The Carboniferous shales of the Midland Valley of Scotland: geology and resource estimation

Drilling of the first conventional hydrocarbon exploration well in the Midland Valley of Scotland at West Calder in 1919. Crown Copyright, BGS photo number P000061.

British Geological Survey
NATURAL ENVIRONMENT RESEARCH COUNCIL

Department of Energy & Climate Change

Suggested citation:

Monaghan, A.A. 2014. *The Carboniferous shales of the Midland Valley of Scotland: geology and resource estimation*. British Geological Survey for Department of Energy and Climate Change, London, UK.

Requests and enquiries should be addressed to:

Toni Harvey

Senior Geoscientist - UK Onshore

Email: toni.harvey@decc.gsi.gov.uk

Foreword

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

Additional information is available at the Department of Energy and Climate Change (DECC) website. https://www.gov.uk/oil-and-gas-onshore-exploration-and-production. This includes licensing regulations, maps, monthly production figures, basic well data and where to view and purchase data. Shale gas related issues including hydraulic fracturing, induced-seismicity risk mitigation and the information regarding the onshore regulatory framework can also be found on this webpage.

Interactive maps, with licence data, seismic examples, relinquishment reports and stratigraphic tops for many wells are available at www.ukogl.org.uk.

A glossary of terms used and equivalences is tabled at the end of the report.

All of the figures in this report are attached in A4 or larger format; thumbnails are also included in the text for reference.

Acknowledgements

The author would like to thank the many contributors to this report, most notably Ian Andrews[1], Don Cameron[1], Steve Banham[1], Mark Kassyk[1], Mike Sankey[1], Mike Browne[1], Sandy Henderson[1], Kirstin Crombie[1], Chris Vane[3], Vicky Moss-Hayes[3], Chris Gent[3], Mike McCormac[1], Nigel Smith[3], Simon Kemp[3], Ian Mounteney[3], A. Chaggar[3], Toni Harvey[2], Ed Hough[3], Rob Ward[3] and external reviewers Sarah Davies[5] and Kevin Taylor[6]. Paul Butler[4] contributed Section 2.3 (groundwater).

[1] British Geological Survey, Edinburgh, UK

[2]Department of Energy and Climate Change, London, UK

[3] British Geological Survey, Keyworth, UK

[4] Scottish Environment Protection Agency, Stirling, UK

[5] University of Leicester, UK

[6] University of Manchester, UK

Thanks also to Dart Energy Ltd and Reach CSG Ltd for sharing commercial-in-confidence data for incorporation in this study.

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Summary

Following the publication of shale gas resource estimates for the Carboniferous Bowland-Hodder shales in northern England (Andrews 2013) and shale oil estimates for the Jurassic of the Weald Basin in southern England (Andrews 2014), this report summarises the background geological knowledge and resource assessment methodology for a preliminary in-place shale gas and shale oil resource calculation undertaken for the Carboniferous shales of the Midland Valley of Scotland.

Underlying the Central Belt of Scotland from Girvan to Greenock in the west, and Dunbar to Stonehaven in the east is the geological terrane of the Midland Valley of Scotland. It is a fault-bounded, WSW–ENE trending Late Palaeozoic sedimentary basin, bounded by the Caledonide Highland Boundary Fault to the north and the Southern Upland Fault to the south, with an internally complex arrangement of Carboniferous sedimentary basins and Carboniferous volcanic rocks overlying Lower Palaeozoic strata. The interbedded Carboniferous sedimentary and volcanic rocks of the Midland Valley of Scotland form a succession up to locally over 18,000 ft (5,500 m) thick. Potentially prospective Carboniferous shales are buried beneath an area from Glasgow to Edinburgh, to the Lothians, Falkirk, Clackmannan and Fife.

Four Carboniferous stratigraphic units contain organic-rich, variably mature shale at suitable depths for shale gas and shale oil in basins of the Midland Valley of Scotland; the Limestone Coal Formation, Lower Limestone Formation, West Lothian Oil-Shale unit and Gullane unit. Historic coal mine workings are present over some of the prospective area and in those areas abandoned deep workings and shafts within the uppermost Limestone Coal Formation are a few hundred feet (tens of metres) above prospective shale units within this same formation. Conventional oil and gas fields, discoveries and seeps in the Midland Valley of Scotland attest to source rock maturation. The West Lothian Oil-Shale Formation at outcrop initiated the oil-shale industry in the 1850s, with over 100 oil-shale works having operated in Scotland by the turn of the 20th century. This study does not consider oil-shale resources, it estimates shale oil and shale gas potential where shale-bearing rocks are more deeply buried and mature for oil and gas generation.

Mature organic-rich mudstones are stacked in sandstone/limestone/shale intervals up to 9,800 ft (3,000 m) thick, with individual shale units varying in thickness from inches to 160 ft (50 m) The percentage of shale in the succession varies from 0-85%. Lacustrine-dominated facies in the west of the study area pass laterally eastwards to fluvio-deltaic and lacustrine facies, with marine influence varying through time. Organic rich mudstones and oil shales were deposited in ephemeral lakes with anaerobic bottom conditions. Syn-depositional volcanism and post-depositional intrusive magmatism increase lithological complexity within the prospective strata. Faulting is observed on numerous orientations and scales, bounding and within the prospective Carboniferous succession. The relatively complex geology and relatively limited amount of good quality constraining seismic and well data result in a higher degree of uncertainty to the Midland Valley of Scotland shale gas and shale oil resource estimation than the previous Bowland-Hodder and Weald Basin studies.

The total organic carbon content (TOC) of Midland Valley shales is uniformly high (2-6 wt %) throughout the western part of the study area and locally up to 20 wt %. In the east, TOC contents are more variable. A range of kerogen types is indicated with oil-prone Type I and gas-prone Type III being most common, but mixed and Type II kerogen are also present at various levels, consistent with a dominant lacustrine or algal and non-marine source rock with periodic marine influence. Pyrolysis results are scattered, but corrected free hydrocarbon (S1) contents of greater than 100 mg oil/g C suggest that some free oil is present outside the kerogen.

As a result of significant burial, uplift and erosion, Carboniferous shales are mature for oil generation at shallow current-day depths over much of the Midland Valley of Scotland study area, and gas-mature shales occur at current-day depths from about 2,300 ft (700 m) below Ordnance Datum. The current day oil- and gas-mature depths of Midland Valley shales are shallow compared to the UK Bowland-Hodder shales, Jurassic shales of the Weald and many commercial plays in the USA. Locally, maturation is enhanced by igneous intrusion.

The mineralogical compositions of many of the Midland Valley of Scotland samples are considerably more clay mineral-rich and carbonate-poor than typical USA unconventional gas- and oil-producing shales. The average composition is approximately 59% phyllosilicates/clay minerals, approximately 9% carbonate minerals and approximately 32% QFP (quartz, feldspar and pyrite), though there is a great deal of variability. A resource assessment of 'hybrid' plays (low-porosity and low permeability rocks juxtaposed against mature shales) is not within the scope of this report, but could represent an exploration target in the stacked lithology of the Carboniferous, with wells fracturing the brittle layers between the shales. This production method has proven successful in North America (e.g. the Bakken oil system).

Geological and geochemical criteria that are widely used to define a successful shale oil and shale gas play can be met in the Midland Valley of Scotland. The total volume of potentially productive Carboniferous shale in the Midland Valley of Scotland was estimated using a regional-scale 3D geological model generated using seismic mapping, integrated with borehole, coal mining and outcrop information. This gross volume was then reduced to a net mature organic-rich shale volume using oil and gas maturity-depth maps, percentage shale maps and TOC> 2% maps. This volume was truncated upwards by using a depth cut-off related to a vertical separation from abandoned deep coal mines. The resource estimates presented as headline figures are the best technical case of exploitable oil- and gas-in-place. A sensitivity test at 1,000 ft (305 m) depth cut-off was also examined.

The volumes of potentially productive shale were used as input parameters for a statistical calculation (using a Monte Carlo simulation) of the in-place oil and gas resource (see Appendix A). This study offers a range of total in-place oil resource estimates for the Carboniferous shale of the Midland Valley of Scotland of **3.2 - 6.0 - 11.2 billion bbl** (421-793-1497 million tonnes) (Table 1). Total in-place gas resource estimates are **49.4 – 80.3 – 134.6 tcf** (1.40 – 2.27 – 3.81 tcm). The West Lothian Oil-Shale unit makes the largest contribution to this estimated resource.

	Total gas in-place estimates (tcm)			**Total gas in-place estimates (tcf)**		
	Low (P90)	Central (P50)	High (P10)	Low (P90)	Central (P50)	High (P10)
Shale gas	1.40	2.27	3.81	49.4	80.3	134.6
	Total oil in-place estimates (million tonnes)			**Total oil in-place estimates (billion bbl)**		
	Low (P90)	Central (P50)	High (P10)	Low (P90)	Central (P50)	High (P10)
Shale oil	421	793	1,497	3.2	6.0	11.2

Table 1 Estimates of the potential total in-place shale oil and shale gas resource in the Carboniferous Midland Valley of Scotland study area.

It should be emphasised that these 'oil-in-place' and 'gas-in-place' figures refer to an estimate for the entire volumes of hydrocarbons contained in the rock formations, not how much can be recovered. It is too early to use a more refined methodology, like the USGS's Technically Recoverable Resource 'top-down' estimates, which require production data from wells. In time, the drilling, fracturing and testing of shale wells will demonstrate if commercially viable production rates can be achieved. These, combined with other non-geological factors such as engineering design, operating costs and the scale of development agreed by the local planning system, will allow estimates of the UK's producible shale oil and shale gas reserves to be made in the future.

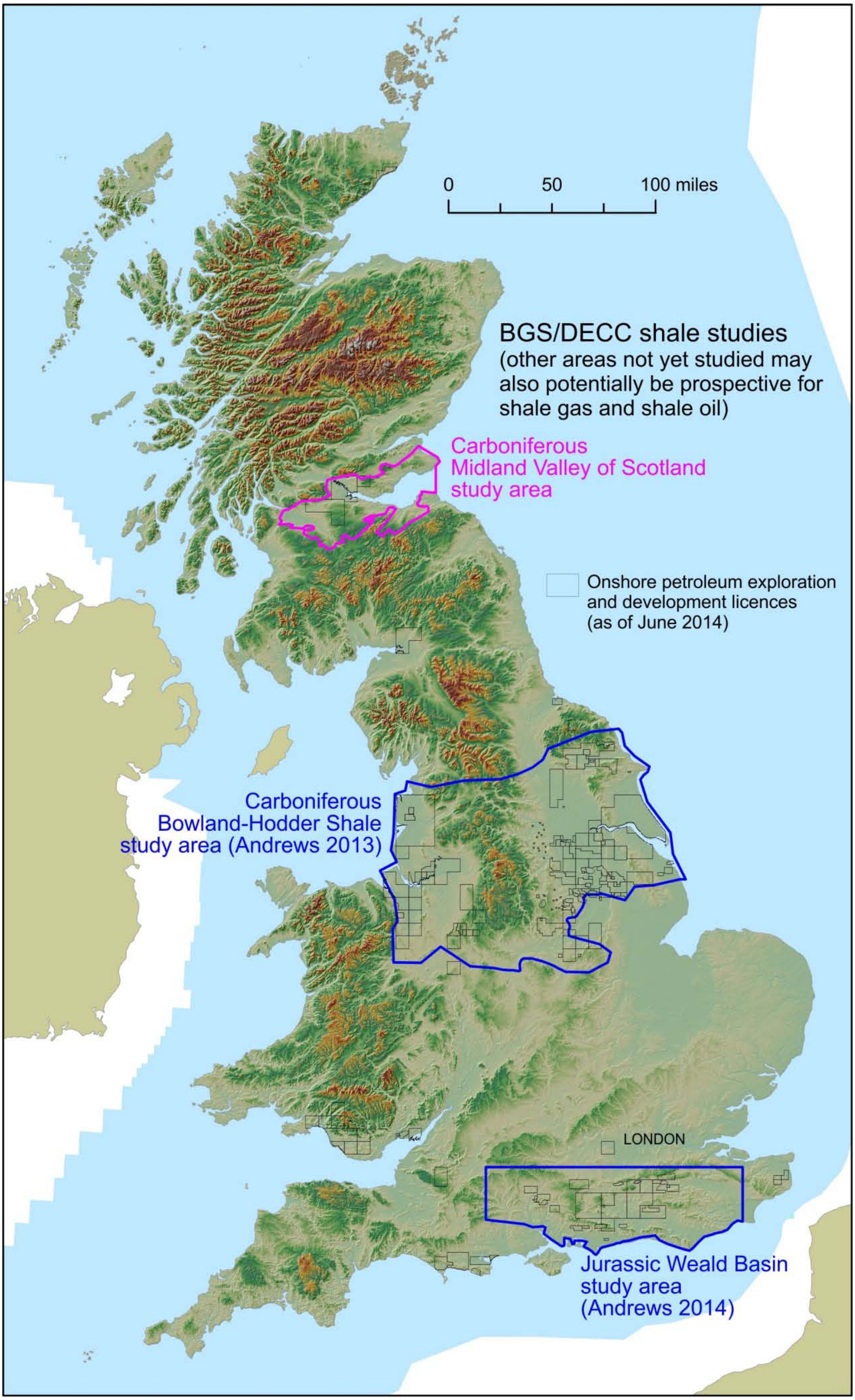


Figure 1 Location of the BGS/DECC Midland Valley of Scotland study area, together with areas assessed for their prospectivity for shale gas in northern Britain and for shale oil in southern Britain, together with currently licensed acreage.

1. Introduction to shale gas, shale oil and resource estimation

1.1. Shale as a source and reservoir rock

Shales have long been recognised as the source rock from which most of our oil and gas is generated. Under high pressure and temperature, organic material is converted to oil and gas and some is expelled and migrates into conventional reservoirs. The fact that some hydrocarbons remain in the argillaceous lithologies has now taken on a new significance with unconventional gas and oil. Further detail on shale gas is given in Andrews (2013) and shale oil in Andrews (2014).

1.2. Shale oil vs. oil-shale

The terms 'shale oil' and 'oil-shale' are both applied to organic-rich source rocks, but the hydrocarbons are present in very different settings (Table 2). Strata prospective for shale oil contain free oil within the host shales; this is in contrast with oil-shales, where there is little or no free oil, and retorting (heating to >350°C) is required to extract the oil. This distinction is particularly important in the Midland Valley of Scotland where historic oil-shale exploitation occurred (see section 2). This report assesses mature shale oil present in rocks in the Midland Valley of Scotland. The oil-shale resource is not included.

Oil-shale	**Shale oil**
Kerogen-rich shale, i.e. organic matter still in its solid state. Does not contain liquid oil. The source rock for conventional oil fields. Grades to carbonaceous shale [i.e. rich in carbon] and cannel coal. Torbanite is a lacustrine type of oil-shale.	Oil occurs in liquid form in largely impermeable lithologies. These can be shale, but also adjacent siltstone, sandstone, limestone etc (note that non-shales are not specifically modelled in this report). Also known as 'tight shale oil', 'tight light oil (TLO)', 'tight oil', 'oil-bearing shale' or 'shale-hosted oil'.
Oil is extracted by (a) in-situ heating of shale at depth or (b) mining of shale at/near the surface which is then retorted. Yields of 15+ gallons/ton are considered viable (25+ gallons/ton is high grade) (see Birdwell *et al.* 2013)	Oil is extracted by horizontal drilling and hydraulic fracturing.
Kerogen is **immature** for oil generation.	Kerogen is **mature** and oil has been generated.
<u>Examples</u>: the Green River Formation in the western USA, Ordovician deposits in Estonia and Sweden, the Tertiary deposits in Queensland, Australia, the El-Lajjun deposit in Jordan, and deposits in France, Germany, Brazil, China, southern Mongolia and Russia. Historical mining in West Lothian, Scotland.	<u>Examples</u>: the Bakken Shale, the Niobrara Formation, Barnett Shale, and the Eagle Ford Shale in the USA, R'Mah Formation in Syria, Sargelu Formation in the northern Gulf of Arabia region, Athel Formation in Oman, Bazhenov Formation and Achimov Formation of West Siberia in Russia, in Coober Pedy in Australia, Chicontepec Formation in Mexico, and the Vaca Muerta oil field in Argentina
In-place resource from Rock-Eval S1+S2	In-place resource from Rock-Eval S1
S2 : the amount of hydrocarbons generated through thermal cracking of non-volatile organic matter (kerogen) when the sample temperature is increased to 550°C. S2 is an indication of the quantity of hydrocarbons that the rock may potentially produce should burial and maturation continue.	**S1** : the amount of hydrocarbons already generated as oil in the rock. These are the free hydrocarbons (oil and gas) already present in the sample, and they are distilled out of the sample at initial heating of the sample to a temperature of 350°C.

Table 2 Criteria that differentiate a shale oil from an oil-shale.

1.3. Definitions

Throughout this report the term 'shale' is used to describe mudstones, carbonaceous mudstones, oil-shales and fine siltstones which may or may not display the characteristic fissility of a shale. At outcrop, many of these units do in fact exhibit the characteristic shale fissility.

In this report the terms:

- *West Lothian Oil-Shale unit* refers to the West Lothian Oil-Shale Formation and its lateral equivalents - the Pathhead, Sandy Craig, Pittenweem, Aberlady and Lawmuir formations
- *Gullane unit* refers to the Gullane Formation and its lateral equivalents - the Anstruther and Fife Ness formations

1.4. Resources vs. reserves

The important distinction between (in-place) resources and (recoverable) reserves is discussed in detail by DECC (2013) and Andrews (2013). In simple terms, the resource estimate for any shale gas or shale oil play is the amount of gas or oil in the ground (some or all of which might never be produced), while the reserve estimate is a more speculative measure which describes the amount of gas or oil that might be able to be extracted given non-geological constraints of the time, including technology, economics and the commercial risk operators are prepared to take. Both resource and reserve estimates find their way into the media and are sometimes confused. However, without substantive data from drilling and production rates, figures for reserves cannot be reliably estimated.

The recovery factor is an estimate of the proportion of the total gas or oil resource that might be extracted, and it is generally expressed as a percentage. It is still too early to determine how much shale gas or oil could technically be extracted at a commercial rate in the UK. In time, the drilling and testing of new wells will give an understanding of whether sustained production rates can be obtained from shales in the Midland Valley of Scotland and elsewhere in the UK.

The aim of this report is to use all available geological information to provide in-place shale oil and in-place shale gas resource estimates for the Midland Valley of Scotland.

1.5. Criteria used to define the Midland Valley of Scotland shale gas and shale oil play

Table 3 summarises some of the most important geological, geochemical and geomechanical criteria that are widely used to define a successful shale oil and shale gas play; some criteria are considered essential, others are desirable. The criteria are based on data from shale plays in North America, which are known to be geologically variable.

Criteria	**Range of data and definitions**	**Midland Valley of Scotland data availability and gaps, and definitions used in this report**
Organic Matter content (TOC)	Shales should be rich in organic matter, with total organic carbon (TOC) values > 2% (TNO 2009, Charpentier & Cook 2011, Gilman & Robinson 2011). >4% (Lewis *et al.* 2004). Jarvie (2012a) used a cut-off of just 1% present-day TOC, and quotes averages for the 10 top US systems as 0.93-5.34% TOC.	Large volume of legacy data available from well reports and theses, plus 50 new BGS samples. A cut-off of TOC > 2% is used. Shales within the Limestone Coal, Lower Limestone Formation, West Lothian Oil-shale unit commonly > 2% TOC; the Gullane unit is more variable.
Gamma-ray values	High gamma radiation is typically an indication of high organic carbon content, especially in marine systems. Gamma log response should preferably be 'high' (Charpentier & Cook 2011); 20 API above shale baseline (Schmoker 1980); >230 API (NPC 1980); >180 API (DECC 2010a); >150 API, but lower if TOC is demonstrably high (D. Gautier, USGS, pers. comm.).	Midland Valley of Scotland shales typically in the range 125 to 175 API have proven TOCs > 2% in Limestone Coal Formation, Lower Limestone Formation, West Lothian Oil-Shale unit.
Kerogen type	Kerogen should be of Type I, II or IIS (Charpentier & Cook 2011). Ideally, Type II (Jarvie 2012a). This indicates a marine origin.	Limited kerogen dataset. Kerogen Types I and III most common, with some Type I/II.
Original hydrogen index (HIo)	HI_o preferably >250 mg/g (TNO, 2009, Charpentier & Cook 2011); 250-800 mg/g (Jarvie 2012a). Note: it is important to have information on original, rather than present day, HI values. This conversion relies heavily on kerogen type.	Only present day HI values are available for UK basins.
Mineralogy /clay content	Clay content should be low (< 35% or < 50% Bowker, 2007) to facilitate hydraulic fracturing and hence gas/oil extraction. Jarvie (2012a) stresses the requirement of a significant silica content (>30%) with some carbonate, and presence of non-swelling clays.	Variable compositions, with an average of approximately 59% phyllosilicates/clay minerals, approximately 9% carbonate minerals and approximately 32% QFP (quartz, feldspar and pyrite). A limited number of samples.
Net shale thickness	Moderate shale thicknesses are considered ideal; >50 ft (15 m) (Charpentier & Cook 2011); >20 m (TNO 2009); >150 ft (Jarvie 2012a). Conventional wisdom is that the 'thicker the better', but this may not necessarily be the case (Gilman & Robinson 2011); >25 m in <200 m gross section (Bent 2012).	Individual shale units are generally thin but occur within a stacked sequence. Percentage shale and percentage shale maps >50ft used as upper and lower bounds.
Shale oil precursor	A shale oil precursor should ideally be identified	Conventional oil and gas discoveries sourced from the West Lothian Oil-Shale unit.
Thermal maturity	Gas generation; R_o = 1.1 – 3.5% (vitrinite reflectance) is widely accepted as the 'gas window'. Charpentier & Cook (2011) use a cut-off of R_o >1.1%. Smith *et al.* (2010) use 1.1% as it demarcates the prospective area in the Fort Worth Basin; Jarvie (2012a) quotes a higher cut-off of R_o >1.4%; 1.2 – 3.5% (BGR 2012); <3.3% (TNO 2009). Oil generation: R_o = 0.6 - 1.1% is widely accepted as the 'oil window'. 'The oil window does vary, depending on the source rock composition, although thermal maturity values from about 0.6 to 1.4% R_o are the most likely values significant for petroleum liquid generation' (Jarvie 2012a).	Shale is considered to be mature for gas generation above an R_o value of 1.1% and oil above 0.6%. Many of the Midland Valley of Scotland samples are above 0.6% with a more limited number on a linear burial trend over 1.1%.

Criteria	**Range of data and definitions**	**Midland Valley of Scotland data availability and gaps, and definitions used in this report**
Gas content/ saturation	Gas should be present as free gas (in matrix and fractures) and adsorbed gas. Gas contents should be 60-200 bcf/section (Bent 2012) or >100 bcf/section (Jarvie 2012a).	There is no published information on gas contents. Data from US analogues are used.
Depth minimum	Depth >5,000 ft (>1,500 m) (Charpentier & Cook 2011). >3,300 ft (>1,000 m) cut-off used by USEIA (2013) as envelope of successful play criteria expands. Lower pressures generally encountered at shallower depths result in low flow rates	Alternative depth cut-off used, related to abandoned deep coal mines plus a vertical separation of 1,000 ft. Also a sensitivity test at 1,000 ft below Ordnance Datum.
Shale porosity	Typically 4 – 7%, but should be less than 15% (Jarvie 2012a).	Limited commercial-in-confidence data available.
Oil yields	'Free oil' content (S1 corrected for evaporative loss) should ideally be >2 mgHC/gRock, or equivalent yield of >50 bbl/acre-ft.	S1 values variable but with reasonable numbers >2 mgHC/gRock
Oil saturation index	The oil saturation index [(S1 x 100)/TOC] should ideally be above 100 (Jarvie 2012b).	Reasonable numbers of samples have oil saturation index over 100 with many falling between 50 and 100.
Tectonics and burial history	Preferably in large, stable basins, without complex tectonics (Charpentier & Cook 2011). Wells should be drilled away from faults where possible	The Midland Valley of Scotland has complex geological history with small basins, faulting and folding at various scales. Additionally, igneous rocks form a proportion of the basin fill with complicated spatial arrangements.

Table 3 Criteria that are widely used to define successful shale gas and shale oil plays. Adapted from Andrews (2013, 2014)

Criteria applied to shale thickness in the Midland Valley of Scotland are discussed further in section 2.9.1 and the depth minimum in section 4.1.1.

2. Geology of prospective units of the Midland Valley of Scotland

2.1 Introduction

An initial scoping study screened all Palaeozoic strata for shale potential within the geological terrane of the Midland Valley of Scotland, extending from the Highland Boundary Fault in the north to the Southern Upland Fault in the south (Figure 2). The Forth Estuary and Firth of Forth were included to just offshore of the 'bay closing line' where the distinction between 'onshore' and offshore' is made for UK licensing purposes. The Firth of Forth has been included in the resource estimation for this study, though it is not currently included in a Strategic Environmental Assessment and so cannot be offered in the 14th UK Onshore Licensing Round.

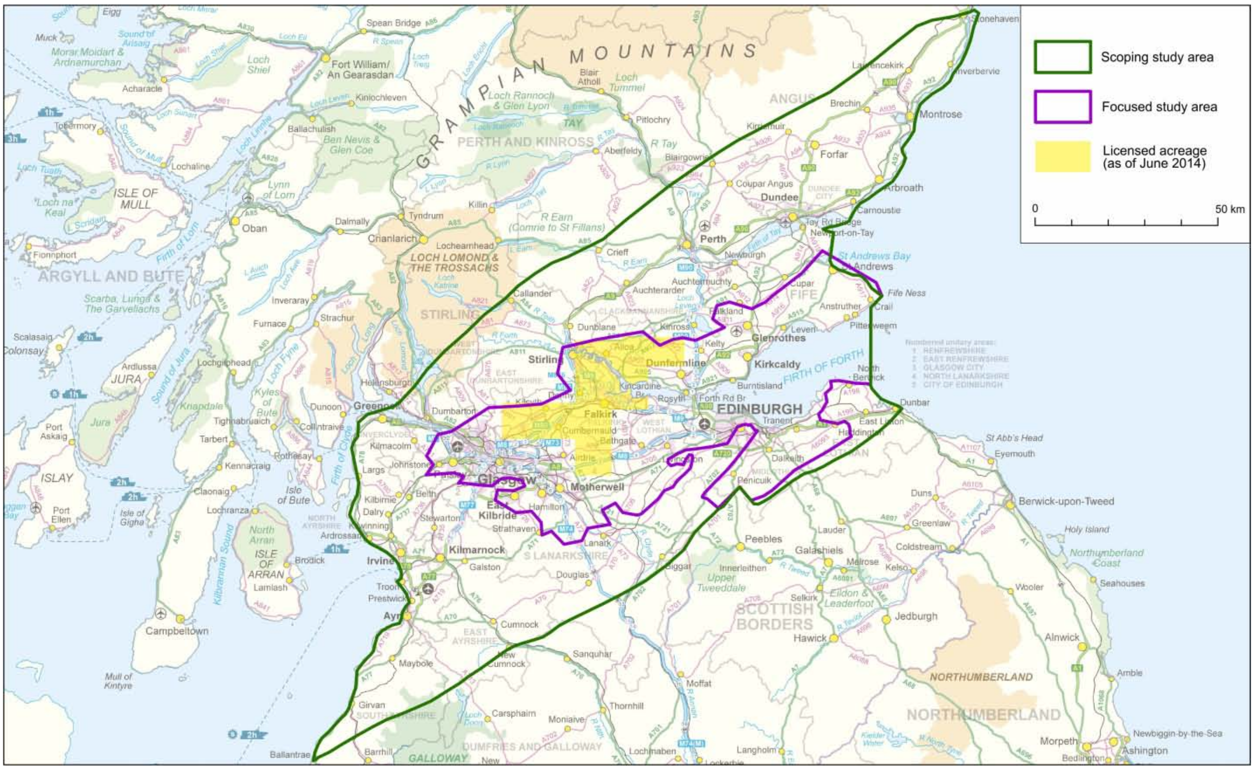


Figure 2 Extent of Midland Valley of Scotland scoping study area and Midland Valley of Scotland focused study area, shown with currently licensed acreage. Ordnance Survey data © Crown copyright 2014

The initial filtering used the standard shale prospectivity criteria (Table 3) on all ages of strata within the scoping study area (Figure 2). As a result, the Carboniferous of the western Midland Valley of Scotland (Ayrshire and Douglas Coalfields), and areas underlain by pre-Carboniferous and lowermost Carboniferous strata were excluded from further study (see Appendix B for details). Strata from the Upper Limestone Formation and younger units were also excluded due to their shallow current-day burial depths.

Four Carboniferous stratigraphic intervals (Table 4) are considered in more detail for shale prospectivity due to their mudstone content and burial depth:

- Limestone Coal Formation
- Lower Limestone Formation
- West Lothian Oil-Shale unit (West Lothian Oil-Shale Formation and age-equivalent Pathhead, Sandy Craig and Pittenweem formations in the east)
- Gullane unit (Gullane and age-equivalent Anstruther Formation in Fife)

Other age-equivalent strata are not considered further due to their sandstone or igneous-dominated lithologies (see Appendix B for details). The result is the focused study area shown on Figure 2, which stretches from Glasgow to Edinburgh, to the Lothians, Falkirk, Clackmannan and Fife.

