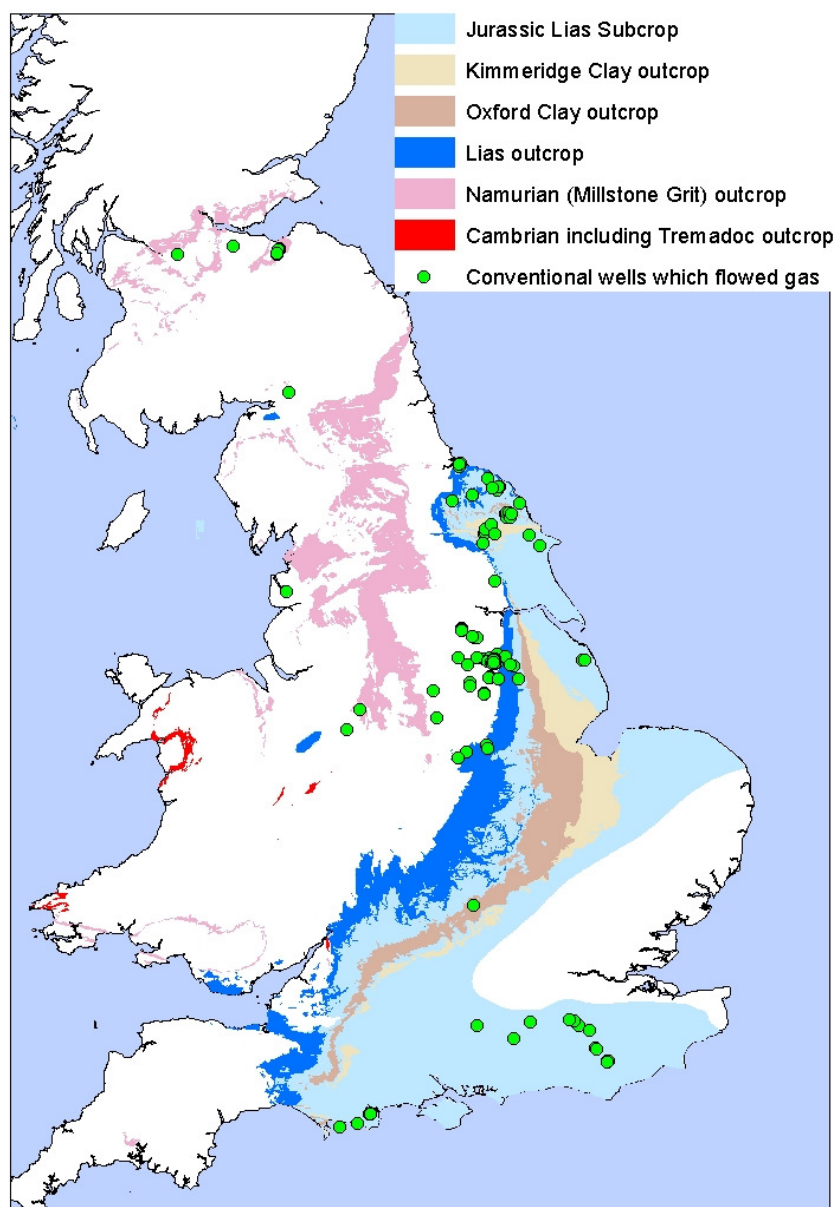


THE UNCONVENTIONAL HYDROCARBON RESOURCES OF BRITAIN'S ONSHORE BASINS - SHALE GAS



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Foreword

This report has been produced under contract by the British Geological Survey (BGS). It is based on recent analysis, together with published data and interpretations.

Additional information is available at the Department of Energy and Climate Change (DECC) website. <https://www.og.decc.gov.uk/information/onshore.htm>. This includes licensing regulations, maps, monthly production figures, basic well data and where to view and purchase released well and seismic data.

Onshore seismic data and stratigraphic tops for wells are available at www.ukogl.org.uk

DECC has now published the technical reports etc acquired or produced for Landward licences following the expiration of the confidentiality period provided for by the licence together with the "Appendix B" licence application documents submitted for the 1st to 8th Landward licensing rounds. Also now available are Field Development Plans and Annual Field Reports for fields where the confidentiality period provided for by the relevant licence has expired. The 9th to 11th Landward licensing round data should be offered in the near future. This information can be purchased from Mosaic Information Solutions on behalf of the DECC. If you require more information please contact: Ian Picton, Mosaic Information Solutions (email: ian@mosaicis.com). Relinquishment reports for some Landward licences can be found on the DECC website for download free of charge at <https://www.og.decc.gov.uk/upstream/licensing/relinqlics/index.htm>

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1. Shale Gas Overview

This document offers a geologic framework to examine the potential for shale gas exploration in the UK. Since the USGS has recognised a large increase in American natural gas reserves from shale resources, there has been a growing interest in European potential for shale gas. UK potential is as yet untested.

Shale has not previously been considered a hydrocarbon reservoir rock in the UK, but instead its organic-rich shales have been studied as world-class source rocks in which oil and gas matured before migrating into conventional fields. Gas shows are commonly observed while drilling through shale stratigraphy, but they are rarely flow tested.

The UK shale gas industry is in its infancy, and ahead of drilling, fracture stimulation and testing there are no reliable indicators of potential productivity. The analogies presented in this report may ultimately prove to be invalid. However, by analogy with similar producing shale gas plays in America, the UK shale gas reserve potential could be as large as 150 bcm – very large compared with 2-6 bcm estimate of undiscovered gas resources for onshore conventional petroleum. The technologies needed to explore for shale gas are only recently available in the UK, and mitigating the environmental impacts of stimulation technology and to large scale development are subject to local authority consent.

Unconventional gas

Shale gas is part of a continuum (Fig 1) of unconventional gas prospectivity from tight gas sands, gas shales to coalbed methane (CBM) in which horizontal drilling and fracture stimulation technology can enhance the natural fractures and recover gas from rocks with low permeability. Exploration for tight gas, shale gas and CBM is all currently underway in the UK.

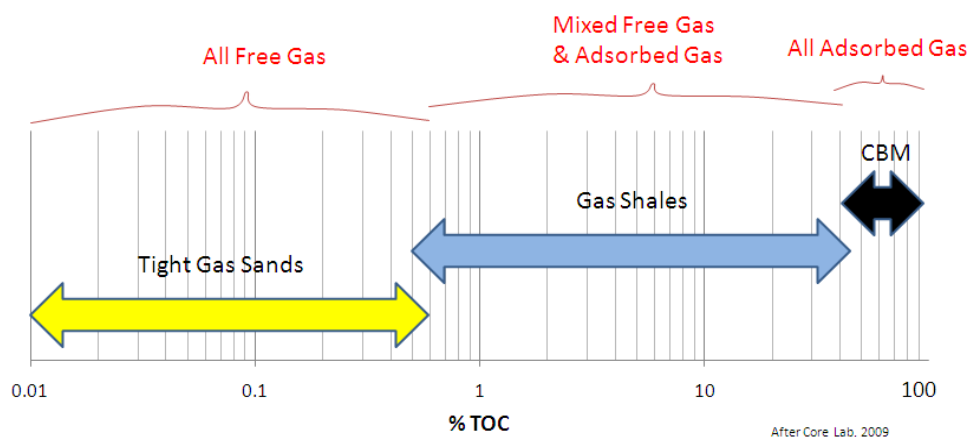


Fig 1 Ranges of Total Organic Carbon in typical tight gas sand, shale gas, and coal bed methane prospects

Some conventional sandstone wells that failed to flow gas are being re-examined in light of American tight gas successes. A tight-gas reservoir is commonly defined as is a rock with matrix porosity of 10% or less and permeability of 0.1 milliDarcy or less, exclusive of fracture permeability.

Gas can be found in the pores and fractures of shales and also bound to the matrix, by a process known as adsorption, where the gas molecules adhere to the surfaces within the shale. During enhanced fracture stimulation drilling technology, fluid is pumped into the ground to make the reservoir more permeable, then the fractures are propped open by small particles, and can enable the released gas to flow at commercial rates. By drilling multi lateral horizontal wells, a greater rock volume can be accessed.

Licensing and activity

A UK Petroleum Exploration and Development licence (PEDL) allows a company to pursue a range of oil and gas exploration activities, subject to necessary drilling/development consents and planning permission. Alongside conventional onshore oil and gas exploration and development, the licence covers exploration and development of tight gas, CBM, mine vent gas, oil shale, shale gas and gas storage in a previous gas field. A PEDL licence does not allow for underground coal gasification (UGC) or CO₂ sequestration. Until 1996, the UK Government issued a sequence of separate licences for each stage of an onshore field's life (Exploration Licences (XL or EXL), Production Licences (PL), Appraisal Licences (AL) and Development Licences (DL) and a number of them, and of even older Mining Licences (ML) are still in force, but have all been converted to the same terms as a PEDL. There are currently 334 Landward licences (Fig. 2). The last Licence Round, the 13th Onshore, was in 2008 with the award of 55 new licences covering more than 7,000 km².

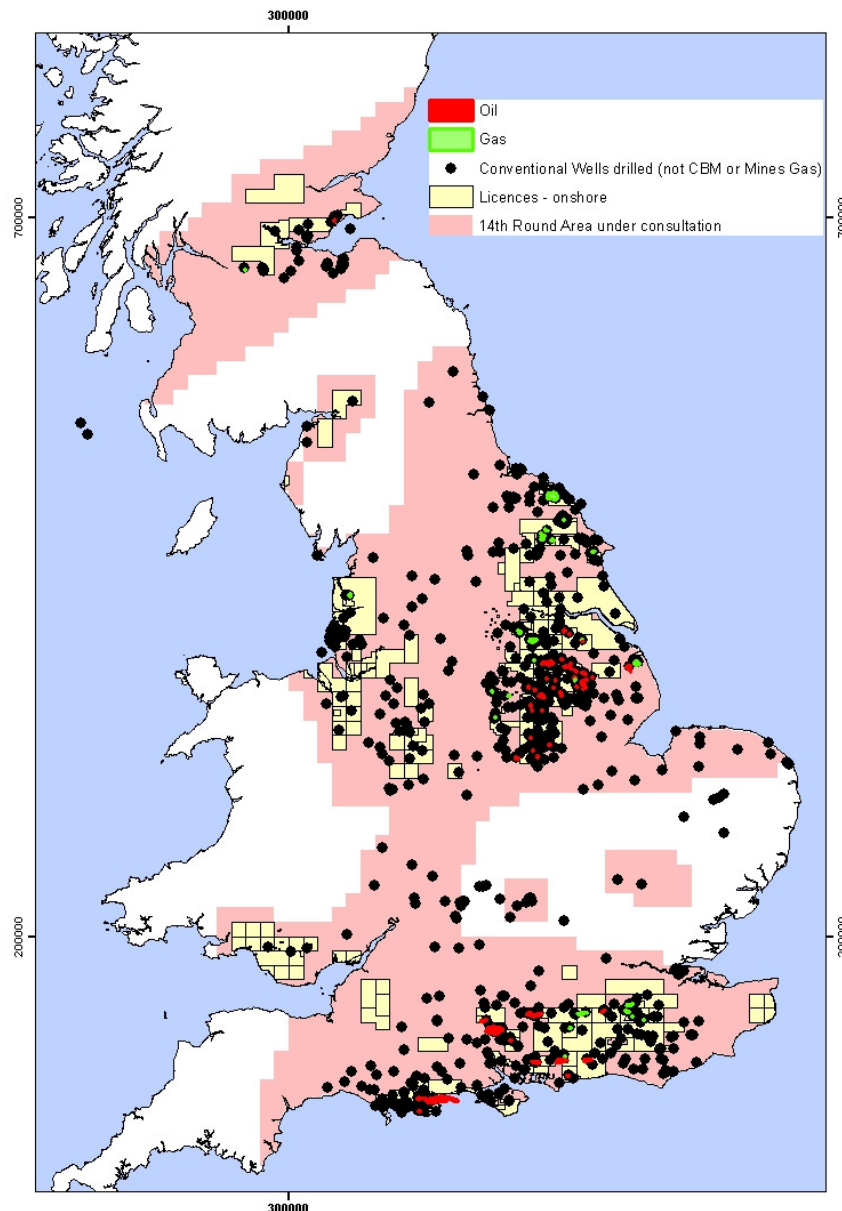


Fig.2 Current UK Petroleum Exploration and Development Licences, conventional Oil and Gas Fields, locations of conventional well drilled, and the areas under consultation currently which may be offered in the 14th onshore Oil and Gas Licensing Round.

In July 2010 DECC published a Strategic Environmental Assessment (SEA) for the 14th UK Onshore Licensing Round on its website for a twelve-week consultation period. DECC will then consider the responses received, and plans to issue a Government Response about one month later. Subject to the outcome of the SEA process DECC should then be in a position to open the 14th Round for a 90 day application period starting in or around February 2011. The exact areas to be available in the Round and the timing are subject to the conclusions of the SEA and Ministerial decision.

2. Shale gas prospectivity – introduction

The initial success in America has been in exploring for shale gas, but in a number of US basins oil is now being targeted also. Four different categories of shale exploration are possible:

- i) Gas-window source rock maturity areas
- ii) Biogenic gas in source rocks immature for oil
- iii) Biogenic gas in older source rocks which have been rejuvenated by bacteria-laden freshwater flushes
- iv) Oil window source rock maturity areas

The lowest risk shale gas exploration is where shale gas prospects are associated with conventional hydrocarbon fields. In the UK onshore, the best shale gas potential thus includes the Upper Bowland Shale of the Pennine Basin (Fig. 3), the Kimmeridge Clay of the Weald Basin, and possibly the Lias of the Weald Basin. Deeper Dinantian shales should also be tested in the Pennine Basin and possibly in the Oil-Shale Group of the Midland Valley of Scotland. Another higher risk target might be the Upper Cambrian source rocks on the Midland Microcraton – although it hasn't been severely tectonised, the Upper Cambrian has not sourced conventional fields. The risk attached to black shales within the Caledonian and Variscan fold belts is likely to be unacceptably high. These fold belts have high organic carbon, but are strongly tectonised (affected by thrusts, cut by igneous intrusions and converted to slates), and they have no overlying fields.

The overlapping hydrocarbon prospectivity is demonstrated on Figure 3 where a geoseismic cross section has been constructed following an extraction from the UKOGL seismic database, which could be improved with seismic reprocessing. The line runs from through the three main structural feature of England; the Caledonide Fold Belt on the north side, through the Midland Microcraton and into the Variscan Fold belt.

In the West Lancashire basin in the north, the Formby oil seeps were used since the 17th century, and lead to the discovery of the very shallow Formby Oilfield in 1939 which has produced 71,560 barrels of oil. And coal mining has dominated the centre of the line, including the Daw Hill Colliery, the largest UK coal producer. In 2008 Daw Hill excavated a record 3.25 million tons of coal, and it holds a Methane Drainage Licence for mine safety. The south coast is bounded by the Wytch Farm giant field which has produced over 450 mmbbls oil (mostly from the Triassic Sherwood Sandstone) and has horizontal wells that extend 11km offshore.

