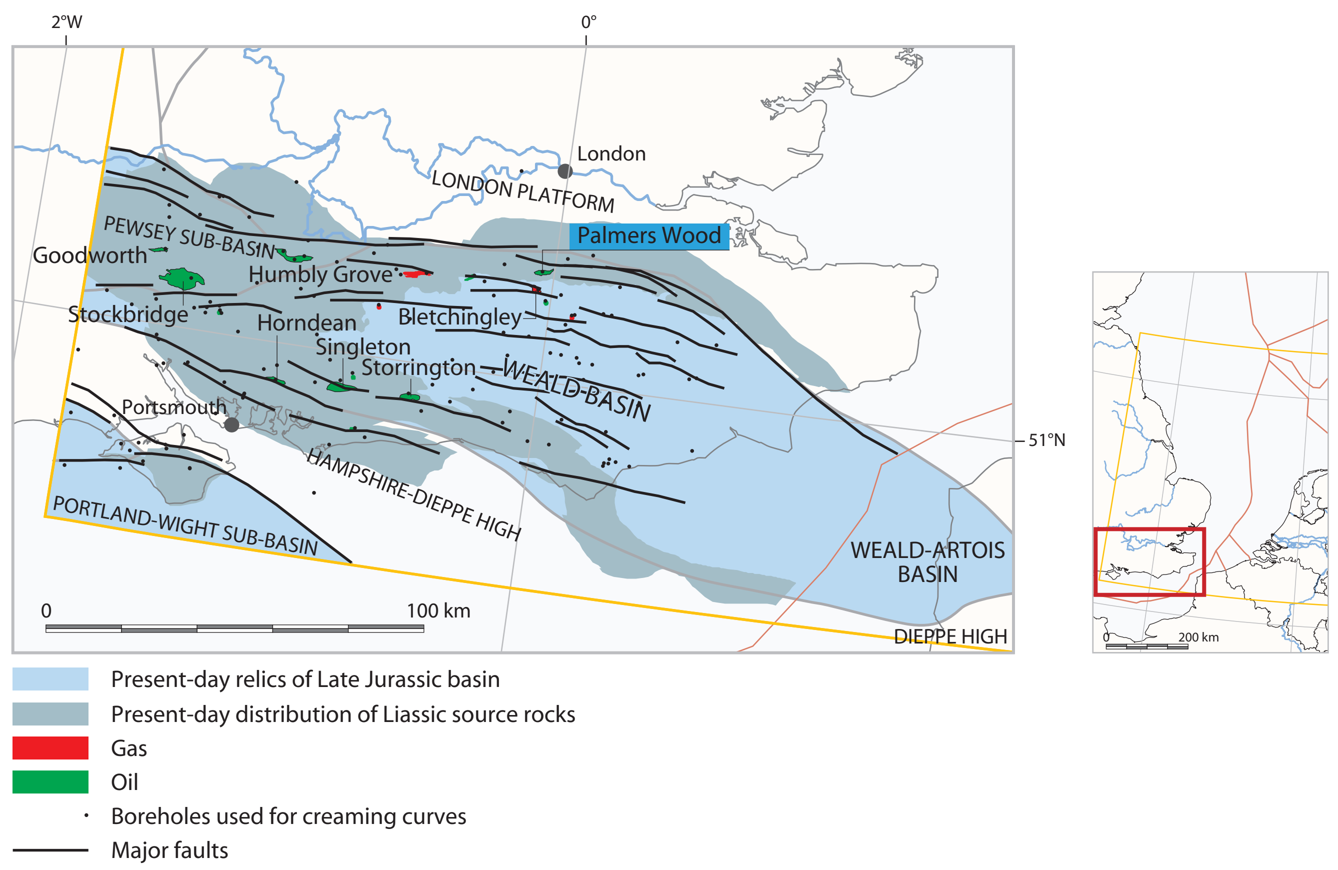


Figure 15.17 The Weald Basin petroleum province. Fields charged by Lower Jurassic source rocks. Main reservoir: Jurassic.

The Lower Cretaceous Wealden Beds provide a third reservoir, as proven by numerous oil and gas shows (including the Heathfield and Ashdown discoveries); however, substantial reserves have yet to be found in the Lower Cretaceous succession.

Hydrocarbon migration has occurred from the basin centre outwards to its northern and southern margins. Faults in the basin are likely to have provided migration pathways that resulted in multiple reservoir horizons with hydrocarbons at shallow and deeper levels in areas strongly affected by Tertiary inversion (Butler & Pullan, 1990).

Exploration

Some 135 exploration wells have been drilled to Jurassic-sourced plays in the Weald Basin (**Figure 15.17**). The majority of these wells were drilled on Jurassic targets, although just over 10% of the exploration wells were drilled to test the Cretaceous section.

The earliest reports of gas in the area were from wells drilled for water in 1836 and 1875 (Dawson, 1898; Pearson, 1903; Adcock, 1963). Water wells drilled in 1895 to 1896 at Heathfield found gas that was used to fuel gaslights at its railway station, which was the UK's first-ever gas production. Early exploration of the Weald Basin during the 1930s to 1960s was based mainly on surface mapping, when no significant discoveries were made. The discovery of the Wytch Farm oilfield in 1973 in the adjacent Wessex-Channel Basin renewed interest in the Weald Basin. New seismic techniques and data led to the realisation that the surface structures resulting from Tertiary inversion were offset from deeper structures in the Jurassic to Cretaceous extensional basin (Butler & Pullan, 1990). Following drilling of the older fault blocks of the Weald Basin, the Humbly Grove oilfield was discovered in 1980 and Stockbridge in 1984 along with most of the remaining smaller discoveries of the region during the 1980s and 1990s (**Figure 15.18**).