<table>
<tr><th>Age</th><th>Group</th><th>Glasgow, Lanarkshire</th><th colspan="3">West Lothian</th><th>East Lothian</th><th colspan="2">Fife</th><th>Marker beds</th></tr>
<tr><td rowspan="3">West-
phalian</td><td rowspan="3">Scottish Coal Measures Group</td><td colspan="7">Scottish Upper Coal Measures Formation
Cyclical sandstone, siltstone, mudstone with minor coal, >3940 ft (>1200 m)</td><td></td></tr>
<tr><td colspan="7">Scottish Middle Coal Measures Formation
Cyclical sandstone, siltstone, mudstone, seatrock and coal, 1150 ft (350 m)</td><td></td></tr>
<tr><td colspan="7">Scottish Lower Coal Measures Formation
Cyclical sandstone, siltstone, mudstone, seatrock and coal, 790 ft (240 m)</td><td></td></tr>
<tr><td rowspan="3">Namurian</td><td rowspan="4">Clack-
mannan
Group</td><td colspan="7">Passage Formation
Sandstone, conglomerate and claystone with minor coal, limestone and ironstone, 1250 ft (380 m)</td><td></td></tr>
<tr><td colspan="3">Upper Limestone Formation</td><td rowspan="4">Bathgate Hills Volcanic Formation
Lava, tuff and volcaniclastic sedimentary rock, up to 3280 ft (1000 m)</td><td colspan="3">Upper Limestone Formation. Cyclical limestone, mudstone, siltstone and sandstone, seatrock and coal, >1970 ft, (>600 m)</td><td>Index Lmst</td></tr>
<tr><td colspan="3">Limestone Coal Formation</td><td colspan="3">Limestone Coal Formation. Cyclical sandstone, siltstone and mudstone, seatrock and coal, >1800 ft (>550 m)</td><td>Top Hosie Lmst</td></tr>
<tr><td rowspan="8">Visean</td><td colspan="3">Lower Limestone Formation</td><td colspan="3">Lower Limestone Formation. Cyclical limestone, mudstone, siltstone and sandstone with minor seatrock and coal, 790 ft (240 m)</td><td>Hurlet Lmst</td></tr>
<tr><td rowspan="7">Strathclyde Group</td><td>Lawmuir Formation
Mudstone, siltstone, sandstone with seatrock, coal and limestone, 990 ft (300 m)</td><td colspan="2" rowspan="3">West Lothian Oil-Shale Formation
Cyclical oil-shale, sandstone, siltstone and mudstone with minor coal, limestone, dolostone and ironstone, >3675 ft (>1120 m)</td><td rowspan="3">Aberlady Formation
Cyclical sandstone, siltstone and mudstone with minor coal, seatrock, limestone and ironstone, 460 ft (140 m)</td><td>Pathhead Formation
Mudstone and siltstone with limestone and dolostone and minor sandstone, coal and ironstone, 720 ft(220m)</td><td rowspan="2">Kinghorn Volcanic Formation, basaltic lava, volcaniclastic and some siliciclastic sedimentary rock and tuff, > 422 m</td><td rowspan="2">Burdiehouse Lmst</td></tr>
<tr><td>Kirkwood Formation
Tuffaceous mudstone and tuff with minor sandstone, siltstone, limestone, 120 ft (36 m)</td><td rowspan="2">West Lothian Oil-Shale Formation</td><td>Sandy Craig Formation
Mudstone and siltstone with minor oil-shale, limestone, sandstone and coal, 2200 ft(670m)</td></tr>
<tr><td></td><td colspan="2">Pittenweem Formation
Mudstone and siltstone with minor limestone, oil-shale and sandstone, >850 ft (>260 m)</td><td></td></tr>
<tr><td rowspan="4">Clyde Plateau Volcanic Formation
Lava, tuff and volcaniclastic sedimentary rock 2950 ft (900 m)</td><td rowspan="4">Salsburgh Volcanic Formation
Tuff and basaltic lava, >335 ft (> 102 m)</td><td colspan="3" rowspan="3">Gullane Formation
Cyclical sandstone, mudstone and siltstone with minor coal, seatrock, limestone, dolostone and ironstone, 1840 ft (560 m)</td><td colspan="2">Anstruther Formation
Mudstone, siltstone and sandstone with minor limestone, dolostone, oil-shale and coal, >2660 ft (>810m)</td><td></td></tr>
<tr><td colspan="2">Charles Hill Volcanic Member
Basalt and tuff, 100 ft (> 30 m)</td><td></td></tr>
<tr><td colspan="2">Fife Ness Formation. Sandstone with mudstone and seatrock, >755 ft (>230 m)</td><td></td></tr>
<tr><td colspan="3">Arthur's Seat and Garleton Hills volcanic formations. Lava, tuff and subordinate volcaniclastic sedimentary rock, 1840 ft (560 m)</td><td colspan="2"></td><td></td></tr>
<tr><td rowspan="3">Tour-
naisian</td><td rowspan="3">Inverclyde Group</td><td colspan="7">Clyde Sandstone Formation
Sandstone with minor mudstone and pedogenic limestone, >980 ft (> 300 m)</td><td></td></tr>
<tr><td colspan="7">Ballagan Formation
Mudstone, siltstone and dolostone with sandstone in some areas, 2950 ft(900 m)</td><td></td></tr>
<tr><td colspan="7">Kinnesswood Formation
Cross-bedded sandstone with minor mudstone and pedogenic limestone, 2100 ft (640 m)</td><td></td></tr>
</table>

Table 4 Summary of the Carboniferous stratigraphy of the Midland Valley of Scotland (modified after Browne et al. 1999). The four potentially prospective shale-rich intervals are colour-shaded. Thick red lines indicate the horizons modelled to define the rock volumes for each unit.

The shale-prospective intervals are located within a number of basins (Figures 3, 4) which are described further below.

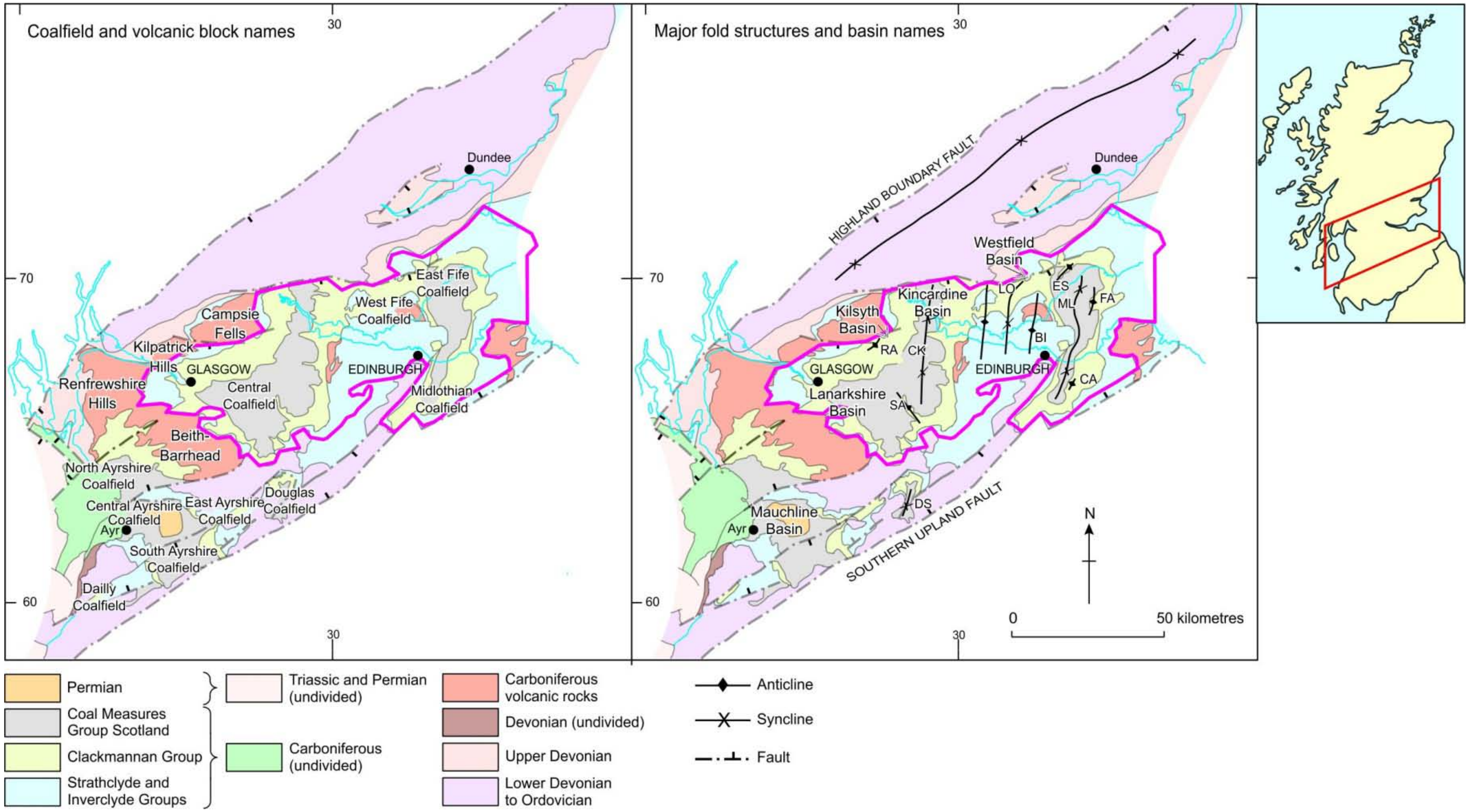


Figure 3 Outcrop geology and main structural elements of the Midland Valley of Scotland using nomenclature adapted from numerous BGS memoirs and from Read (1988). Key: CA = D'Arcy – Cousland Anticline, ML = Midlothian – Leven Syncline, ES = Earl's Seat Anticline, BI = Burntisland Anticline, LO = Lochore Syncline, CK = Clackmannan Syncline, RA = Riggin Anticline, SA = Salsburgh Anticline, DS = Douglas Syncline, FA = Forth Anticline.

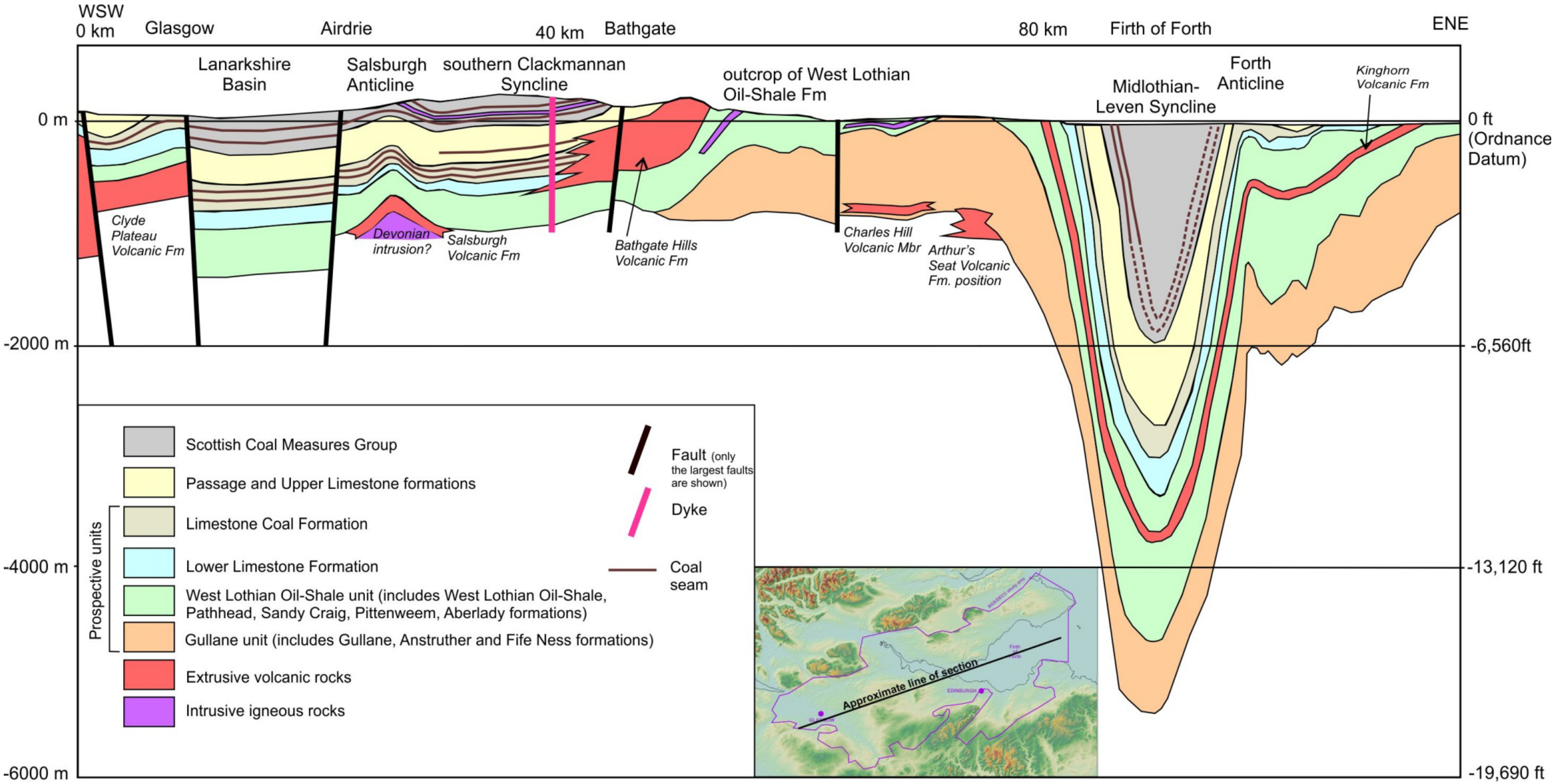


Figure 4 Schematic cross-section across the Midland Valley of Scotland to illustrate some of the main geological features. Note the significant vertical exaggeration x10.

2.2 History of hydrocarbon exploration, petroleum seeps, discoveries and shows in the Midland Valley of Scotland

Hydrocarbon exploration and exploitation has occurred within the Midland Valley of Scotland since the mid-19th century. Scotland has been credited as the birthplace of the hydrocarbons industry (Hallett *et al.* 1985), beginning with the economic exploitation of torbanites, oil-shales and cannel coals from the mid-19th to 20th century. Oil and gas exploration continued from the latter part of the First World War through to the 1990s. In recent years, there has been coalbed methane (CBM) exploration.

2.2.1 Oil-shales

Hydrocarbon production on an economic scale began with the extraction of oil from torbanite (a fine-grained black oil-shale, sometimes referred to as a bog-head coal) near Bathgate in 1851 (Conacher 1927, Hallett *et al.* 1985). James Young, a Glasgow-born chemist, improved on methods of destructive distillation of coals to produce paraffin oil. The process pioneered by Young was a commercial success. By the 1860s, the best-quality torbanites, yielding up to 120 gallons of oil per tonne, were rapidly depleted by the increasing demand. Oil-shales derived from the West Lothian Oil-Shale Formation eventually yielded an average of only 40 gallons per ton (Conacher 1927, Bailey 1927, Table 5).

James Young subsequently opened a processing plant at West Calder in 1865 (Hallett *et al*. 1985). At its peak in the 1860s, there were approximately 67 works refining oil-shales in Scotland (Redwood 1897), with up to 120 different works existing over the duration of oil-shale exploitation (Russell 1990). Production of oil rose to 500,000 bbl/year in 1878, 1 million bbl/year in 1878 and, at its peak, 2 million bbl/year in 1912 (Hallett *et al.* 1985). By peak production only six companies remained, and by 1920 these companies were consolidated under one company, Scottish Oil Ltd (Russell 1990). Production halved after the First World War as a result of competition from cheap imported oil from the Middle East and the American oil fields, but oil-shale production remained constant at approximately 1 million bbl/year up until the 1950s. These production rates were sustained due to favourable tax conditions. The industry collapsed immediately after tax concessions were withdrawn in 1964, ending 114 years of oil-shale production in Scotland.

Over the course of oil-shale exploitation, several different seams within the West Lothian Oil-Shale Formation were exploited to different extents, depending on prevailing geologic and economic factors. Key horizons worked included the Pumpherston Shales within the lower part of the formation, and the Camps, Dunnet, Champfleurie, Broxburn, and Fells shales within the upper part of the formation (Carruthers 1927; see Figure 31). In addition, the Lillie's coal shale was worked in the Renfrewshire area.

The various mines which exploited seams within the West Lothian Oil-Shale Formation covered a geographic extent of approximately 203 km^2 in West Lothian, with the northernmost workings being found east of South Queensferry, and the southernmost workings found at Tarbrax. (A comprehensive map of the distribution of mines and refineries can be found at http://www.scottishshale.co.uk/GazMines/MineMaps/AAMinesField.html). The highest concentrations of mine workings are around the towns of West Calder, Pumpherston, and Broxburn, where the formation is at outcrop or has a thin cover of superficial deposits. Smaller satellite fields were located at Straiton to the south-east of Edinburgh, and at Burntisland in Fife. The yield of oil from the exploited oil-shales varied both between the different seams, but also spatially within the seams. Historic production data summarising these variations are recorded in Table 5 (Bailey 1927).

Seam worked	Gallons of crude oil per ton		Ash content (%)
	Minimum	Maximum	
Fells	12.2	50.9	71.1
Broxburn	27.4	50.1	71.9
Dunnet	4.7	39.6	73.3
Camps	16.1	20.3	73.1
Pumpherston	8.5	31.4	74.4

Table 5 Yields of crude oil and ash content of various seams within the West Lothian Oil-Shale Field (Bailey 1927).

Mining of the oil-shales was conducted in a similar manner to coal mining. Where seams occurred close to the surface, dipping at a relatively shallow angle, an adit (a near horizontal mine entrance) was dug, following the seam. For steeply dipping seams, a vertical shaft was sunk.

Throughout the duration of oil-shale exploitation of the West Lothian Oil-Shale Formation, approximately 75 million barrels of oil was produced (Hallett *et al.* 1985). The remaining reserves are estimated at 37 million barrels of oil (Cameron & McAdam 1978).

2.2.2 History of oil & gas exploration

Exploration for conventional oil in the Midland Valley of Scotland was initiated by the Ministry of Munitions as a consequence of war-time demands during the early part of the 20th century. The Government contracted S. Pearson & Son Ltd. to drill 11 test wells across the UK, two of which were in Scotland: the first at West Calder and the second at D'Arcy House (Lees & Cox 1937, Hallett *et al*. 1985). Drilling at West Calder commenced in 1919 with sandstones in the Strathclyde Group being the principal target. The well was completed in 1921 at a total depth of 3,920 ft (1,195 m). The West Calder 1 well was devoid of any significant quantity of oil, with only minor shows observed (Hallett *et al*. 1985). The D'Arcy well on the crest of a Carboniferous anticline commenced in late 1919 with the objective of penetrating the Binny, Hailes and Granton sandstones within the Strathclyde Group. The well encountered gas at 724 ft (221 m), which flowed at approximately 30,000 cf/d and after continuing, the well encountered oil in sandstones interpreted to be the Binny Sandstone at approximately 1,810 ft (552 m). The well was completed in 1922, with approximately 50 barrels of oil recovered during this time (Hallett *et al.* 1985).

Oil exploration ceased within the UK during the years following the First World War until a second phase of exploration within the Midland Valley of Scotland was led by D'Arcy Exploration and the Anglo American Oil Company in the 1930s.

Anglo American drilled six wells on the D'Arcy – Cousland anticline trend between 1937 and 1939. Gas was discovered in their first well and oil in the third well. The discovery was named the Midlothian field and production was improved from 2.5 to 3.5 bbl per day after formation stimulation using a perforation gun. The Midlothian oil field continued producing until approximately 1964, during which time it produced approximately 30,000 bbl of oil (Hallett *et al*. 1985). Exploration in the Cousland prospect encountered gas, which was tested to yield 5.9 million cubic feet/day (mmscfd), however exploration was suspended during the war years (Lees & Taitt 1945), before resuming in 1947. Continued exploration on the Cousland-D'Arcy anticline at Cousland yielded oil, with a flow of 30 gallons/day at Cousland 4 and 40 gallons/day at Cousland 5, before completion and abandonment of both wells.

Exploration for oil and gas in the Midland Valley of Scotland ceased after completion of Cousland 6 in 1959 due to a low oil price, before interest was rekindled by rising oil prices in the 1980s. Over the course of the 1980s, 30 exploration wells were drilled, many on anticlinal structures. Most of these wells exhibited minor oil and gas shows: either as fluorescence, crush cut, or water cut in sandstones within the Limestone Coal and Lower Limestone formations, or Strathclyde Group; or as gas within the drilling mud associated with coals or shales, usually up to a maximum of a few percent (Figures 5, 6, Tables 1 and 2 in Appendix B)

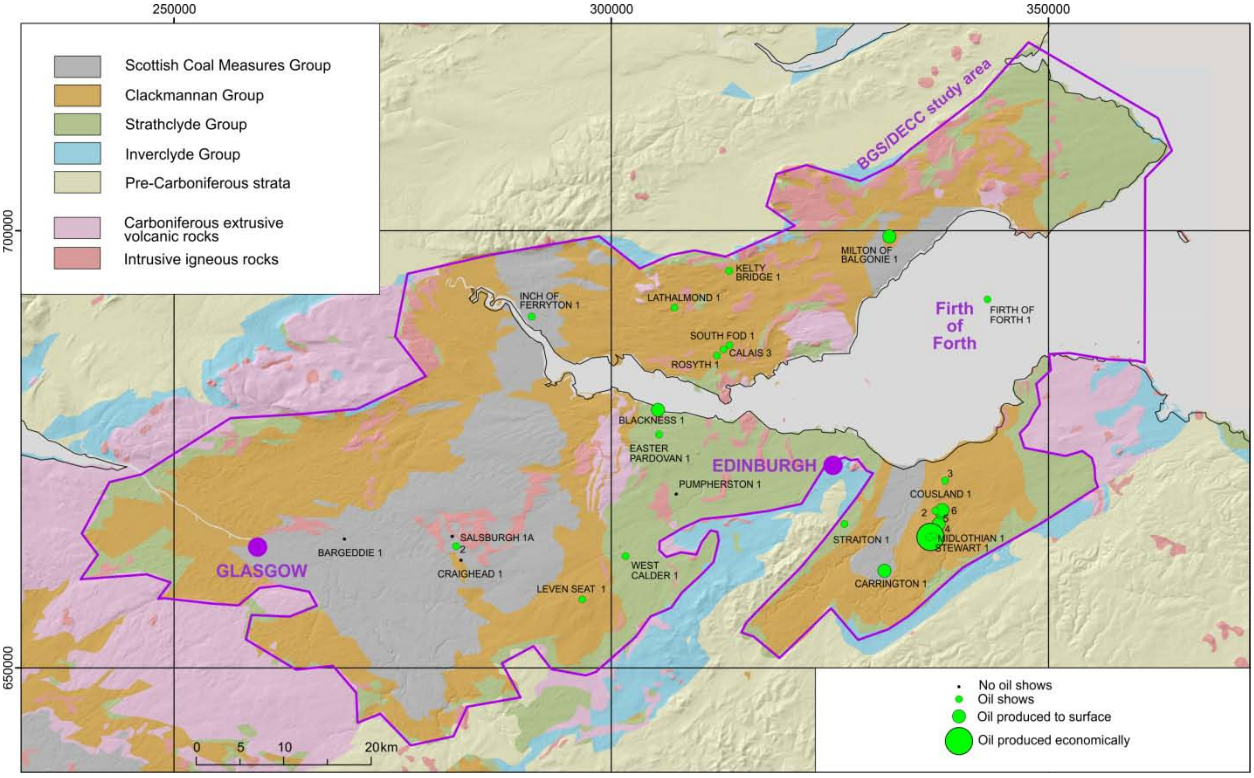


Figure 5 Map depicting historic oil shows, oil produced to surface and oil produced economically within the study area, based on commercial well reports and available references to oil shows in the literature. Geological information ©BGS/NERC.

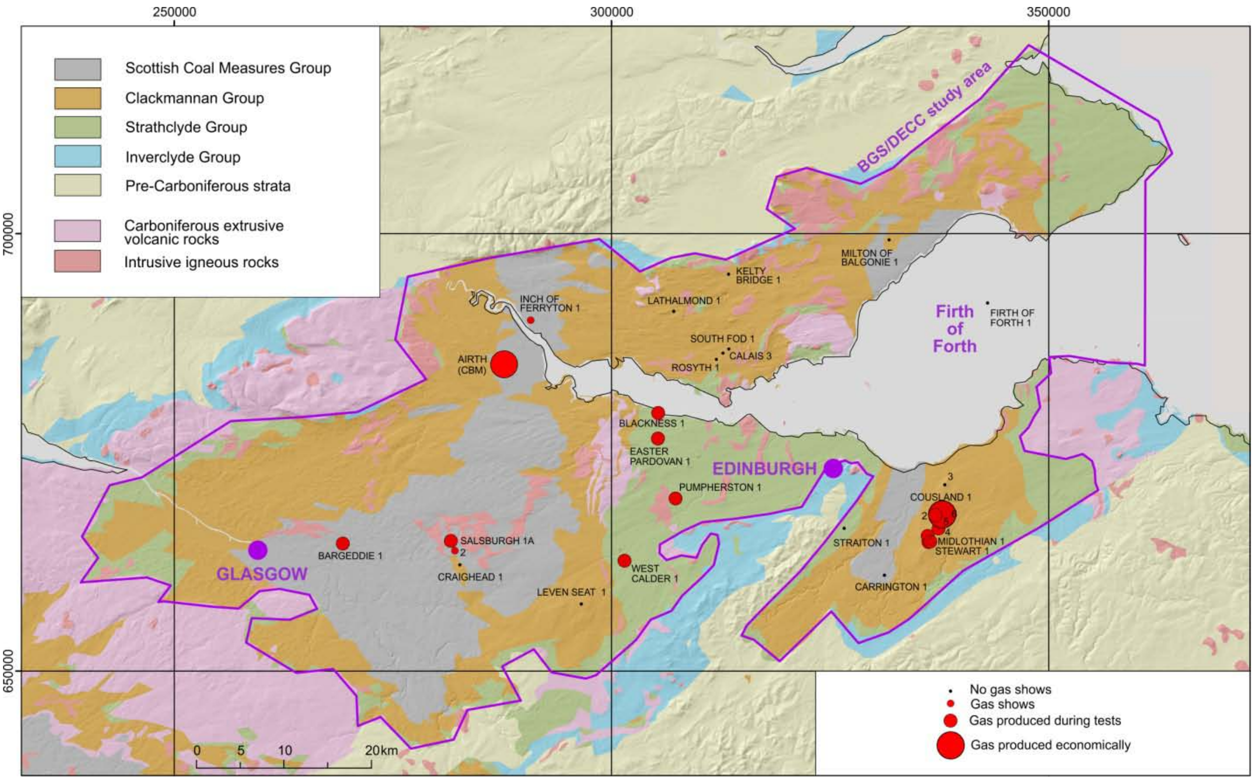


Figure 6 Map depicting historic gas shows, gas produced during tests, and gas produced economically within the study area, based on commercial well reports and available references to gas shows in the literature. Geological information ©BGS/NERC.

Hydrocarbon discoveries were made in the late 1980s to early 1990s in Milton of Balgonie 1 and Bargeddie 1, and a coalbed methane (CBM) discovery was made at Airth 1. The Firth of Forth 1 well was drilled in 1990 by Conoco with some waxy oil recovered. At Milton of Balgonie, oil was encountered within the Lower Limestone Formation, however upon testing, the well yielded just ½ barrel of oil. The oil was waxy and close to its pour point, thus proving uneconomical to exploit (Underhill *et al.* 2008). At Bargeddie 1, gas was encountered in the West Lothian Oil-Shale Formation and initial well tests produced 360 mcf/d. Ongoing tests resulted in the production of 7.3 mmscf of gas before the reservoir was nearly depleted (released Bargeddie well report).

During the course of exploration, well stimulation to improve fluid flow into the well bore by use of perforation charges (Midlothian 1) or hydraulic fracturing (Bargeddie 1) has been verbally reported to DECC by operators as having been conducted as a routine part of drill-string testing.

Summary tables of oil and gas shows in Midland Valley of Scotland wells are presented in Appendix B.

2.2.3 Coalbed methane

A number of Airth coal bed methane wells were drilled as part of a pilot project in 1993 by the Hillfarm Coal Company. The Bannockburn Coal seam was exploited for its high methane content and after hydrofracturing, produced 60 mcf/d from January 1994. Production dropped to 6 mcf/d for a duration of time before returning to 35 mcf/d during 1995 (DECC, 2010b). Coal Bed Methane Ltd subsequently took over the licence in 1996 and drilled a further three wells. After the award of PEDL133 in 2004 to Composite Energy, six further wells were drilled with horizontal sidetracks. The Airth Field Development plan was approved with the first coalbed methane gas produced in October 2007. In 2010, Dart Energy Ltd acquired Composite Energy and drilled a further three wells. In 2012, Dart Energy Ltd press-released a sustained gas flow in excess of 0.5 mmscfd from the Airth 12 well. Based on their interpretation of commercial gas production, they submitted an expanded Field Development Plan to DECC and sought SEPA permits and local planning permission. A two-stage development is proposed for 10 wells and compression for 35 mmscfd, followed by an additional 25 wells. Dart Energy Ltd's planning application went to a planning inquiry during March 2014.