Unconventional gas is now found in these same basins. A few Operators are actively developing CMM vent gas, using modular generators for electricity generation. There is ongoing drilling of exploration and appraisal boreholes for CBM in the Carboniferous coals away from mine workings. There is production testing of the deviated wells drilled at the Potteries CBM Field (at Keele Park), and the Doe Green CMB field has installed on-site electricity generation. Drilling is underway in the Namurian Bowland Shale with planned fracture stimulation and testing of the shale gas potential.

While the onshore UK basins have had over 2000 conventional wells (Fig. 2), drilling was not targeted at shale reservoirs. Only recently has drilling begun on Cuadrilla's 13th Round licences in the West Lancashire Basin and in the Weald Basin (Fig. 4), where the targets are Early Namurian (Late Mississippian) and Kimmeridgian (Late Jurassic) in age respectively (Cuadrilla 2009, 2010). Under licence terms, the results of those wells will be held confidential for four years from the well completion date.

Shale gas wells will need to be drilled, fracture stimulated and tested both in areas that have been explored for conventional hydrocarbons (*e.g.* the Wessex Basin which contains the Wytch Farm field with over 170 wells), and in areas with little conventional drilling (*e.g.* the Midlands Microcraton).

UKOGL seismic

The UK Onshore Geophysical Library (UKOGL) is in the process of preparing a number of composite regional cross sections over areas of interest in the United Kingdom, using post-stack reprocessing to balance phase, amplitudes and frequencies of the various surveys. This cross section is a preliminary product generated for the Promote CD that has not undergone such reprocessing and has been produced by simply cutting and pasting existing processed data. Some of the lines incorporated into the section were processed up to 40 years ago: recent experience has shown that these can be expected to show significant improvement if reprocessed from field tapes held by UKOGL ([click here for larger seismic image](#)).

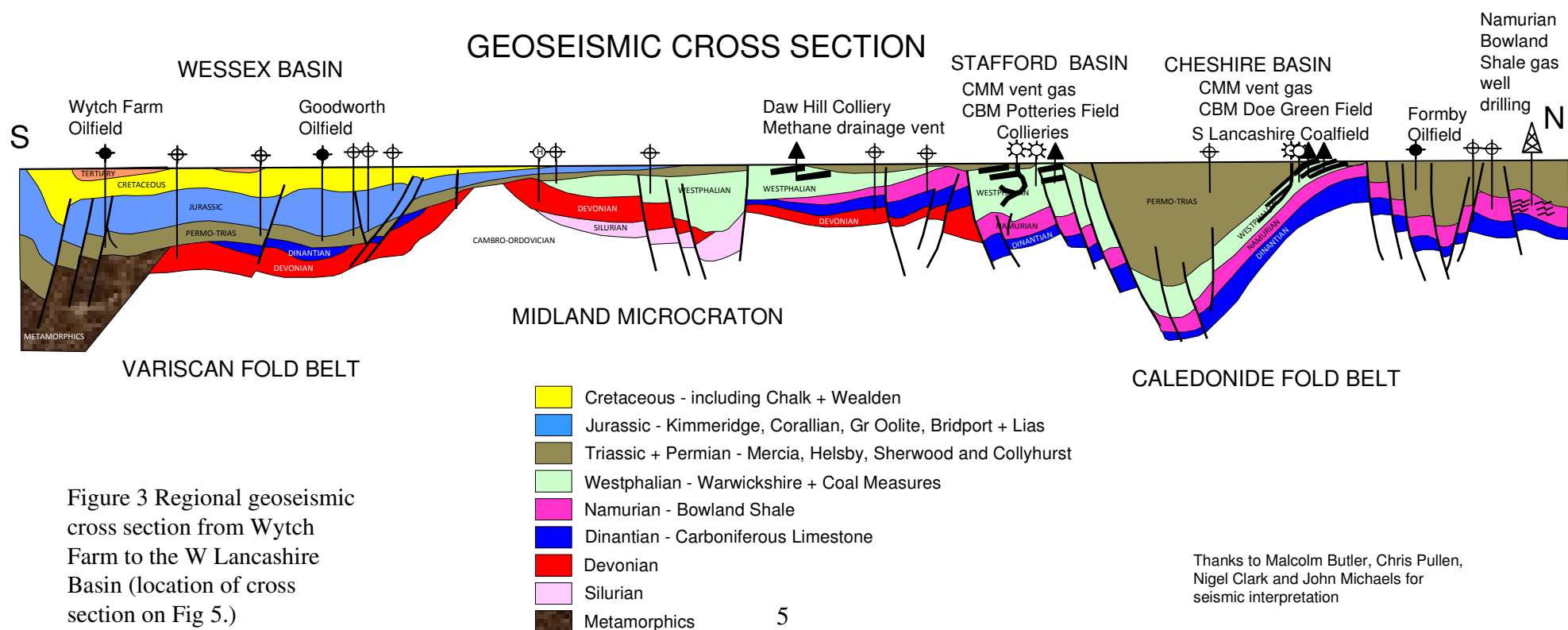
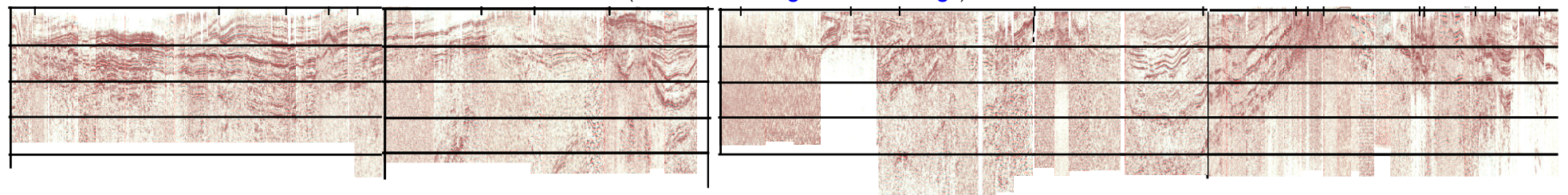


Figure 3 Regional geoseismic cross section from Wytch Farm to the W Lancashire Basin (location of cross section on Fig 5.)

Thanks to Malcolm Butler, Chris Pullen, Nigel Clark and John Michaels for seismic interpretation

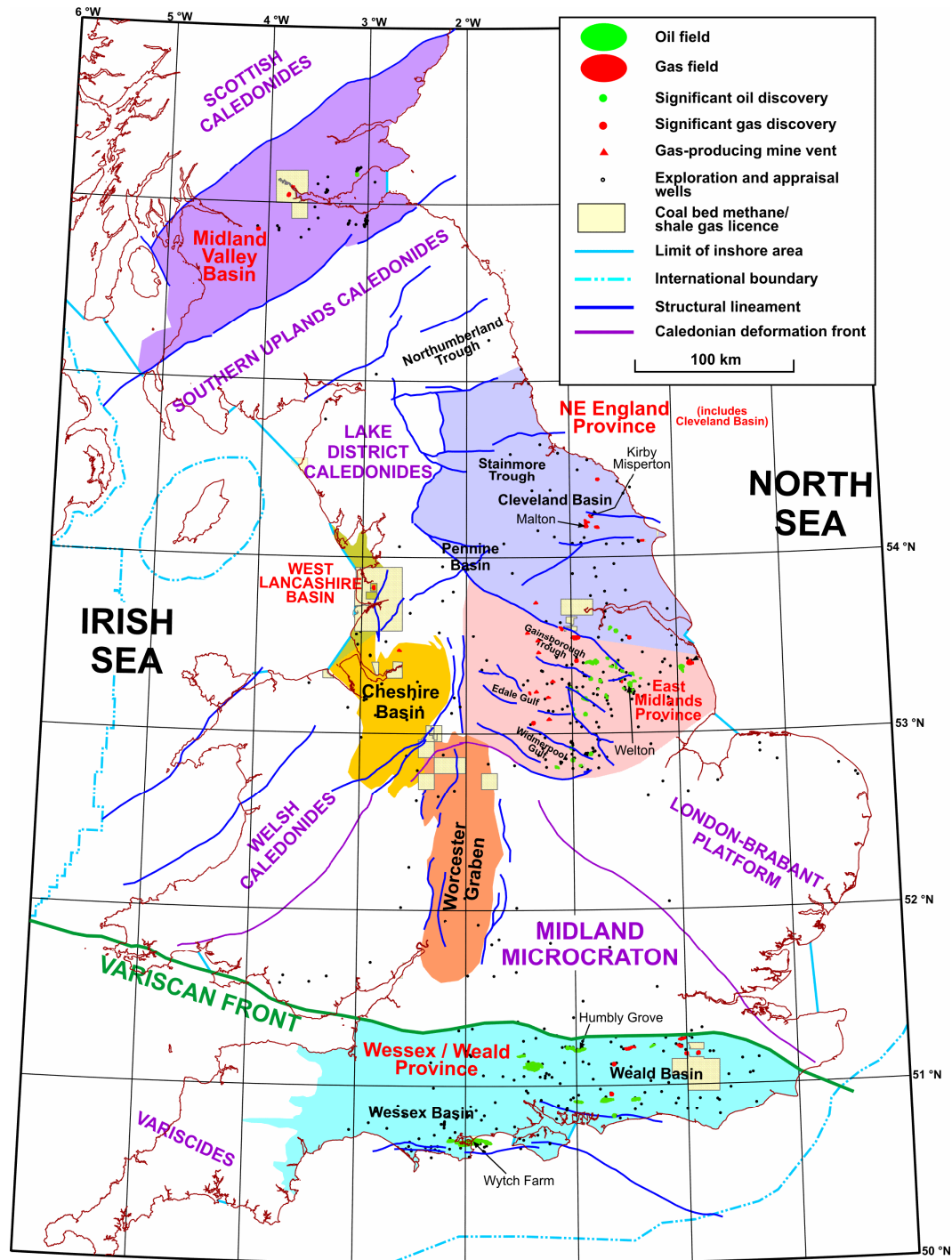


Fig. 4 Principal UK onshore hydrocarbon provinces

There are 3 main age-constrained UK shale groupings that are of interest (Smith *et al.* in press):

- (i) Early Namurian (Late Mississippian) shales are the principal source rocks for conventional hydrocarbon fields in the East Midlands, Formby and in the offshore fields of the East Irish Sea Basin. These shales also occur widely in the Carboniferous Pennine Basin of northern England.
- (ii) Three Jurassic shale intervals in the Weald and Wessex basins of southern England have sourced hydrocarbons in numerous shows and small fields along the northern and southern margins of the Weald Basin and at Wytch Farm (Fig. 4). Only the Lower Jurassic Lias shales lie within the oil window over a wide area. The remaining Jurassic shales are largely immature.

- (iii) A riskier UK play comprises the Upper Cambrian shales that are thought to occur widely in the subsurface between the Caledonides and Variscan fold belts on the Midland Microcraton (Fig. 4). Thick overlying Ordovician, Tremadoc shales are geochemically lean but may have reservoir attributes. No conventional hydrocarbon fields sourced from Lower Palaeozoic shales have been found in the UK, unlike on most of the other cratons of the world. Conventional UK hydrocarbon exploration wells on this play include at Cooles Farm, Collington, Usk and Fownhope (Fig. 5).

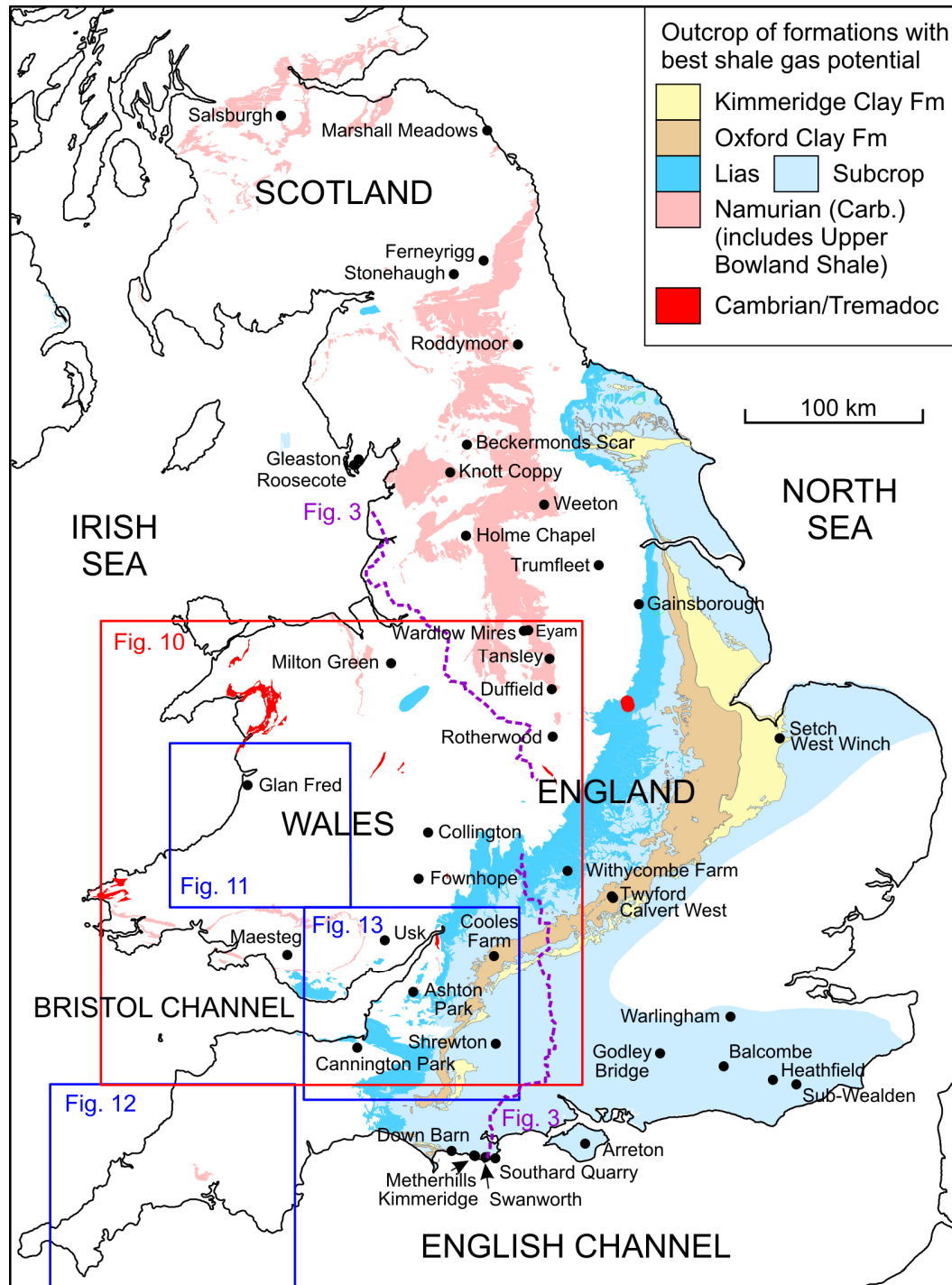


Fig. 5 Locations of boreholes referred to in this report and of Figures 3 and 10-13

Other possible UK plays comprise Lower Palaeozoic black shales within the Caledonides fold belt and Devonian to Carboniferous black shales within the Variscides fold belt. Similarly tectonised black shales are now being considered to be possible shale gas producers within their equivalent fold belts in North America.