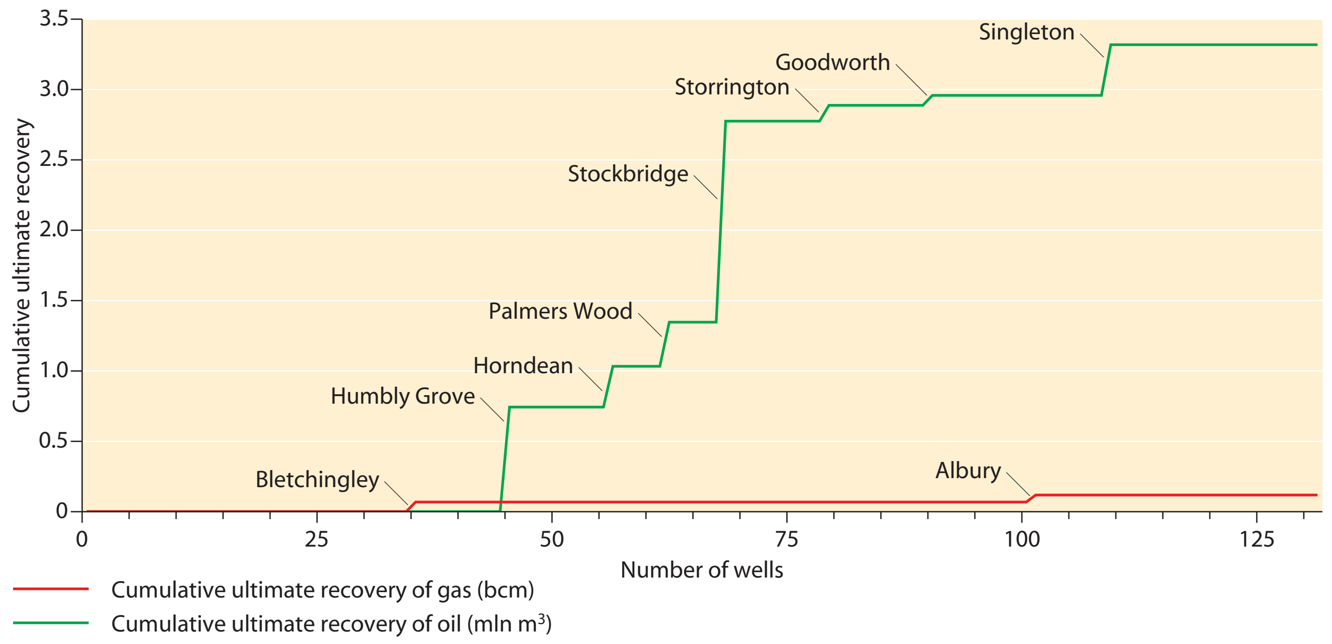


Figure 15.18 Creaming curve for the Weald Basin petroleum province.

The exploration risk is expected to be higher on the Hampshire-Dieppe High at the southern basin margin as this structure is generally beyond the limits of hydrocarbon migration from the main hydrocarbon kitchen in the centre of the Weald Basin. However, the Lidsey discovery found on the high suggests that local generation has occurred in a small sub-basin.

Ultimate recovery

Estimated ultimate recovery from the fields and discoveries of the Weald Basin is 3.28 mln m^3 oil and 0.12 bcm gas (excluding ten discoveries for which the ultimate recovery is not known) (**Figure 15.18**).

Development history

Eight oilfields are currently producing (Brockham, Goodworth, Horndean, Humbly Grove, Palmers Wood, Singleton, Stockbridge and Storrington), and one gasfield (Albury). Oil production at Humbly Grove started in 1985 and still continues. Development of the Goodworth and Horndean oilfields followed in 1988, and Stockbridge, Palmers Wood, Singleton and Storrington oilfields came onstream between 1990 and 1998. Gas production at Albury began in 1994. The producing oilfields of the Weald Basin had yielded 2.32 bcm of oil by the end of 2005.

5.3.2 Tail End Graben

Field characteristics and volumes

Figure 15.19 shows the fields that have been discovered in the area of the Tail End Graben, which are considered to have been sourced by shales of the Farsund Formation. The fields and their main field attributes are listed in **Appendix 3.9**. **Table 15.1** summarises the hydrocarbon volumes.

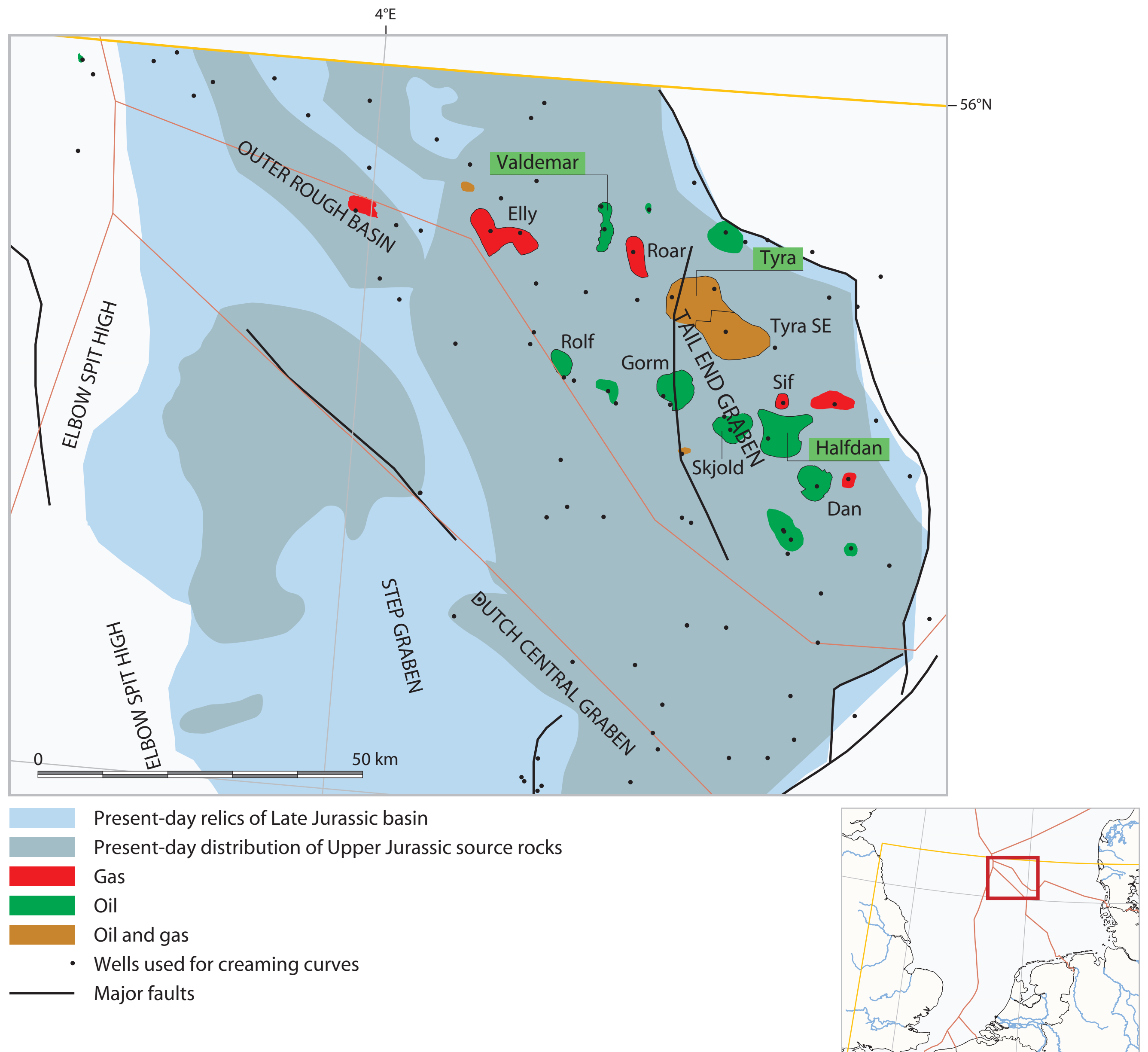


Figure 15.19 The Tail End Graben petroleum province. Fields charged by Jurassic source rocks. Main reservoir: Cretaceous.

Creaming curves

A total of 84 exploration wells have been targeted at Farsund Formation sourced plays in the Tail End Graben area. A little more than half of the wells have targeted Cretaceous plays whereas the majority of the remainder targeted Jurassic plays. About 33% of the wells were successful in discovering hydrocarbons and about 25% have led to commercial discoveries (**Appendix 3.9**). **Figure 15.20** shows the creaming curve for the Cretaceous/Jurassic plays.