2.2.4 Natural petroleum seeps

Petroleum seeps are known from St Catherine's Well (along the Pentland Fault) and Straiton near Edinburgh and also at Alva in the Devonian of the Ochil Hills (Parnell 1984, Selley 1992, Underhill *et al*. 2008). Robinson *et al*. (1989) examined the composition of bitumen from Devonian lavas north of the West Ochil Fault and Carboniferous sedimentary rocks, and used biomarkers to show that Carboniferous mudstones were the likely source. Hydrocarbon generation south of the West Ochil Fault was proposed, with migration along the fault and associated fractures.

2.2.5 Coal mining

Coals have been mined in Scotland since the 12th century. Of importance to this study is that methane was a serious problem for coal mining in Limestone Coal Formation strata in the western part of the Central Coalfield (e.g. the Bedlay and Cardowan collieries; HM Inspectorate of Mines and Quarries 1982). Oil seepages were also recorded close to large faults in the St Flannans (above the Kilsyth Coking Coal), Auchenreoch and Gartshore 11 collieries near Kirkintilloch, with 56 tonnes of oil recovered from St Flannans in 1905-06 (Robertson & Haldane 1937). Today, methane venting from coal mines takes place in some areas such as Chryston in North Lanarkshire. The coal-mine gas is generally assumed to be released from coal seams, no studies have been found that examine whether a component of the gas could be from mature organic-rich mudstones.

2.3 Groundwater

2.3.1 Groundwater bodies

Aquifers across Scotland have been subdivided into groundwater bodies by the Scottish Environment Protection Agency (SEPA), to meet the requirements of the Water Framework Directive (2000/60/EC).

Groundwater bodies are used to manage groundwater in a sustainable way and ensure relevant environmental objectives are met. This includes identifying and resolving groundwater management problems and preventing new risks from arising.

Groundwater body delineation has been undertaken in accordance with UK Technical Advisory Group criteria (UKTAG 2012). The initial extents of the bodies were defined on the basis of significant geological/hydrogeological boundaries as identified by the British Geological Survey. SEPA then sub-divided these, where necessary, using significant surface water catchment boundaries to establish the final groundwater bodies for the Water Framework Directive (Ó Dochartaigh *et al*. in press; Figure 7). These bedrock and superficial groundwater bodies provide the basis for all groundwater management purposes in Scotland in terms of both water quality and abstraction pressures.

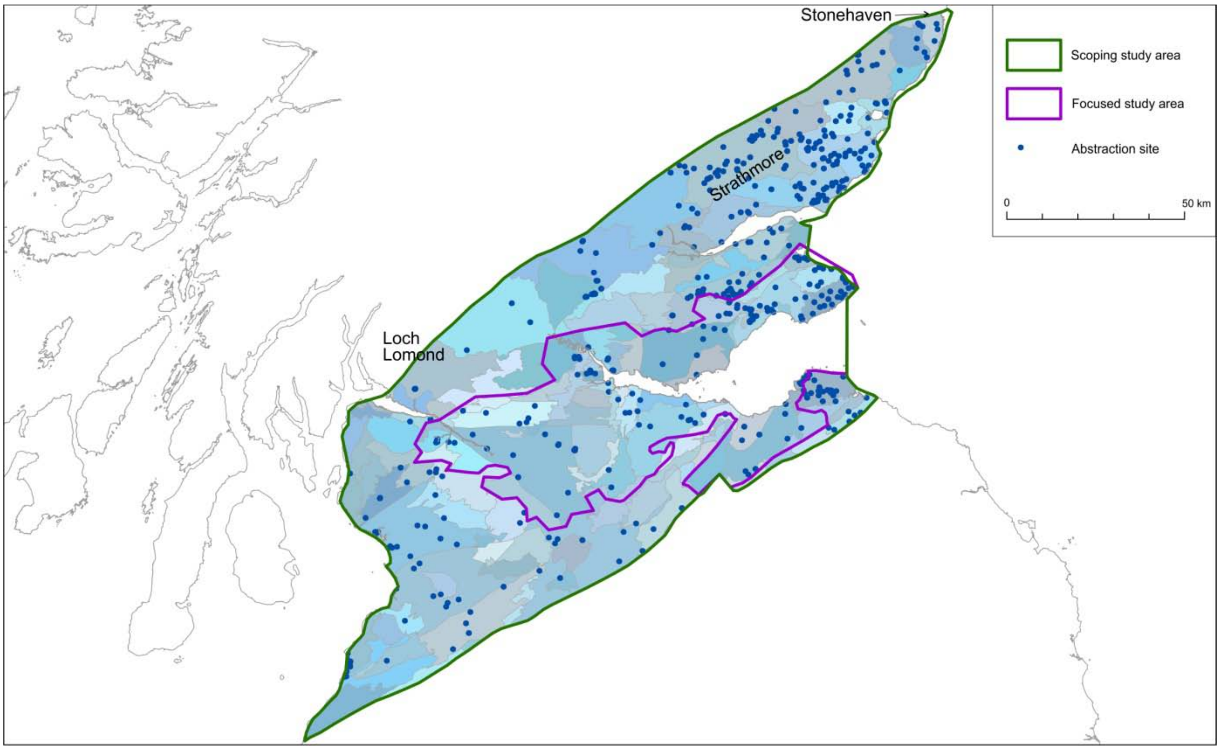


Figure 7 Groundwater bodies (bedrock only; coloured in various blue-grey shades) in the Midland Valley of Scotland from Ó Dochartaigh et al. (in press). Groundwater abstractions in the study area are shown as dots, from SEPA. Ordnance Survey data © Crown Copyright 2014.

Groundwater is an important resource in Scotland, providing around 75% of private drinking water supplies and 5% of public water supply. The distribution of groundwater abstractions in the Midland Valley of Scotland (Figure 7) indicates that the groundwater resource is more widely utilised in the north and east. In northern parts of the Midland Valley of Scotland, the Devonian sandstones of Strathmore (from Loch Lomond in the south-west to Stonehaven in the north-east) and the Devonian/Carboniferous sandstones of Fife form strategically important aquifers. These are some of the most productive aquifers in Scotland, and are heavily utilised to provide drinking water supplies and as a source of water for agricultural irrigation. There are no Carboniferous shales in the Strathmore area.

As well as being used directly, groundwater also plays an important role in supporting surface water ecosystems in rivers, lochs and wetlands. Groundwater provides one third of river flow in Scotland's rivers and supports two-thirds of all statutory designated wetland sites.

To assess the significance of chemical and quantitative pressures on groundwater, the condition (status) of groundwater bodies is evaluated on a regular basis along with an assessment of the risk of future deterioration. More than 80% of Scotland's groundwater bodies are in good condition, but there are particular areas with significant problems. The legacy of mining in the Midland Valley of Scotland is an example. Figure 8 shows the groundwater bodies in the Midland Valley of Scotland that are at poor status due to the impacts of mining. The Passage Formation contains the most productive aquifer sandstones in areas where unconventional hydrocarbon developments are likely to take place and thus it is notable that the Passage Formation groundwater bodies are at good status (Figure 8).

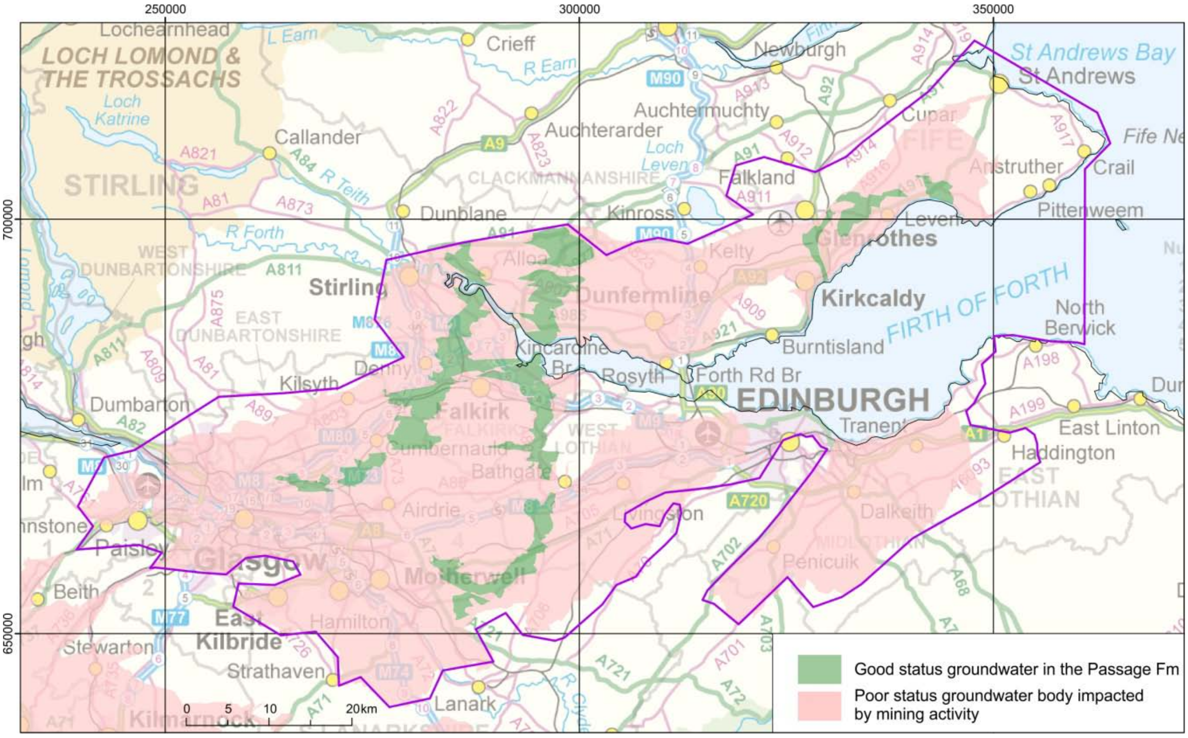


Figure 8 Poor status groundwater bodies impacted by mining activity (red) and good status Passage Formation groundwater bodies (green, from SEPA 2013 Water Framework Directive Classification) Ordnance Survey data © Crown Copyright 2014.

2.3.2 Well drilling and protection of the water environment

The Water Environment (Controlled Activities) (Scotland) Regulations 2011 ("CAR") provide SEPA with controls relating to the activities required as part of unconventional oil or gas development.

The drilling of new wells greater than 200 m deep requires a CAR licence from SEPA. In a risk based approach, the applicant undertakes a water features survey up to a distance of 3,937 ft (1,200 m) from the proposed well, including both the surface position and the lateral extent of well. This survey identifies abstractions, surface waters, springs and wetlands for which potential impacts have to be assessed as part of the risk assessment process. It also includes details of faults, mine workings and other deep boreholes or wells, which are all discontinuities within the rock volume and have the potential to act as pathways for fluid or gas migration (IEA 2012, The Royal Society 2012, Davies *et al*. 2014). SEPA (2013) provides further details of the requirements for well construction.

In addition to well drilling, a CAR licence is also required to; abstract groundwater or surface water for site use or hydraulic fracture fluid preparation, abstract groundwater to facilitate gas or oil extraction, inject fracturing fluids and discharges of treated effluent. Further details of how SEPA regulates unconventional hydrocarbon activities can be found on the SEPA website[1].

2.3.3 Groundwater monitoring

A robust water environment monitoring plan will be an essential component of managing the risks of any unconventional gas or oil development in the Midland Valley of Scotland. Monitoring is required to demonstrate that no impacts are occurring to receptors as a result of the proposed development during operation and after de-commissioning. SEPA also requires monitoring to be carried out prior to unconventional gas borehole construction to establish a baseline. The monitoring plan is a requirement under SEPA's CAR licensing regime and details can be found on their website.

2.3.4 Methane in groundwater

Naturally occurring detectable methane can be present in groundwater from most aquifers (BGS 2013c). BGS has been studying methane in UK groundwaters since the 1980s to investigate sources of methane in the subsurface, the hydrogeochemical controls on its fate, and behaviour and potential for methane emissions from groundwaters (BGS 2013c). Methane in groundwater is formed by one of two processes: firstly biogenic, which is produced by bacteria, and is often associated with shallow anaerobic groundwater environments, such as peat bogs, wetlands, lake sediments and landfills, although it is detectable in nearly all groundwater. Secondly, thermogenic methane, which is formed during thermal decomposition of organic matter at depth under high pressures, and is often associated with coal, oil and conventional gas fields.

Methane can migrate from the location at which it is formed either as free gas or dissolved in water (or other fluids). Thermogenic gas produced at considerable depths can migrate upwards if overlain by more permeable geological formations. In some cases, it can become trapped below an impermeable cap rock to form a gas reservoir or it can continue to migrate towards the surface and enter shallow groundwater or appear as seepages at the surface. The presence of methane (CH_4) in groundwater is generally only of concern if it reaches concentrations that, if de-gassing should occur, it could reach explosive levels. Methane becomes an explosive hazard at concentrations of 5-15% by volume in air. Assuming complete outgassing from water, this typically requires a minimum dissolved methane concentration of 1.6 mg/l.

Initial results from the National Methane Baseline Survey of UK groundwaters and a summary of existing data are available on the BGS website[2]. The data show that methane is almost always detected in groundwater, but generally at low concentrations. Median methane concentration sampled in the Midland Valley area was 0.0036 mg/l, with variable individual values to a maximum of 1.68 mg/l considered as 'baseline'. Further details of groundwater geochemistry in central Scotland are given in Ó Dochartaigh *et al*. (2011).

[1]SEPA - Regulatory guidance: Coal bed methane and shale gas - Version 121119,
[2]http://www.bgs.ac.uk/research/groundwater/quality/methane_baseline_initial_results.html

2.4 Seismic, well, borehole, mining and outcrop dataset

This assessment of the Carboniferous Midland Valley of Scotland is based upon seismic mapping integrated with hydrocarbon well, stratigraphic borehole information, mine abandonment plan depth data and outcrop geology.

2.4.1 Seismic data

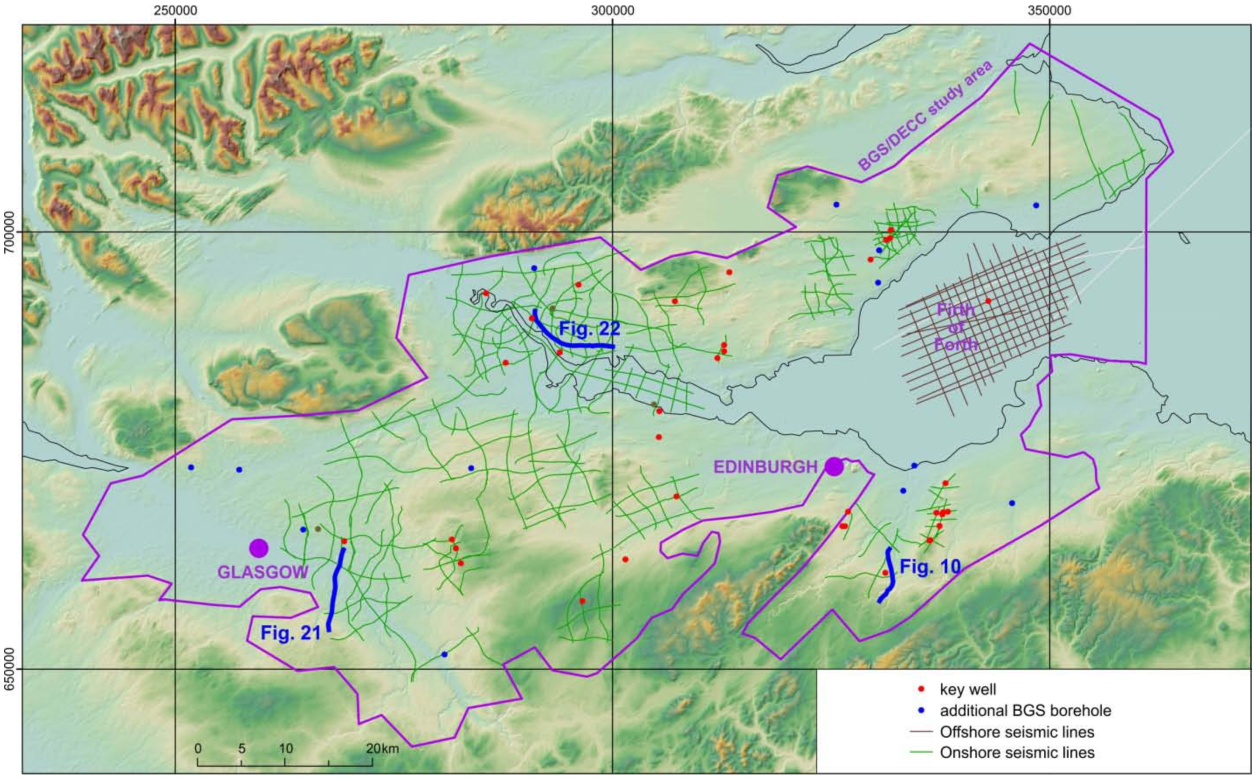


Figure 9 Location of 2D seismic profiles used to assess the shale potential of the Midland Valley of Scotland study area. The locations of the seismic examples illustrated in this report are highlighted in blue

All of the available onshore seismic data was obtained from the UK Onshore Geophysical Library (UKOGL www.ukogl.org.uk). A total of 1,325 km (823 miles) of onshore seismic data was interpreted along with 478 km (297 miles) of previously interpreted offshore 2D seismic data (Figure 9). The seismic data, dating from 1977-88, is of variable quality, ranging from poor in the Midlothian area and around the Rashiehill borehole and Bathgate Hills, to moderate-good in the Firth of Forth. An iterative approach was employed, finding seismic lines with the good evidence for horizon mapping and well ties, then circling back through the poorer quality lines, with an interpretation that was consistent with the BGS outcrop mapping and with nearby wells. Some areas of seismic data such as over the Burntisland Anticline and Kilsyth Basin had no well ties and time-converted borehole and mining data was used as a guide.

Seismic data from the National Coal Board was not utilised as it is focused at shallow depths and some Geological Survey lines (e.g. Line IGS-1982, Forsyth *et al*. 1996) were not available in digital format. In the Firth of Forth, existing BGS interpretations made on reprocessed seismic data tied to the Firth of Forth 1 well were used (Monaghan *et al*. 2012).

An example of a poor quality, short line length seismic profile from the Midlothian area is given in Figure 10. In this area, mining data on coal seams within the Limestone Coal Formation together with borehole data provides a higher confidence dataset. Examples of better quality seismic lines are shown in section 2.7.1 and in Underhill *et al*. (2008) and Monaghan *et al*. (2012).

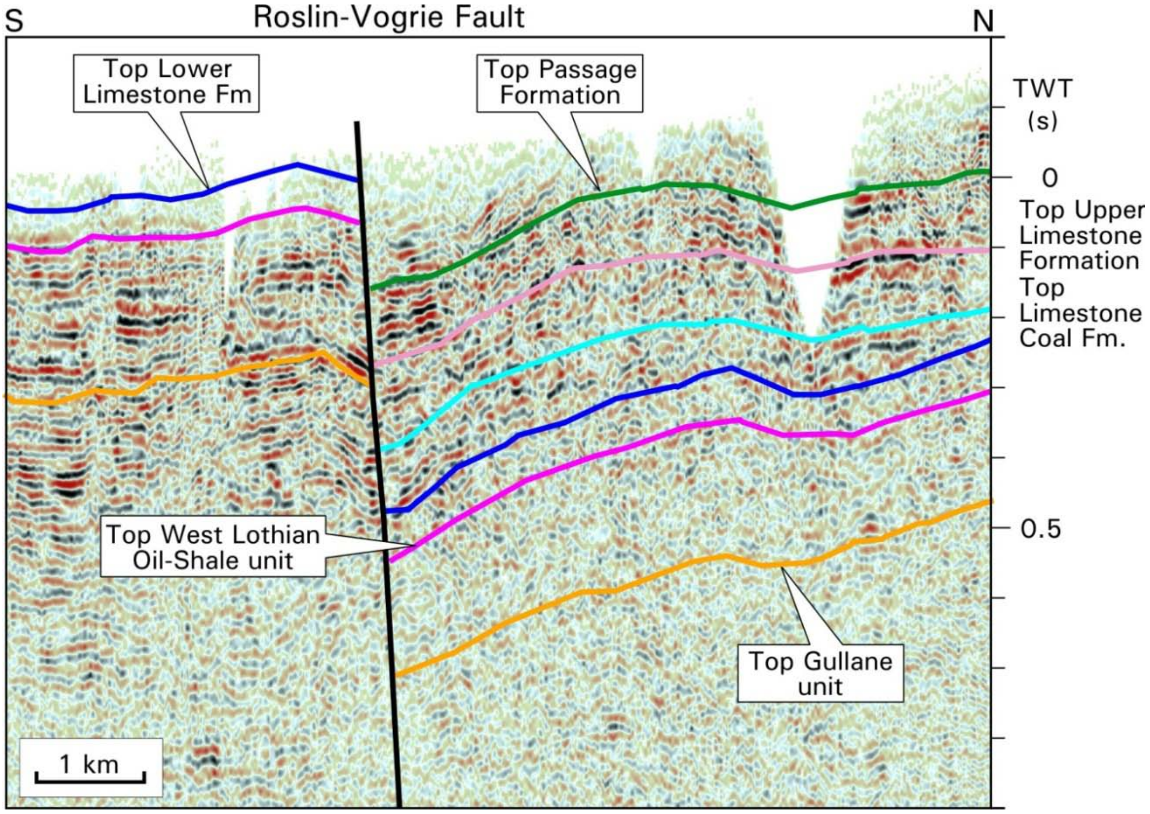


Figure 10 Seismic line LV82-04 along the Midlothian syncline and across the Roslin-Vogrie Fault, the Carrington well is some way up-dip of the line.

2.4.2 Well and borehole data

A distinction is made between 'wells' that have been drilled to evaluate hydrocarbon or coal resources and generally have associated downhole geophysical data and 'boreholes' that have been drilled for numerous resource (including coal, fireclay, limestone, sand and gravel), commercial development and scientific purposes that generally lack associated downhole geophysical data.

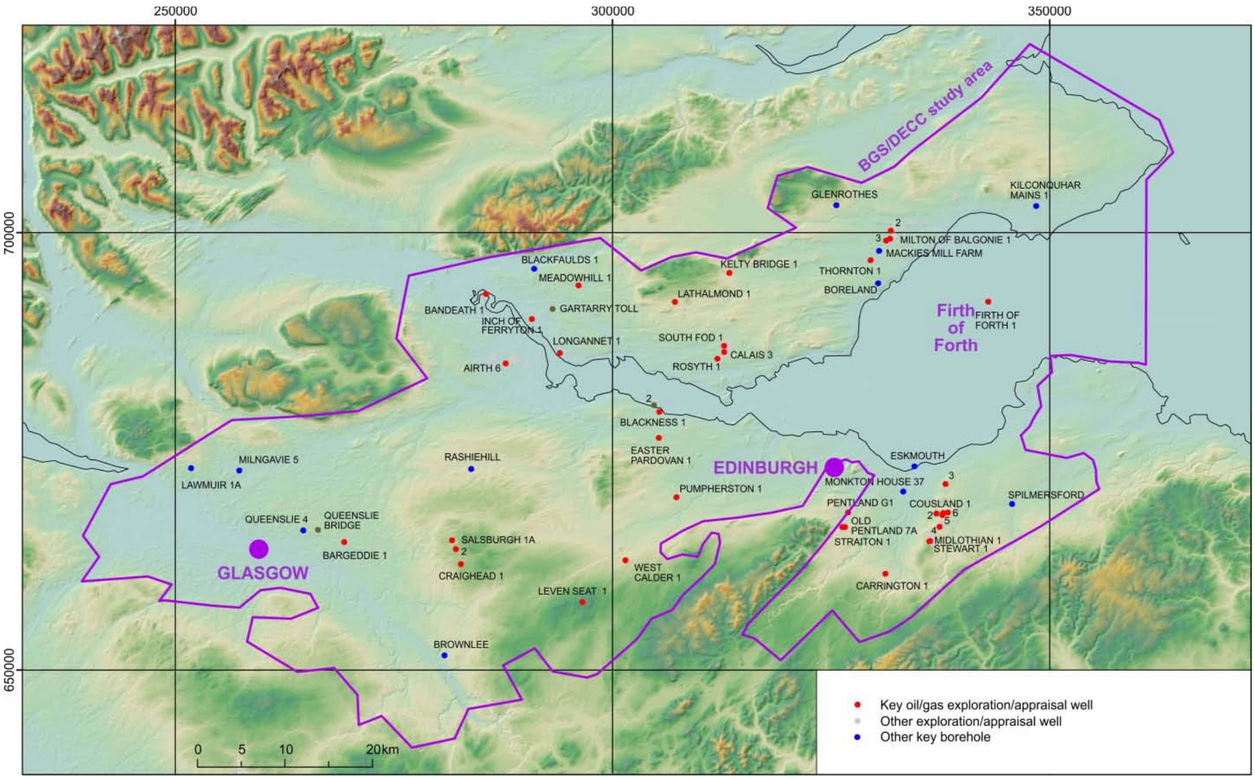


Figure 11 Distribution of the key wells and other deep boreholes used in the study

A total of 98 hydrocarbon exploration and appraisal wells were drilled within the Midland Valley of Scotland between 1919 and 2008. Of these, 37 of the deepest, highest quality and best spatially distributed wells have been utilised extensively for seismic and 3D model interpretation, calculation of percentage of the succession composed of shale etc. The majority of the conventional oil and gas wells were drilled on structural highs including anticlines or fault-block highs.

BGS holds in its borehole database over 215,000 records in the Midland Valley of Scotland, 56 records over 1,000 m (3,281 ft) and 289 over 500 m (1,640 ft) drilled depth (note that these figures include a record for most of the hydrocarbon wells). All boreholes over 1,000 m (3,280 ft) drilled depth and selected boreholes over 500 m (1,640 ft) were considered for this study, along with some additional key borehole records (e.g. BGS Lawmuir 1A, north of Glasgow). BGS boreholes at Spilmersford, Rashiehill and Glenrothes have associated downhole geophysical data which was utilised. Stratigraphic information was recalled from the BGS borehole database to constrain the modelled depth surfaces. For example, on the base of the Limestone Coal Formation, stratigraphic information from 514 boreholes was utilised as model constraint.

The spatial distribution of key wells and boreholes is heterogeneous, as are the strata penetrated. One kilometre (3,280 ft) deep wells in the centre of coalfields reach only the Upper Carboniferous coal-bearing strata (usually no deeper than the Limestone Coal Formation) whereas wells of a similar drilled depth commencing on anticline highs penetrate a variably thick Lower Carboniferous sedimentary and volcanic succession.

Being so deeply buried, the base of the West Lothian Oil-Shale unit and base of the Gullane unit have particularly poor well/borehole control. For example, the base of the Gullane unit is only penetrated by 15 wells/boreholes, over half of which are very shallow, and are close to outcrop.

A selection of the key well and borehole interpretations is discussed and illustrated in five correlation panels in Appendix C.

2.4.3 Outcrop data

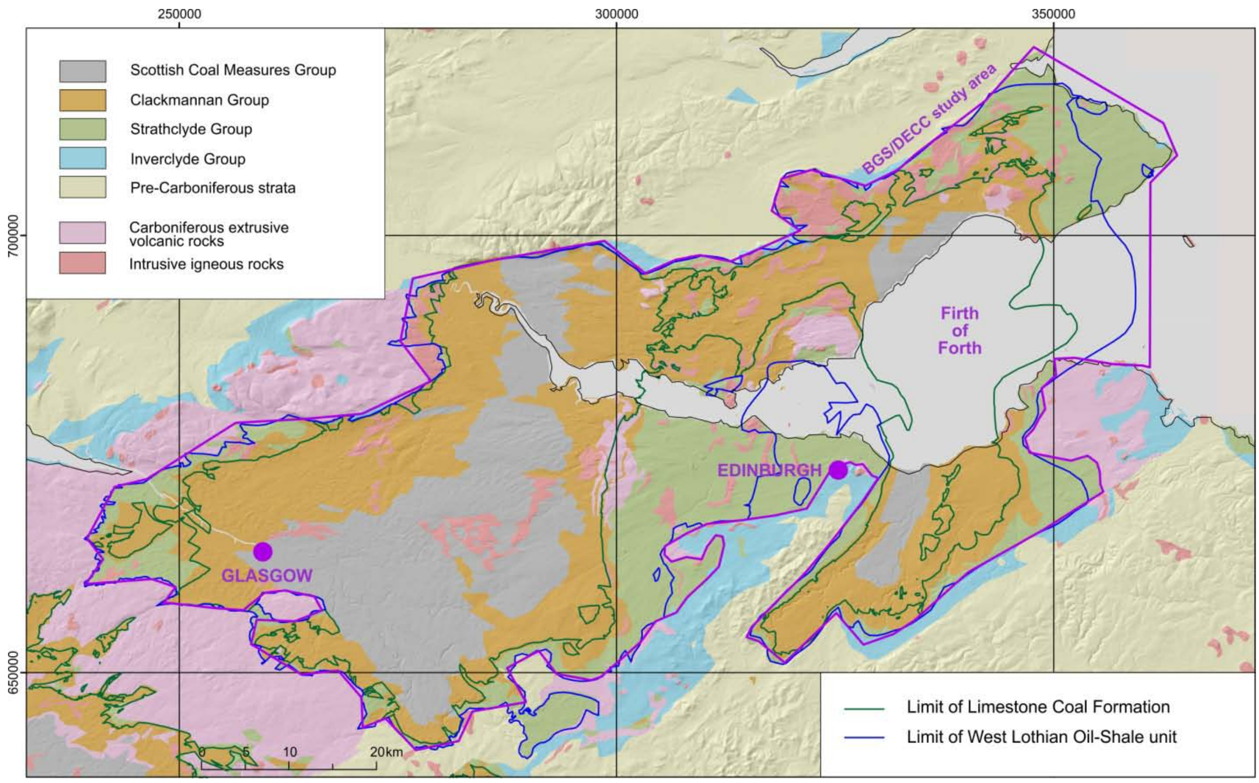


Figure 12 Geological map at 1:625 000 scale (BGS 2008) together with the extent of the Limestone Coal Formation and West Lothian Oil-Shale unit extracted from BGS DigMap 1:50,000 (BGS 2013a). Geological information ©BGS/NERC.