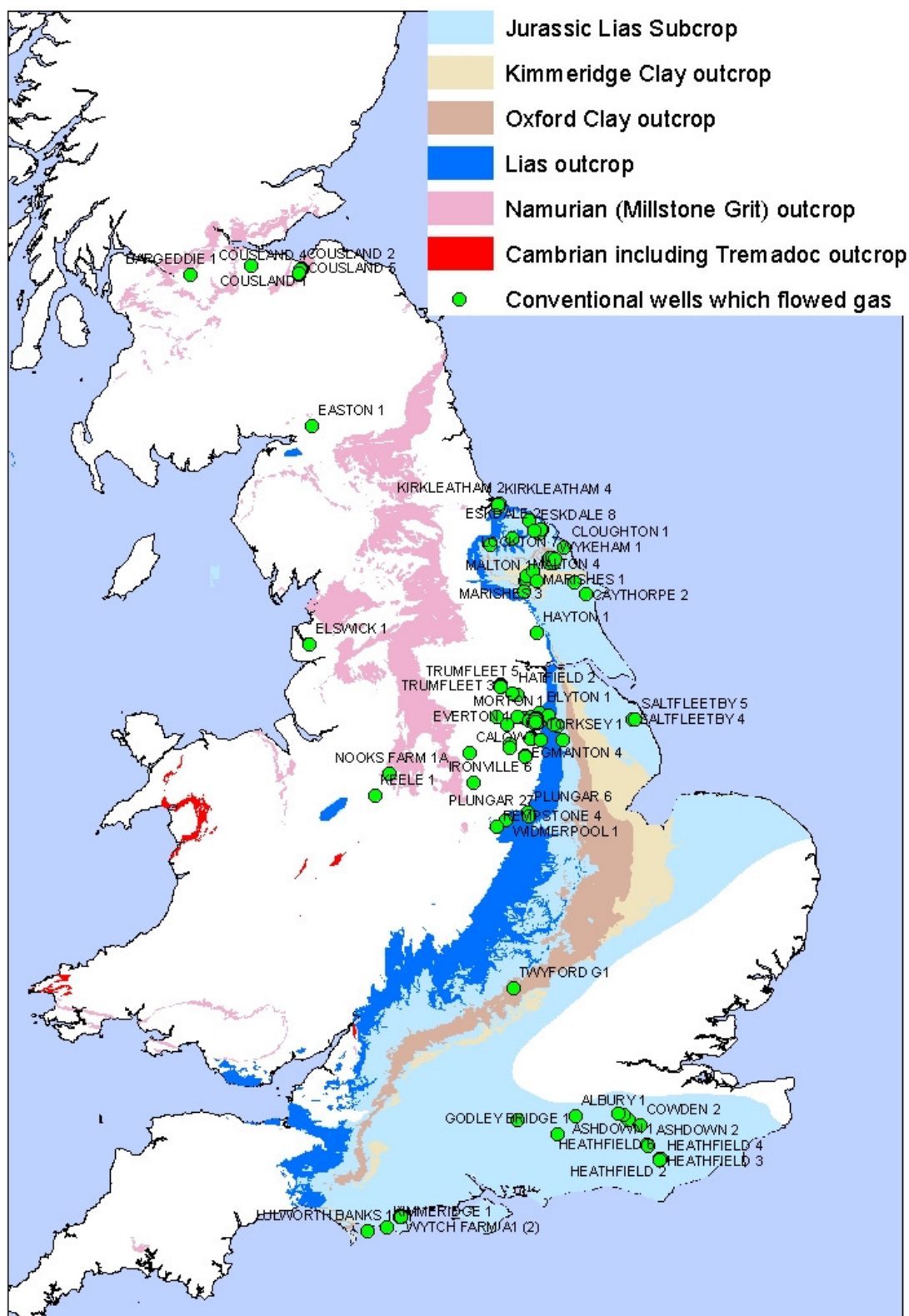


Fig. 6 Main areas of prospective UK shale formations (Namurian and deeper potential not shown) and conventional wells which have flowed gas. E Midlands wells are mostly associated gas with oil fields and some wells flowed from the Coal Measures, even though they were not drilled for coalbed methane (CBM).

US shale gas exploration started in 1821, near to a burning spring (seep), with a 27-foot deep well which produced gas from Dunkirk Shales (Devonian) near Fredonia, New York State. The major American breakthrough came with the Barnett Shale in the Fort Worth Basin, where from 1981 Mitchell Energy persistently modified completion techniques over a 20 year period, gradually improving well completion, with horizontal drilling being successfully applied to the problem after Devon took over operations. By 2008, over 28,000 gas shale wells were producing nearly 380 bcf of gas yearly from five U.S. basins

It is clear that the US exploration, led by small and medium-sized companies, is at least 30 years ahead of the rest of the world (Smith *et al.* in press). The U.S. now benefits from a 12% shale gas contribution to their gas production total. Most of new worldwide shale gas exploration has turned to the USA to understand the new exploration techniques required and to attempt to shortcut the learning curve based on US experience.

Because onshore gas is meeting customer demand in the USA, there has not been any exploration for offshore shale gas resources there as yet, but this should not prevent the economics of such ventures being considered for the future. Much larger areas are prospective offshore for shale gas, and some of these might be accessible by extended reach drilling from onshore in the early stages of offshore exploration.

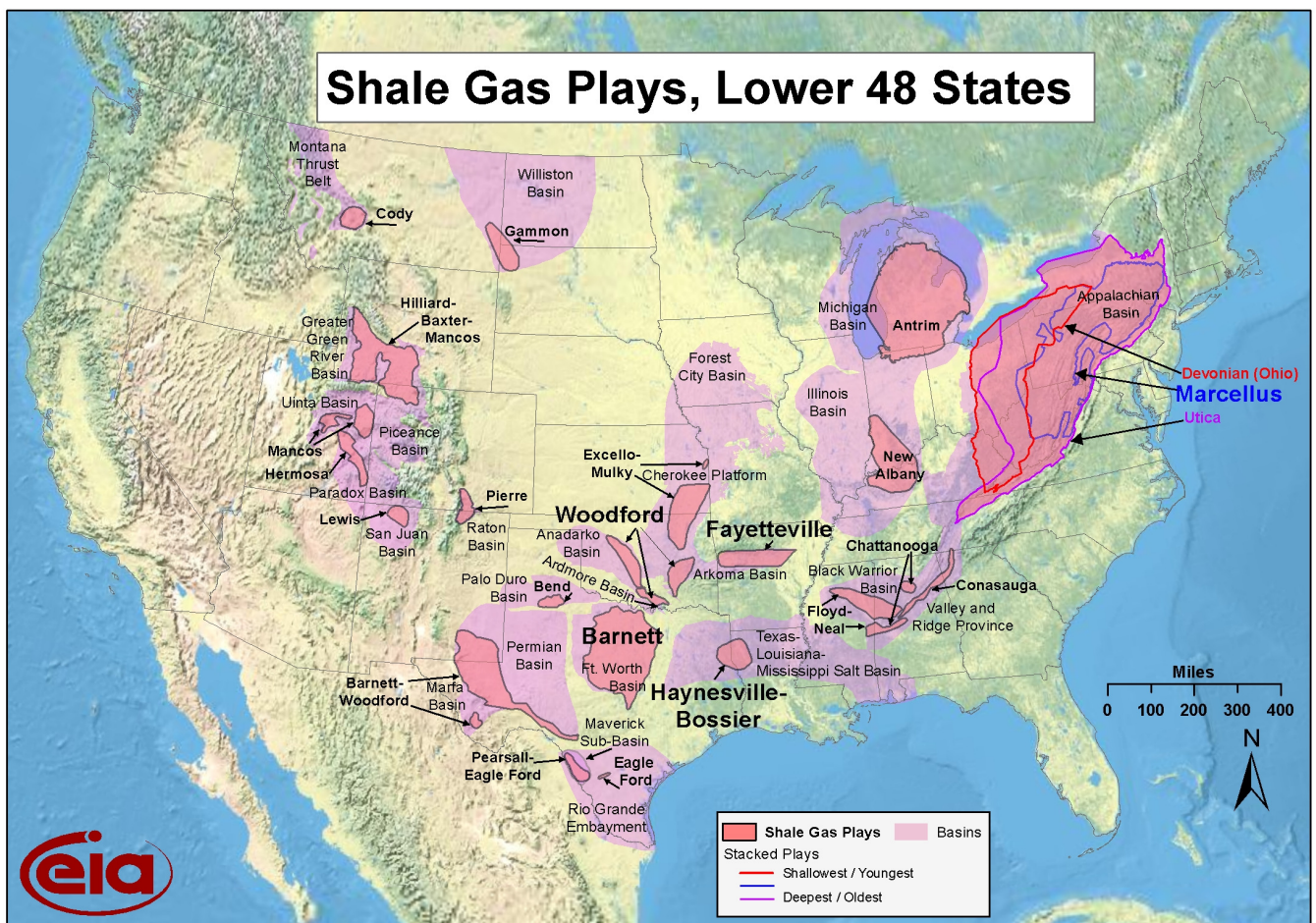


Fig. 7 Shale Gas Plays, US Energy Information Administration www.eia.gov

American analogue

The Middle Cambrian Conasauga Shale of Alabama play has probably the greatest relevance to areas in the UK that have not previously been associated with hydrocarbon production. Its Big Canoe Creek gasfield discovered by Dominion in 2006 within the Appalachian thrust belt is unique for three reasons:

- (i) Its shales are the oldest to support production in the US.
- (ii) Its shale thickness is enhanced by thrust fault duplication.
- (iii) No conventional fields appear to be associated with the Conasauga Shale.

Wells in the Conasauga Shale play produce 80-100 mcf/d, and are hence not as prolific as in the Barnett or younger shales in the USA. Nevertheless, the success here opens up the possibility that:

- (i) Commercial shale gas production can be obtained from black shales within the external parts of other fold belts, including perhaps in the UK.
- (ii) Lower Palaeozoic shales can still retain gas, even within fold belts.
- (iii) There is no requirement for shale gas source rocks to have associated conventional fields.

It is, however, possible that the Conasauga Shale has in the past sourced conventional fields that have been eroded or breached during Appalachian folding and uplift.

Analogies Used to Estimate Shale Gas Potential Reserves

The UK shale gas industry is in its infancy, and ahead of drilling there are no reliable indicators of potential productivity of its most prospective Jurassic, Carboniferous and Cambrian shale gas plays. For that reason, resource estimates can only be made by analogy with producing shale gas plays in America, although again ahead of drilling these analogies may ultimately prove to be invalid.

The Barnett Shale play in America has an estimated resource base of 10 tcf shale gas, of which 2.5 tcf comprised proven reserves in 2002 (Bowker 2002). Comprising a thermally mature source rock, the Barnett Shale is probably not a good analogue for the UK Jurassic plays of the Weald and Wessex basins, but it may provide an indicator of the possible productivity of the UK Carboniferous shale gas play. The Antrim Shale of the Michigan Basin produces gas of biogenic origin, and is a more realistic analogue for the Weald and Wessex basins. No resource estimates are available yet for the Middle Cambrian Conasauga Shale of Alabama, which is the most likely analogue for the UK Cambrian shale gas play on the Midland Microcraton.

UK Jurassic shale gas play

The Antrim Shale in Michigan produces 47 mmcf/km² shale gas (Faraj *et al.* 2004). If similarly productive, the Weald Basin petroleum system occupies an area of approximately 4,500 km², and could thus contain 200 bcf recoverable shale gas. The onshore component of the Wessex Basin petroleum system covers approximately 700 km² and could perhaps yield up to 30 bcf shale gas.

UK Carboniferous (Upper Bowland Shale) shale gas play

The Barnett Shale of the Forth Worth Basin produces 268 mmcf/ km² shale gas (Faraj *et al.* 2004, but using a larger basin area than stated in their table 2). It seems unlikely that all of the UK's Pennine Basin petroleum system could be similarly productive, but if so its 17,500 km², comprising a mosaic of separate sub-basins (Fig. 18) could potentially yield up to 4,700 bcf shale gas. Even if its productivity could match the Antrim Shale, its ultimate yield could be up to 2,100 bcf shale gas.

UK Cambrian shale gas play (Midland Microcraton)

The Cambrian Basin on the Midland Microcraton occupies approximately 18,000 km². Assuming a more conservative productivity of 20 mmcf/ km², the higher risk Cambrian play could potentially yield up to 300 bcf shale gas.

Exploration criteria

Exploration for shale gas is initially simpler than conventional hydrocarbon exploration, because problems of migration into non-source rock lithologies and the conventional reservoir characteristics are of no importance. Completion of wells in low permeability shales is likely to be a key hurdle in the UK, unless US experience is

directly transferable to the UK. Exploration needs to concentrate on identifying good hydrocarbon source rocks, their generative kitchens, areas of high total organic carbon (TOC), and areas of gas window maturity. Much of this work was carried out in the UK for the onshore conventional hydrocarbons mini-boom of the 1980s.

The main criteria identified for successful shale gas plays in the USA are:

- (i) Shales containing more than 2% TOC, rock-eval, T_{\max} and HI values for maturity
- (ii) Shales having a thickness exceeding about 40 metres.
- (iii) Depths from surface to the shale ranging from about 1,000 to 3,500 metres.
- (iv) Overpressured zones
- (v) A limit of vitrinite reflectance (V_R) of 3.0% and equivalent other indices (e.g. T_{AI}): Maturity of shale must be limited to within the gas window.
- (vi) Petrography: high % of non-clay minerals is required (Barnett Shale has only 27% clay minerals).
- (vii) An area of more than 100 km² and avoiding towns (in the US, however, the Newark East gasfield partly underlies the city of Fort Worth)
- (viii) Shales unaffected by orogeny, that is, in areas restricted to forelands or cratons rather than within fold belts (however the productive Conasauga Shale in Alabama lies within the outer zones of the Appalachian thrust belt)
- (ix) Offshore areas are excluded (so far)
- (x) Other key elements include palaeogeography and structural setting.
- (xi) Legacy wells having geophysical logs including Gamma Ray, Density (Sonic) and Resistivity to identify shale beds and indicate porosity or high organic content.

To these we should also add:

- (i) The presence of conventional gas fields (particularly those shown to be not sourced from Coal Measures). In the US there are so many gas fields this advice has not been needed.
- (ii) The presence of gas shows in shales. It is unlikely, given the poroperm characteristics of shales that gas has migrated into shales from elsewhere – the gas found within shales is likely to have been generated from these shale intervals.

Discussion of these criteria

Probably most of the (above) factors require caveats, and these caveats are being tested thoroughly in some plays. US productive shales have variable characteristics, for example including the high gas-content Barnett Shale, which contains mostly free gas and the average gas-content Antrim Shale, which contains mostly adsorbed gas. An obvious effect of this difference is a varying well production decline curve (Drake 2007).

The geochemistry of the shales is a key factor, as at least initially shale gas exploration will target high TOC shales. The maturity of the shales is perhaps more flexible, because recent biogenic shales can be expected to have lower vitrinite reflectance ($V_R < 0.65\%$) than in the oil window. Older shales where recent groundwaters have introduced bacteria may have any level of maturity. However the presence of oil in the shales lowers gas permeability significantly. Even the oil window shales are now being tested in America by some companies to produce shale oil rather than gas. Any cut-off by virtue of the thickness of shales is probably dependant on whether other stacked shale formations could be considered prospective, either above or below, and the poroperm characteristics of these shale formations.