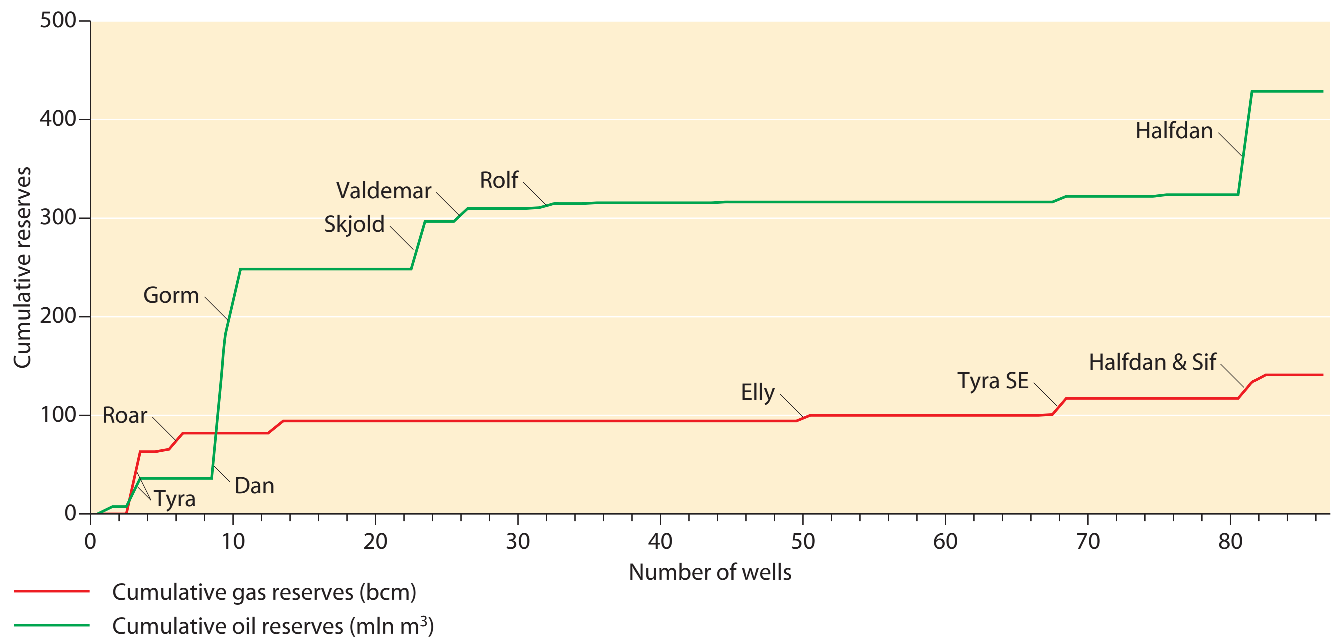


Figure 15.20 Creaming curve for the Tail End Graben petroleum province.

Exploration drilling in the area started in 1966 with the Danish A-1X well, which resulted in the first ever oil discovery in the North Sea. The discovery was made within a structural closure at Top Chalk level. More structural closures were drilled with success during the following years leading to, amongst others, the relatively large discoveries at Tyra (Section 4.3 of Chapter 11), Dan and Gorm that dominate the early part of the creaming curve. As more advanced exploration techniques became available, such as seismic inversion and modelling of fluid dynamics, further significant hydrocarbon volumes were discovered in Tyra SE and subsequently in the Halfdan (Section 4.2 of Chapter 11) and Sif fields. This is shown in the upper part of the creaming curve.

Exploration of Jurassic plays in the southern part of the Tail End Graben and Central Graben within the SPBA area have not contributed significantly to the overall success of this petroleum system as yet. The nature of the deeper Jurassic reservoirs has made the Jurassic play more complicated to explore. However, four fields have been proven and other discoveries have been made in Middle and Upper Jurassic sandstones.

Development

Sixteen of the discoveries have been developed (**Appendix 3.9**). The first was the Dan field, which came onstream in 1972. The main infrastructure was established in the early 1980s when an oil pipeline and a gas pipeline were laid from the west coast of Jylland to the Gorm oilfield and the Tyra gasfield respectively.

Drilling of horizontal wells and water injection commenced in the late 1980s to improve oil recovery from the tight chalk layers containing the bulk of the oil discoveries within the area of the petroleum system. A prime example of this development is the Dan field. Until 1987, the production strategy for the field consisted of natural depletion by means of deviated wells. The recovery factor was then estimated at 7%, but the horizontal wells and water injection allowed further development such that by 2008 the recovery factor was estimated to be five times greater than in 1987. The field provides a good example of how technological development can impact on a field within a relatively short time.

Mærsk Olie og Gas AS has developed a simplified and cost efficient wellhead platform to improve the development of satellite fields, known as the STAR (Slim Tripod Adopted to Rig) Platform. STAR consists of a leg-supported caisson accommodating up to ten well conductors. The use of the STAR Platform leads to considerable cost savings compared to the expense of conventional steel-jacket construction and installation.

The main infrastructure was expanded in 2003 by a gas pipeline from Tyra to the F03-FB platform in the Dutch sector. From there, gas is conveyed through the NOGAT pipeline to the Netherlands. The pipeline started operating in 2004. To improve the efficiency of oil displacement, the Halfdan field has been developed with long horizontal wells arranged in a pattern of alternate production and injection wells with parallel trajectories.

5.3.3 Dutch Central Graben

Field characteristics and volumes

Figure 15.21 shows the fields that have been discovered in the area of the Dutch Central Graben and are considered to have been sourced by the Jurassic Posidonia Shale. The main field attributes are listed in **Appendix 3.10**. **Table 15.1** shows the volumes related to these discoveries.

History

Exploration

A total of 46 exploration wells have been targeted at Posidonia Shale sourced plays in the Dutch Central Graben (**Figure 15.22**). The majority of these wells have been drilled on Upper Jurassic to Lower Cretaceous targets. The remainder were drilled on Chalk Group targets, mostly above salt domes.

Figure 15.22 shows the creaming curve for the Upper Jurassic / Lower Cretaceous play. The curve is dominated by two relatively large discoveries. The largest, F03-FB was discovered in 1974 during an early stage of offshore exploration in the Netherlands that started in 1968. The other major discoveries were made in the early 1980s, but no large discoveries have been made since then.

Exploration of the Chalk play has not been very successful so far: out of almost 20 attempts, there has been only one commercial discovery at the F2-Hanze field, the southernmost of several similar fields in the Danish sector. However, oil shows have been observed in many cases indicating that petroleum migration into these structures has occurred.

Development

Only three of the 12 discoveries have been developed (**Appendix 3.10**). This is due to heavy faulting and compartmentalisation in the southern part of the Dutch Central Graben. Moreover, there is no oil evacuation pipeline system in the area.