Outcrop data were derived from BGS DigMap 1:50,000 scale (BGS 2013a) and used to constrain seismic interpretation and modelling. All of the prospective units crop out around basin margins within the study area, providing insight into facies variability.

2.4.4 Mining data

The Coal Authority provides the definitive coal mining dataset for the UK. Information on the extent and depth of abandoned coal mine workings greater than 500 m (1,640 ft) below Ordnance Datum was licensed from The Coal Authority. This information was used to exclude rock volumes situated close to existing mine workings from the shale resource estimation (see section 4.1.1 for further description).

Former mine workings of the West Lothian Oil-Shale are extensive in West Lothian and present in parts of Midlothian. These non-coal mines are relatively shallow (less than around 985 ft (300 m) below OD : Carruthers *et al*. 1927 and BGS records).

Selected coal mine abandonment plan data collated by BGS provided good quality, spatially extensive constraints on the modelled depth surfaces of the Upper Limestone and Limestone Coal formations.

2.4.5 Gravity and magnetic data

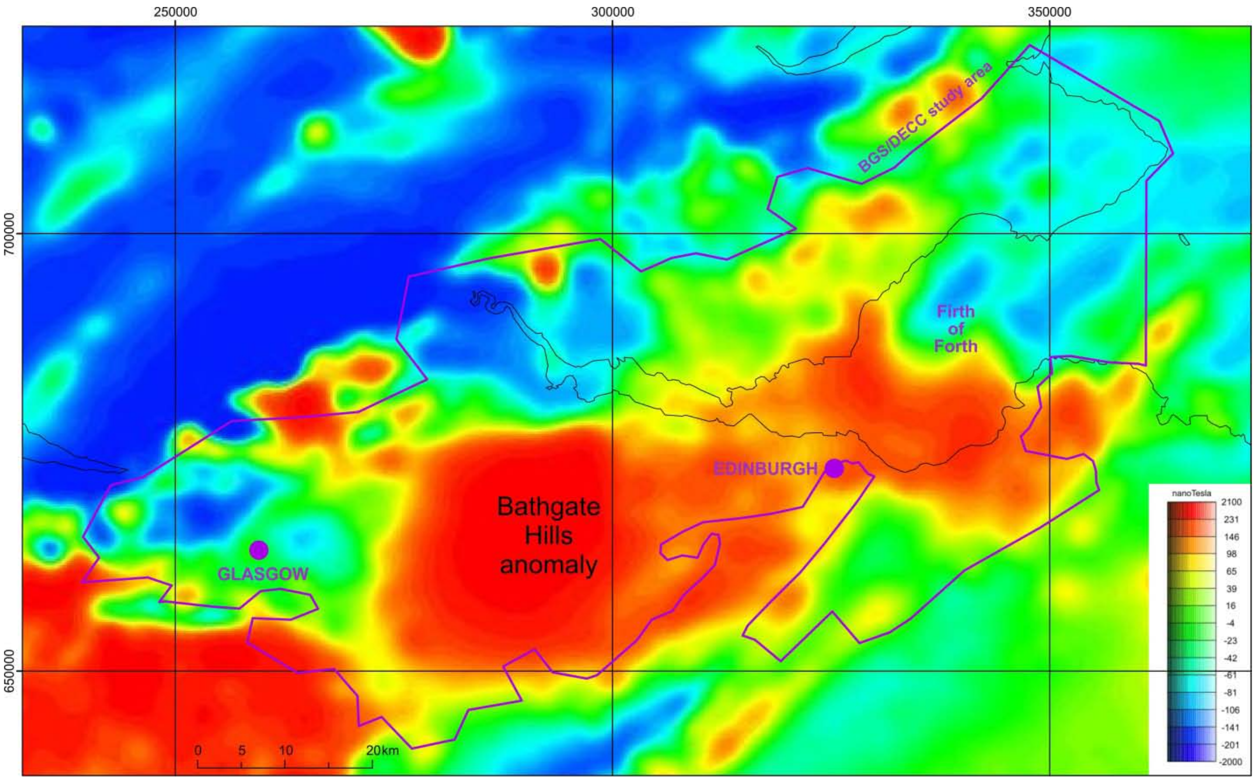


Figure 13 BGS Magnetic anomaly map for the BGS/DECC study area of the central and eastern Midland Valley. Red-yellow = high, blue = low. Geophysical information ©BGS/NERC.

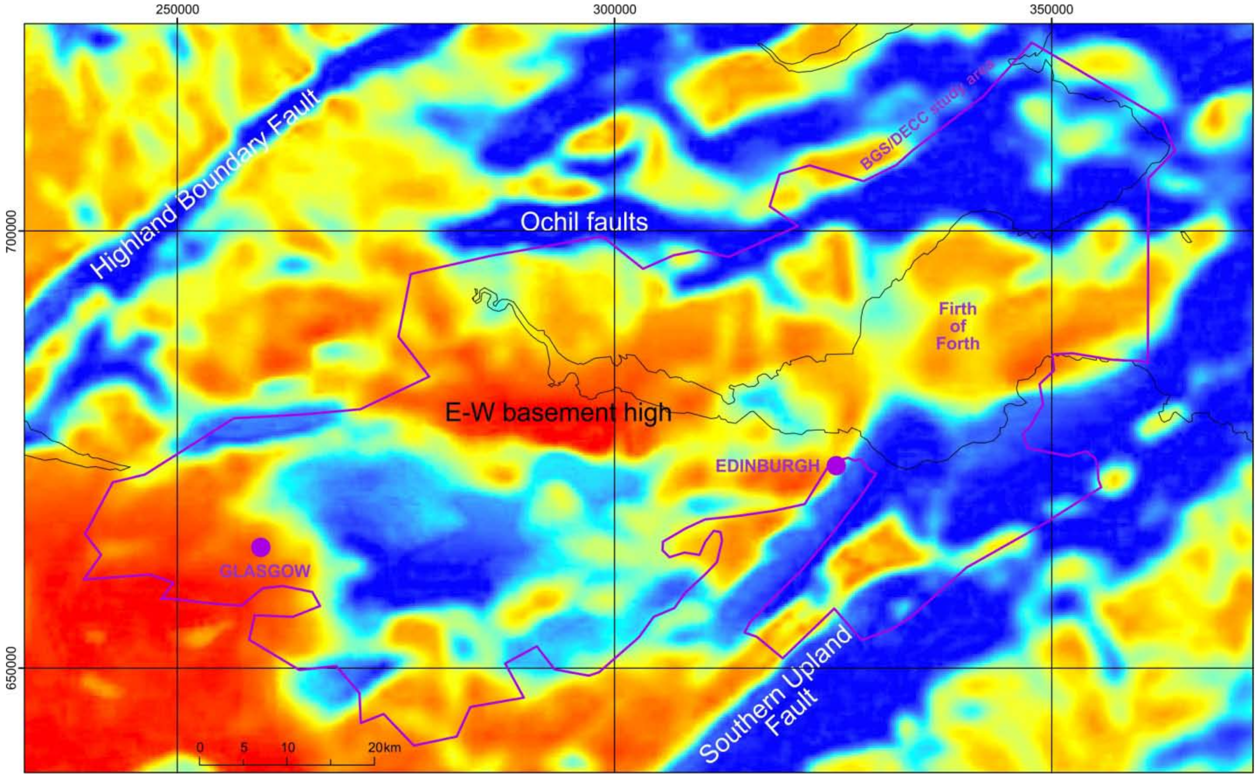


Figure 14 BGS Gravity anomaly map for the BGS/DECC study area of the central and eastern Midland Valley. Red-yellow = high, blue = low. Geophysical information ©BGS/NERC.

The magnetic anomaly map (Figure 13; available at http://mapapps2.bgs.ac.uk/geoindex/home.html?theme=geophysics) shows a high anomaly in the area of the Bathgate Hills Volcanic Formation in the southern part of the Central Coalfield. 3D geophysical modelling concluded that a large basic igneous mass extending to a depth of 5 km or more beneath overlying lavas could create the anomaly, as could the lavas separated from an underlying basic mass or basement block by Devonian sedimentary and volcanic rocks (Rollin *et al.* 2009). Other volcanic centres (e.g. Campsie, Garleton and Burntisland) were also modelled as a lava pile over a deep intrusive source. Gravity anomalies suggest that an east-west basement horst extends from the Bathgate area to the Garleton Hills (East Lothian; Rollin *et al.* 2009; Figure 14). Both the Highland Boundary and Southern Upland faults can be observed in gravity and magnetic data, along with the position of the East and West Ochil Faults (gravity data only; Figures 13, 14).

2.5 3D geological modelling and depth maps

A 3D geological model was generated from seismic, well, borehole, mining and map data using GOCAD-SKUA® for the purpose of providing regional scale (1:100,000 - 1:250,000) depth surfaces, plus gross and net rock volumes for the four shale-prospective resource units over the study area.

The main limitations of the regional-scale model are the exclusion of numerous faults with throws less than a few hundred metres (approx. 700-1,000 ft), the lack of mapped surfaces for volcanic units and igneous intrusions, and the large uncertainties on the interpretation of the base Gullane unit and base West Lothian Oil-Shale unit surfaces resulting from lack of data/poor quality seismic data.

The resultant depth maps of the prospective succession show a range from surface to -19,250 ft (-5,870 m; on base Gullane unit) relative to OD in the Midlothian-Leven Syncline (Figures 15-18 and 20). The major structures discussed in more detail in section 2.7 below are depicted on the base West Lothian Oil-Shale unit image (Figure 20). Note that only the main unit limits are shown, small outliers mapped at 1:50,000 scale are not shown.

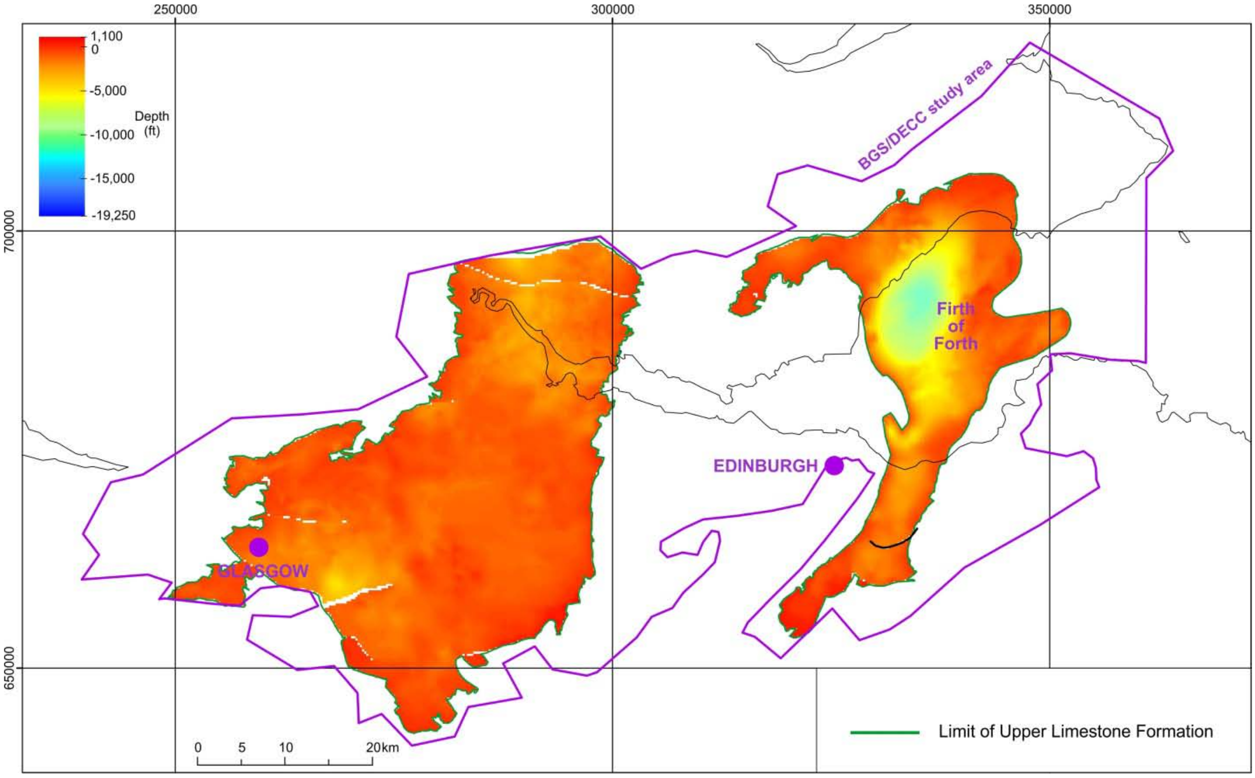


Figure 15 Depth map to the base of the Upper Limestone Formation (top Limestone Coal Formation) in feet relative to Ordnance Datum.

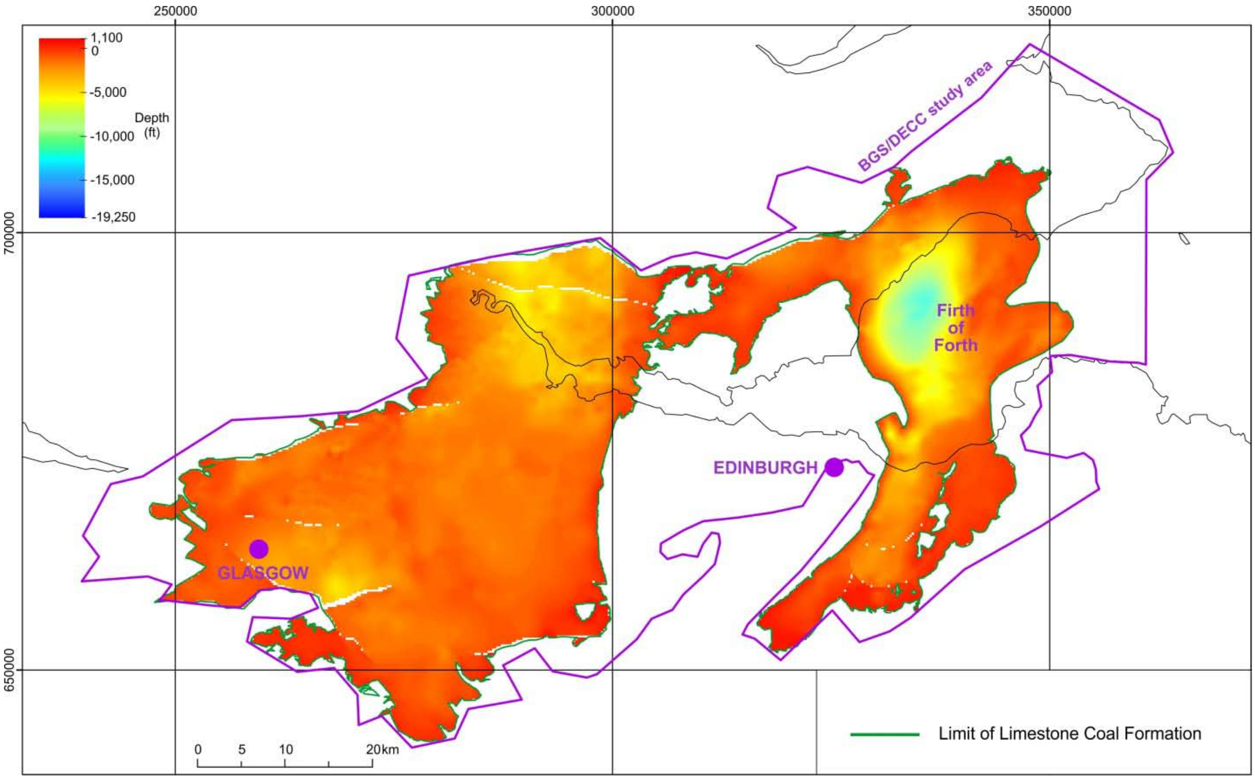


Figure 16 Depth map to the base of the Limestone Coal Formation in feet relative to Ordnance Datum.

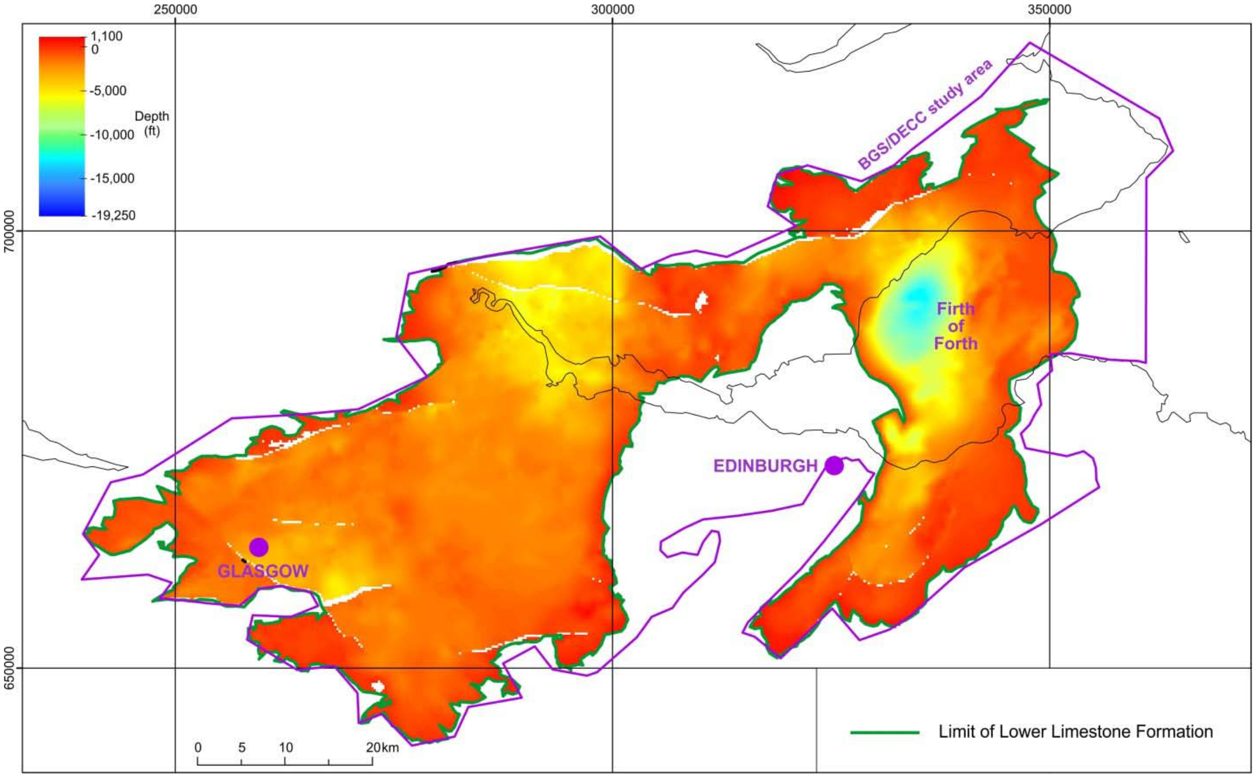


Figure 17 Depth map to the base of the Lower Limestone Formation in feet relative to Ordnance Datum.

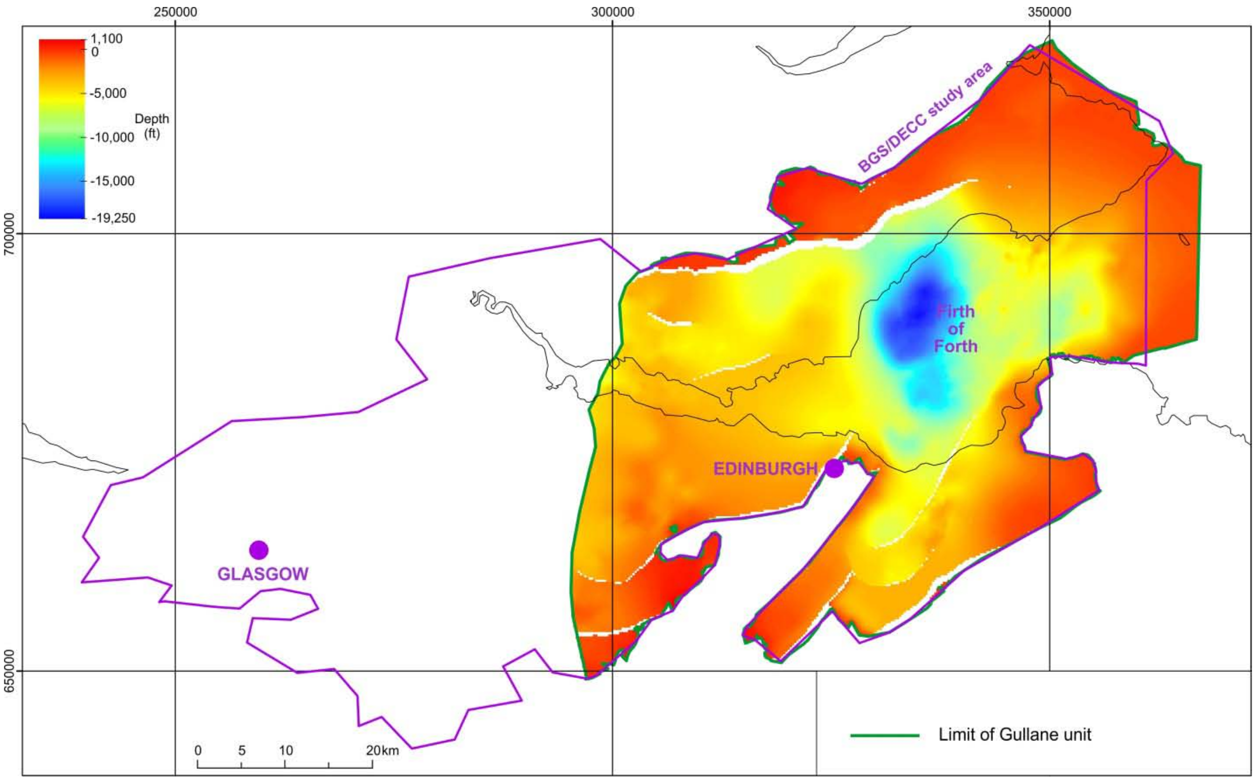


Figure 18 Depth map to the base of the Gullane unit in feet relative to Ordnance Datum.

The Gullane unit has not been proven in the west of the study area, where the West Lothian Oil-Shale and equivalents overlie the Clyde Plateau Volcanic Formation, Salsburgh Volcanic Formation (e.g. as proved by Salsburgh 1A) or the Inverclyde Group (as proved by Inch of Ferryton 1).

2.6 Magmatism

Carboniferous to Permian magmatism in the Midland Valley of Scotland is unusual in its longevity of up to 90 Ma (Upton *et al.* 2004). Carboniferous, transitional to alkaline lavas, sills, plugs and dykes have an extension-related, intraplate petrogenesis (Smedley 1986). Early Visean activity (e.g. Garleton Hills, Arthur's Seat, Clyde Plateau volcanic formations) comprised basaltic to rhyolitic lavas, tuffs and related intrusions. Later Visean and Namurian activity (e.g. Kinghorn and Bathgate Hills volcanic formations) was dominated by basaltic lavas and tuffs (Smedley 1986, Stephenson *et al*. 2003, Upton *et al.* 2004). A short-lived extensional interval of tholeiitic magmatism in the latest Carboniferous extended across the Midland Valley of Scotland and northern England to Scandinavia (Timmerman 2004, Monaghan & Parrish 2006). Permian alkaline magmatism (Wallis 1989) is related to post-orogenic extension, recognised across NW Europe (Neumann *et al.* 2004).

Appendix B describes the Midland Valley magmatism and the regional tectonic context in more detail.

Magmatism influences the shale resource of the Midland Valley of Scotland in several ways. Firstly, voluminous extrusive magmatism shortly before and coeval with the shale prospective succession strongly influenced basin palaeogeography, as well as forming a locally significant proportion of the basin fill succession. Secondly, higher heat flow during the Carboniferous in the western, more volcanically active part of the Midland Valley of Scotland is inferred from maturity data (see section 3.6). Thirdly, intrusive magmatism, particularly the end Carboniferous tholeiitic Midland Valley Sill-Complex locally enhanced sediment maturity up to ranks of R_o=6% within an approximately 300 m (980 ft) aureole of higher rank (see section 3.6). Further study or analogues of the possible discontinuities and pathways created by post-depositional igneous intrusions such as regionally extensive, near vertical E-W dykes in the Central Coalfield would be valuable.

Defining the extent, character and timing of magmatism is therefore important. The tops of the Clyde Plateau, Salsburgh, Arthur's Seat and Garleton Hills Volcanic formations form the base of the prospective sequence in many parts of the study area. The subsurface dataset has not been mapped, modelled or interpreted for the complex relationship between intrusive and extrusive igneous rock geometries within, or laterally equivalent to, shale-prospective strata due to data quality and distribution. Instead, the volume of igneous rock within the succession is incorporated into the percentage shale maps (section 2.9). For example, the percentage shale in the Lower Limestone Formation in the area of the Bathgate Hills Volcanic Formation is very low (0-10 %) because the strata are dominated by igneous rock.

2.7 Basin development

A wide variety of fault orientations (Figures 3, 20), sub-basins and differential uplift patterns across the Midland Valley of Scotland result from a complex Palaeozoic to recent basin history. Broadly, four stages can be summarised:

- Late Devonian to Early Carboniferous basin formation in the Variscan foreland
- Mid to Late Carboniferous basin formation to inversion
- Latest Carboniferous to Permian tholeiitic magmatism and post-orogenic extension
- Post Carboniferous deposition, uplift and erosion

As a result, the Carboniferous Midland Valley of Scotland is not a simple graben containing a single basin; it is composed of a series of inter-related depocentres and intra-basinal highs (Figures 19, 20). Appendix B provides a more detailed summary.

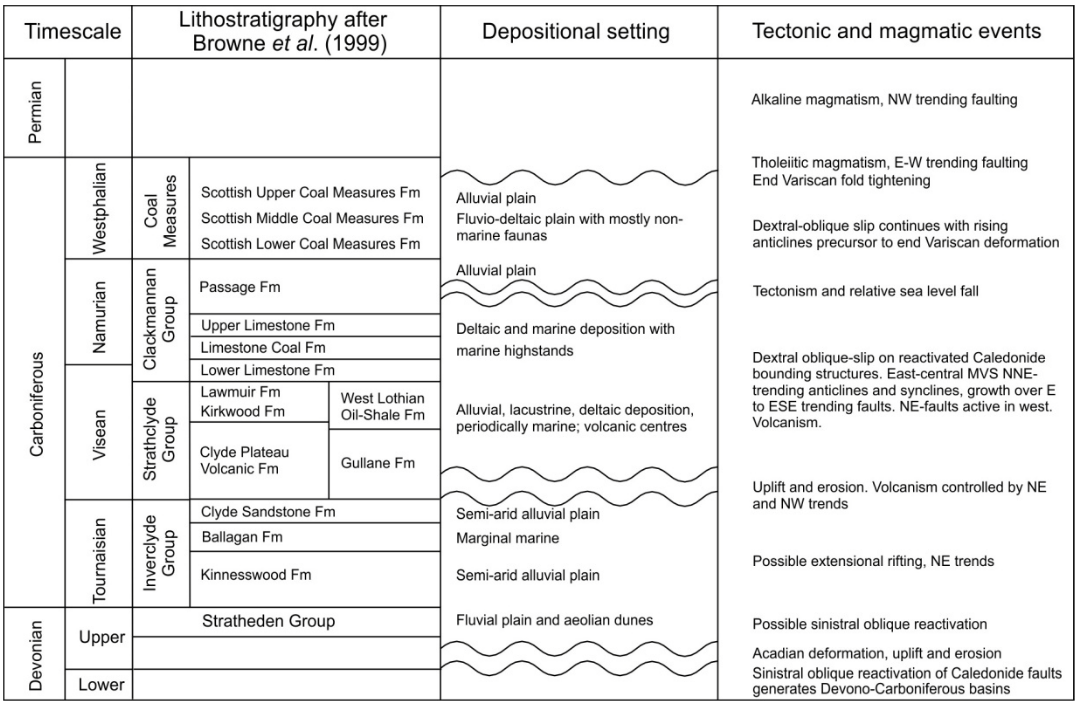


Figure 19 Summary chart of Midland Valley of Scotland Carboniferous tectonic, magmatic and depositional history

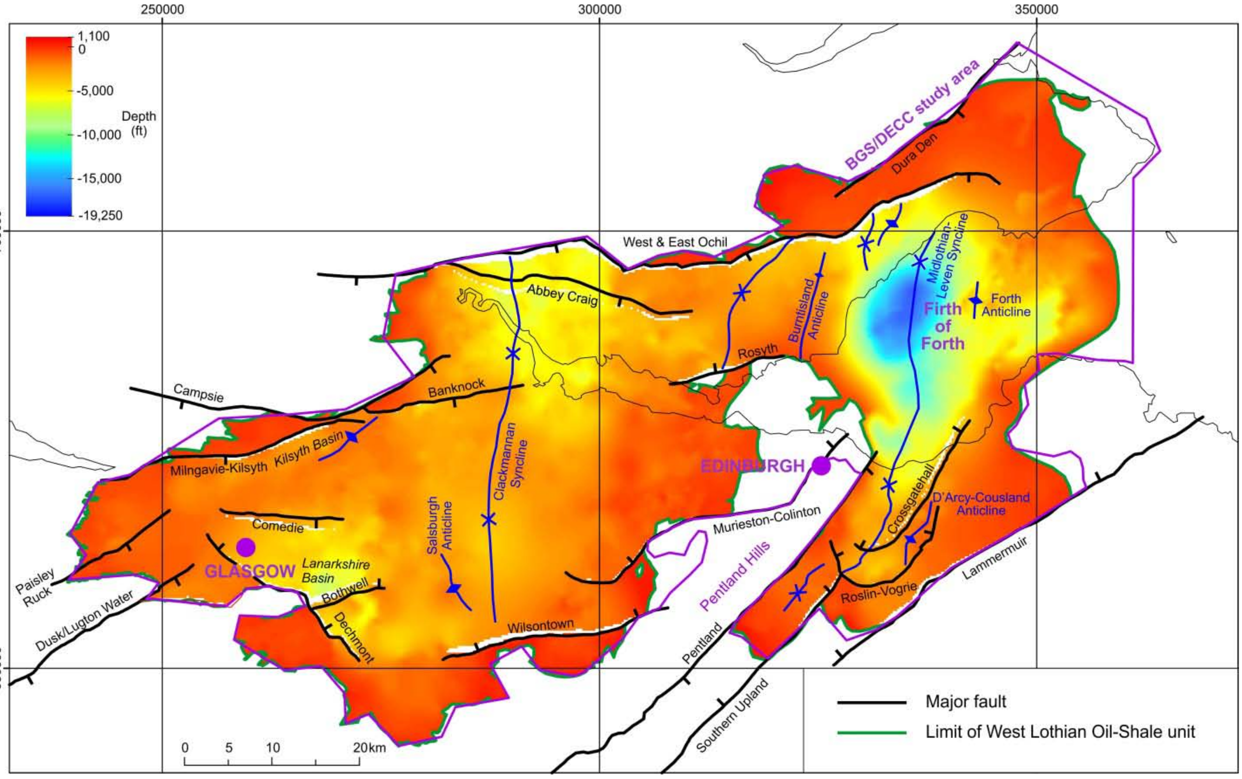


Figure 20 Map showing outcrop position of regional-scale faults included in the geological model, together with the main structural features, using the base of the West Lothian Oil-Shale unit as an illustrative depth map.