In America, the higher production in the Late Jurassic Haynesville Shale compared to the Barnett Shale is attributed to a better seal and an absence of overlying reservoirs. In the UK we have not reached this level of exploration sophistication, and the presence of overlying or nearby (small) conventional reservoirs is considered to be an initially important consideration. The age of the shale, affecting permeability, might also be a factor. Jurassic shales in the UK have not been so adversely affected by the Alpine Orogeny as Carboniferous and Lower Palaeozoic rocks affected by the Variscan and/or Caledonian orogenies. These deformation fronts form a triangle (Midland Microcraton) in south and central England and Wales that is comparatively unaffected by folding and intrusion of igneous rocks. (Smith 1987).

There is no evidence of overpressure in UK basins, so it is unlikely that well production rates will be as high in the UK as in America.

In America, the Haynesville Shale (Upper Jurassic) overlies the Ouachita (Variscan) fold belt but is younger than the age of orogenic deformation. In the UK the Jurassic shales of the Weald Basin have a similar geographic juxtaposition to the Haynesville Shale, relative to the concealed UK Variscan fold belt.

The petrography of all potential gas shales is generally related to the Barnett Shale standard. However, the Barnett Shale's low clay content is not typical for many other shale gas plays in the USA, and may hence be not applicable to UK gas plays either.

UK Source Rocks

All source rocks can be defined by known petroleum systems. In the UK there are (oil) petroleum systems in the Weald, Wessex, Pennine, West Lancashire and Midland Valley basins. Minor (gas) petroleum systems are present in all these basins and in the Cleveland Basin (an onshore extension of the Southern Permian Basin petroleum system). Source rocks in other UK basins have not provided hydrocarbons to conventional fields, but may have some potential for retaining some proportion of hydrocarbons generated. Few of these have been sampled for TOC content or drilled into. Only limited details are provided for the areas with the highest risk, that is, within fold belts.

UK Gas content

There are no known studies focused on the gas content of UK shales. For safety aspects associated with coal mining, Creedy (1988, 1989) collected and analysed the gas contents of non-coal lithologies in coal mining areas. There is no published information on how these data were collected and how quickly they were analysed, but Creedy's analyses suggest that carbonaceous mudstones and marine bands are likely to contain about four times as much gas as other lithologies. For comparison, coals are likely to contain at least 200 cubic feet of gas per ton. Jurassic mudstones analysed by Creedy have very low values but there is no published information on where his samples were obtained or on the exact stratigraphic interval sampled.

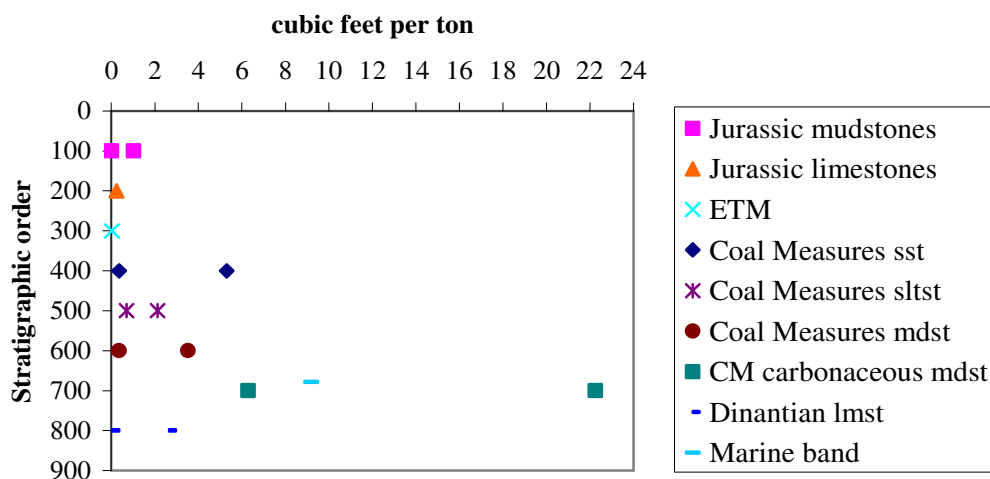


Fig. 8 Gas contents of various non-coal lithologies measured for coal mine safety purposes (Creedy 1989). These are grouped stratigraphically and the vertical scale does not represent true depths.

3. Shale gas prospectivity – UK pre-Carboniferous shale formations

All of the UK formations in the following section display a relatively small selection only of the exploration criteria listed in Section 2 as characterising successful shale gas plays in the USA. They are largely distinguished from less prospective UK shales by their description as being 'black', highlighting potential prospectivity. Only limited details are provided for shale intervals with the highest risk, that is, within fold belts. Lake District and Southern Uplands shale formations and metamorphosed shales are not considered prospective, and are excluded from this report.

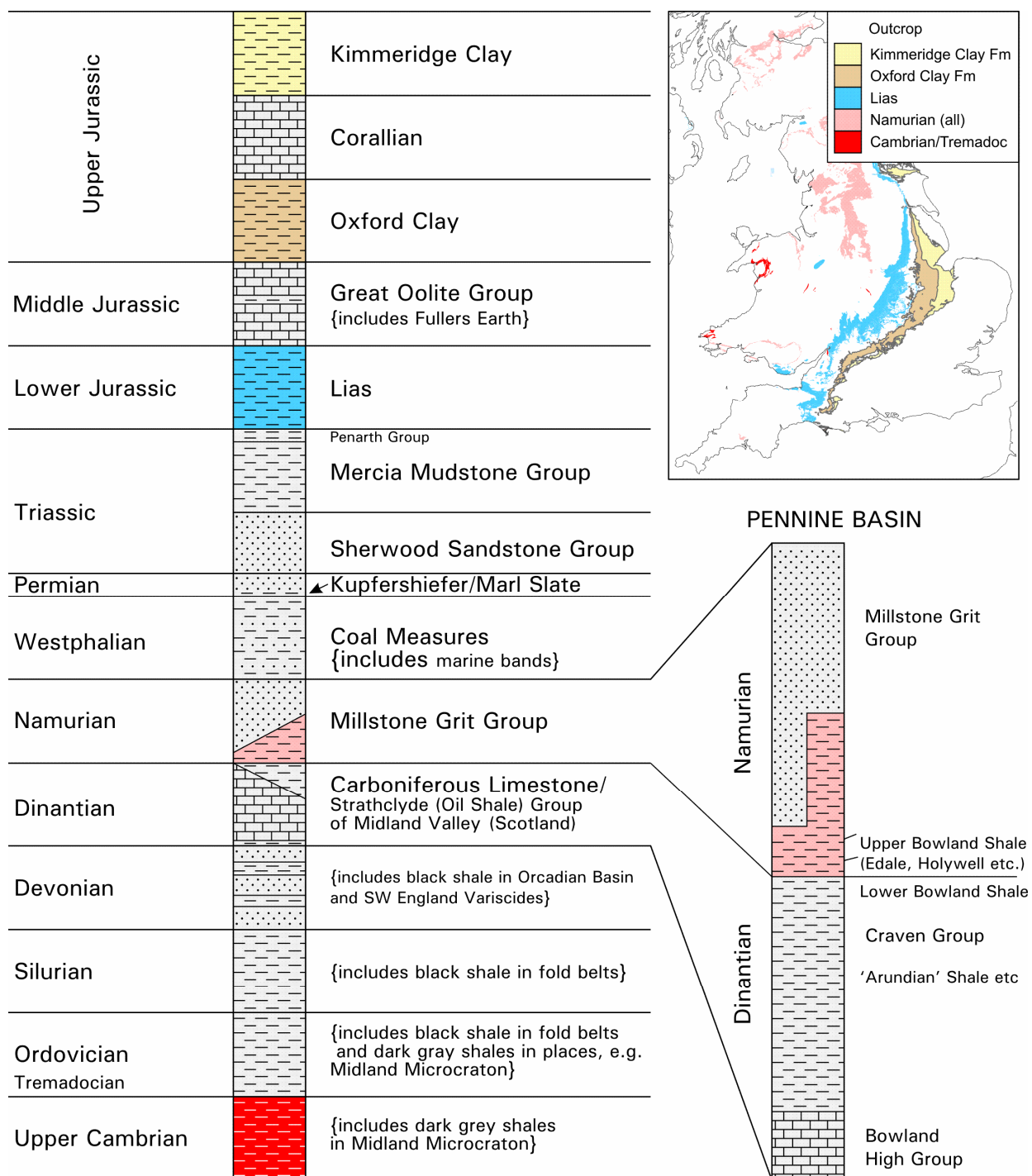


Fig. 9 Simplified UK onshore lithostratigraphy

Precambrian formations

Precambrian non-metamorphosed rocks occur in the English Midlands, but they are largely dominated by red beds or volcanoclastics and are considered unprospective here. These volcanoclastics are fossiliferous at outcrop at Charnwood, so it is not impossible that less oxidised sections with lower amounts of volcanoclastics occur at depth elsewhere in the UK.

Cambrian formations

Dark grey and black Cambrian shales in North Wales include the Menevian Shales (100 m thick), the Penrhos Member slates (350 m thick), and the Black Band within the Dolgelley Beds (Smith & George 1961). At outcrop in the Welsh Borderland there is evidence for high organic content in Upper Cambrian shales (Smith *et al.* 2010), although they are probably overmature for conventional hydrocarbons here and where concealed to the east and south. The Early Cambrian acritarch alteration index is 4-5 (wet gas) in the Withycombe Farm borehole (Fig. 5, S Molyneux, pers. comm.).

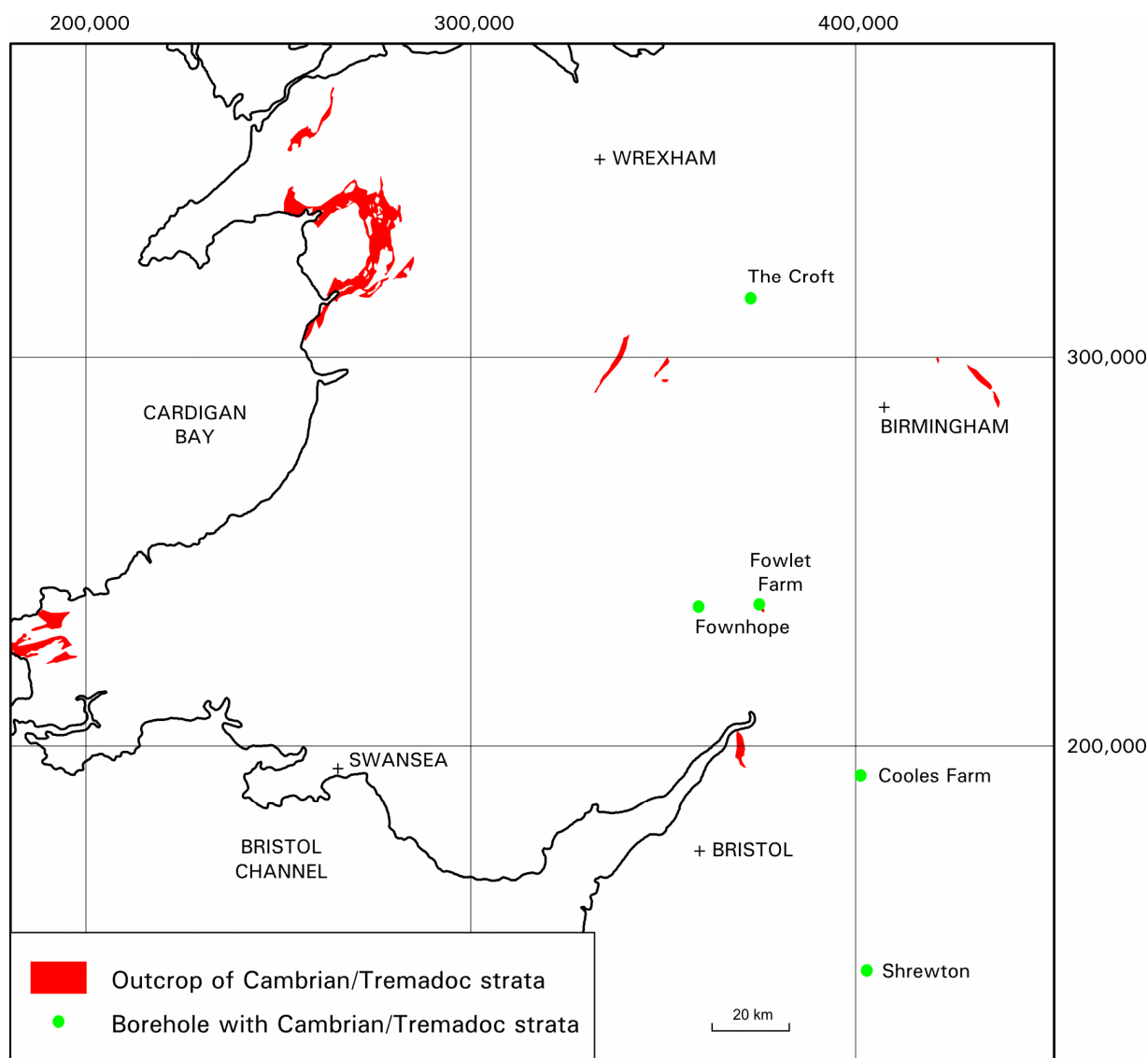


Fig. 10 Cambrian and Tremadoc outcrop. Many very small outcrops are not shown.

Ordovician formations

In addition to the Tremadoc and Caradoc shales discussed below Leggett (1980) recorded black shales within Arenig- to Llandeilo-age Welsh sequences in the Carmarthen-Pembroke area.

Tremadoc

Tremadoc shales are widespread and thick on the Midland Microcraton (Smith & Rushton 1993), but are lean where analysed and without high gamma values where drilled (Smith *et al.* in press). Tappin & Downie (1978) recorded dark grey, thinly laminated, cleaved Tremadoc shales in core offshore of Tenby, south Wales, so parts of the Midland Microcraton and outer Variscides may contain a relatively organic-rich facies.

At outcrop near Merevale in central England and in well samples at Shrewton in the Wessex Basin (Fig. 5), Tremadoc shales have a maturity of 1.3-2.6 $V_R\%$ equivalent (Smith 1993). Equivalent shales are also present in the outer Variscan zones under the Weald and Wessex basins (Smith 1985). In the Shrewton well between 1,743 and 2,073 m depth, these shales have poor TOC values (0.20-0.38 %). Underlying Cambrian shales may be a potential target at the southern end of the Palaeozoic Worcester Graben.

Tremadoc gas shows

Calvert well in Buckinghamshire (Fig. 5) discovered gas in 1911 over a 13.3 m interval in probable Tremadoc-age non-black strata. Although the well was deepened and another well drilled farther east, there were no further signs of gas. The gas composition was reported to be high in nitrogen and in ethane, though this may be incorrect. Another sub-economic gasfield was found by BP to the north at Twyford (Fig. 5) in porous Late Triassic, Penarth Group strata directly overlying Tremadoc shales. This gas also had high nitrogen content, but no ethane. Brunstrom (1966) and Oswald (1996) noted the presence of helium in this gas. The most likely source for the gas may be Westphalian strata in Oxfordshire to the west, rather than from Tremadoc shales. Helium and nitrogen do not rule out a coal source, although high ethane values are relatively unusual for a coal source.