The developed 'oil' fields F03-FB and F2-Hanze also produce gas. This reflects the typical composition of the hydrocarbons generated by the Posidonia Shale in this area. The gas is evacuated through the NOGAT pipeline from the F03-FB platform. The oil is locally buffered and then transported by ship. The only gasfield developed so far is L06-A. The gas is evacuated via a subsea completion and pipeline to block G17, entering the NGT pipeline.

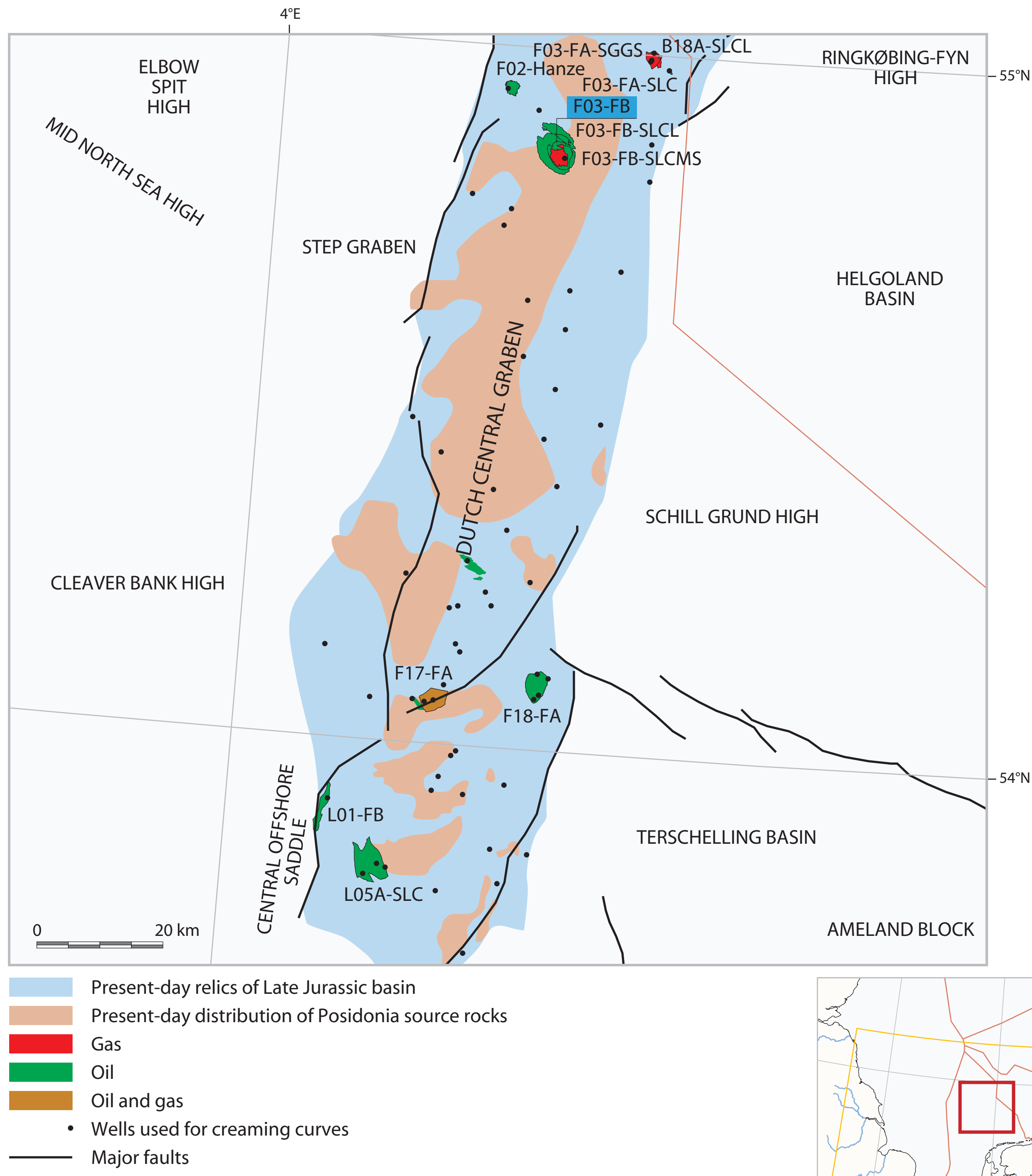


Figure 15.21 The Dutch Central Graben petroleum province. Fields charged by the Posidonia Shale Formation. Main reservoir: Jurassic.