The main structural features include the deep low of the Midlothian-Leven Syncline in the Firth of Forth, Fife and Midlothian, the shallower Clackmannan Syncline and the Lanarkshire Basin in the Central Coalfield area (Figures 3, 20). Coal Measures Group strata are preserved in the centre of the synclines and basins, in a Carboniferous succession over 18,000 ft (5.5 km) thick in the Firth of Forth and over 6,500 ft (2 km) thick in the Central Coalfield. Significant throws of up to 5,900 ft (1,800 m) characterise the main basin bounding fault structures such as E-W trending West and East Ochil faults, the NW-trending Dechmont Fault and the NE-trending Pentland Fault. The Lower Palaeozoic inlier of the Pentland Hills forms a major intrabasinal high.

E-W to NE-SW faults with smaller throws of up to approximately 2,600 ft (800 m) bound parts of the basin and outcrop (e.g. Wilsontown, Campsie faults), whereas other faults with throws ranging from approximately 650 ft to 1,300 ft (200 to 400 m) offset the basin fill succession (e.g. Comedie, Bothwell, Crossgatehall faults). Numerous mapped faults with throws smaller than a few hundred metres have not been included in this regional scale study. Fault dips estimated from outcrop/opencast sites, mining data and seismic data vary from near-vertical to 50° with evidence of normal (e.g. East Ochil), reversed (e.g. Pentland) and strike-slip (e.g. Crossgatehall) movements. Faults were modelled as planar structures of varying dip, simplified from seismic and mapped traces.

The structural development of the Midlothian-Leven Syncline and surrounding anticlines has been documented by Underhill *et al*. (2008) as Visean-Westphalian dextral strike-slip followed by Late Carboniferous fold tightening. Read (1989) highlighted the role of Upper Carboniferous dextral strike-slip in the variety of fault and fold structures located in the footwall of the East Ochil and Campsie Faults during Upper Carboniferous times. The West Ochil Fault may have been buried during the Namurian and Westphalian, with reactivation during end Carboniferous N-S extension (Rippon *et al*. 1996).

The Central Coalfield is comprised of several structural elements, whose genesis is less well-studied. The Clackmannan syncline forms the largest structure and is deepest and best-defined at its northern 'Kincardine Basin' end (Figures 3, 20), where the eastern limb is more steeply dipping than the western limb (see Figure 17). Visean syn-sedimentary syncline growth was interpreted by Hooper (2004), focusing on the interval above the Hurlet Limestone where reflectors were tied to stratigraphy. The Clackmannan Syncline is cut by numerous east-west faults, two of which define the narrow 'Forth Graben' of Hooper (2004), a syn-depositionally active extension of the Kilsyth Basin. The Banknock Fault bounds the northern edge of this graben (Figure 20).

The Salsburgh Anticline divides the Clackmannan syncline and Lanarkshire Basin in the southern part of the Central Coalfield. Visean fault growth in the Salsburgh area was interpreted by Hooper (2004) from seismic interpretation, followed by basin subsidence in the Namurian and subsequent post-depositional inversion to produce the current anticlinal structure.

The Lanarkshire Basin (defined in Hall *et al*., 1998, variously termed the Motherwell Basin or, in its southern part, the Uddingston Syncline or basin) in the hanging wall of the Dechmont Fault shows syn-depositional growth on ENE-trending fault structures such as the Bothwell Fault (this study, Hooper 2004), with much of the large throw on the Dechmont Fault being considered post-depositional (Paterson *et al.,* 1998).

Taking together all the various orientations and ages of fault and fold structures Hooper (2004) favoured a Visean-Westphalian dextral transtension model for the Central Coalfield, cut by later E-W faults.

2.7.1 Examples of structural features

Clear packages of sub-parallel reflectors can be seen on some seismic lines in the Lanarkshire Basin area to the south-west of Glasgow, defining a relatively deep half-graben structure (Figure 21). Tied to the Bargeddie well, these show stratal thickening towards the ENE-trending Bothwell Fault and could indicate a thick West Lothian Oil-Shale or older succession which has not previously been recognised in regional palaeogeographies. Complex fault patterns to the south of the Bothwell Fault on BGS maps are difficult to reconcile with several seismically identified faults, such that the current interpretation at base West Lothian Oil-Shale unit shows considerable topographic relief related to faults, which have not been specifically modelled.

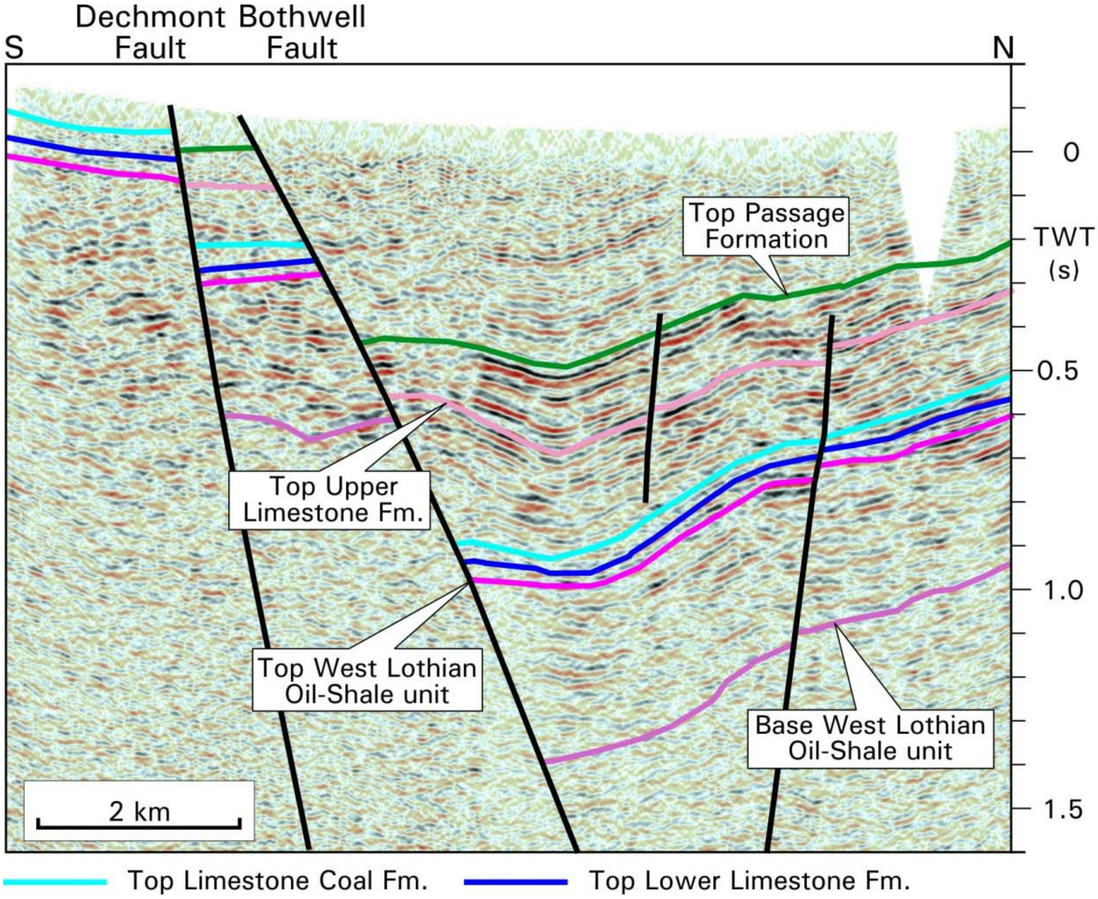


Figure 21 Seismic line SAX-85-06 showing a syn-depositional half-graben bounded by the Bothwell and Dechmont faults in the Lanarkshire Basin.

Seismic lines at the northern end of the Clackmannan Syncline ('Kincardine Basin') are of variable quality (Figure 22). Normal faults with throws in the order <100 ms (approx. <150 m/500 ft) are fairly commonly interpreted, though the data quality and line spacing makes the position/orientation of some faults difficult to tie in with similar scale structures derived from mining and map datasets. Faults of this <100 ms scale shown on Figure 22 have not been included within the 3D geological model due to the number and complexity of the structures and the minimal overall effect on regional resource volumes.

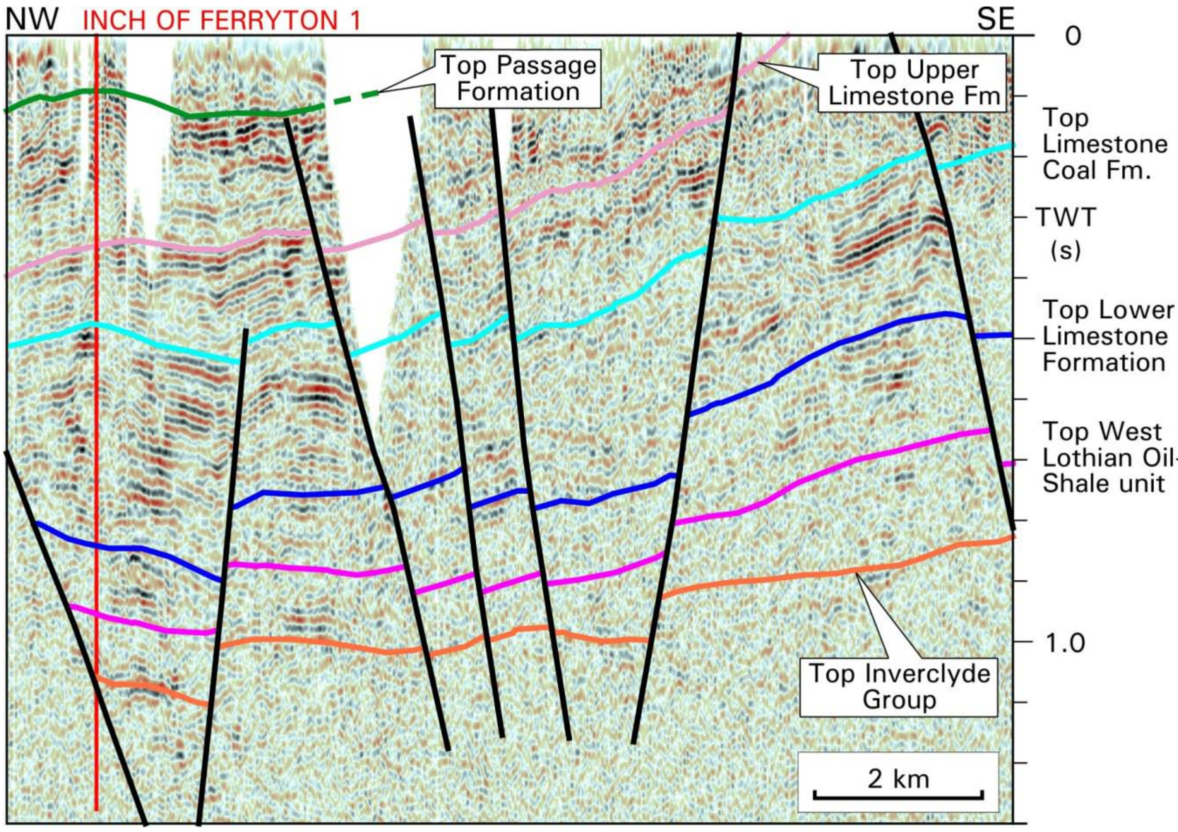


Figure 22 Example seismic line TOC82-V03 tied to Inch of Ferryton 1 well in the centre of the Clackmannan Syncline, with numerous relatively small offset faults interpreted

Isopach (vertical thickness) maps derived from the 3D geological model contain local highs and lows related to the variable data distribution and data quality used to calculate the model, as well as significant variations in highly dipping strata from the true unit thickness, such as along the western Midlothian-Leven Syncline. Table 2 in Appendix C provides examples of the variation in formation thickness observed across the Midland Valley of Scotland.

2.7.2 Faulting and the shale resource

The set of standard criteria for a successful shale resource includes the preference that they occur in large, stable basins, without complex tectonics (Charpentier & Cook 2011). The location and character of pre-existing, natural faults influences the compartmentalisation of the resource. Faults have the potential to act as pathways or barriers for fluid or gas migration, plus there are risks of induced seismicity related to hydraulic fracturing (IEA 2012, The Royal Society 2012). The Midland Valley of Scotland has a complex tectonic history resulting in significant faulting and folding of prospective strata (see section 2.7).

In the Midland Valley of Scotland, the geometry of fault structures with throws over tens of metres (approx. 150 ft) can be reasonably well interpreted using a combination of mining, borehole, seismic and map data, where that data exists. However, it should be noted that due to seismic data quality, poor coverage and geological complexity, different geologists would very likely make different detailed interpretations of seismic picks and faults on the same dataset; a point examined by Polson & Curtis (2010) using seismic data from the Firth of Forth. Also, not all faults mapped at surface can be interpreted on seismic data at depth, this may be because faults die out at depth, they are below seismic resolution, or their throw/extent/position was poorly constrained when the map was made. Conversely, there are some faults which can be picked on seismic data at depth which are not recognised on BGS maps. This may be because they die out towards the surface or because there was no near surface data available to deduce their presence when the map was made.

Interestingly, recent reprocessing of the Firth of Forth seismic data to focus on deeper intervals revealed coherent steeply dipping and tightly folded reflectors, compared to incoherent reflectors in the original dataset often interpreted as faults, reducing the overall number of faults interpreted (Smith *et al*. 2012 p. 54). Reprocessing the 1980s onshore 2D seismic data could be a valuable tool in further elucidating basin structure.

This study considers only the largest, regional-scale faults (more than approximately 200-400 m (650-1,300 ft) throw) which significantly impact the resource volume. More detailed local studies at the licence block scale would greatly benefit from high resolution 3D seismic data to better define fault extents and geometries. Mine abandonment plans can also provide measured depth/extent data to define faults at scales from metres to hundreds of metres and could be used to characterise the extent of unfaulted blocks as well as fault length-throw scaling relationships within different structural basins of the Midland Valley of Scotland.

No measured data on whether Midland Valley of Scotland faults are sealing (barrier to fluid flow), non-sealing (pathway to fluid flow) or both, were available for this study. Over geological time hydrocarbons have migrated along some fault structures (section 2.2.4). Over timescales of years, the author is aware of water monitoring boreholes proving that moderate-size faults (few hundred metres throw) in opencast coal sites can form hydrogeological barriers.

2.8 Current day stress fields and seismicity of the Midland Valley of Scotland

Using earthquake focal mechanisms, Baptie (2010) summarised the current stress field of Scotland as near east-west extension. This is in agreement with the NNW trend for the maximum horizontal compressive stress shown on the World Stress Map 2008 release (Heidbach *et al*. 2008).

Earthquakes ≥ 2.5ML have been recorded in several locations within the Midland Valley of Scotland, with smaller events recorded in the coalfields (e.g. northern Central Coalfield and the Midlothian Coalfield) attributed to roof/pillar collapse (e.g. Ottemoller & Thomas 2007, Baptie 2010; Figure 23).

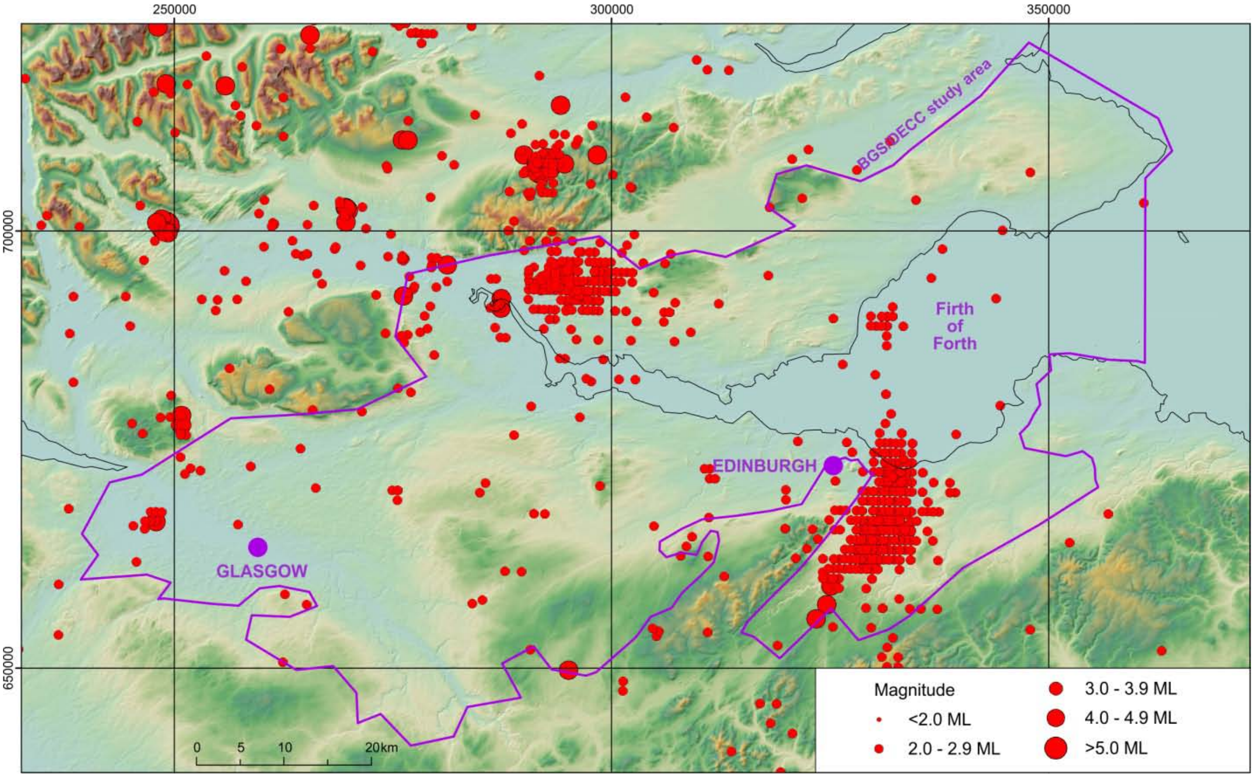


Figure 23 Earthquakes recorded instrumentally by BGS from 1970 to May 2014 across Central Scotland. The clusters of smallest magnitude earthquakes (<2.0 ML) were associated with coal mining activity, which was only detected because temporary monitoring networks were deployed. It is quite possible that there were small mining-induced earthquakes in other coalfields that have not been recorded. The size of the red circle depicts the earthquake magnitude (ML = Richter local magnitude). Information ©BGS/NERC.

2.9 Shale-prospective stratigraphy

The Midland Valley of Scotland has stacked and possibly a "hybrid" shale play (the latter being one where a carbonate or sandstone horizon to be hydraulically fractured is sandwiched between mature shales). The potentially prospective Midland Valley of Scotland succession is up to 9,800 ft (3 km) thick and contains numerous shale-rich intervals within a vertically and laterally heterogeneous sequence (Figures C2-C6, Appendix C). Shale beds vary in thickness from a few inches to around 160 ft (50 m) and are interbedded with numerous lithologies including sandstone, limestone and coal, as well as igneous rocks.

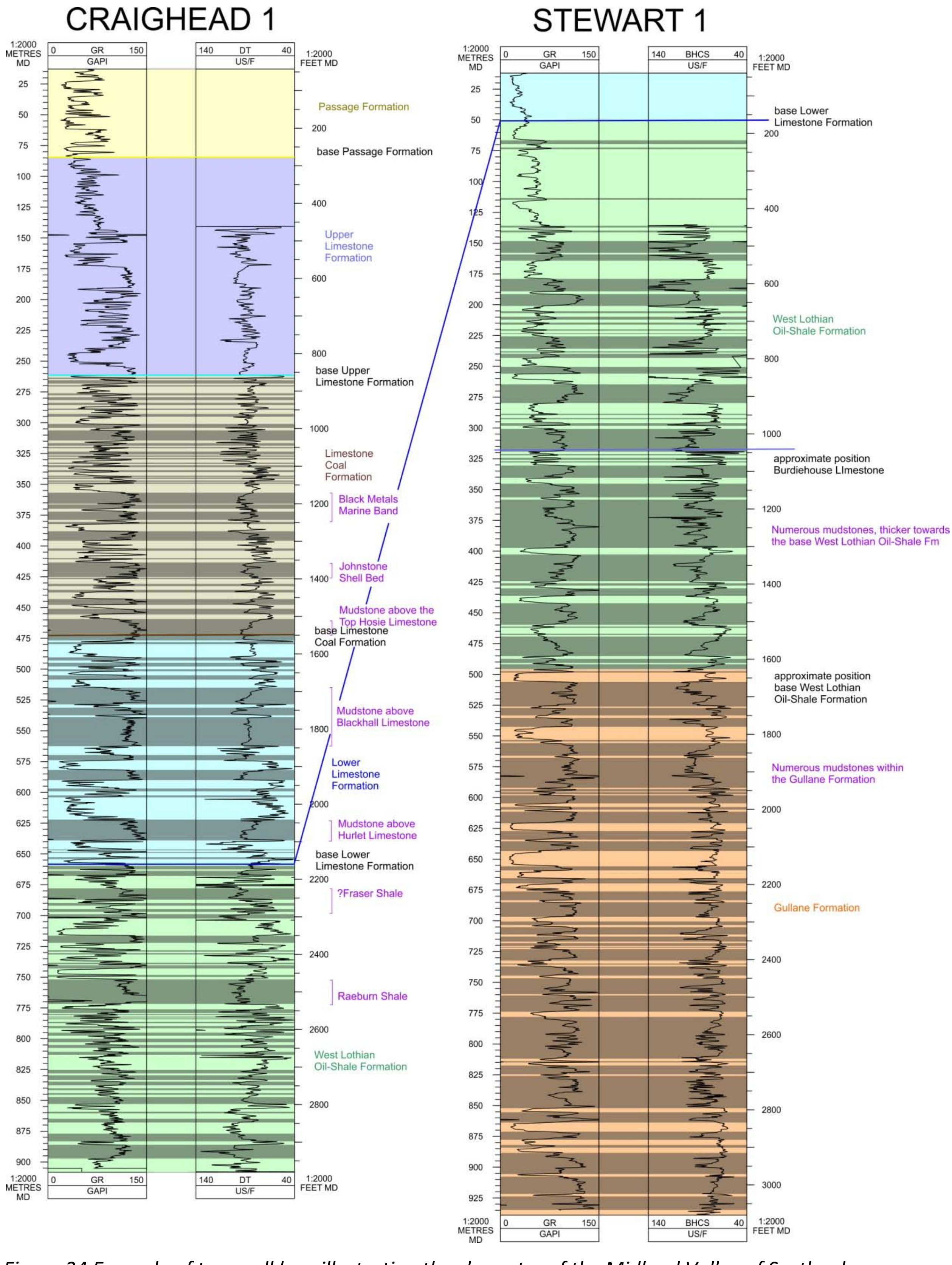


Figure 24 Example of two well logs illustrating the character of the Midland Valley of Scotland prospective shale succession as numerous mudstones (grey) within a stacked sequence. The illustrated section extends from the Passage and Upper Limestone formations (not assessed in this study) and through all four of the prospective shale units.

The prospective Midland Valley of Scotland units were deposited in lacustrine, fluvio-deltaic and shallow marine depositional environments which varied in space and time (sections 2.9.3-2.9.6). Marine beds are identified at many levels, and are more dominant in some units (e.g. Lower Limestone Formation), but on a regional scale it is not possible to identify a specific prospective 'marine shale' interval. This contrasts with the deep marine depositional environment of many USA productive shales and to the Bowland-Hodder shale of northern England. The depositional environment of Midland Valley shales controls several aspects of prospectivity from shale thickness and continuity to TOC content and kerogen type, and is detailed below (sections 2.9.3.-2.9.6).

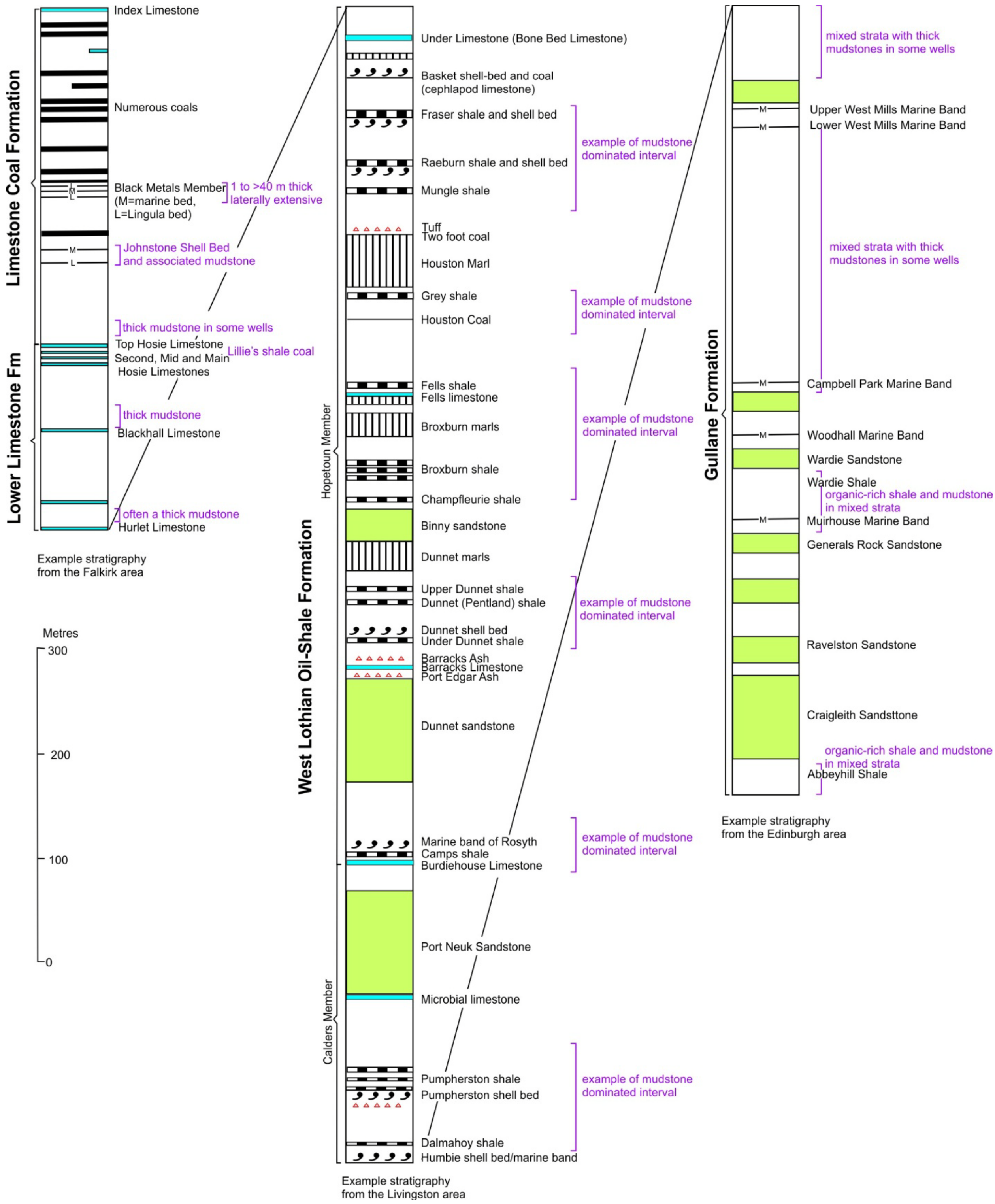


Figure 25 Example of thickness and nomenclature of the main Carboniferous intervals examined for shale prospectivity in the Midland Valley of Scotland, taken from BGS 1:50,000 scale maps and Jones (2007). Examples of potential mudstone-dominated (shale) intervals are shown in purple. Note that white intervals represent mixed lithologies in which mudstones are likely to be a significant proportion. Thicknesses and nomenclature changes laterally from the examples shown here. The shale beds highlighted within the West Lothian Oil-Shale Formation are oil-shales sensu stricto.