Caradoc

The Caradoc-age Nod Glas Formation and underlying beds of N Wales are up to 400 m thick and contain jet-black shales (Smith & George 1961). Equivalent Caradoc black shales lie unconformably on Precambrian strata in Shropshire, indicating a transgression which penetrated at least the NW margin of the Midland Microcraton. This is the only post-Tremadoc-age Ordovician interval to be present on the Midland Microcraton (Smith 1987).

Ordovician to Silurian formations

The lead mine at Van in mid Wales (Fig. 11) encountered methane, water and hydrogen sulphide in Ashgill- and Llandovery-age mudstones, beginning about the year 1865 and culminating in an explosion in 1908 (Hughes 1991).

Silurian formations

Silurian shales appear to be lean on the Midland Microcraton, based on their geophysical log character. Surface or subsurface geochemical sampling is needed here. Silurian samples on the margin of the Weald Basin gave low TOC, P1 and P2 yields. Graptolite reflectance and conodont alteration indices suggest oil window maturity in the Welsh Borderland and higher maturity in the Welsh Basin. Velocity data (used as a proxy for maturity) suggest a similar pattern for Silurian shales in the East Anglian Caledonides.

Leggett (1980, Fig. 11) illustrated the distribution of hemi-pelagic black Llandovery-age (Early Silurian) shales in central Wales. The graptolitic basin facies of the Ludlow (Late Silurian) in the Clun Forest area may have some shale gas potential (Earp & Hains 1971, fig. 35) – most of this sequence is described as grey in colour, with slumped and turbiditic beds. None of the Silurian basin facies rocks have been drilled or logged except at Glan Fred (Fig. 5).

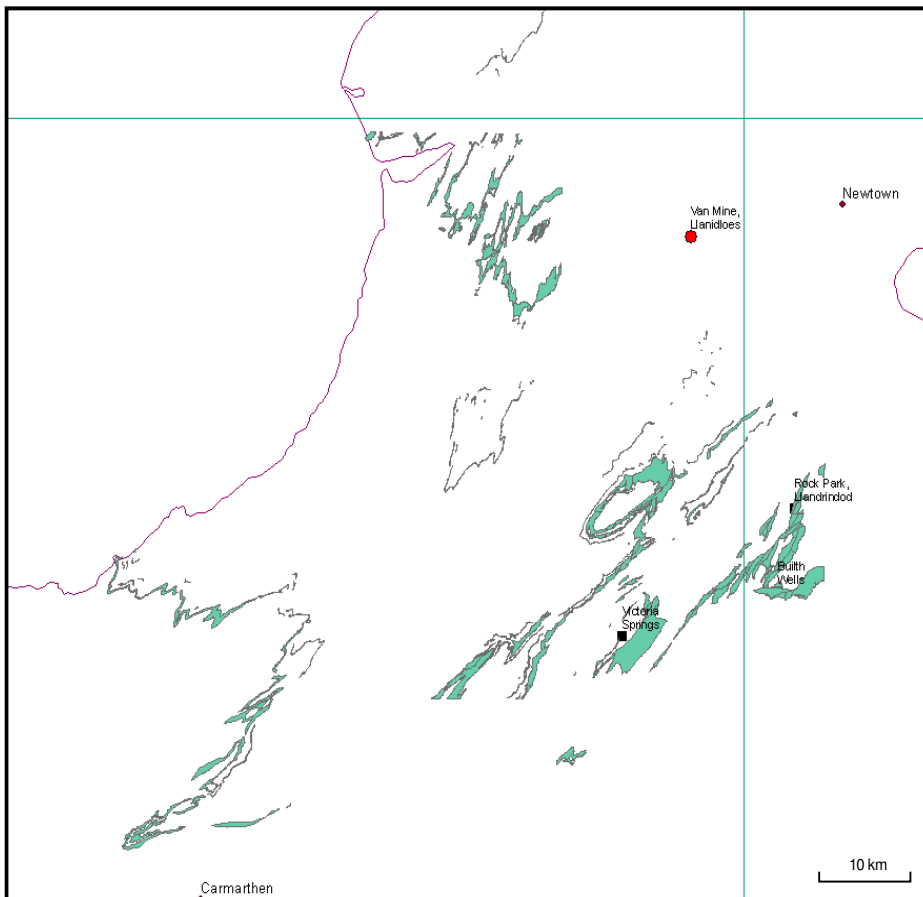


Fig. 11 Silurian hemi-pelagic mudstones in Wales. NB Abrupt terminations reveal areas where not mapped in detail. Red dot signifies gas shows at the Van lead mine, black squares indicate springs with hydrogen sulphide.

Devonian formations

Orcadian Basin

Lower and Middle Devonian clastic sediments unconformably overlie metamorphic basement in the Orcadian Basin (northern Scotland) of Caithness, Orkney and Shetland islands. The Middle Devonian sediments include 180 m of rich, mature lacustrine source rocks (Eday Marls), which accumulated in Lake Orcadie. These have been thoroughly studied because various geochemical data suggest their source rocks have contributed to fill of the Beatrice Oilfield (Bailey *et al.* 1990).

In Orkney the average TOC of the Devonian is 1.4% (Marshall *et al.* 1985). Within this succession the Lower Stromness Flagstones have TOC values over 6%, whereas the Sandwich Fish Bed (20 m thick) and Upper Stromness Flagstones have an average TOC of 2.3%. A Permanent Lake facies occurs in cycles about 1.5 m thick, repeated 108 times. The potential source rock is therefore dispersed between less promising sediment within a total thickness of over 800 m. The organic matter is Type II, derived from cellulose of land plants. However, the Devonian strata here are only marginally mature for oil generation in Orkney (Hillier & Marshall 1992) and are hence unprospective for shale gas.

Towards the centre of the Orcadian Basin, the Devonian sequence exceeds 4,000 m in thickness. Based on offshore data, this sequence may locally include significant thicknesses of Lower Devonian lacustrine shales, with possible shale gas potential.

Devonian rocks of SW England Variscides

Sequences of basinal shales occur at various intervals within the Devonian strata of south-west England. Their TOC values are unknown, but their maturity is suspected to be probably within the dry gas window. Nevertheless, their involvement in the Variscan orogeny renders these Devonian strata unattractive as primary shale gas targets.

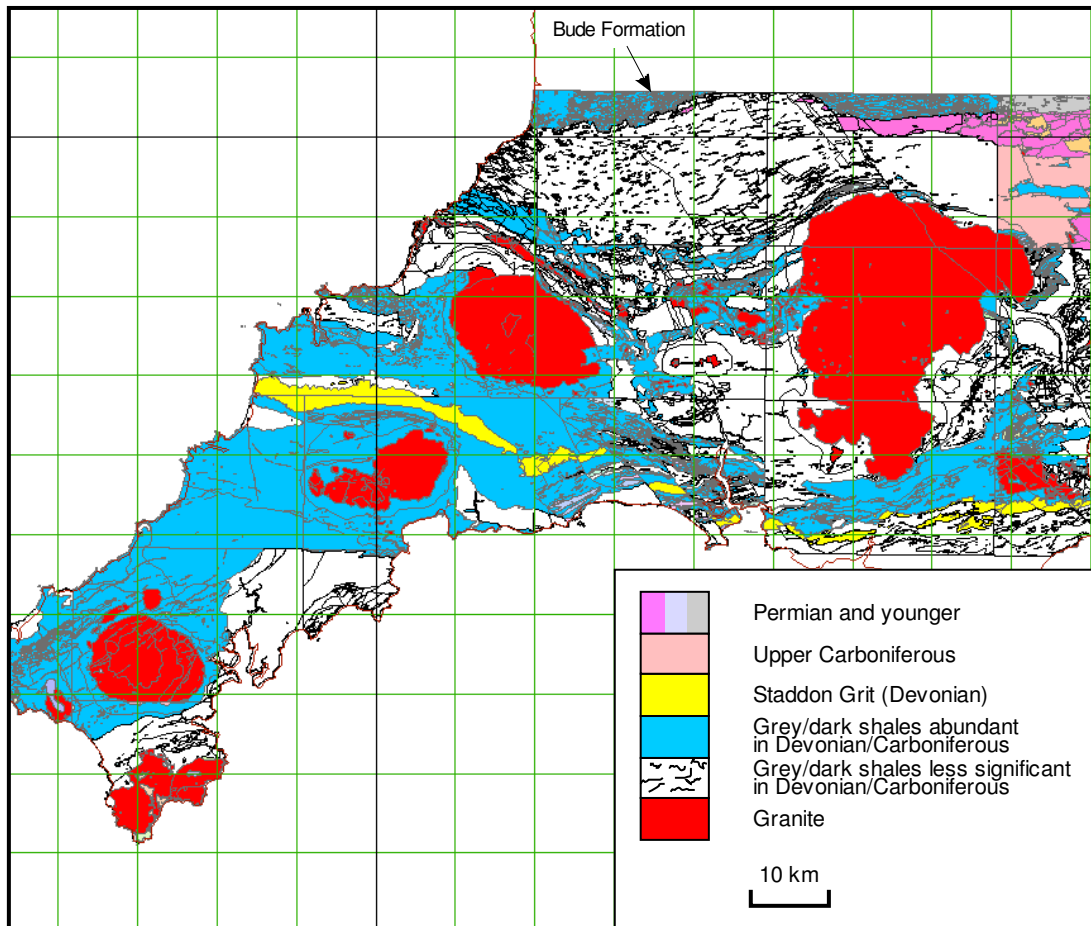


Fig. 12 SW England Devonian and Carboniferous formations. The Devonian black shales dip north beneath the Carboniferous Culm, north of the granites. Though not been proved in any boreholes there, they are also likely to be present at depth beneath the Wessex Basin, east of this map.

4. Shale gas prospectivity – UK Carboniferous to Triassic shale formations

Lower Carboniferous shale formations

Early Carboniferous Strathclyde Group: former Oil-Shale Group of Scottish Midland Valley (West Lothian)

Several oil-shale intervals in a 670 m sequence within the Strathclyde Group were extensively worked for hydrocarbons between the years 1850-1962 (*e.g.* Carruthers *et al.* 1927). These source rocks are immature for oil at crop in the oil-shale fields, but they display free oil adjacent to sill intrusions that have increased their maturity. An interval termed Houston Marls tested 330 mcf/d gas in BP Salsburgh 1A well (Fig. 5) at about 850 m downhole. Unfortunately the well was not logged to TD so the identification of oil-shales in the well was derived only from cuttings.

Tournaisian Lower Limestone Shale (now Avon Group)

Occupying the South Wales Variscan foreland basin, the earliest Carboniferous Lower Limestone Shale may have some shale gas potential. It is generally black in South Wales, but at Cannington Park borehole south of Bristol Channel (Fig. 13) it comprises dark grey mudstones interbedded with thin limestones. In this borehole it is tectonised, with steep dips, overturned, much fractured and veined and is hence probably non-prospective. Total organic carbon data is needed for the less tectonised South Wales sequence, but the vitrinite reflectance is high (over 3.5%). The same formation evidently extends eastwards beneath the Weald Basin, but detailed sampling has only been made at Warlingham borehole (Fig. 5), where the formation is 34 m thick and consists of dolomitic siltstone and dark grey shelly mudstones (Worssam & Ivimey-Cook 1971).

Topmost Dinantian Upper Limestone Shales (Oystermouth Formation) to Early Namurian Marros Group (lower part)

Together equivalent to the Lower and Upper Bowland Shales of the Pennine Basin, these formations of the South Wales-Bristol Basin offer high gamma shales, but are interbedded with thick sandstones and underlain by limestones in Maesteg borehole (Fig. 5). In Ashton Park borehole (Fig. 5) thin high gamma ray shales, with pyrite, phosphates, fish debris, cherts and a marine fauna are present, interbedded with sandstones. If these shales thicken to the south, which is likely, and maintain their high gamma ray characteristic they could provide a realistic shale gas target.

Although perhaps having no relevance to shale gas prospectivity, the tectonic morphology of the South Wales-Bristol Basin (Fig. 13) is remarkably similar to, but much smaller than the Fort Worth Basin (USA) containing the Barnett Shale. Both are foreland basins, with aulacogens intervening perpendicular to an adjacent fold belt (Smith *et al.* in press). However, the UK's Lower Carboniferous shales rest conformably on Upper Devonian strata, whereas the Barnett Shale lies unconformably on Lower Palaeozoic rocks. The South Wales-Bristol Basin thickens toward the fold belt, whereas the Barnett Shale thickens towards the aulacogen.

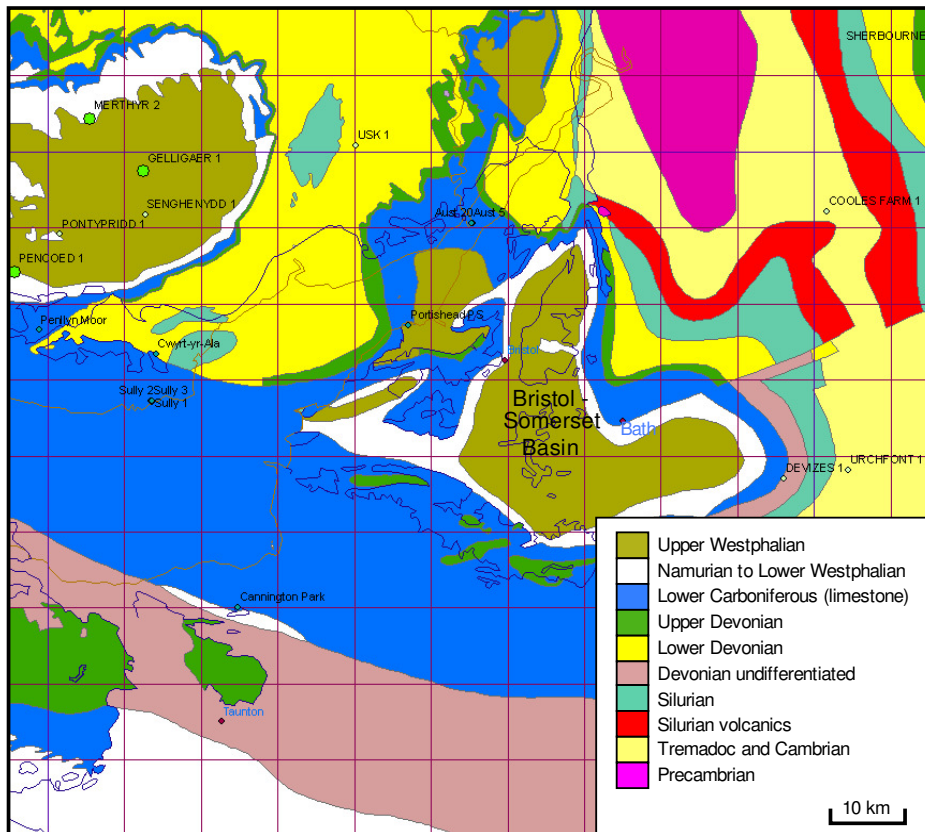


Fig 13 Bristol-Somerset Basin, wedged between Variscan Front thrust (to south) and Worcester Uplift. The Variscan Front bisects the Bristol Coalfield near Bath and affects the southern end of the Worcester Uplift.