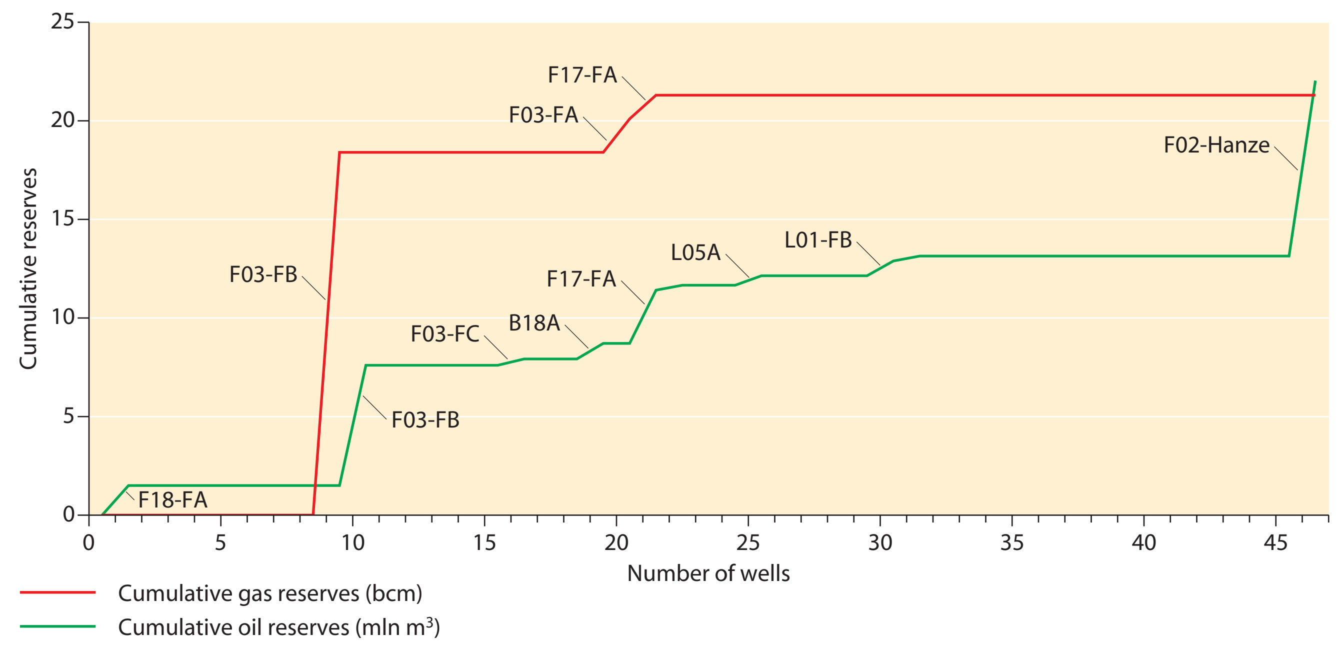
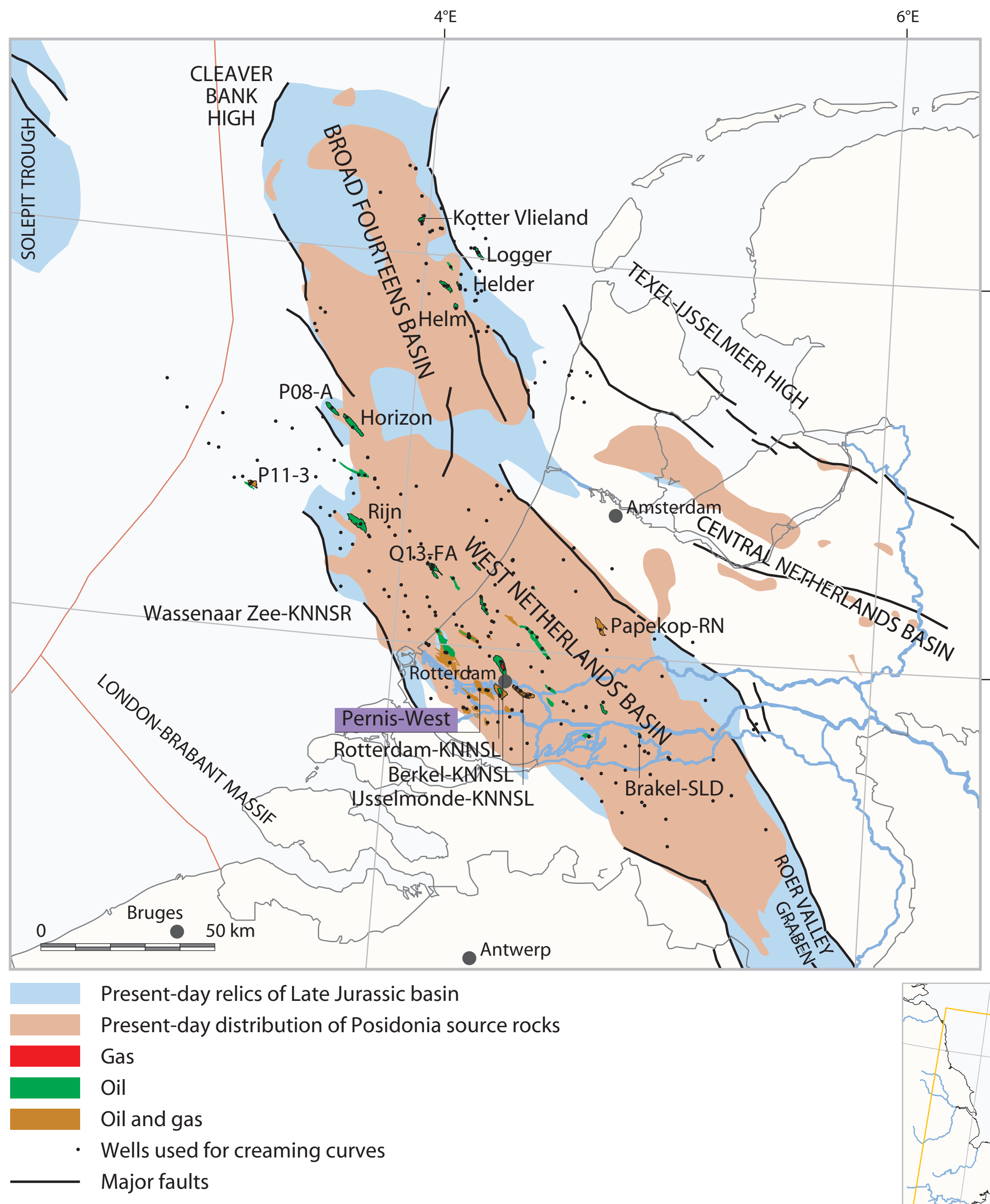


Figure 15.22 Creaming curve for the Dutch Central Graben petroleum province.

5.3.4 West Netherlands and Broad Fourteens basins

Field characteristics and volumes
Figure 15.23 shows the fields that have been discovered in the area of the West Netherlands and Broad Fourteens basins. The oil is considered to have been sourced by the Jurassic Posidonia Shale. The main field attributes are listed in **Appendix 3.11**. **Table 15.1** shows the volumes related to discoveries in the basins that are sourced by the Posidonia Shale. The total STOIIP was estimated in 1996 at 210 mln m^3 (Raceno-Baena & Drake, 1996). The reserves are significantly lower due to uneconomic volumes and/or poor reservoir quality resulting in low recovery.



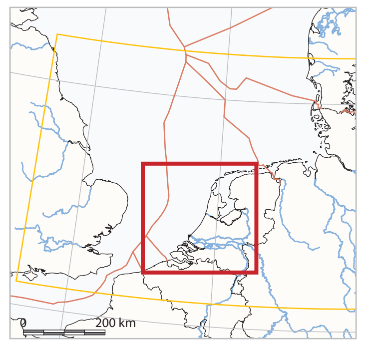


Figure 15.23 The West Netherlands and Broad Fourteens basins petroleum province. Fields charged by the Posidonia Shale Formation. Main reservoirs: Jurassic, Cretaceous.

The oil play of the Broad Fourteens and West Netherlands basins can be delineated by:

- the distribution of the Posidonia source rock (**Figure 15.2** & see Chapter 10, Figure 10.3);
- the distribution of the reservoir rocks either of the Jurassic-Cretaceous Delfland and Vlieland Sandstone reservoirs (see Chapter 10, Figure 10.4; Chapter 11, Figure 11.2) or Triassic reservoirs (see Chapter 9, Figure 9.3); and
- the distribution of the main seal(s) formed by the Vlieland Claystone and Middle Triassic Claystones (see Chapter 9, Figure 9.5).

References to these maps are found in **Appendix 2**.

Figure 15.23 shows that the oilfields are almost all aligned with their source rocks, which are only found (either preserved or only deposited) within the West Netherlands and Broad Fourteens basins. Although it is commonly accepted that the Posidonia Shale is the main, or even the exclusive source rock for oil in the basins, some studies have hinted that additional sourcing comes from the Carboniferous (De Jager et al., 1996).

History

Exploration
Figure 15.24 shows the discovery history of this petroleum province. As with numerous other great discoveries, the discovery of oil and gas in the West Netherlands and Broad Fourteens basins is a classic example of serendipity. Oil exploration in the Netherlands started in the early to mid-20th century close to the Dutch-German border. The West Netherlands Basin was not considered attractive for exploration as it was believed that the Tertiary cover was very thick. However in 1938, a demonstration of a counter-flush drilling system at an exhibition on the Netherlands Idees the 'Bataafse Petroleum Maatschappij', unexpectedly struck oil shows in Cretaceous strata (Brouwer & Coenen, 1968). The two prerequisites for an oil play, a mature source rock and migration paths, were subsequently proven. Further exploration of the play resulted in the first economic discovery in 1953, the Rijswijk oilfield, which came onstream in 1954. The onshore area of the West Netherlands Basin was explored first, followed by offshore exploration in the 1960s, which led to the first oil discovery in the Q1/P9 blocks in 1980.