This thick sequence containing numerous relatively thin shales contrasts with some of the shale gas and shale oil plays around the world which utilise mudstone units hundreds of feet thick (e.g. Barnett, Marcellus shales: Jarvie 2012a), and with the thick Bowland-Hodder Shale of northern England (Andrews 2013). The Midland Valley of Scotland succession can be considered as a stacked play.

Stacked shale targets are now common in many USA plays, including the Spraberry and Wolfcamp shales of the Midland Basin, Texas in which there are individual shales between approx. 200-600 ft thick (Pioneer Natural Resources website http://www.pxd.com/operations/permian-basin and Investor presentation). In the USA, the Green River Shale in the Uinta Basin exhibits stacked shale intervals, deposited in a lacustrine/alluvial environment (Dubiel 1992). Little evidence can be found in published literature of shale plays containing igneous rocks, though the Onnagawa shale in Japan is within a formation containing tuff and dolerite (Kamitsuji *et al*. 2013).

USA hybrid plays (including the Bakken and Barnett plays USA, Jarvie 2011) are also targeted for tight oil and gas (i.e. organic-rich shales where petroleum is stored in adjacent sandstone/limestone/siltstone of low permeability that requires hydraulic fracturing to be economically produced). This study has focused on estimating the shale resource and has not considered the hybrid conventional, tight oil and tight gas resource which could be present within the stacked, heterolithic sequence. Evidence of numerous oil and gas shows in wells (section 2.2) suggests that tight oil/gas could be a complementary resource in the Midland Valley of Scotland.

2.9.1 Percentage shale measurements

In order to quantify the volume of shale within the heterolithic Midland Valley of Scotland succession for the resource estimation, the percentage of shale was measured from natural gamma logs and from selected borehole records for each of the four prospective shale units. A cut-off at around 50% of the API range of the gamma log was used to determine the shale intervals.

Igneous rocks (intrusive and extrusive) within the four shale units were included as a non-shale lithology, to give a realistic shale percentage in the rock volume at that locality. Selected borehole records were used for areas lacking in well data. This was done by taking the sum of mudstone, carbonaceous mudstone, muddy siltstone, siltstone etc. lithology thickness, compared to the overall thickness of that stratigraphic unit. The borehole shale values generally gave higher shale percentages than gamma logs due to the inclusion of siltstone. This was factored into contouring the maps. The percentage shale data points from wells and boreholes were geologist-contoured at regional scale using the basin palaeogeographies (Figures 27, 32, 33, 38) as a guide in areas of no measured data points. The contours were then interpolated to give the percentage shale maps shown below (Figures 28, 34, 36, 39).

The thickness of shale units incorporated in the percentage shale maps varies from a few inches to tens of feet. Though the overall percentage shale in wells may be similar, the shale can be distributed through the succession in very different ways, largely dependent on the depositional environment. For example, in the Bargeddie 1 well (on the western side of the study area), shales over a hundred feet thick were interpreted as deposited in a relatively restricted setting, whereas in the Kilconquhar Mains borehole (on the eastern side of the study area), a heterolithic succession was deposited in an area interpreted as cut by meandering fluvio-deltaic systems, resulting in only a few shales >50 ft thick (Figure 26).

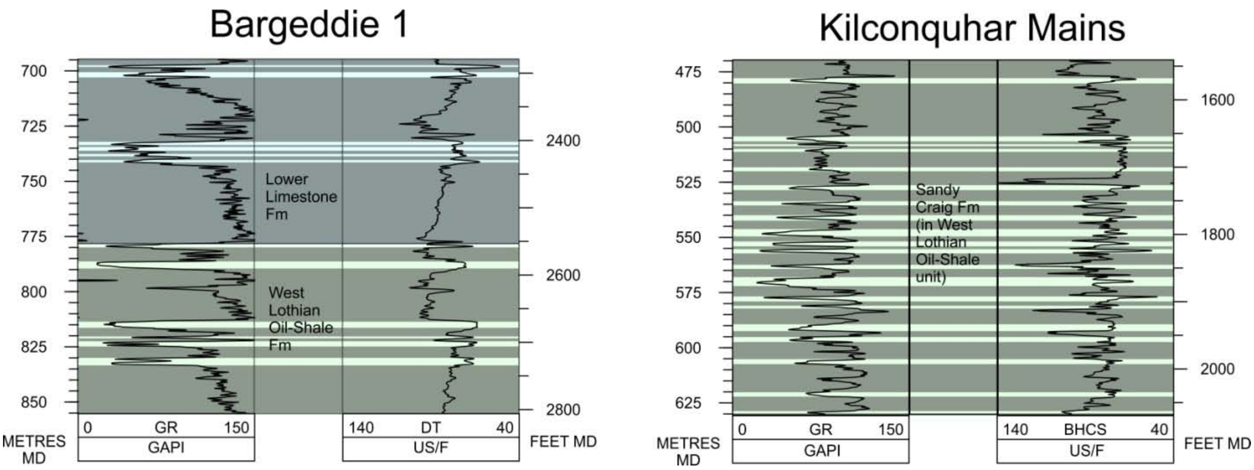


Figure 26 Comparison of gamma and sonic logs for two wells with overall similar percentages of shale, but with differing distributions of shale.

Even within a stacked play, the thinnest shales are unlikely to form an exploitable resource. Standard criteria (Table 3) give an ideal thickness of shale units of 50 ft (15 m; Charpentier & Cook 2011). Thus a second set of 'shale percentage >50 ft' maps (Figures 29, 35, 37, 40) were produced to allow calculation of resource volumes meeting standard criteria. The 'percentage shale >50 ft' maps exclude the situation where two relatively thick (e.g. 35 ft) shale units are separated by a thin interbed of sandstone, limestone, ironstone etc and so give a lower bound to the resource volume (see section 4).

2.9.2 Methodology

Particularly within the West Lothian Oil-Shale and Gullane units, lateral facies variations within time-equivalent fluvio-deltaic, lacustrine and volcanic strata are key to determining the volume of the shale resource.

Regional-scale facies variations and palaeogeographies have been illustrated for four time slices using a geochronological framework based on $^{40}Ar/^{39}Ar$ and U/Pb ages of Midland Valley of Scotland igneous rocks integrated with palynology, palaeontological and stratigraphical constraints (Monaghan & Pringle 2004, Monaghan & Parrish 2006, Monaghan *et al*. in press). The evidence from deep wells and selected boreholes has been compiled in a GIS at regional scale with BGS 1:50,000 scale DiGMapGB data (Figures 27a, 33a, 33a, 38a). Previously published palaeogeographies have been consulted and incorporated (e.g. Loftus & Greensmith 1988, Read 1989, Read *et al*. 2002). It was noted that some of these studies were not spatially precise and summarised large time spans thus incorporating several distinct igneous episodes. The time slices (Figures 27, 32, 33, 38) aim to further break down the interpretation, but they by no means illustrate the variety of environments present from marine shelf to arborescent coal swamp deposition; rather they are a snapshot of the dominant process of that time. The detail of all field outcrops plus the substantial quantity of information residing in the BGS borehole database for this area have not been fully utilised for the regional scale palaeogeographies or percentage shale maps presented, meaning that local variability is not shown.

2.9.3 Gullane unit (Gullane and Anstruther formations)

The approximately 1,840 ft (560 m) thick Gullane Formation at outcrop (Mitchell & Mykura 1962) consists of a cyclical sequence of fine- to coarse-grained sandstone interbedded with grey mudstone and siltstone, as recognised in the Lothians south of the Firth of Forth. Subordinate lithologies are coal, seatrock, ostracod-rich limestone/dolostone, sideritic ironstone and rarely, marine beds with restricted faunas. The depositional environment was predominantly fluvio-deltaic, into lakes that only occasionally became marine (Browne *et al*. 1999). The Gullane Formation is of TC palynomorph zonation (Neves *et al*. 1973, Neves & Ioannides 1974) Asbian age (Waters *et al*. 2011b).

In the deep wells, the Gullane Formation is not recognised farther west than Leven Seat 1 (where it is interbedded within volcanic rock), Pumpherston 1 and Rosyth 1 wells. In the west, the unit is missing by unconformity, or replaced by volcanic rocks in the Inch of Ferryton 1, Rashiehill and Salsburgh 1A wells

(Figure C4 Appendix C) and at outcrop. In the Straiton 1 well, mudstone forms a large proportion of the Gullane Formation, whereas the character in the Carrington 1 and Stewart 1 wells is more heterolithic (Figure C3 Appendix C). Over 2,625 ft (800 m) of Gullane Formation is interpreted in the Pumpherston 1 well, contrasting with the approx. 1,840 ft (560 m) observed further east. Correlating individual shale-rich intervals from the sparse well dataset has not been attempted, and it is difficult to gain an understanding of the lateral extent and continuity of these intervals.

The age-equivalent (Asbian, TC palynomorph zonation, Owens *et al*. 2005, Waters *et al*. 2011b) Anstruther Formation in Fife, north of the Firth of Forth, is more than 2,660 ft (810 m) thick and consists of cyclical mudstone, siltstone and sandstone (Forsyth & Chisholm 1977). Non-marine limestone and dolostone are also developed, usually as thin beds, some of which contain oncolites and stromatolites. Minor components include marine mudstone and siltstone, a few algal-rich oil-shale beds, plus thin beds of coal and ironstone (Browne *et al*. 1999). The unit is dominantly non-marine, with the overall pattern of sedimentation consisting of upward-coarsening lake delta cycles, with thinner upward-fining fluvial units erosively capping them. Parnell (1984) sampled dark marine shales with over 10% TOC from the Anstruther Formation and the easternmost oil-shale mine in the Midland Valley of Scotland was at Pitcorthie near Anstruther (http://www.scottishshale.co.uk/GazWorks/KilrennyOilWorks.html).

The Anstruther Formation is present at depths of over 6,230 ft (1,900 m) in the Firth of Forth 1 and Milton of Balgonie 1 wells. From the Fife coastal section near Aberdour to the South Fod 1, Blackness 1 and Easter Pardovan 1 wells, volcanic rocks of the Charles Hill Volcanic Member are interbedded towards the base of the Gullane/Anstruther formation. Reconstruction of a palaeogeography is difficult due to the sparse data points, but Figure 27 indicates a heterolithic fluvio-deltaic succession sourced from the north-east, interbedded with localised volcanic rocks.

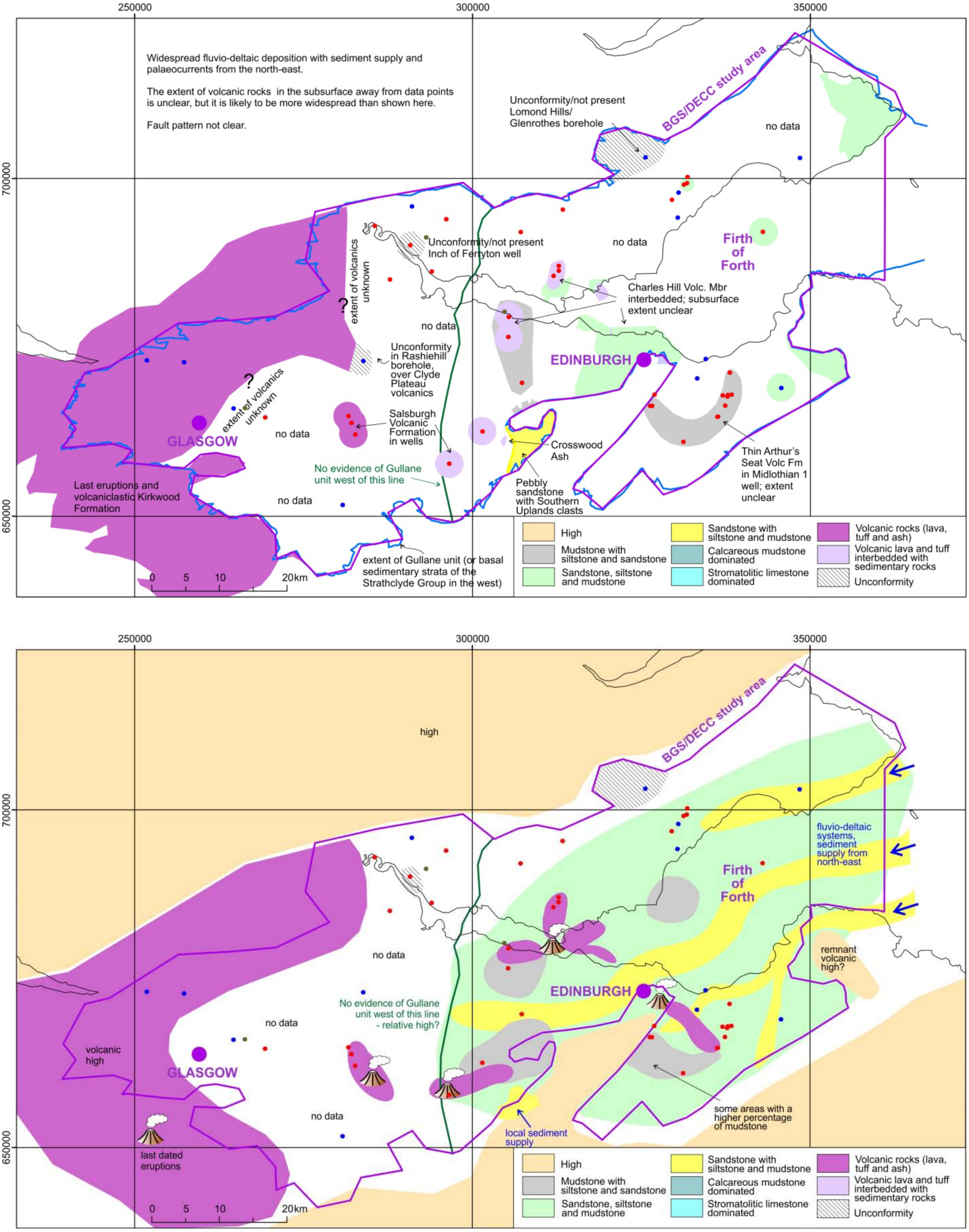


Figure 27 Gullane unit times (c. 336 Ma, TC palynomorph zone). a) Summary of evidence from well/borehole and outcrop data, note that wells/boreholes proving the Gullane unit or an unconformity are surrounded by shading, other wells/boreholes do not prove the Gullane unit. b) Summary palaeogeography. Evidence is patchy and the reconstruction is tentative.

Within the mixed succession, shale percentage maps (Figures 28, 29) are influenced by the thick mudstones in the Straiton 1 well in Midlothian and also by mudstones in the Blackness 1, Easter Pardovan 1 and West Calder 1 wells (see Figure 11 for well locations). The data from these three West Lothian wells should be treated with caution due to the age of the record and lack of downhole geophysical logs.

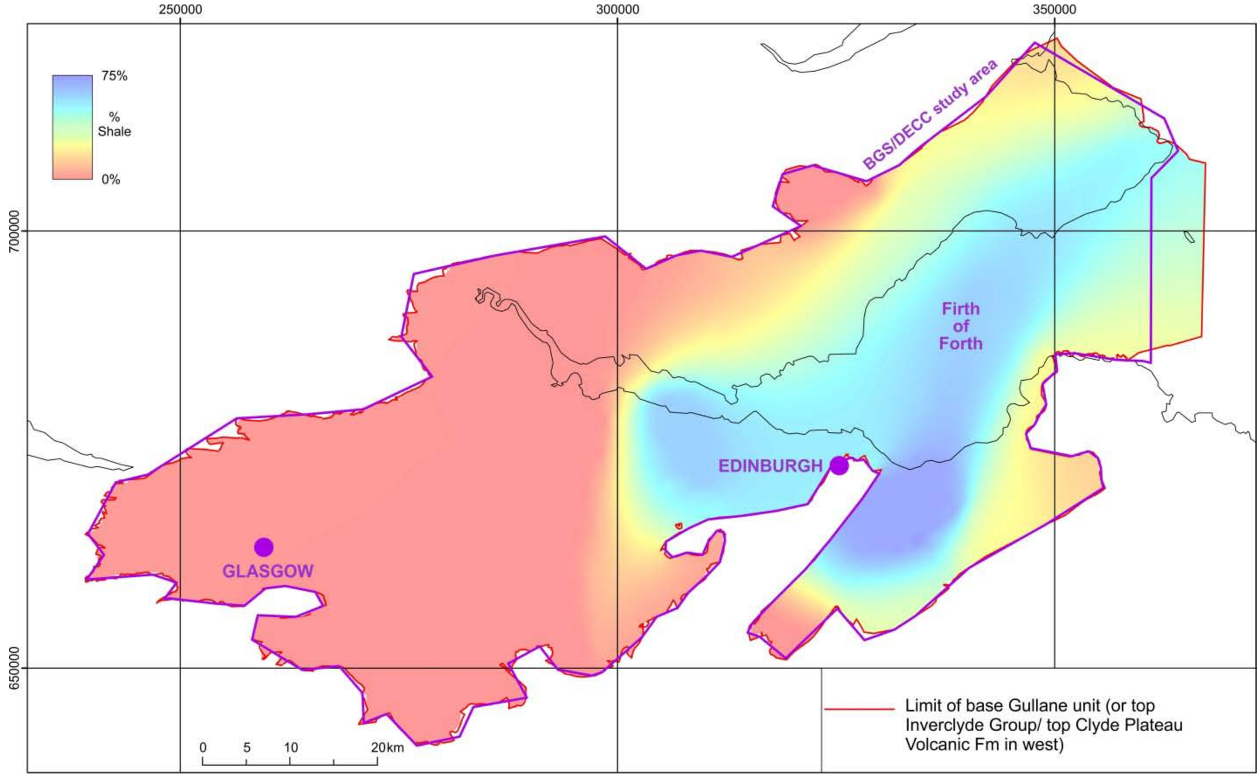


Figure 28 Percentage shale map for the Gullane unit, note that the western part of the area has zero percent shale where the Gullane unit is not proven.

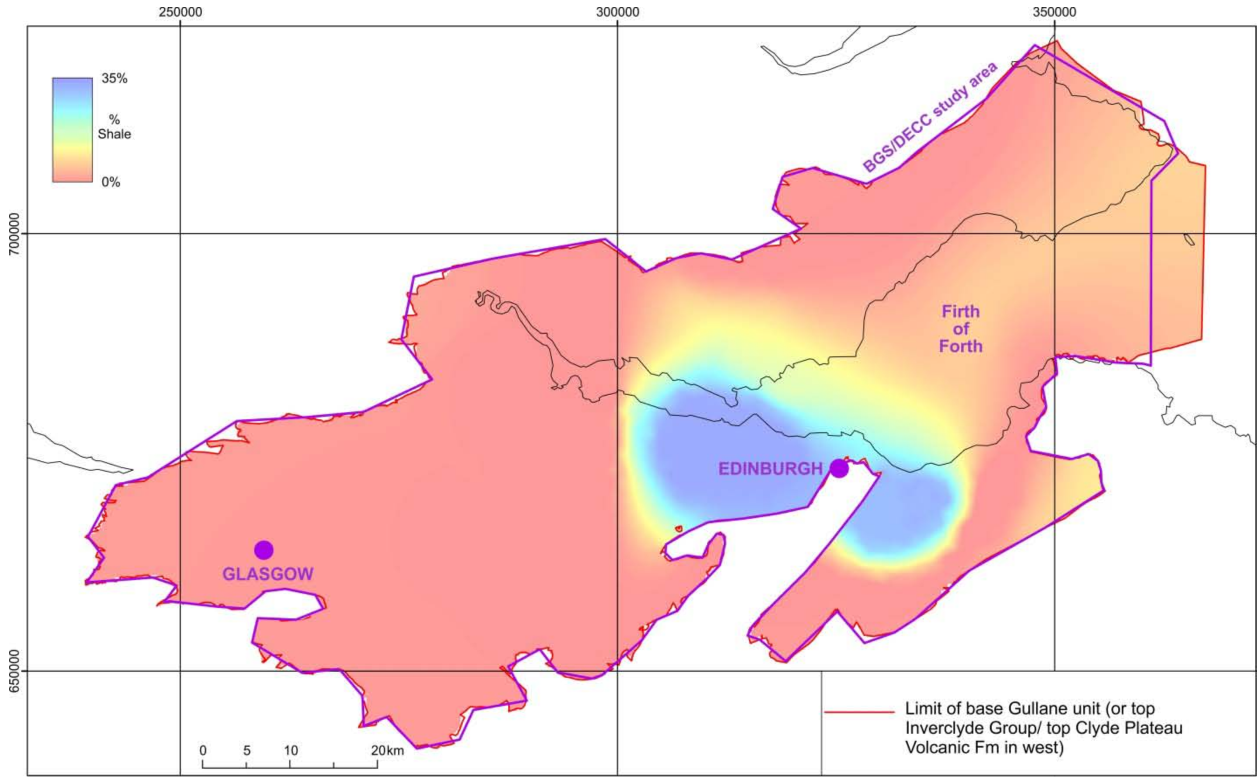


Figure 29 Percentage shale map for shale intervals greater than 50 ft (15 m) within the Gullane unit, note that the western part of the area has zero percent shale where the Gullane unit is not proven.

2.9.4 West Lothian Oil-Shale unit (West Lothian Oil-Shale Formation and equivalents)

The West Lothian Oil-Shale Formation is up to 3,675 ft (1,120 m) thick as measured from field sections and boreholes and is characterised by thin seams of oil-shale in a cyclical sequence dominated by sandstones interbedded with grey siltstones and mudstones. Subordinate lithologies include coal, ostracod-rich (and occasionally algal) limestone/dolostone, sideritic ironstone and marine beds, including bioclastic limestones with rich and relatively diverse marine faunas (Browne *et al*. 1999). Thick, pale green-grey or grey argillaceous beds containing volcanic detrital components (historically termed 'marl') are present (Jones 2007), as well as beds of tuff and ash (e.g. the Port Edgar Ash). The West Lothian Oil-Shale Formation is of Asbian to Brigantian age, NM-VF palynomorph zones (Browne *et al*. 1999, Waters *et al*. 2011b). Laterally, the formation passes into the Lawmuir, Pittenweem, Sandy Craig, Pathhead and Aberlady sedimentary formations, and the Kinghorn and Bathgate Hills volcanic formations (described below or in Appendix B). The non-marine Burdiehouse Limestone is an important regional marker bed, dividing the upper Hopetoun Member and lower Calders Member of the West Lothian Oil-Shale Formation (Chisholm & Brand 1994, Appendix B). An estimated 5% of the West Lothian Oil-Shale Formation is considered to be marine-influenced (M. Browne pers. comm. 2014).

The formation crops out over a large area of West Lothian and also on the western side of the Midlothian Syncline, south of Edinburgh. The upper parts of the West Lothian Oil-Shale Formation are proven in the subsurface westwards beneath the Central Coalfield in the Salsburgh 1A, Salsburgh 2, Craighead 1 and Bargeddie wells. In the Rashiehill borehole, it is replaced by the Bathgate Hills Volcanic Formation. North and north-westwards the West Lothian Oil-Shale/Pathhead formation strata are proven in the Inch of Ferryton 1, South Fod 1 and Rosyth wells (Figures 32, 33 and Figure C2 Appendix C).

The oil-shale bearing strata have been described in detail by Carruthers *et al*. (1927). The correlation of summary stratigraphic sections from that memoir (Figure 30) gives an important insight into lateral thickness changes, the relatively high percentage of sandstone in some parts of the succession, the presence of volcanic beds and the sub-regional correlation of a number of oil-shale beds.

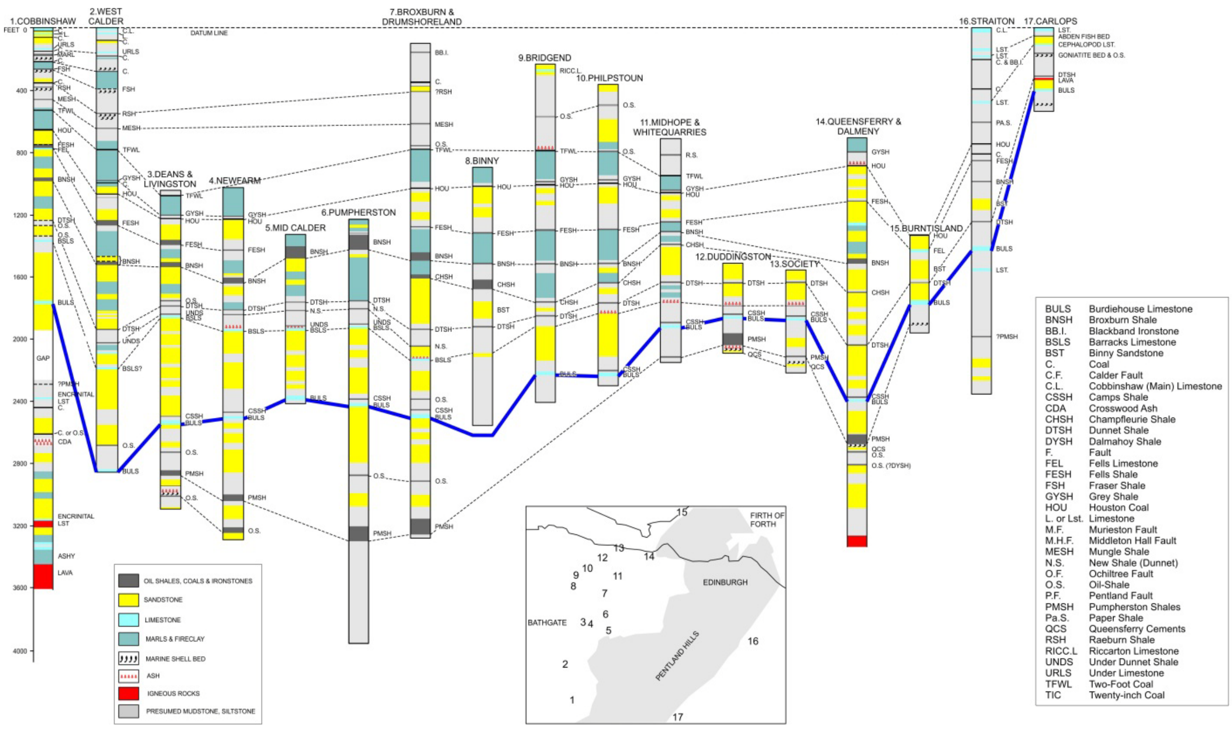


Figure 30 Summary stratigraphic sections through the West Lothian Oil-Shale Formation in selected mined areas, redrawn from Carruthers et al. (1927).

Oil-shales *sensu stricto* form only about 3% (by thickness) of the West Lothian Oil-Shale Formation and are highly kerogen-rich, TOC-rich (up to 35%) sediments ranging from a few inches to 16 ft (5 m) thick (Loftus & Greensmith 1988). In thin section, the oil-shales are thinly laminated and are believed to be of laminar algal and discrete algal body origin (Loftus & Greensmith 1988, Parnell 1988, Raymond 1991).

The oil-shales are interpreted as algal oozes (blooms) formed in shallow, stratified lakes, characterised by anerobic bottom conditions (Parnell 1988), though marine ostracods in some oil-shales imply marginal marine conditions existed at times (Wilkinson 2005, Jones 2007). Raymond (1991) and Lea (2012) use microscopy to give further detail on mudstone composition and structure. Oil-shales are characterised in hand specimen as 'leathery', 'wooden', giving a brown streak and are relatively ductile.

Jones (2007) defined 11 sedimentological facies within the West Lothian Oil-Shale Formation; these represent variations within a predominantly lacustrine environment. Periods of lake development and expansion were marked by deposition of lacustrine limestones and desiccation-cracked mudstones, with lake maxima marked by the deposition of oil-shale facies. The lakes were generally filled by fine-grained siliciclastic (muddy) sediment, although minor channel systems fed coarser sediment (sand) into the lakes via small prograding delta systems. The calcareous mudstone ('marl') facies comprised a significant component of altered volcanic material. Laminated grey lacustrine mudstone facies (Figure 31) and desiccation-cracked mudstone (Jones 2007) may form the relatively thick, high-gamma 'shales' of interest to this study e.g. at 3,050-2,970 ft (930-905 m) in the Bargeddie 1 well around the Raeburn Shale *sensu stricto* (Figure C3 Appendix C).