Carboniferous of Pennine Basin – Lower Bowland Shale (Widmerpool Formation, Worston Shale, Arundian Shale etc of Dinantian age)

Dinantian shales are often present on upstanding structural blocks in northern England (e.g. Rossendale) as thin developments within a largely limestone sequence, but they expand considerably into adjacent half graben sub-basins of the Pennine Basin (Kirby *et al.* 2000, Smith *et al.* 2005). These shales do not have the high gamma signature of, and are hence less prospective than, the overlying Upper Bowland Shale.

Carboniferous of Pennine Basin – Bowland Shale Group of early Namurian age

The Early Namurian shale units (local names Bowland, Edale, Holywell shales, top part of Craven Group) of the Pennine Basin offer the best potential for shale gas exploration in the UK because they have sourced hydrocarbons, and have high TOCs (Armstrong *et al.* 1997). These shales are more widespread than the Dinantian-aged shales, because they were deposited as the extensional half graben subsidence was transforming to a more regional thermal subsidence.

Bowland Shale Group (Namurian)

Bowland Shale Group – Total Organic Carbon (TOC)

Namurian marine shales have generally higher TOC values (over 4%) compared to non-marine shales (Spears & Amin 1981), which have an average value of around 2% (Fig. 14).

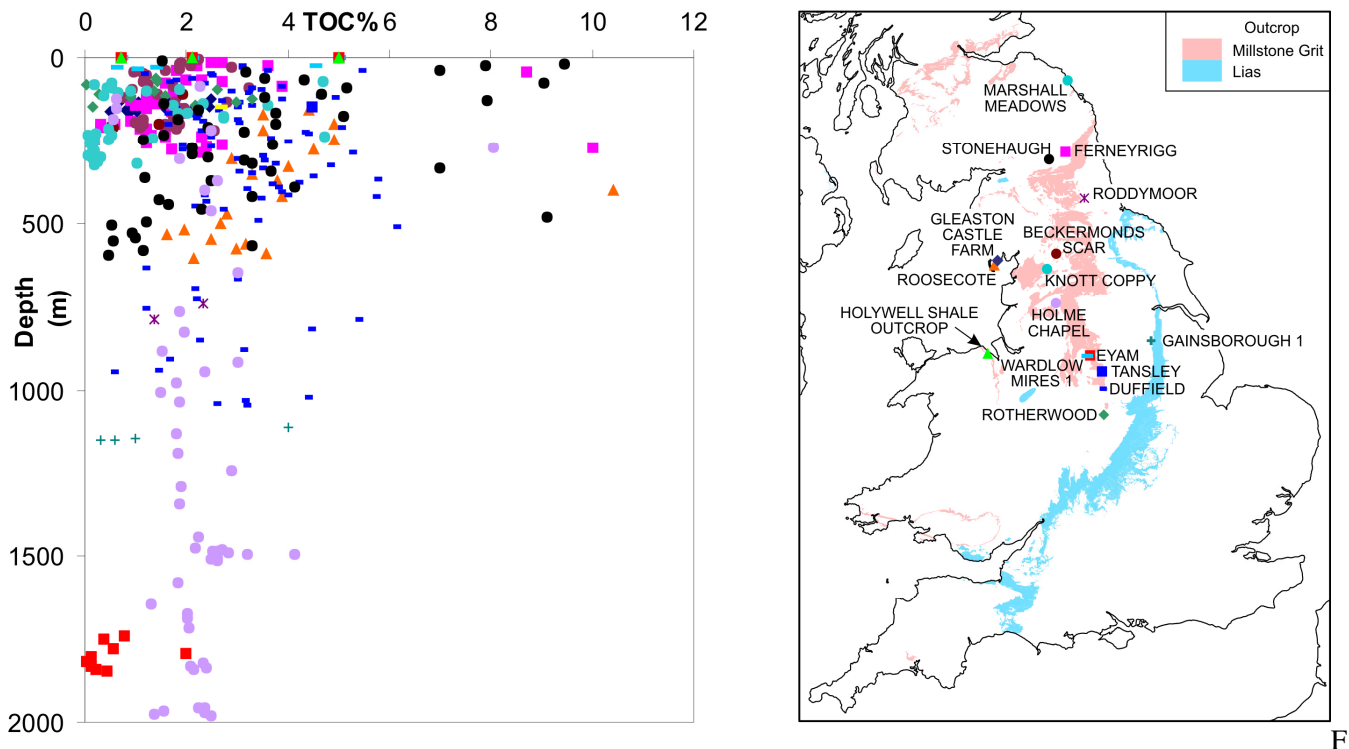


fig. 14 Variation of TOC contents in Carboniferous boreholes from northern England. Gleaston borehole is in south Cumbria; Ferneyrigg, Stonehaugh and Marshall Meadows are in the Northumberland Trough, Roddymoor is on the Alston Block, Beckermonds is on the Askrigg Block, and all other boreholes are in the Pennine Basin.

Maynard *et al.* (1991) found that two thin Namurian black shale marine bands had a TOC content of between 10-13%, whereas values within interbedded strata ranged between 2 and 3%. The Namurian Holywell Shale, source rock for the southern East Irish Sea gas and oil fields and Formby oil field, has TOC values ranging from 0.7-5%, with an average of 2.1% (Armstrong *et al.* 1997). The lower part of this formation has an average of 3% TOC with pyrolysis yields of 7 kg/tonne⁻¹. These values are comparable with producing US gas shales.

Bowland Shale Group – Thermal Maturity

There is no agreement on the lower limit of maturity for gas generation, which has variously been put at 2% R_o (Landes 1967), 3% R_o (Dow 1977), 3.2% R_o (Dow & Connor 1982) and 5% R_o (Hood *et al.* 1975). In this study a value of 1.1% R_o has been used to differentiate maturity levels above and below the gas window (Fig. 15), because this value defines the maturity limit for the Barnett Shale in the American Newark East gasfield (Pollastro *et al.* 2004). A number of papers now put the floor for shale gas prospectivity at R_o 3.5%, and it will be interesting to see if this theoretical limit is tested in any of the developing plays worldwide.

Vitrinite reflectance (% R_o) measurements at outcrop and in boreholes provide a widely accepted proxy for thermal maturity and hydrocarbon generation. These are shown for the nearest value analysed to the basal Namurian (Fig. 15). The orange and red symbols show boreholes drilled in sub-basins where the gas window is present (Cheshire Basin SE of Milton Green, Gainsborough 2 in Gainsborough Trough). A vast area with no data probably also lies in the gas window, for example between Trumfleet and Weeton (Fig. 5) and in the subsurface of the Craven Basin and its adjacent West Lancashire Basin. The Widmerpool Gulf is defined by the white area SW of Duffield (Fig. 15), where there is no drilling. Duffield borehole (Fig. 5) lies within the oil window but lies north of the basin depocentre. Most of the Cleveland Basin is within the gas window, with the southern line of gas fields (*e.g.* Kirby Misperton) at a lower level of maturity on the crests of structures. The large area to the south of these fields has thick, subcropping Coal Measures (Smith 1985), with no deep wells, but is probably also within the gas window.

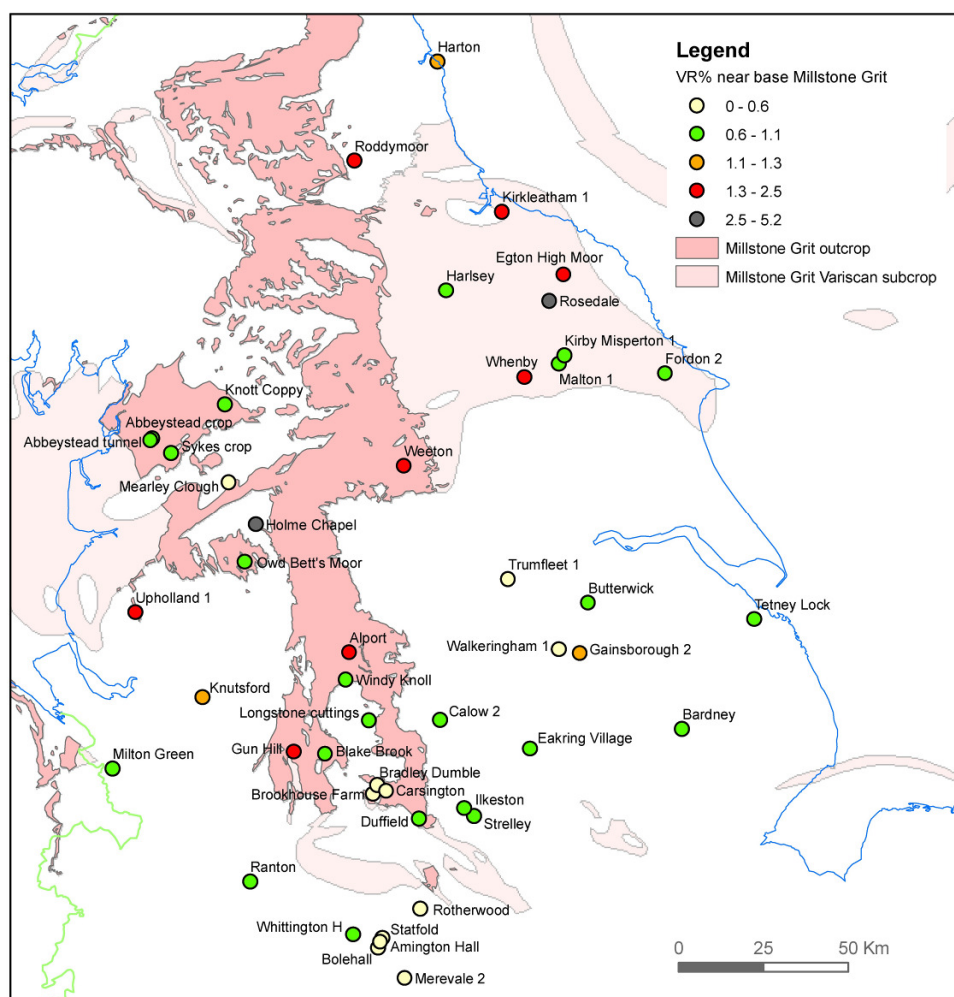


Fig. 15 Maturity of wells in Pennine Basin (see text for details)

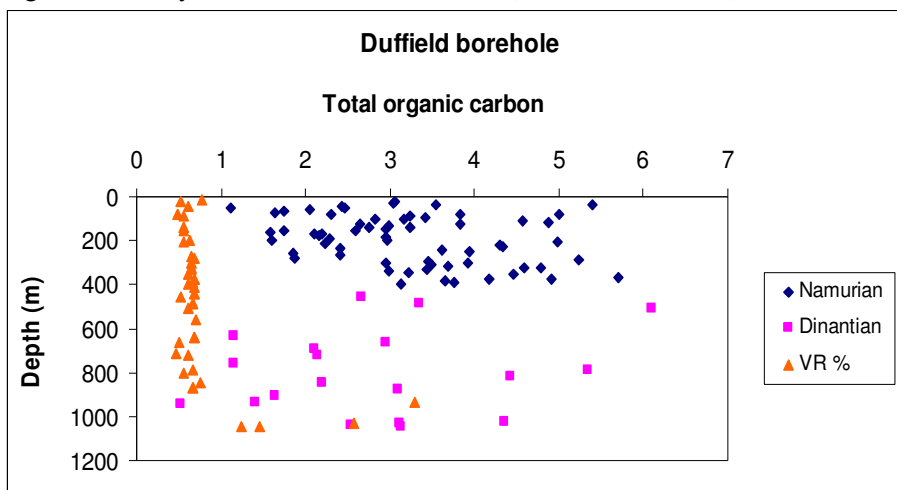


Fig. 16 Range of total organic carbon contents and vitrinite reflectance in the BGS Duffield borehole, Widmerpool Gulf (Fig. 5). The high $V_R\%$ near the base of the borehole is caused by proximity to igneous sills – these may lead to gas window maturity near or below terminal depth.

Bowland Shale Group – Porosity, Permeability and Fracture Porosity

There is no porosity data available for Pennine Basin Namurian shales. From BGS boreholes in the southern Midlands, porosities of 5-10% appear to survive to depths of over 900 m in Upper Palaeozoic shales (Poole 1977,

1978). Upper Carboniferous Coal Measures mudstones, seat-earth and siltstones have measured permeability values in the range 4.34×10^{-6} to 7.1×10^{-3} mD (Oldroyd *et al.* 1971).

Joints, developed in the limestone platforms of Derbyshire and the Askrigg Block (Moseley & Ahmed 1967), are predominantly sub-vertical and perpendicular to bedding. Joint development preceded the main phase of movement on the main fault zones and they are frequently mineralized. Well-bedded marine shales between these limestones tend to have a high joint density, in contrast to mudstones and sand-rich shale units. Minor joints are more difficult to distinguish in argillaceous rocks, but master joints persist strongly with a high fracture density (0.6-3 m spacing).

The predominant NW trend of the main Carboniferous joint sets is coincident with the present day maximum horizontal stress direction (145/325°, Evans & Brereton 1990). Rogers (2003) predicted that the stress-induced fracture permeability is likely to be highest along this trend in the current UK stress field.

Bowland Shale Group – Mineralogy

The Al₂O₃ content of UK Carboniferous mudstones ranges between 12-38%, with an average of around 25% (Ramsbottom *et al.* 1981). Marine and non-marine shales in the Tansley borehole (Fig. 5) have average Al₂O₃ contents of 20.6% and 17.9% respectively, with clay minerals making up 59% and 56% of the shale matrix (Spears & Amin 1981). The Barnett Shale has a relatively low clay content (c. 27%, Jarvie *et al.* 2004) compared to other gas shales. The presence of significant amounts of quartz (45%) and carbonate (10%) in the shale matrix, imparts brittleness to the rock, facilitating artificial fracturing.

Bowland Shale Group – Associated Gas Fields and Discoveries

The presence of conventional gas fields in UK Carboniferous basins (Fig. 4) demonstrates that gas has been generated. In a few cases there is unambiguous evidence of the source being Namurian shales (*e.g.* the Elswick Gasfield in the West Lancashire Basin, Fig. 3), because Coal Measures are absent in the subcrop (Smith 1985). In some gas fields migration could have occurred from either a Coal Measures source or from Namurian strata uplifted in an inverted basin (*e.g.* Nooks Farm, Fig. 5). Along the southern margin of the Cleveland Basin (Marishes to Malton gas fields, Fig. 4) migration along E-W faults from the Southern North Sea, is also a possibility.

Gas wetness (percentage of non-methane gas) values (Smith *et al.* in press, fig. 10) are high when gas is associated with oil in the source rock, and lower (<5%) when the gas has been exclusively derived from coal-rich strata or is biogenic or overmature. Jarvie *et al.* (2004) typified two gas samples in the Barnett Shale as overmature dry gas, with gas wetness values of around 5%; in contrast oil associated gas had values over 12%. In the Carboniferous of the UK, high gas wetness values measured at Welbeck Colliery are associated with oil shows, but at nearby Thoresby Colliery (also associated with oil) the gas is rich in methane and was probably sourced from the Coal Measures (Challinor 1990).