Early exploration was typically focussed on Cretaceous reservoirs, either in sandstones of the marine Vlieland Sandstone Formation and/or the terrestrial Delfland Subgroup. Reservoir distribution is due to the complex interplay of sedimentation, erosion as a function of sea-level fluctuations, and tectonics (Den Hartog Jager, 1996). Fields found with these reservoirs are invariably 4-way dip closures or faulted dip closures. Only oil has accumulated in the Delfland Subgroup reservoirs. The sealing potential of the intra-Delfland seals for gas proved to be insufficient. Gas caps (gas from Carboniferous sources or associated gas) are found in the reservoirs of the Vlieland Formation under the strong regional seal of the Vlieland Claystone Formation. After the early 1980s, exploration resulted only in the discovery of small oilfields with hardly any economic value.

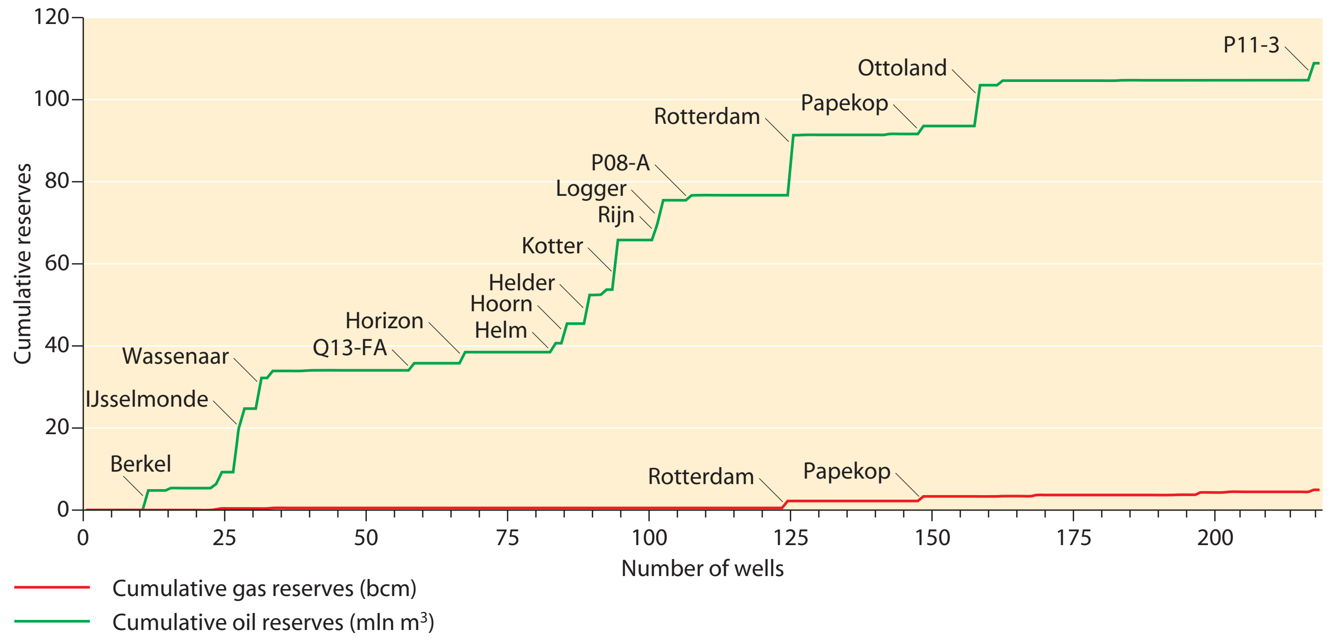


Figure 15.24 Creaming curve for the West Netherlands and Broad Fourteens basins petroleum province.

It was later realised that oil could be trapped in Triassic reservoirs, when these had been uplifted during the Late Cretaceous inversion, in a structurally higher position than the Posidonia Shale in the downthrown blocks (see Chapter 13, Section 2.4.3). The first discovery in this sub-play was the Papekop field in 1986. **Figure 15.23** shows that exploration on Triassic prospects took place predominantly on the fringes of the basins due to reservoir deterioration as a result of deep pre-inversion burial in the basin centre.

The play area was thought to occur between the main basin-bounding faults. However, as a result of a series of failures when exploring the Triassic truncation trap play in the south-east of block P11, a commitment well was eventually targeted at a high-risk prospect in the south-west corner of the block. The main risks were charging, the absence of an oil source rock nearby and immature to marginally mature rocks, and a seal risk due to the potential presence of a (Vlieland) thief sand on the unconformity. The discovery of the P11-de Ruyter field proved the possibility of long-distance migration of oil from source to reservoir through a complex pathway of some 20-30 km.

Development
Only 31 of the 43 discoveries have been developed (**Appendix 3.11**). Most of the developed discoveries have Cretaceous reservoirs, which prove to have the best reservoir quality and thus recoverable reserves. The developed Triassic discoveries are limited to the southern margin of the West Netherlands Basin because permeability was preserved due to shallower burial relative to the basin centre.

Most of the developed oilfields have been abandoned or are near the end of production. A number of plans have been submitted recently to bring undeveloped fields on stream, as for example at the Papekop and Q13-FA fields. Redevelopment of abandoned oilfields is also being considered as for example at the Rijn oilfield.

5.3.5 Lower Saxony Basin and Dogger Troughs

Field characteristics and volumes
Figure 15.25 shows the fields in the area of the Lower Saxony Basin (including the Schoonebeek oilfield in the Netherlands) and the Dogger Troughs. The fields are considered to have been sourced by the Jurassic (Posidonia Shale) and/or the Cretaceous (Wealden). The main field attributes are listed in **Appendix 3.12**. **Table 15.1** shows the volumes related to discoveries in the Lower Saxony Basin and Dogger Troughs that are considered to have been sourced by the Posidonia Shale and/or Wealden shales.

History
Figure 15.26 shows the discovery history of this petroleum province. Some of the most productive oilfields in Germany were discovered in the 1940s and 1950s. They are located at the western margin of the Lower Saxony Basin, which extends into the Netherlands. The largest of these producing oilfields