Using the more recent wells (including Bargeddie 1, Inch of Ferryton 1, Craighead 1) in the Central Coalfield some of the shale units can be correlated. For example, the Raeburn Shale mudstone interval can be tentatively identified across that area, varying from 50-65 ft (15-20 m) thick. Correlation and an understanding of lateral continuity of shale units becomes difficult north-eastwards into Fife and eastwards to Midlothian.

Figure 31 View of Laminated Grey Lacustrine Mudstone facies of the West Lothian Oil-Shale Formation from Jones (2007). Note the thin silty sandstone bed (grey) above the compass and the brown ironstone bed below the compass. Linhouse Water, West Calder Wood [NT 07475 66063].

The palaeogeography of Loftus & Greensmith (1988) proposed high ground to the north, south and west of 'Lake Cadell' (Greensmith 1962, 1965), deltaic sandstones sourced to the north-east, and marine influence from the south-east. The facies changes observed represent a complex interaction of freshwater lacustrine, transitional lagoonal and fully marine conditions (Loftus & Greensmith 1988). The Macgregor Marine Bands (Wilson 1989), towards the base of the West Lothian Oil-Shale Formation, only extend as far west as West Lothian, with open sea interpreted in East Lothian and the Firth of Forth. However, biofacies in the Dykebar limestone near the top of the age-equivalent Lawmuir Formation (see Appendix B for description) indicate that a marine influence also extended on occasion in from the west of Glasgow (Wilson 1989).

In the current study, two palaeogeographic time slices have been produced for the West Lothian Oil-Shale unit to illustrate the spatial and temporal variability of volcanic rocks, which have a considerable influence on the percentage of shale in the succession: one near the top and another in the lower part of the formation (Figures 32, 33).

Near the top of the West Lothian Oil-Shale Formation (and lateral equivalents) volcanic rocks of the Bathgate Hills and Kinghorn volcanic formations dominate the succession in the West Lothian-Falkirk and Central Fife-Firth of Forth areas (Figure 32). Other areas such as the southern Central Coalfield and parts of west Fife prove successions rich in thick lacustrine mudstones with marine incursions. The thick shales of the upper part of the West Lothian Oil-Shale Formation proven by Bargeddie 1 in 1989 allowed the lacustrine depositional basin to be extended farther west than Loftus & Greensmith (1988) had evidence for. The thick seismic package observed adjacent to the Bothwell Fault, tied to the Bargeddie 1 well could be interpreted as a further westwards continuation of similar strata.

In contrast, the palaeogeography for the lower West Lothian Oil-Shale unit (near Burdiehouse Limestone level) highlights a time period of relative volcanic quiescence (Figure 33). Differences with the published palaeogeography of Loftus & Greensmith (1988) for Burdiehouse Limestone times include the lack of the Bathgate Hills and Kinghorn volcanic formation highs (proven at stratigraphically higher levels only), no 'Old Red Sandstone' high in Fife and an attempt to represent the east Fife fluvio-deltaic succession with narrower, mobile sandbodies and intervening lagoonal/lacustrine environments as indicated by the relatively high percentage of mudstone in the succession in that area.

Percentage shale maps for the West Lothian Oil-Shale Formation and lateral equivalents highlight the predominance of shale units greater than 50 ft (15 m) thick in the western Central Coalfield and in West Lothian. Eastern areas of Fife and Lothian contain a relatively high percentage of shale, but with far less in units greater than 50 ft (15 m) thick (Figure 35).

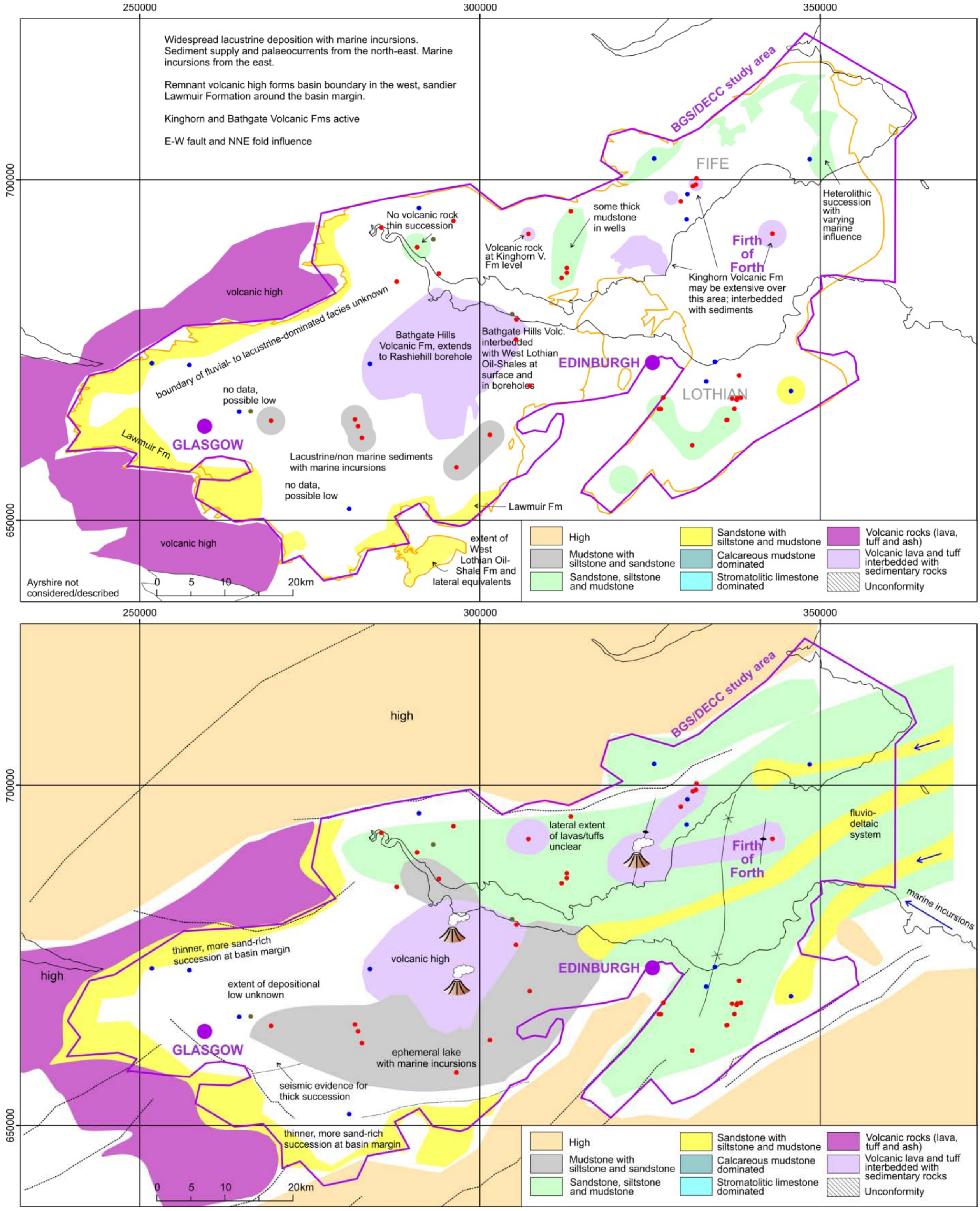


Figure 32 Latest West Lothian Oil-Shale unit times (near the top of the unit, c.331 Ma, NM palynomorph zone). a) Evidence from well/borehole and surface exposures. Note that wells/boreholes proving the upper West Lothian Oil-Shale unit are surrounded by shading, other wells/boreholes do not prove the upper West Lothian Oil-Shale unit. b) Summary of the palaeogeography. Evidence is patchy and the reconstruction is tentative. Dashed lines are faults and folds with evidence for active growth.

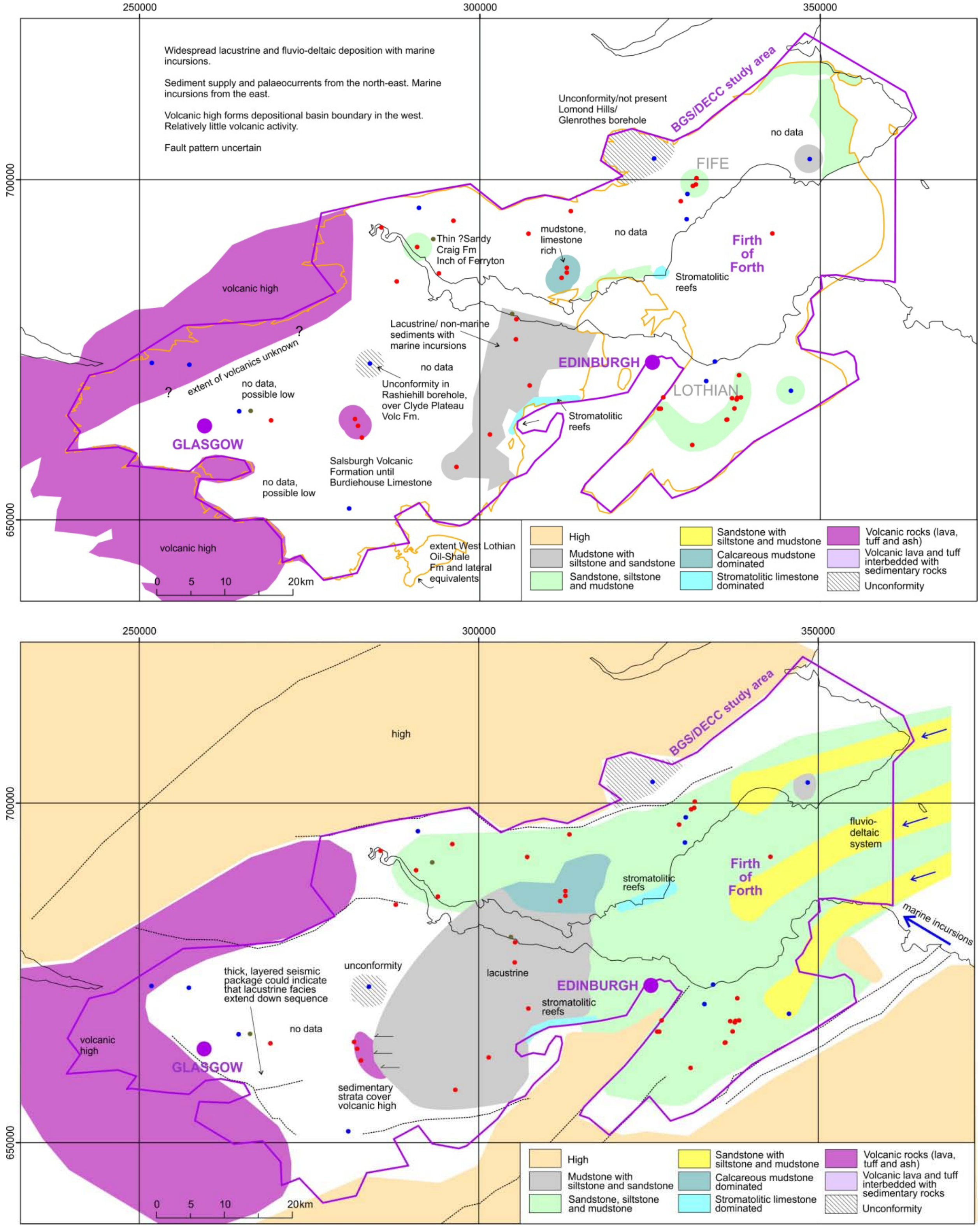


Figure 33 Early West Lothian Oil-Shale unit times (around the level of the Burdiehouse Limestone, c.333.5 Ma, around NM/TC palynomorph zones). a) Evidence from well/borehole and surface exposures. Note that wells/boreholes proving the lower West Lothian Oil-Shale unit are surrounded by shading, other wells/boreholes do not prove the lower West Lothian Oil-Shale unit. b) Summary of the palaeogeography. Evidence is patchy and the reconstruction is tentative. Dashed lines are faults and folds with evidence for active growth.

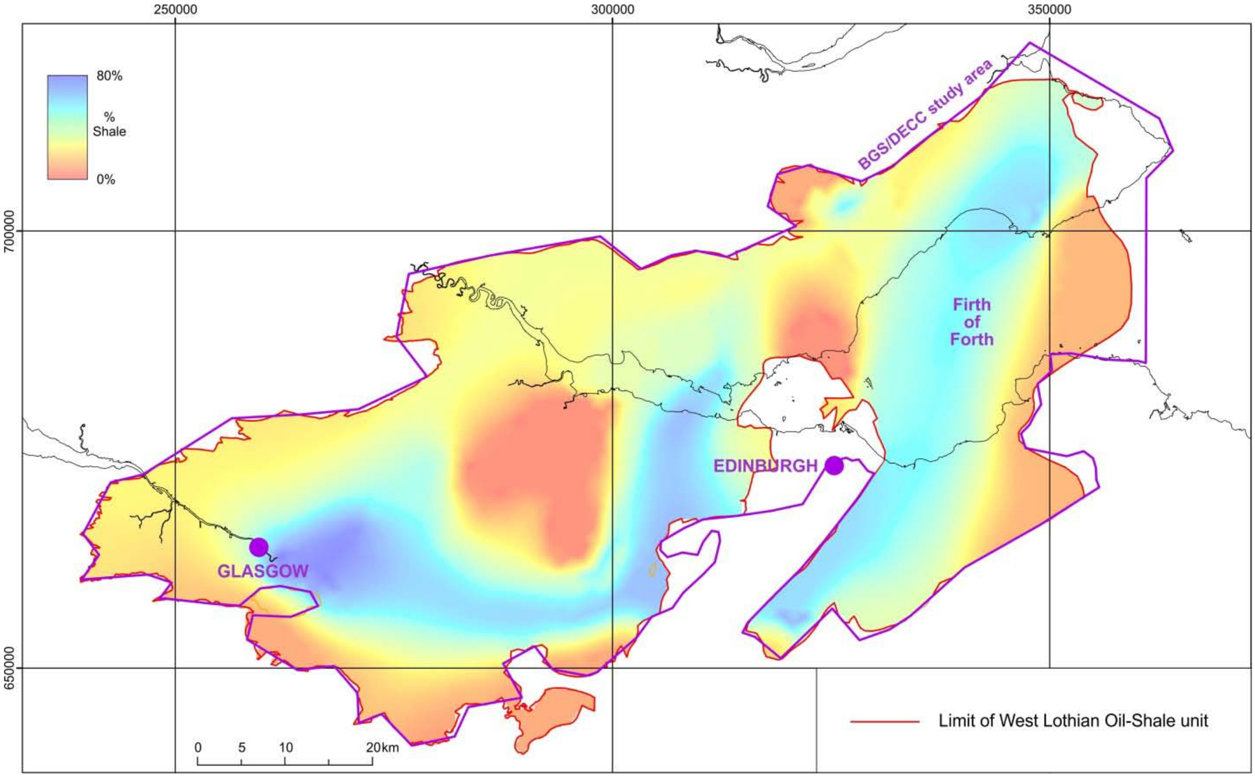


Figure 34 Percentage shale map for West Lothian Oil-Shale unit.

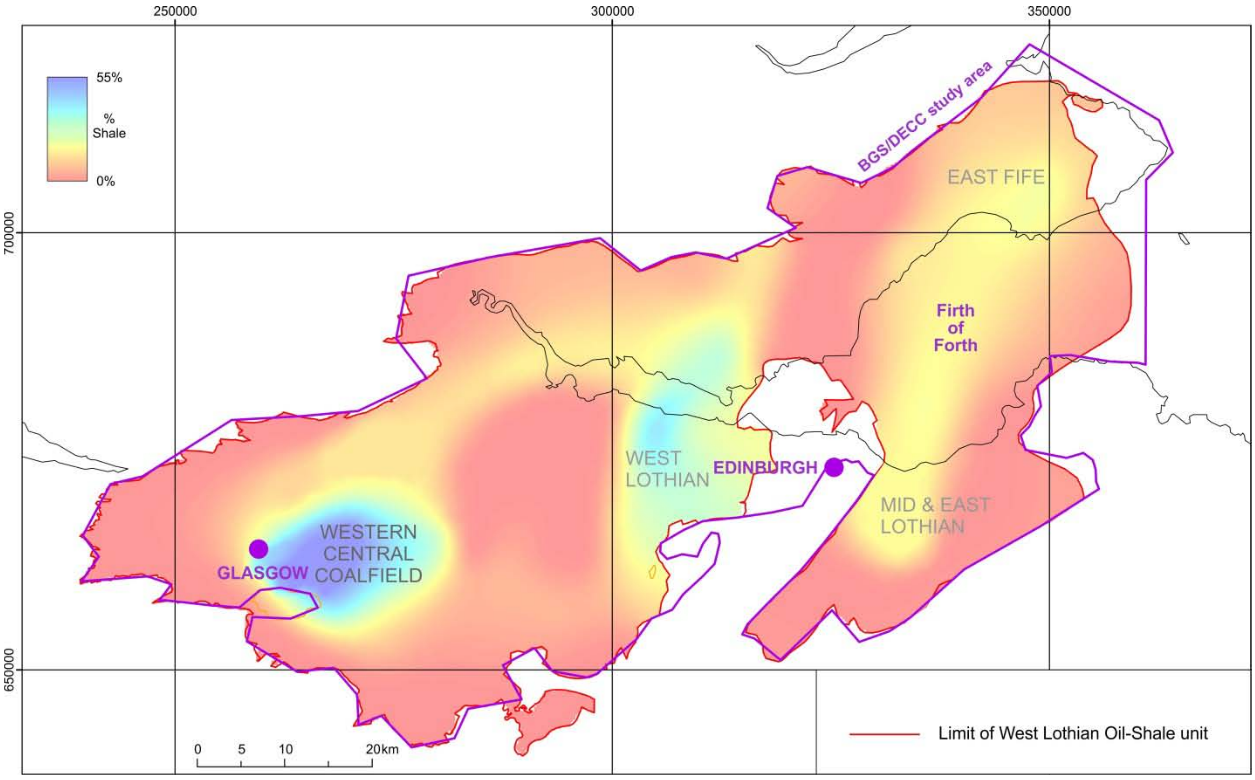


Figure 35 Percentage shale map for shale intervals greater than 50 ft (15 m) thick within the West Lothian Oil-Shale unit.

The Pittenweem, Sandy Craig and Pathhead formations are of Asbian to Brigantian age and represent the lateral equivalent of the West Lothian Oil-Shale Formation in Fife. They span the NM-VF palynomorph zones (Owens *et al*. 2005, Waters *et al*. 2011b). The Burdiehouse Limestone (where developed) divides the lower Pittenweem Formation from the upper Sandy Craig and Pathhead formations.

The Pittenweem Formation is more than 850 ft (260 m) thick and is dominated by lacustrine mudstone and siltstone with sandstone, and minor marine mudstone, non-marine and marine limestones, coal, ironstone and algal-rich oil-shale beds. Marine faunas are usually diverse and marine strata could make up approximately 40% of the succession (M. Browne pers. comm.).

The overlying Sandy Craig Formation is up to 2,200 ft (670 m) thick and is characterised by non-marine mudstone and siltstone, with a small percentage of algal-rich oil-shale, calcareous mudstone, coal and ironstone. Thin beds of non-marine limestone and dolostone are also developed. Fine- to medium-grained sandstone is subordinate to the argillaceous rocks, but thick, upward-fining, multi-storey sandstones are locally developed. Upward-coarsening deltaic cycles and thinner upward-fining fluvial units are observed, but in contrast those occurring in the Pittenweem Formation, marine faunas are very rare and restricted (Browne *et al*. 1999).

The Pathhead Formation is approximately 720 ft (220 m) thick and consists predominantly of mudstone and siltstone with subordinate sandstone and minor beds of limestone, dolostone, coal and ironstone. Marine strata are much more common than in the Sandy Craig and Pittenweem formations and their faunas are usually diverse and abundant (Browne *et al*. 1999).

Overall, the Pittenweem, Sandy Craig and Pathhead formation rocks were laid down in deltaic to marine environments, closer to the siliciclastic sediment source and to marine influence than the laterally equivalent, lacustrine-dominated West Lothian Oil-Shale Formation (Figures 32, 33). Percentage shale maps (Figures 34, 35) over Fife show lower values than further west, but still contain a significant percentage of shale.

2.9.5 Lower Limestone Formation

The Lower Limestone Formation is of Brigantian age, up to 790 ft (240 m) thick, and consists of repeated upward-coarsening cycles of limestone, mudstone, siltstone and sandstone. Thin beds of seatearth and coal may cap the cycles. The limestones, which are almost all marine and fossiliferous, are pale to dark grey in colour. The mudstones, many of which also contain marine fossils, and siltstones are predominantly grey to black. Nodular clayband ironstones and limestones are well developed in the mudstones (Browne *et al*. 1999). The depositional environment is interpreted as the repeated advance and retreat of fluvio-deltaic systems into a marine embayment of varying salinity. Rocks of the Lower Limestone Formation are the most marine of the units considered prospective for shale, with up to 70% of the succession containing rich marine faunas.

The biofacies of the Hurlet and Blackhall Limestones were used by Wilson (1989) to indicate nearshore, brackish faunas around Glasgow to progressively deeper and clearer shallow shelf seas to offshore to the south and east, with some islands of volcanic rocks. Goodlet (1957) proposed a different style of lithofacies map for the Lower Limestone Formation, with limestone notably more dominant in the strata in the east (Lothian) and muddier, clastic-dominated strata in the west (Lanarkshire), consistent on a regional scale with Wilson (1989).

Borehole and field data indicate limestone- and sandstone-dominated strata at basin margins with thinner limestones and thicker mudstones towards basin centres (Hall *et al*. 1998). To the south and west of Edinburgh, the formation comprises of a relatively high percentage of limestone (Browne *et al*. in press). The thickest, laterally correlated shales are the approx. 66 ft (20 m) thick mudstone above the Blackhall Limestone, and an approximately 50 ft (15 m) mudstone above the Hurlet Limestone (for example in the Craighead 1 and Bargeddie 1 wells; Appendix C Figure C3).

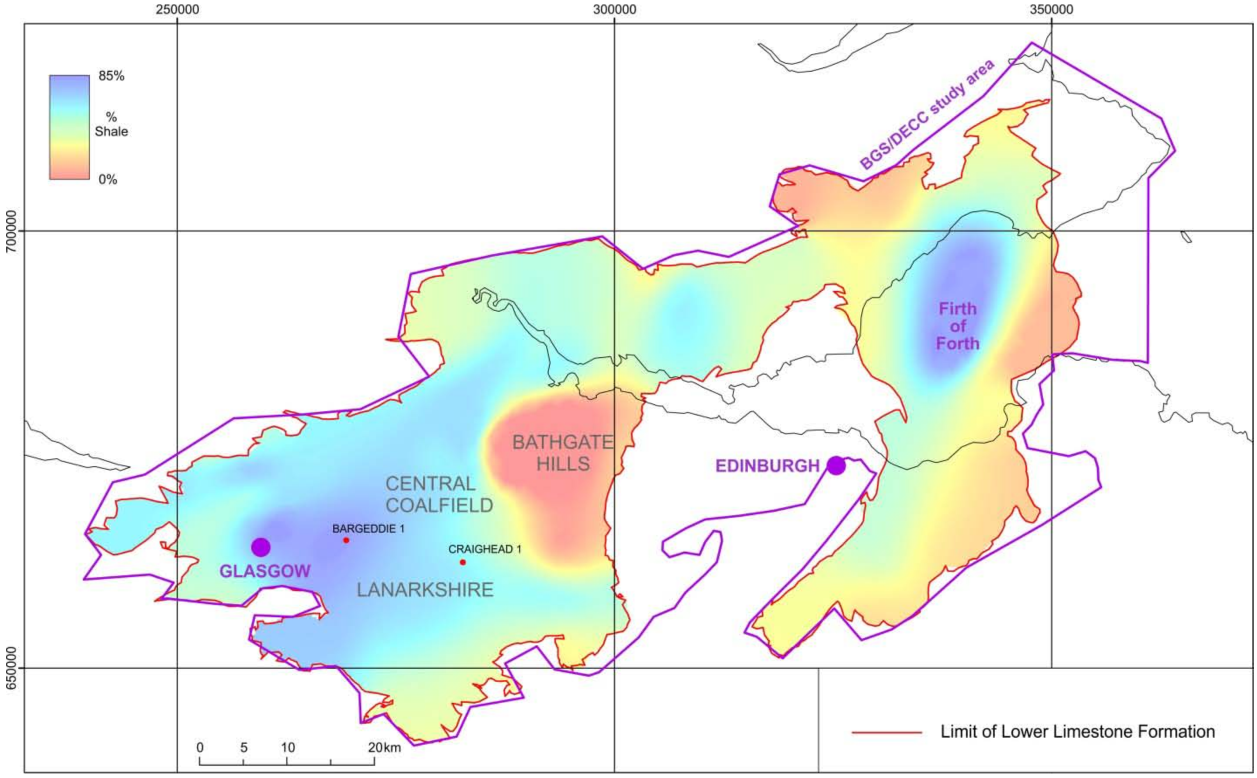


Figure 36 Percentage shale map for the Lower Limestone Formation, the position of wells discussed in the text is shown.

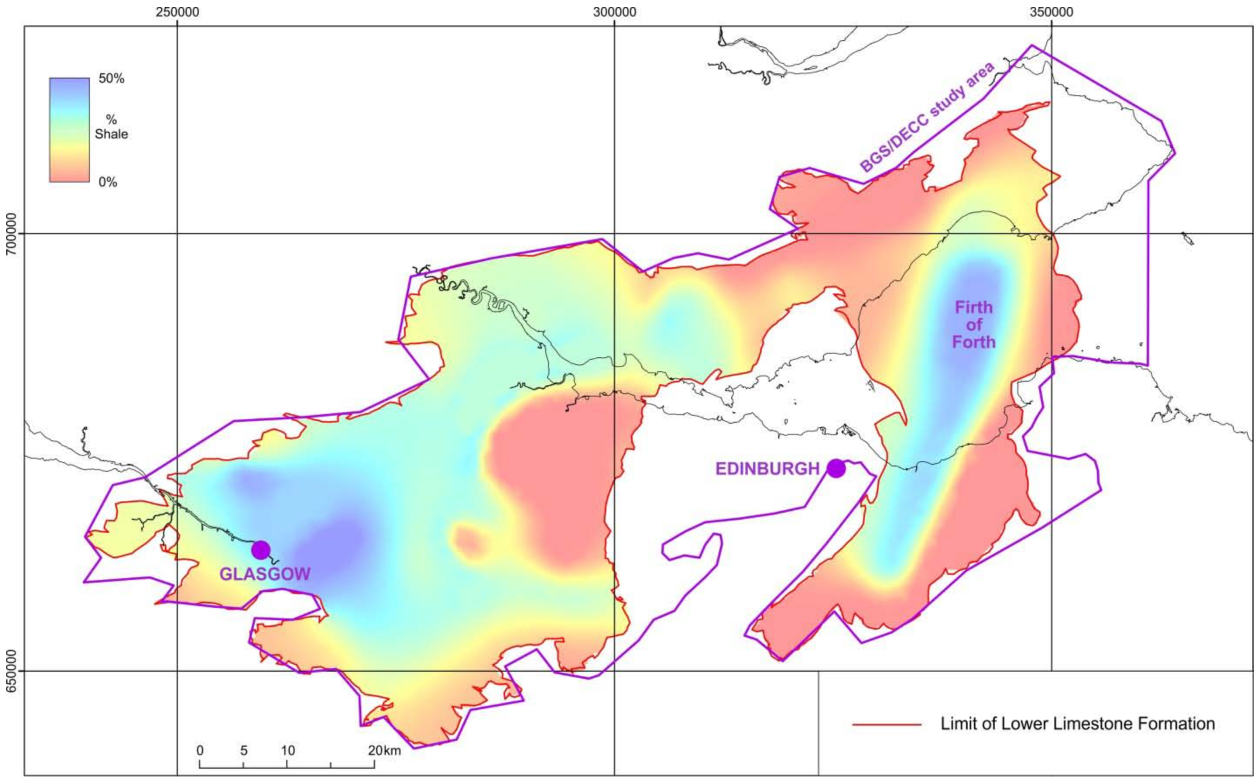


Figure 37 Percentage shale map for shale intervals greater than 50 ft (15 m) thick within the Lower Limestone Formation

Percentage shale maps for the Lower Limestone Formation reflect the high mudstone content of this formation, particularly in the west. The area of the active Bathgate Hills volcanism on the eastern side of the Central Coalfield has a negligible percentage of shale.

2.9.6 Limestone Coal Formation

The Limestone Coal Formation of Namurian (Pendleian) age is more than 1,800 ft (550 m) thick in places and comprises sandstone, siltstone, mudstone, seatrock and coal or blackband ironstones in repeated cycles. The siltstone and mudstone are usually grey to black. Coal seams are common and many exceed a foot in thickness. Minor lithologies include cannel, and clayband ironstone. Beds containing large numbers of shells (coquinas) of *Lingula* or of the non-marine bivalves *Naiadites* and *Curvirimula* occur in the fine-grained rocks. Marine shells are present in some fine-grained strata, but marine limestones are not a significant feature (Browne *et al*. 1999). Thick multi-storey sandstones are present, though locally, successions may be particularly sandy or argillaceous. Regionally correlated marine bands that reach over 165 ft (50 m) in thickness (e.g. Black Metals Member along the Kilsyth Basin) consist largely of carbonaceous mudstone with clayband ironstones. Up to 30% of the lower part of the formation may be marine influenced. Stronger fluvial influences in the cyclical Limestone Coal Formation strata are noted in channel belts in the Clackmannan area and to the east of the Midland Valley (Read *et al*. 2002; Figure 38), along with active fault and fold growth. Numerous coals within the Limestone Coal Formation have been extensively extracted by deep mining and opencast methods in all of the Midland Valley coalfields.