In most UK gas fields there are insufficient gas composition and carbon isotope data available to resolve the migration directions. Carbon and hydrogen isotope data from methane samples accompanying water flows within Wyresdale Tunnel (Fig. 15, the methane caused the Abbeystead explosion in 1985) in Namurian strata (Smith *et al.* in press, fig. 7) suggest that the gas either had a modern biogenic origin or formed through CO₂ reduction. The US Antrim Shale and New Albany Shale (Smith *et al.* in press, fig. 7, Illinois Quaternary-hosted gas) have late generation biogenic gas systems related to glacial meltwater ingress via fractures (Schurr & Ridgley 2002). US exploration has used stable isotopes to confirm source, maturity and hydrocarbon generation zone. In the UK we need to apply these methods to resolve the source of already discovered fields and shows.

Wherever present, the Upper Bowland Shale is an attractive prospect because high gamma shales are present together with other shale-dominated facies. The gross thickness of the formation ranges from 0-300 m (Fig. 17). The organic rich, net thickness is defined by gamma values greater than 180 API and ranges between 0-110 m thickness. Other shales need to be mapped in the same way, in the overlying Namurian and underlying Dinantian successions. The Dinantian half graben basins (Fraser *et al.* 1990, Fig. 18) indicate the areas where basin-centred prospects exist.

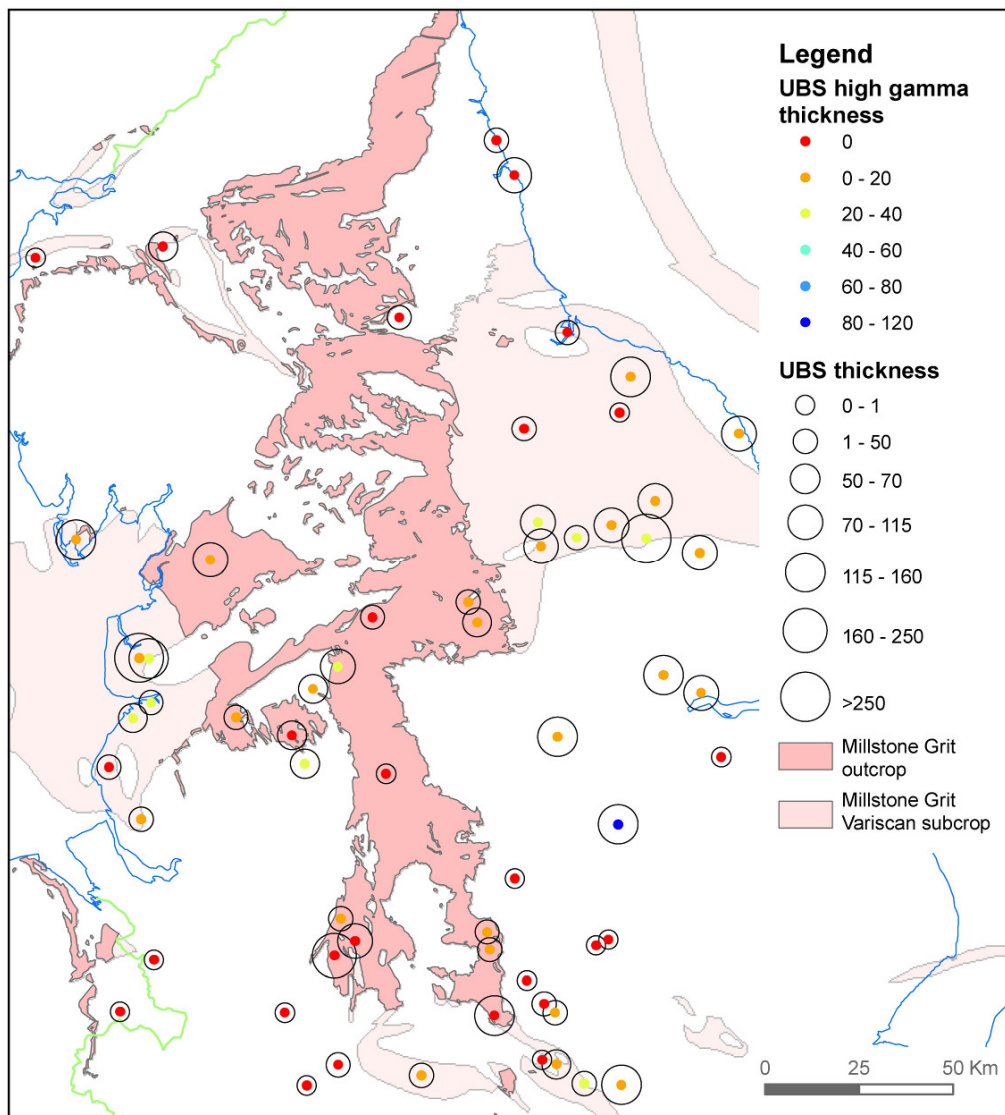


Fig. 17 Gross thickness, and thickness of high gamma facies in the Upper Bowland Shale (Namurian part only). Black circles show gross thickness (metres) and coloured circles show thickness of high gamma shales in metres.

On their website, Island Gas (<http://www.islandgas.com/uploads/090120doegreenfdp.pdf>) report that they have assessed their shale gas prospects at deeper levels than their current coal-bed methane exploration as potentially containing 3,823 bcf shale gas within 1,195 km² of their Point of Ayr licence. This prognosed shale gas is contained within Holywell Shales (Upper Bowland Shale equivalent) with an average thickness of 250 m, and with an average TOC of 2.1%.

Carboniferous of Pennine Basin – Northumberland and Stainmore Troughs

The Northumberland and Stainmore Trough basins may have some shale gas potential, because their TOC contents are high in a largely gas-prone facies. Shale units within the late Dinantian to early Namurian Yoredale and earlier formations in these basins tend to be thin. A possible tight gas play was indicated by the Errington well and it is likely that thicker, perhaps shalier sequences occur off-structure, *e.g.* against the Stublick Fault.

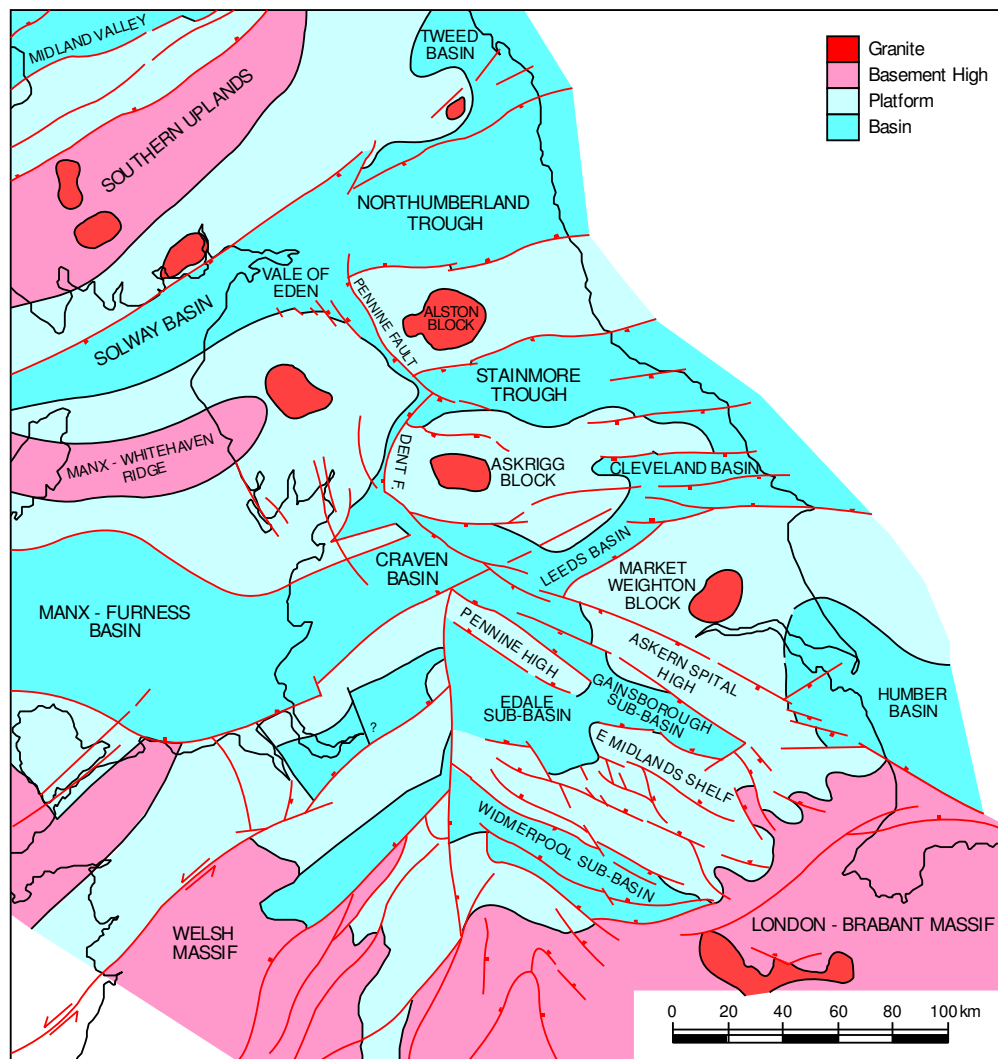


Fig. 18 Carboniferous basins of central Britain, adapted from Fraser *et al.* (1990, fig. 4)

Carboniferous Culm of SW England

The early Westphalian Bude Formation includes dark mudstones with graded sandstones, interpreted to have filled a large equatorial lake, but it is strongly tectonised. Organic carbon contents vary from 0.5-2.9% and there are thin marine bands (Higgs 1991).

Permian formations – Kupferschiefer/Marl Slate

Although very thin, this basal Upper Permian unit has a very high organic content and high metal content. Marl Slate samples in Durham (Hirst & Dunham 1963) show that organic matter and molybdenum, copper and nickel are positively correlated.

Triassic formations

Almost all UK Triassic formations are strongly oxidised. The Westbury Formation in the uppermost Triassic Penarth Group is a black shale that might have some potential if it weren't immature for oil, even in the Bristol Channel margins (Macquaker *et al.* 1986).

5. Shale gas prospectivity – UK Jurassic shale formations

Lias

The Lower Jurassic Lias (Toarcian) of the Yorkshire coast consists of a shale facies containing 40% illite, 30% kaolinite, 25% mixed layer clays and 5% chlorite (Morris 1979). Hallam (1960) distinguished four lithologies within the Blue Lias of Dorset and Glamorgan by their differing carbon contents – its bituminous shales contain from 3.9-7% carbon, its laminated marls 8% carbon, and its other marls and limestone less than 1.9% carbon. Lias oil-shale is present at Kilve on the southern side of the Bristol Channel (Shatwell *et al.* 1924). Both shores of the Channel are immature for oil (Cornford 1986). Though probably lying in the oil window offshore, the Lias is immature for shale gas in all of these areas.

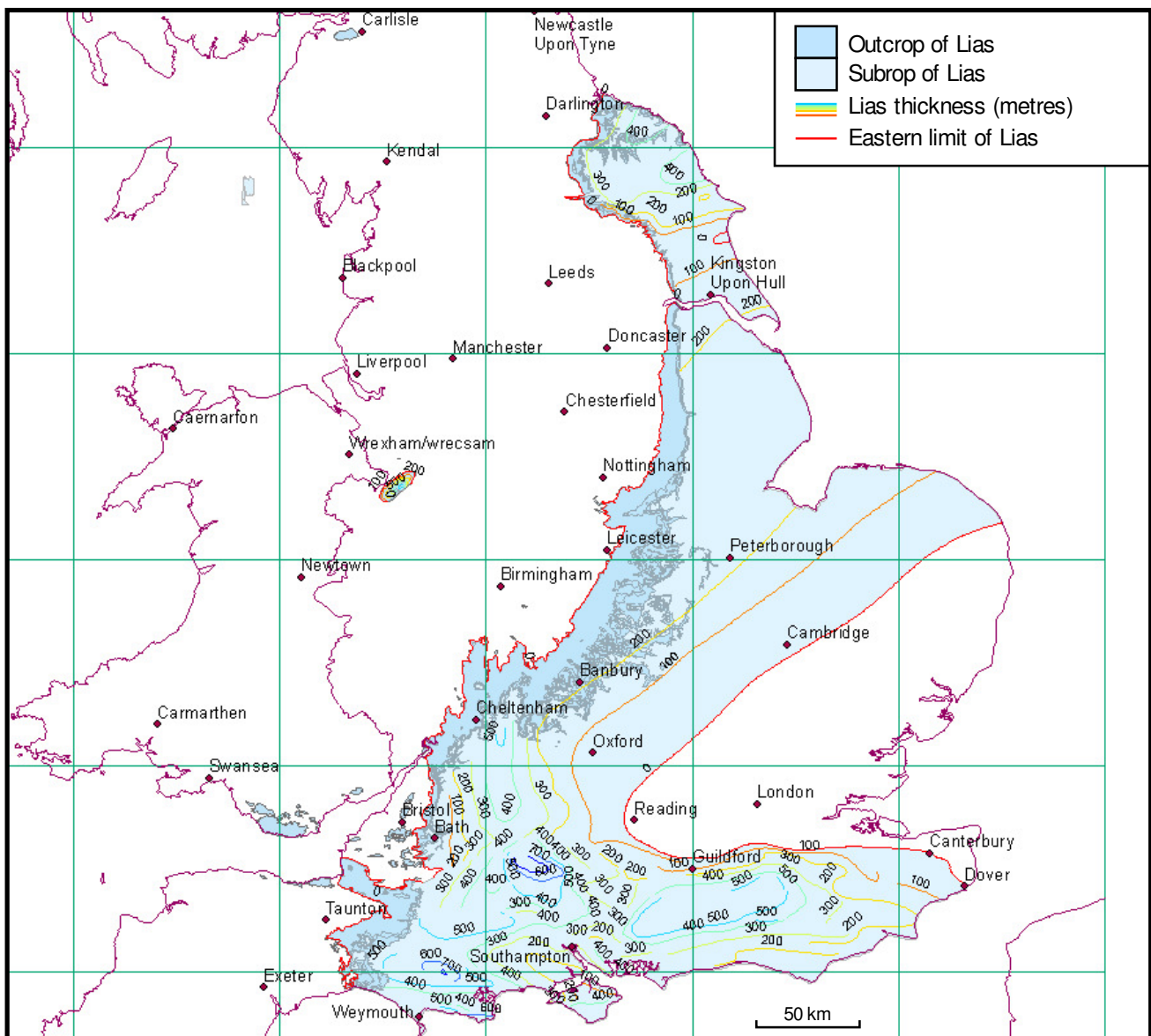


Fig. 19 Outcrop and subcrop and thickness in metres of the Lias in eastern Britain

The Lias is the source rock for the Weald Basin petroleum system and for the Wessex Basin (Ebukanson & Kinghorn 1986), with migration into 3 different reservoirs in Wytch Farm oil field. Colter & Havard (1981)

deduced that the Lias in the Arretton 2 well (Fig. 5) does not show a high gamma profile, and the sampled TOCs are low. The well lies about 50 km east of the probable source of oil at Wytch Farm.

Maturity is low on the former tilt-block highs on the footwall to the syn-sedimentary faults in the Weald and Wessex Basins. In the Cleveland Basin the Lias is within the oil window and there are extensive oil shows but no gas in its iron-ore mines.

In Godley Bridge 1 well (Fig. 5) the Lias downhole gas readings are fairly low, whereas the overlying Fuller's Earth had higher values.