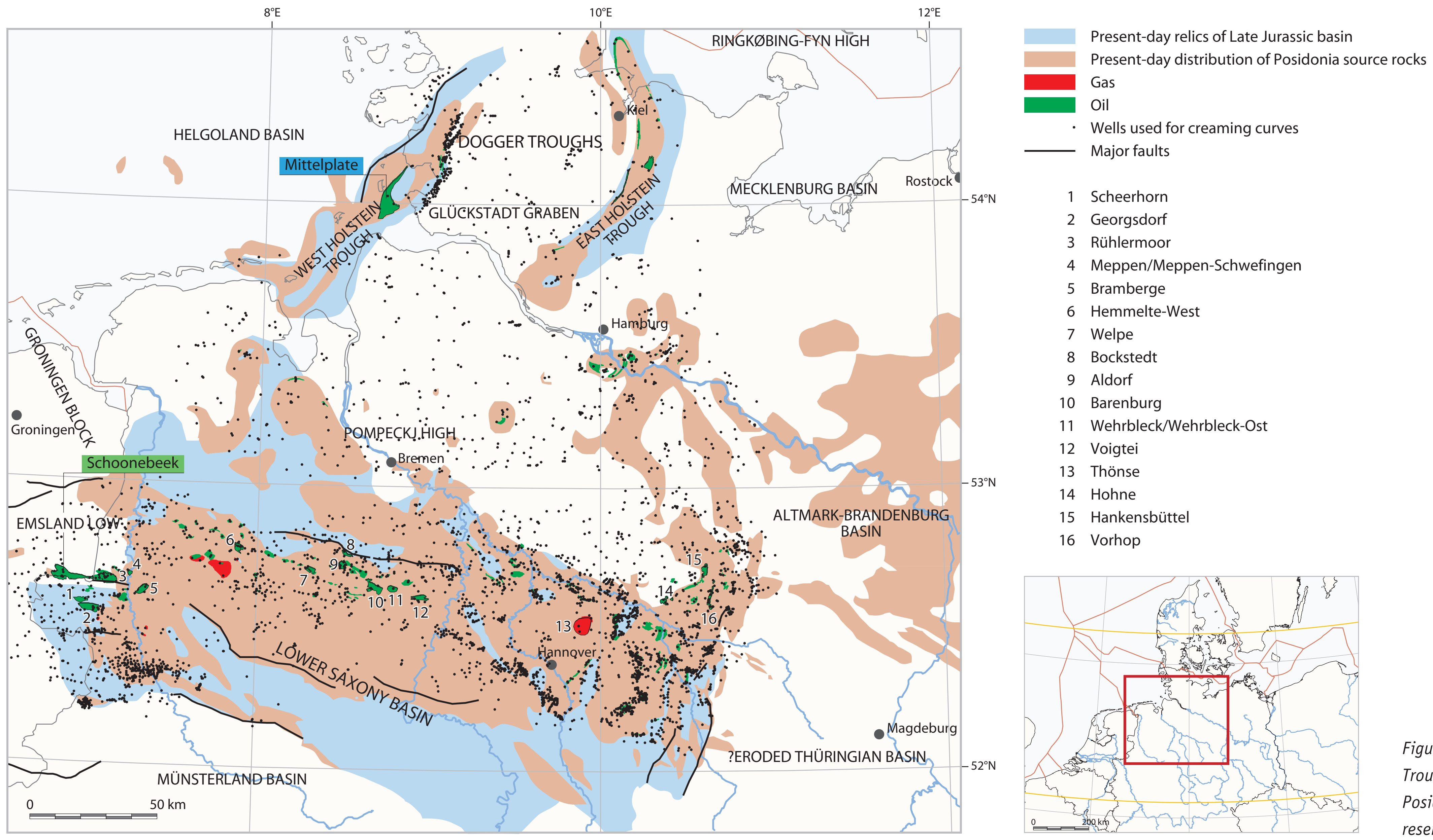


Figure 15.25 The Lower Saxony Basin and Dogger Troughs petroleum province. Fields charged by the Posidonia Shale Formation (+ Wealden). Main reservoirs: Jurassic, Cretaceous.

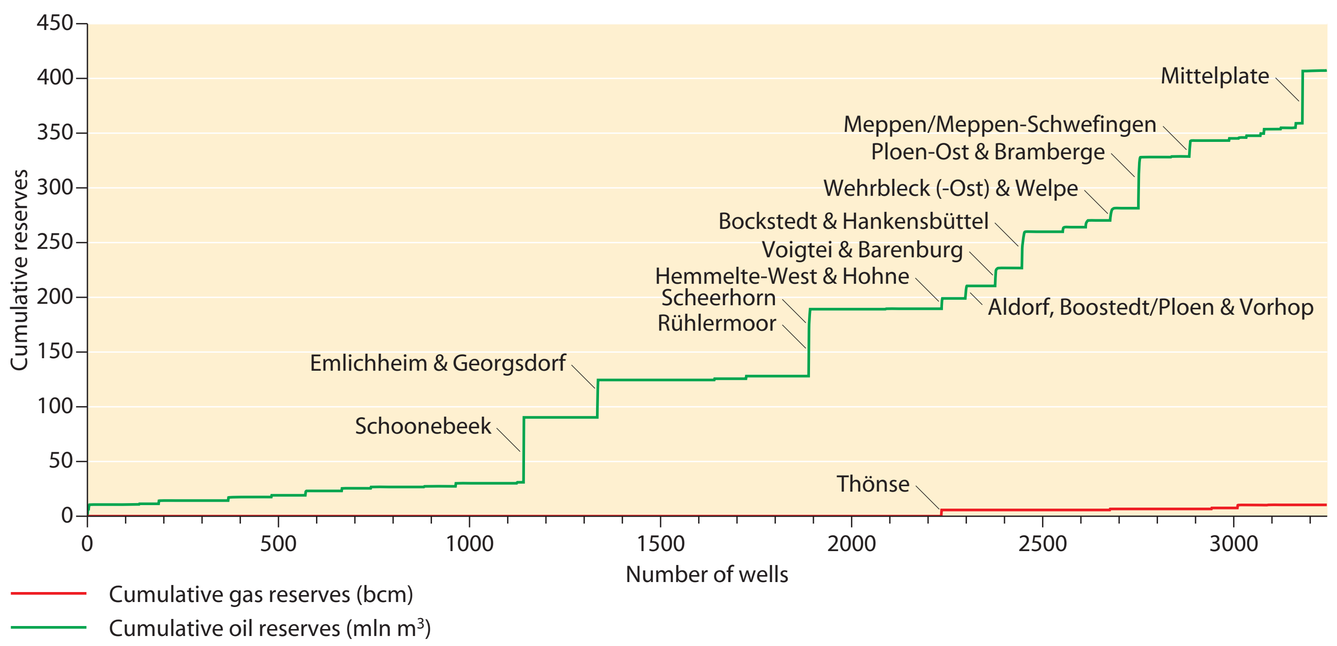


Figure 15.26 Creaming curve for the Lower Saxony Basin and Dogger Troughs petroleum province.

in Germany are Rühle (discovered 1949), Bramberge (discovered 1958) and Georgsdorf (discovered 1944), with a cumulative production of 35, 21 and 20 mln m^3 of oil, respectively. They have been sourced from the Lower Cretaceous Wealden Clay Formation. Production is presently obtained from the Lower Cretaceous (Valanginian) Bentheim Sandstone. There are numerous smaller fields in the Lower Saxony Basin that have been charged from the Wealden Formation (oil only) and the Posidonia Shale Formation (oil and some gas). The most recent, albeit small, oil discovery in the Lower Saxony Basin was in 1998 when the Ringe Z1 well discovered oil in the Bentheim Sandstone. Production started in 2001 and by the end of 2005 (reporting date) the field had produced about 0.09 mln m^3 of oil from the Lower Cretaceous sandstone.

The Posidonia Shale not only sources oil reservoirs but also some gas accumulations in the Lower Saxony Basin. One of these is the Thönse gasfield, (see Section 3.1.6 in Chapter 9), which was discovered in 1952 and has produced about 3.4 bcm of gas and some condensate from Upper Triassic and Middle to Upper Jurassic sandstones. The Löningen-Südost/Menslage gasfield was discovered in 1963 and by the end of 2005 had produced 2.3 bcm of gas and some condensate from Jurassic sandstones.

Several oilfields in north-west Germany are located in rim-synclines (Dogger Troughs), notably at Mittelplate (see Section 6.3.4 in Chapter 10). The Mittelplate-1 well was drilled in 1980 in what is now the biggest oilfield in Germany. Even by international standards it can be considered to be a large oilfield. Annual production in 2005 was 2.4 mln m^3 and the estimated initial reserves could amount to more than 60 mln m^3 of oil. The Mittelplate oilfield forms a structural trap at the western flank of the Buesum salt dome and its deltaic Middle Jurassic reservoir sandstones pinch-out on the flank of the salt dome. Short-distance hydrocarbon migration from the Lower Jurassic Posidonia Shale into the overlying reservoirs occurred from the deeper subsiding rim-syncline into the structural trap at the flank of the salt dome. On a broader scale, the field is located in the Jade West Holstein Trough, a diapiric structure of predominantly north-north-east-trending Permian salt deposits. Halokinetic movements started during the Triassic resulting in the formation of thick, mainly Jurassic sedimentary sequences within the primary rim-synclines of the West Holstein and East Holstein troughs. The latter trough contains the abandoned oilfields at Schwedeneck and Schwedeneck-See. Production from the larger offshore area started in 1984 and, over a period of 16 years, produced about 3.9 mln m^3 of oil and 0.032 bcm gas from Middle Jurassic sandstones. The importance of the Jurassic troughs is linked to their thick Liassic Posidonia Shale source rocks. In addition to the rim-synclines described above, there are other Jurassic troughs on the Pompeckj Swell that are related to salt tectonics. This includes the Gifhorn Trough, which displays a similar strike to the Holstein troughs. One of the larger oilfields in Germany, Hankensbüttel, is located in the northern part of this trough. Since its discovery in 1954, this field has produced almost 15 mln m^3 of oil and 0.32 bcm of gas from the Dogger 'beta' sandstones. The Gifhorn Trough also contains a number of smaller oilfields such as Vorhop, which was discovered 1952 on the flank of a salt dome. Oil was produced from Lower and Middle Jurassic sandstones, which in 2005 was in the order of 21 000 m^3, with cumulative production of 3.3 mln m^3.

Development

Appendix 3.12 shows that there are no undeveloped discoveries in this petroleum province. All of the producing fields with the exception of Mittelplate are located onshore, where a comprehensive infrastructure facilitates the evacuation of oil and gas. Mittelplate was discovered in 1980, although production only started in 1987 due largely to its location in the North Sea tidal-flat area at the southern boundary of a National Park. NAM is planning to revive the Schoonebeek oilfield using horizontal drilling and low-pressure steam injection. About 100 to 120 MMbo (about 160 to 190 mln m^3)are expected to be produced over a 25-year period starting in 2009/2010.

5.4 Shallow-gas source

Chapter 13 gives an overview of the gas accumulations at shallow depth. There are many indications of these shallow-gas accumulations on seismic data, but many have also been penetrated during drilling and are considered to be a drilling hazard.

In terms of commercial development, the shallow-gas play is currently restricted to the northern Dutch sector in quadrants A and B (**Figure 15.27** and Section 9 in Chapter 12); the fields are listed in **Appendix 3.13**. The number of wells directed at shallow gas is too small to allow a creaming curve to be constructed. Production from these fields started in 2008 and there is still much to be learned about the production behaviour of these shallow accumulations.

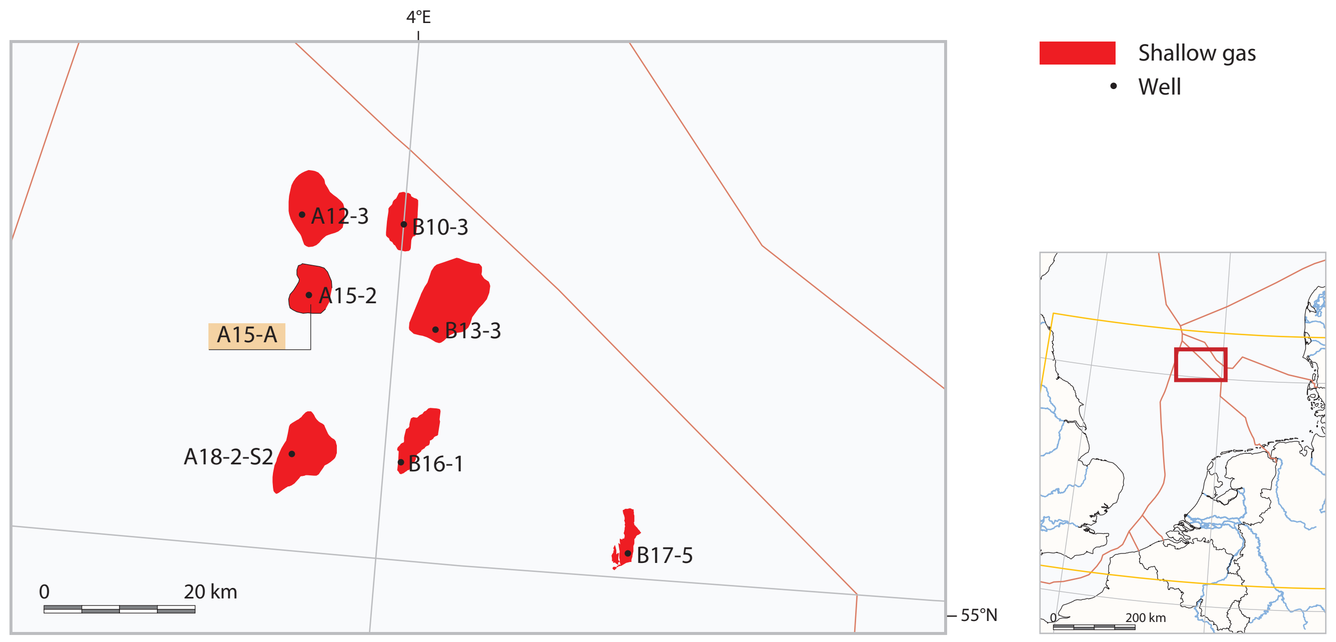


Figure 15.27 The shallow gas petroleum province (Netherlands offshore). Main reservoir: Cenozoic. Fields with Cenozoic reservoir.

Acknowledgements

Through the country co-ordinators of the SPBA project, institutes and government agencies have contributed by providing the data on oil and gasfields that form the basis of this chapter and the closely related **Appendix 3**. The extremely important contribution by the SPBA data sponsor, IHS Energy, is gratefully acknowledged. The authors greatly appreciated the skilled and dedicated support of Ms Jenny Hettelaar of TNO in creating the petroleum province and overview maps.