Fuller's Earth

TOC values are good (up to 3.48%) within the Fuller's Earth in the Weald Basin, but it has only reached oil window maturity in the basin's depocentre.

Oxford Clay

Overlying the Great Oolite Group oil reservoir in the Weald Basin, the Oxford Clay is affected by late Cimmerian erosion (Fig. 20) on the tilt block highs, but thickens towards syn-sedimentary faults controlling the half graben within the basins. The Oxford Clay is immature for hydrocarbon generation in the English Midlands, but it is significantly organic-rich to be self-firing in the Fletton brick-making process (Gallois 1979). In the Weald Basin its TOC reaches 7.83% and it lies within the oil window at the basin's depocentre. In southern England and central England there is often a bituminous horizon near the base, but this is absent in Yorkshire (Duff 1975). TOCs average below 2% in the non-bituminous sections but are over 4% in most of the bituminous sections of central England (Duff 1975), where they are immature for oil.

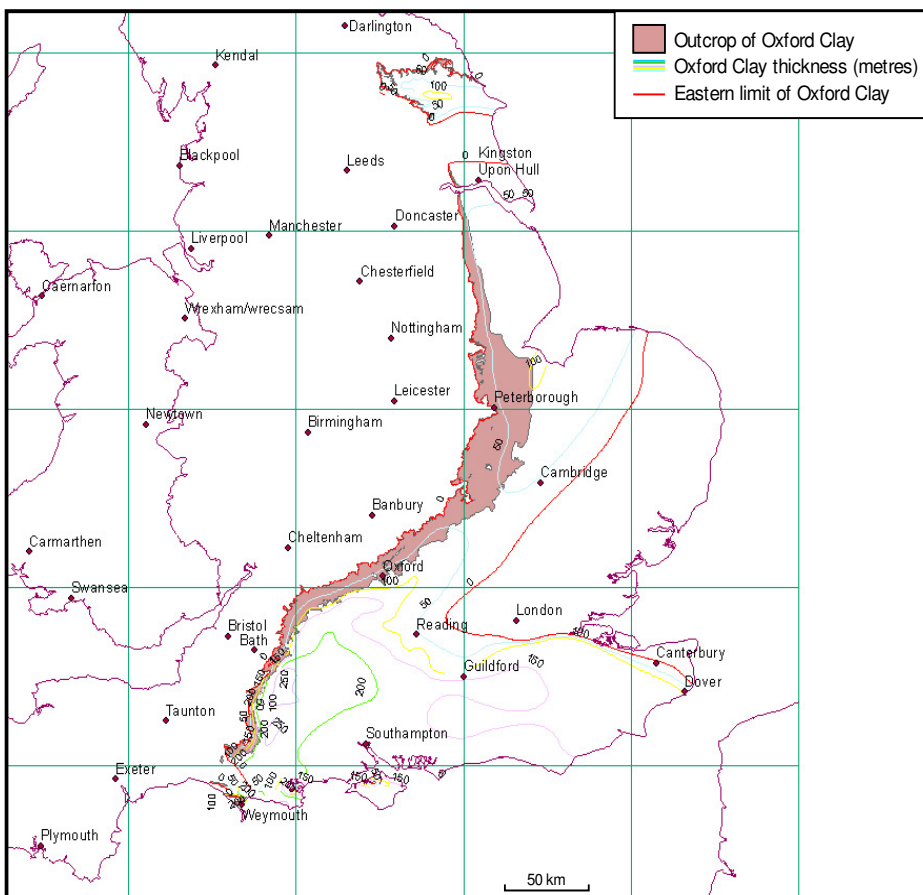


Fig. 20 Oxford Clay outcrop and isopachs in metres (from Whittaker 1985)

Shelly horizons within the Oxford Clay contain free oil in the Wytch Farm Oilfield (Colter & Havard 1981), but this might represent migrated oil.

Kimmeridge Clay

The Kimmeridge Clay Formation of onshore eastern and southern England (Fig. 21) is a potentially prospective shale (for oil and probably biogenic gas) because it contains ubiquitous oil-shale beds (Gallois 1979). Its background shale has TOC up to about 10%, its bituminous shale has TOC values up to 30% and its oil-shales have TOCs reaching 70% (e.g. the Blackstone Bed, Stocks & Lawrence 1990). Five basins show thickening of the formation in response to syn-sedimentary faulting (Weald, Wessex, English Channel, Cleveland and Lincolnshire-Norfolk).

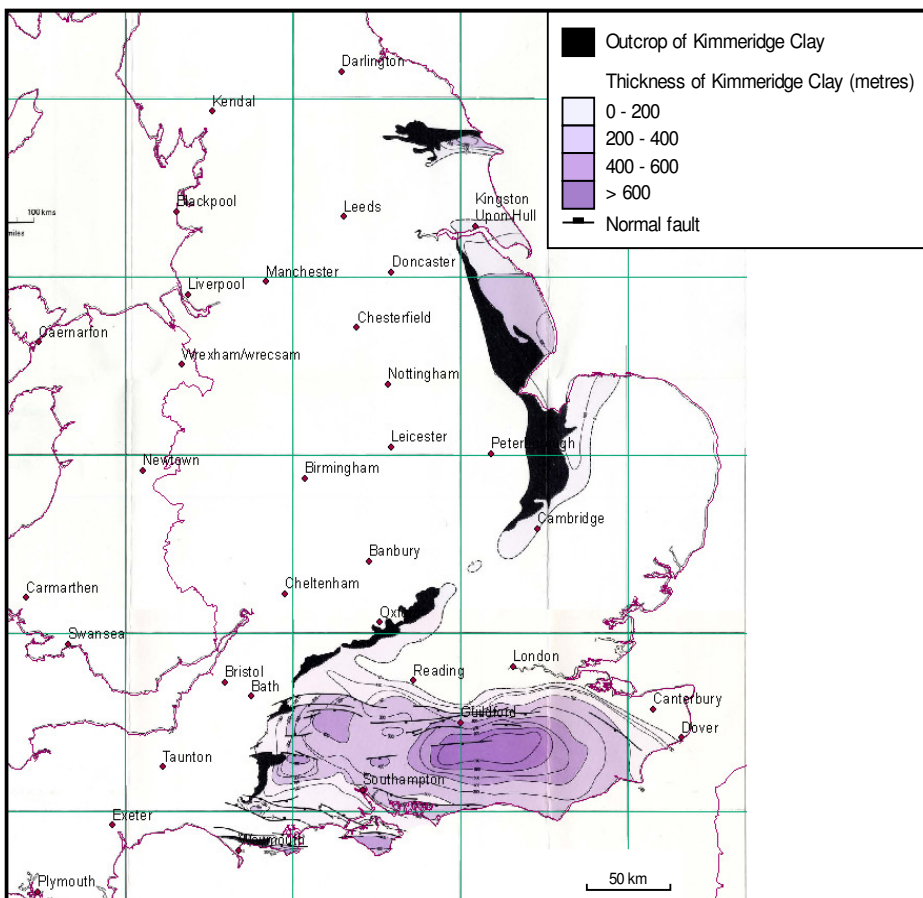


Fig. 21 Kimmeridge Clay outcrop and subcrop. The Kimmeridge Clay is immature in south-east England. Nevertheless it is associated with oil and gas shows, indicating a probable biogenic gas play. Oil-shales have been worked and assessed in Dorset and Norfolk-Lincolnshire. The isopachs are from Whittaker (1985).

The Kimmeridge Clay Formation is immature for thermogenic gas generation onshore (Scotchman 1991) and it is only marginally mature for oil generation in the Weald Basin depocentre. Its carbonate content varies from 12% (oil-shales) to 94% (limestones, Farrimond *et al.* 1984). Scotchman (1991) showed that high TOCs and sedimentation rate result in high phytane/TOC values. The low maturity is confirmed by T_{MAX} 403-437 °C on pyrolysis. Samples confirmed kerogen of Type II or mixed Type II-III on the Van Krevelen diagram (Tissot *et al.* 1974).

Exploration for oil-shale deposits was conducted in Dorset at Corton after World War 1 (Strahan 1920). Similarly, English Oilfields Ltd and the Norfolk Oil Shale Syndicate drilled about 50 wells in an attempt to develop a mining operation on an immature source rock in Norfolk at West Winch and Setch (Fig. 5), with over-optimistic shareholder information becoming confused with scientific statements (Forbes-Leslie 1917a, 1920).

Key stratigraphic boreholes (Swanworth and Metherhills, Fig. 5) were drilled in the Wessex Basin for research purposes (Taylor *et al.* 2001). The sediments encountered are immature for oil generation, with V_R values $< 0.4\%$.

After the first OPEC oil price increase of 1973, twelve additional wells were drilled along the Kimmeridge Clay outcrop of eastern-southern England to assess the thickness, extent and composition of the oil-shales. These wells showed a very condensed section near to the London-Brabant Massif from NE of Swindon to Cambridge (Fig. 21) where the oil-shales are replaced by mudstones and the remaining beds are very thin. Near Swindon a sandy facies is present (Gallois 1979).

Exploitation of these Kimmeridge Clay oil-shale beds was uneconomic because of the thinness of the beds and high sulphur content. This may be overcome by horizontal drilling, and future exploration could be a combination of coal bed methane-type exploration (in relatively thin oil-shale beds), and shale gas exploration in the formation as a whole. The English Channel Basin, particularly south of Purbeck and on the southern Isle of Wight, contains more mature source rocks at all levels than in the area near Wytch Farm oil field (Colter & Havard 1981), because of Alpine inversion.. There are already precedents for deviating wells from the onshore to the offshore (Amoco's Down Barn (Fig. 5) and the Wytch Farm development wells in Dorset) to access the main part of the basin for shale gas.

Kimmeridge Clay – gas shows

Shows of oil and gas were detected in several Weald Basin wells, including Sub-Wealden 1 & 2 (Fig. 5, Pearson 1904). The gas has migrated into reservoir beds (Corallian, Portland, Purbeck and Wealden), but its source is probably Kimmeridge Clay or Purbeck Shales. The gas in the Heathfield wells (Fig. 5) is at various horizons, some sandy but others in thin limestones and shale. As the deeper Lias shales are probably within the oil window at depth here the gas, although relatively wet, is probably biogenic. It is probably not of post-Pleistocene age related to bacteria-carrying meltwater, as in the Antrim Shale of USA, but it has begun migrating since the Alpine anticlines were formed in Miocene times. Southard Quarry well (Fig. 5) discovered gas in an inversion anticline, near to an offshore gas seep at Anvil Point and in well 98/11-2.

Kimmeridge Clay – gas fields

Small gas fields and gas discoveries occur in a line along the northern Weald Basin (Albury, Bletchingley, Lingfield and Cowden), with Godley Bridge, Baxter's Copse and Heathfield fields in the centre and south of the basin (Fig. 5). The Heathfield gas has been used to light its railway station since 1899, producing about 20 mmcf.

Kimmeridge Clay – gas composition

Conventional gas exploration has distinguished between gas associated (with oil) and non-associated gas, the latter deriving mostly from coal-bearing formations. Non-associated gas is characterised as a dry gas (low gas wetness) according to Gadon (1987), but the gas wetness variability (e.g. Southern North Sea Hewett Field gas, assumed to be derived from coals) seems to overlap with associated gas wetness values. Some obvious coal-derived gases do show low gas wetness and it may be that a significant component of Southern North Sea gas is not derived from coal (Lokhurst 1998). This leaves a problem attributing the source to some of the onshore gases discovered. They might have potential for shale gas prospects if it could be shown that they were not derived from coal, but the gas compositional evidence is ambiguous. Many fields and discoveries lie between a coal source on one side and an inverted shale basin on the other side (e. g. Nooks Farm, Ryedale fields of southern Cleveland Basin and Cousland in East Lothian). The Weald Basin wet gases confirm a non-coal source but do not discriminate between other types of source (biogenic or thermogenic). From the work of Scotchman (1991) and others the Kimmeridge Clay is shown to be immature for oil onshore. Therefore the many gas shows within the Kimmeridge Clay or probably derived from it must be biogenic (e.g. Heathfield). Unfortunately there are no stable carbon isotopic analyses available in the public domain to confirm this.

Purbeck

There is also a Purbeck oil-shale (Pearson 1904), at outcrop in the Purbeck Inlier on the Wealden Anticline in Sussex.

6. Environmental concerns

Environmental problems are a likely concern in the UK for shale gas fracturing completions. Whereas with coal bed methane all the (saline) water needs to be disposed of, in shale gas well completions up to a million gallons of water, treated in various ways and containing (ceramic) proppants and resin-coated sands and other chemicals will probably be required initially to fracture the shale and hold the fractures open. Re-fracturing might be expected to be repeated every 4-5 years in successful wells. About a third of the water is returned to the surface. It might be possible to re-use produced water by a recycling process, or to reduce the potential environmental impact by changing the chemicals added, but at the moment freshwater is needed for the fracturing.

Drilling close to urban areas may also pose problems. Similar problems on a smaller scale in the UK were found and solved by BP at Gainsborough Oilfield in 1959, where the field underlies the nearby village, and at Wareham, Dorset where the oilfield underlies the town. The main problem in the UK is that, in contrast to the US, there are fewer or no local people with any vested interest in the success of these projects.

7. Shale oil

Oil-shales are immature source rocks, which have been mined and retorted to release oil, for example in the Midland Valley of Scotland. Oil-shales which lie in the oil window, that is, down-dip of the near surface mines could have potential for production of shale oil. The shale oil could be accessed by the sort of completion techniques used to produce shale gas. Cannel coals (from most of the UK's coalfields) have been used as sources of oil and gas in industrial plants (Strahan 1920).

Conventional source rocks at oil window maturity could be targeted for shale oil. These source rocks could include those lying close to the established oilfields in the East Midlands and Wessex-Weald basins (half-graben basins controlled by syn-sedimentary faults).

Part of the Kimmeridge Bay Oilfield production was said to be derived from fractured Oxford Clay (Evans *et al.* 1998). Kimmeridge 2 well produced a few barrels on DST from sandstones within the Oxford Clay, so this oil is unlikely to be indigenous to the Oxford Clay.

8. Conclusions

Shale gas exploration plays have been described as 'basin-centred'. This term neatly reflects the difference in drilling philosophy between conventional and unconventional plays. Conventional plays drill structural highs near to mature source rocks but unconventional plays need to drill the basin depocentres. For this reason, conventional hydrocarbon wells are not always useful for shale gas exploration because, having been drilled on highs, source rocks in the wells are often thin or absent entirely. New wells specifically targeting shale gas will be needed to delineate the potential.

Shale gas is currently produced in significant volumes only in the US, but that success has raised interest in the UK potential. The untested shale rock volume in the UK is very large, however, prior to drilling, fracture stimulating and testing, it is not clear that UK shales have the right rock properties to exploit for shale gas.

Even if one assumes that the American shale gas producing analogies are valid, many of the operating conditions are different in the UK. In the UK, land owners do not own mineral rights, so there is little incentive to support development, and local authorities must grant planning consent. The US has relatively permissive environmental regulations, low population densities, tax incentives, existing infrastructure, well developed supply chains and access to technology. Cumulatively, these factors mean that it is far from certain that the conditions that underpin shale gas production in North America will be replicable in the UK.

9. References

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