The thick mudstones of the Black Metals Member and Johnstone Shell Bed form the most shale prospective part of the succession.

The palaeogeography for the Limestone Coal Formation (Figure 38) highlights growth on syn-sedimentary folds and faults, and the palaeocurrent directions of fluvial systems taken from Read (1988) and Hooper (2004). Eruption of lavas and tuffs occurred in the Bathgate and Saline hills.

The percentage shale maps have high values in the north, north-west and western Central Coalfield, where the Black Metals Member is particularly thick (Figure 39). Relatively high percentages of shale are also shown in the Midlothian-Leven Syncline, though the number of shale units thicker than 50 ft (15 m) is relatively low due to the small scale of fluvio-deltaic cycles here (Figure 39).

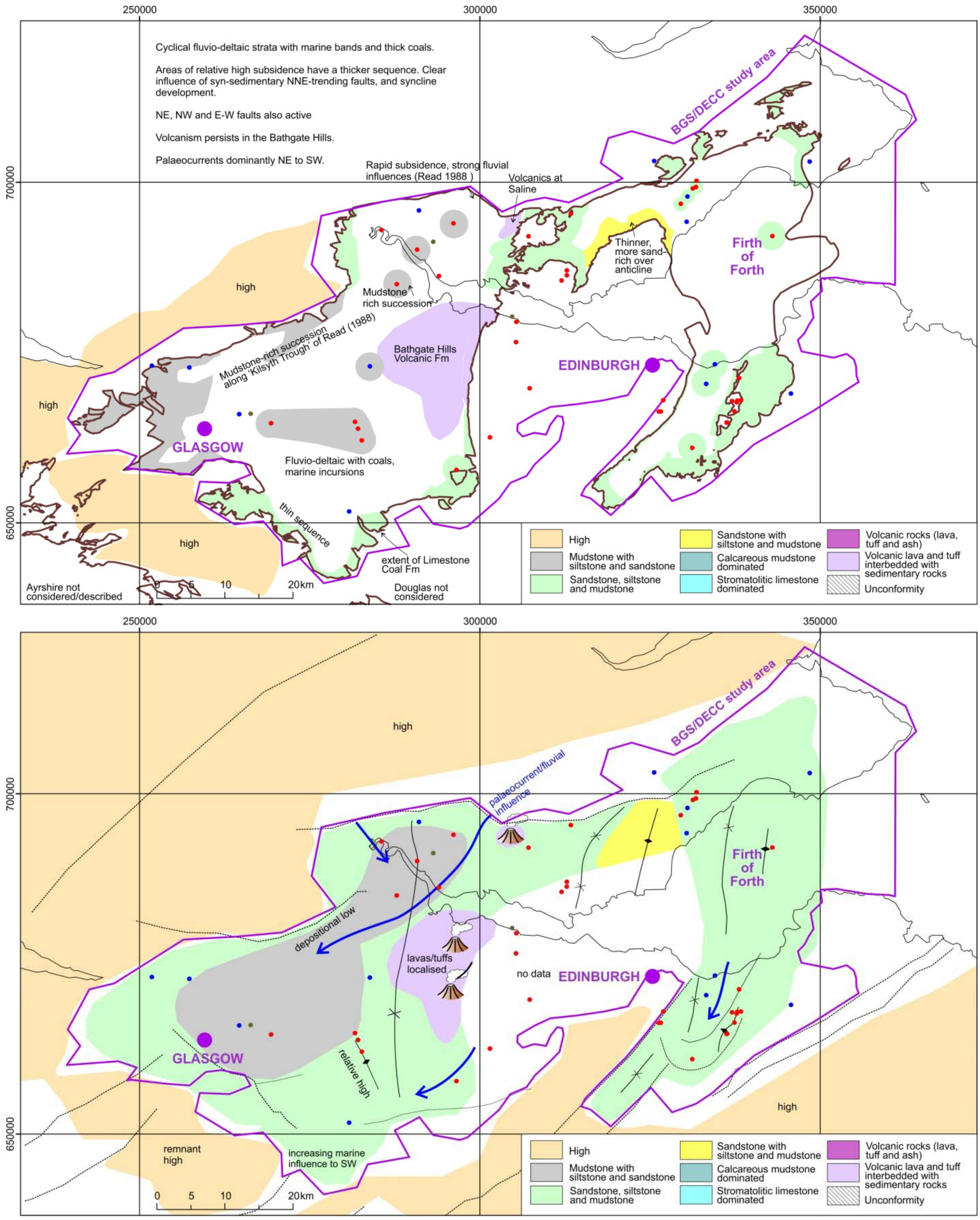


Figure 38 Limestone Coal Formation times (around c.329 Ma, NC palynomorph zone). a) Evidence from well/borehole and surface exposures. Note that wells/boreholes proving the Limestone Coal Formation unit are surrounded by shading, other wells/boreholes do not prove the Limestone Coal Formation. b) Summary of the palaeogeography. Evidence is patchy and the reconstruction is tentative. Dashed lines are faults and folds with evidence for active growth. Blue arrows show fluvial palaeocurrent directions.

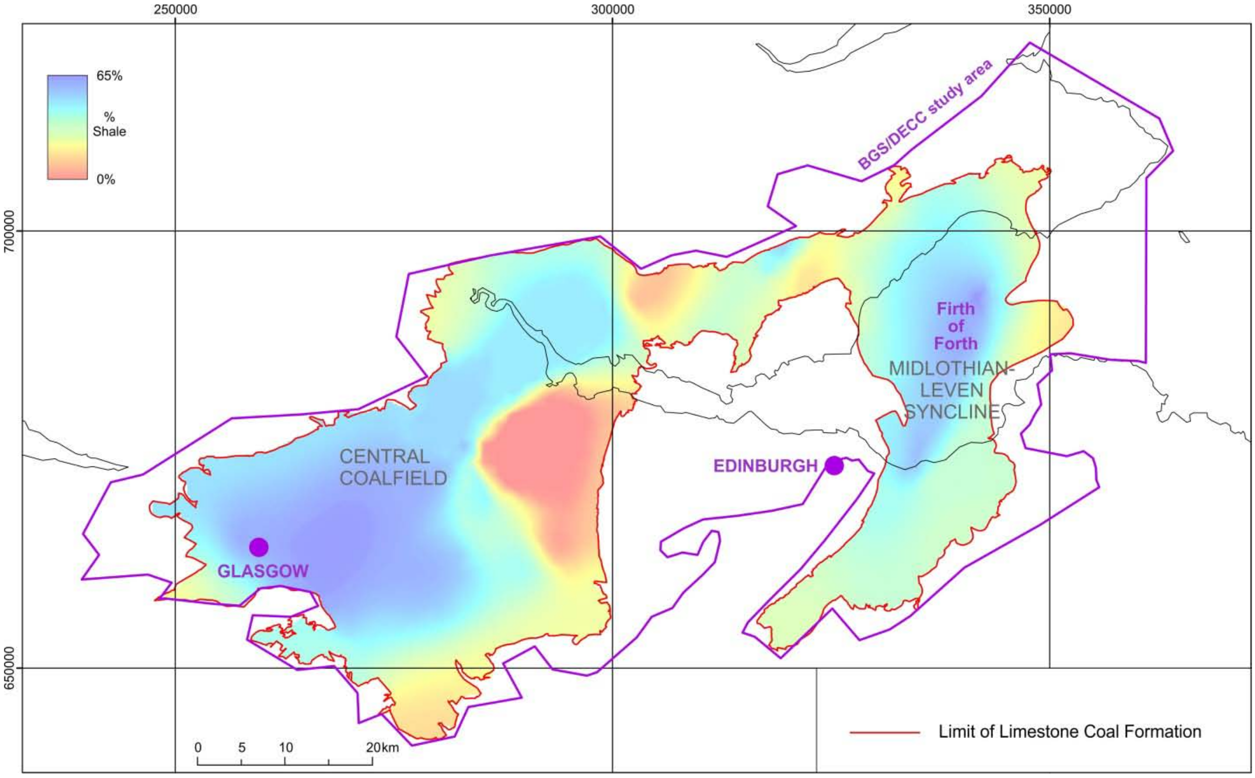


Figure 39 Percentage shale map for the Limestone Coal Formation.

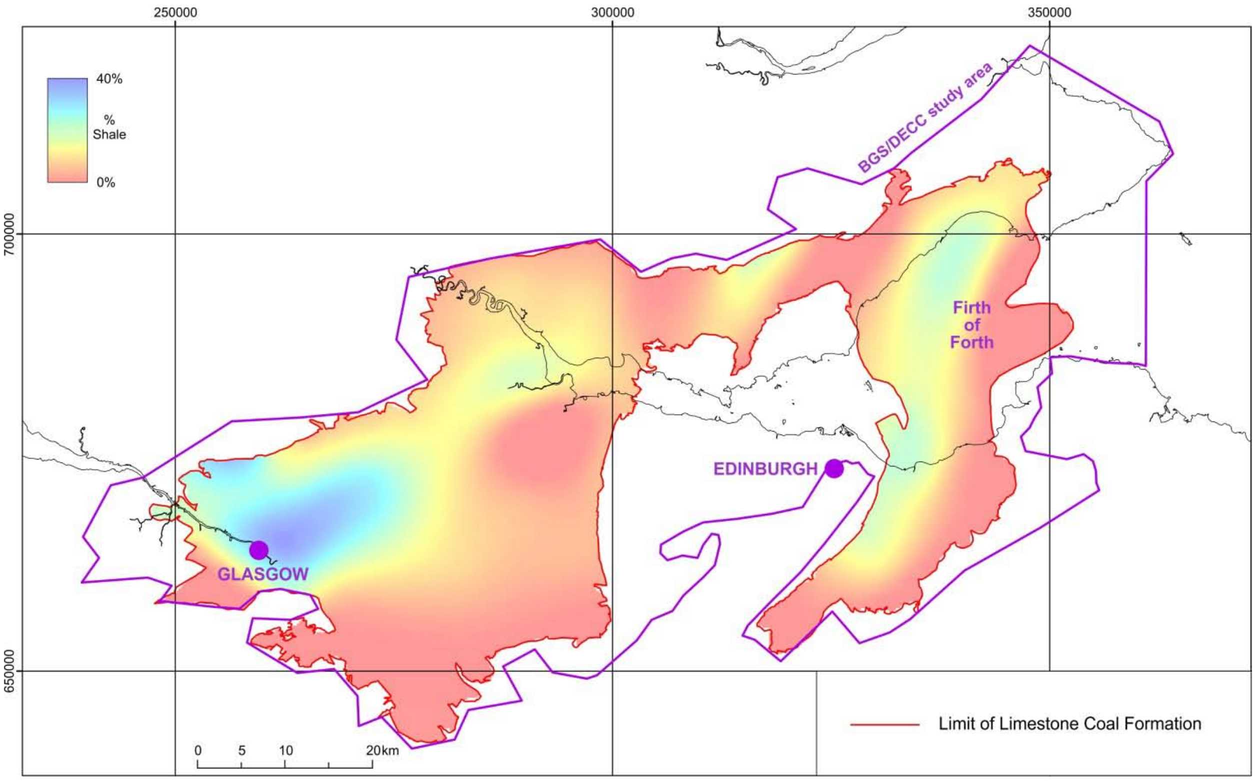


Figure 40 Percentage shale map for shale intervals greater than 50 ft (15 m) thick within the Limestone Coal Formation.

3 Organic geochemistry, thermal maturity and mineralogy

3.1 BGS 2014 sampling

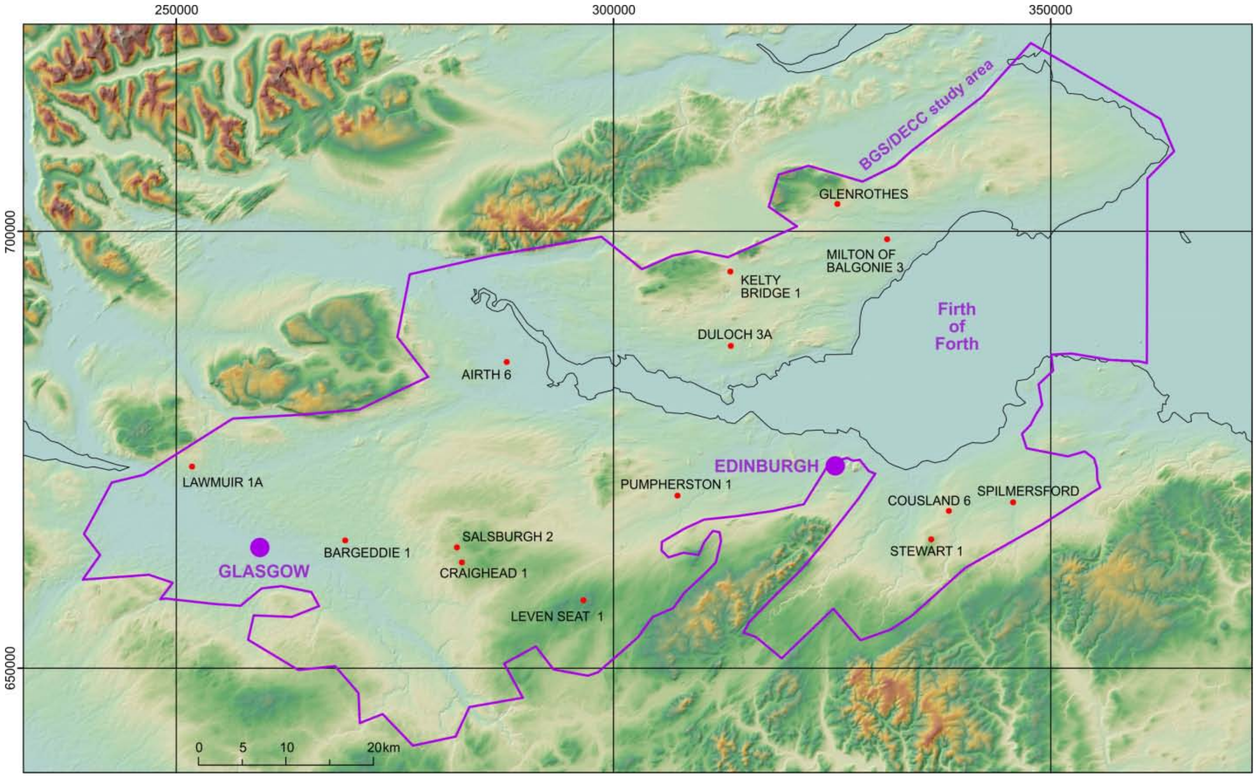


Figure 41 Location of wells and boreholes sampled for geochemistry and mineralogy by BGS in 2014.

Given the good quantity of pre-existing data relating to organic-rich oil-shales, the new BGS samples for Rock-Eval and XRD analysis were purposefully collected from grey mudstones and one ironstone to test the organic geochemistry of the thicker, more voluminous and more variable strata within the Midland Valley succession. The BGS sampling strategy also included age-equivalent strata to the West Lothian Oil-Shale Formation toward the basin margin and to the east, to test the lateral extent of organic-rich strata. The sampling (Figure 41) was constrained by the relatively limited amount of core and cuttings material preserved and donated to the BGS National Geoscience Data Centre. Core material was chosen in preference to cuttings, where possible, as Jarvie (2012a) highlights some inconsistencies caused by a mixing effect in cuttings. The core and cuttings material sampled by BGS 2014 was drilled between 9-70 years ago, does not represent in situ conditions, give original HI values, and is likely to have suffered losses (e.g. S1 values).

It is also worth noting that organic geochemistry parameters such as TOC, S1, S2 etc are generally considered less reliable from outcrop samples due to losses and artefacts of weathering. None of the BGS 2014 samples were from outcrop, though a limited amount of data incorporated in sections 3.2-3.6 below is from outcrop samples.

The raw data from the BGS 2014 Rock-Eval analyses are provided in Appendix D and mineralogy results are described in Appendix E.

3.2 Total Organic Carbon content (TOC)

3.2.1 Previous work

The source rock potential of the West Lothian Oil-Shale Formation was reviewed by Parnell (1988). He considered the oil-shales to be a high quality oil-prone source rock, with up to 30% TOC. Other shales and dark limestones within the formation were also considered to have petroleum source potential, with TOC values ranging from 1.5 to 22.7% (Parnell 1988: Table 1). The potentially high hydrocarbon yield was linked to the abundance of alginate in the kerogenous sedimentary rocks. The organic matter was predominantly algal. Parnell (1988) summarised that 'black shales' yielded up to 15% TOC and noted that TOC up to 11.4% had been determined in shales containing desiccation cracks. Other published analyses give 11.2% TOC in an oil-shale (Bitterli 1963), 34.9% and 49.0% TOC in torbanite and boghead coal, and 16.9% and 11.7% TOC in Dunnet and Broxburn oil-shales respectively (Bjørøy *et al*. 1988).

Organic-rich shales within the Lower Limestone to Coal Measures formations were also considered potential sources of hydrocarbons by Parnell (1984). Though no samples from the 'Cementstone Group' (Ballagan and Clyde Sandstone formations) were analysed, it was considered that dark lacustrine shales and dolomitic laminites had some hydrocarbon generating potential (Parnell 1988). Turner (1991) analysed 27 Ballagan Formation shale samples, reporting values ranging from less than 0.01% carbon at Dunbar (East Lothian) to 1.2% carbon at Ballagan Burn (north of Glasgow).

Lower Palaeozoic shales present at depth are considered to have been potential source rocks at some point in their history (Parnell 1984). However, judging by the very limited amount of solid hydrocarbon minerals found in the Lower Palaeozoic rocks of the Southern Uplands, they are not considered to be a source for Carboniferous oils (Parnell 1984). Robinson *et al.* (1989) give a Rock-Eval result of TOC = 0.9%. for the organic-rich shales of the Lower Devonian Dundee Flagstone Formation. Along with Parnell (1984), who cited values up to 1.5% organic carbon for the 'Lower Old Red Sandstone of Angus', Robinson *et al.* (1989) considered the Devonian shales as plausible source rocks if present in sufficient quantity. However, they note that it is difficult to extrapolate their occurrence westwards away from outcrop into the subsurface.

In the Leven Seat 1 well report, Petrachem (1989) document highly variable TOC contents for the silty mudstones, carbonaceous mudstones and coals of the Limestone Coal Formation interval from 5.7% to 83.0% TOC. Lower Limestone Formation strata produced similar, variable results from 1.7 to 34.4% TOC and Asbian (West Lothian Oil-Shale and Gullane formations) sedimentary rocks gave 0.1 to 4.8 % TOC. Grey siltstones and mudstones in strata tentatively interpreted as Pu palynomorph zone 'Cementstone Group' rocks (Ballagan or Clyde Sandstone formation) gave TOC contents of 1.2-3.2%, with red mudstone material giving 0.04-0.3 % TOC.

A Petrachem (1986) report from the Inch of Ferryton 1 well documents variably high TOC in the Limestone Coal Formation (2.3 -30.8 %), Lower Limestone Formation (2.9-10.7 %) and Strathclyde Group (0.6-18.8 %), with most argillaceous sediments between 4.6% and 6.7 % TOC and carbonaceous claystones 11.2-18.8 % TOC. Devonian strata in this well have generally poor organic richness (0.02-1.2 % TOC, generally <0.5 %) and were considered unlikely for hydrocarbon generation.

Twenty-nine Rock-Eval analyses from outcrops in Fife prove that the upper part of the Anstruther Formation (Gullane unit) and part of the Pittenweem Formation (lower part of the West Lothian Oil-Shale unit) are particularly organic-rich (TOC values 1-24%; Raymond 1991).

3.2.2 Data synthesis

Nearly 500 TOC measurements have been compiled from BGS, well report, thesis and company data spanning a range of Carboniferous strata from the Passage Formation down to the Inverclyde Group. The wide range of TOC contents (Figure 42) reflects the organic-rich nature of the Visean and Namurian oil-shale and coal-bearing strata. An effect of the BGS sampling strategy (see section above) on Figure 42 is that the BGS samples are at the lower end of the TOC values, though nearly half of the BGS samples have TOC greater than 2%.

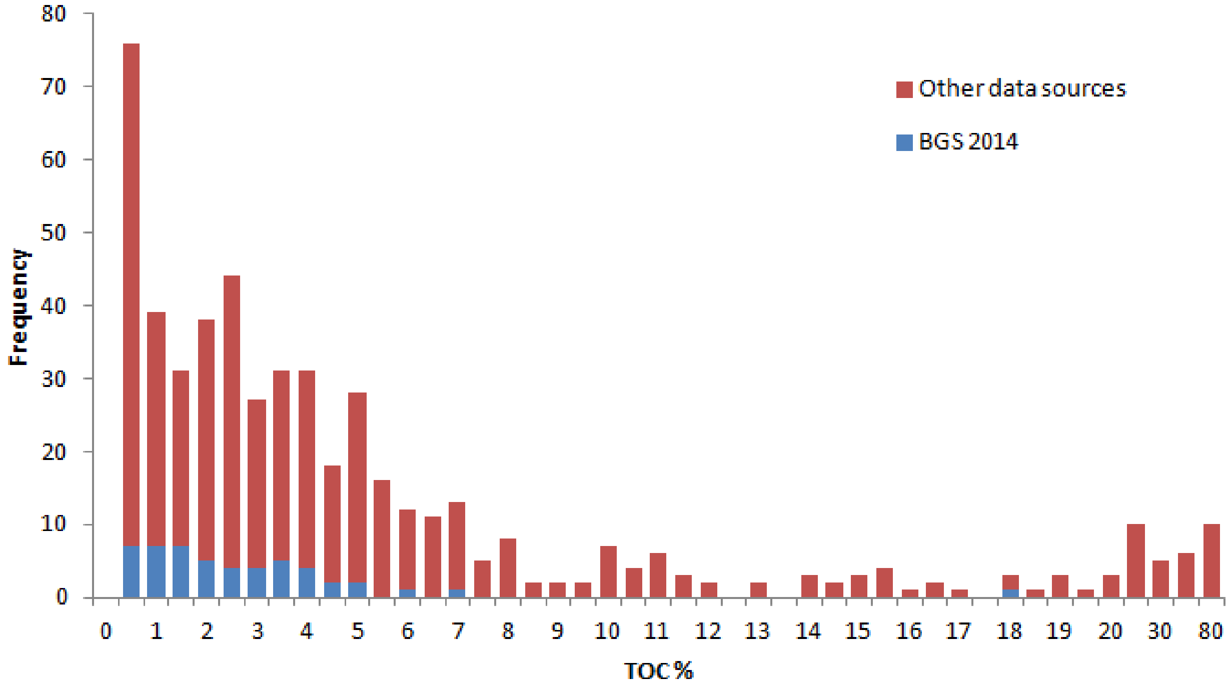


Figure 42 Histogram showing the distribution of TOC measurements (n=516) in all Carboniferous samples from the Midland Valley of Scotland (including units not considered prospective for shale).

Examining the TOC dataset by stratigraphic unit provides additional information (Figures 43-47).

The Gullane unit is dominated by TOC values between 1-3.5% (Figure 43), with a smaller number of high TOC samples.

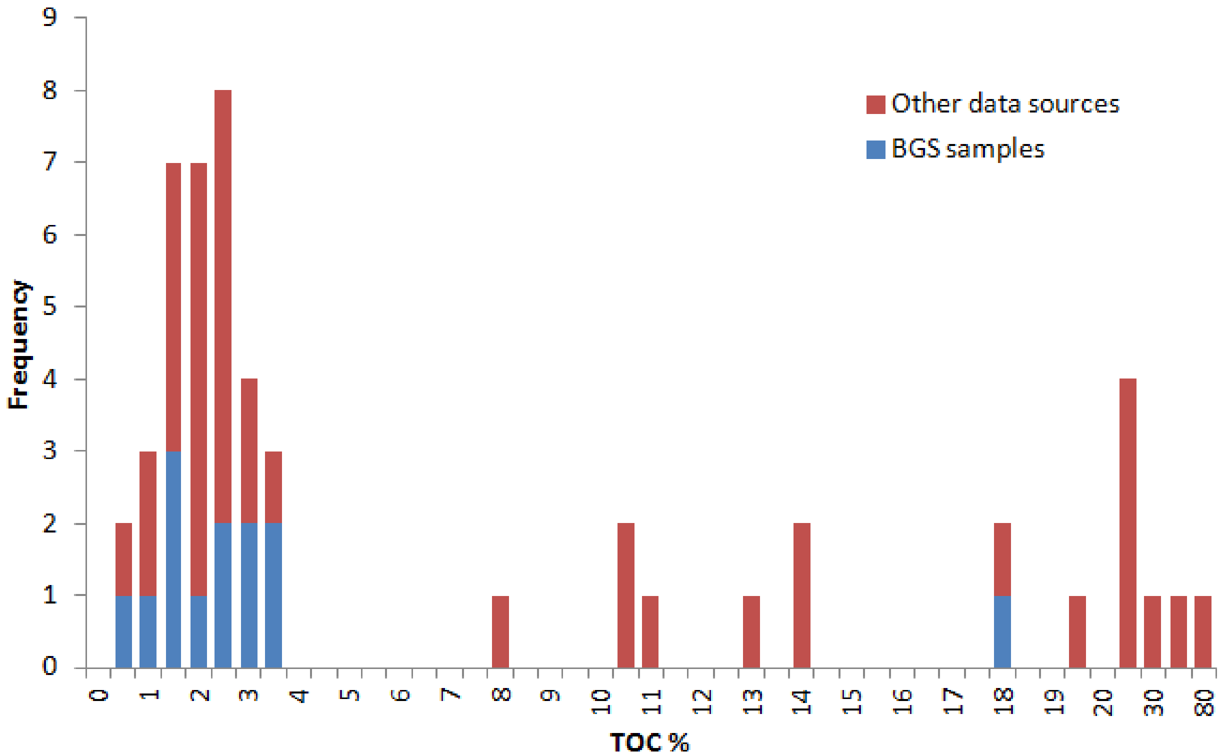


Figure 43 Histogram showing the distribution of TOC measurements (n=51) in the Gullane unit.

The West Lothian Oil-Shale unit has a large proportion of the samples between 1-7% TOC and a significant number between 7% and 30%. (Figure 44). By contrast, the Lawmuir Formation, the basin margin equivalent of the West Lothian Oil-Shale Formation, has TOC < 2% in three of the four samples analysed (the fourth having TOC = 2.09%).

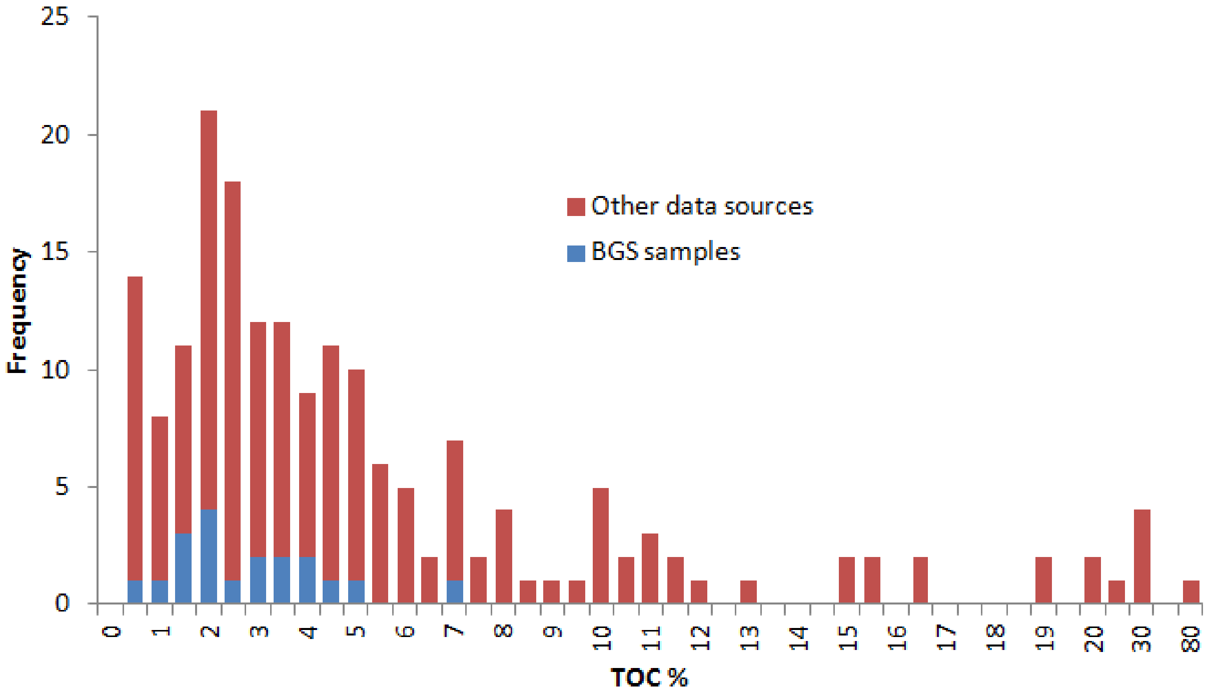


Figure 44 Histogram showing the distribution of TOC measurements (n=185) in the West Lothian Oil-Shale unit (does not include the Lawmuir Formation).

The Lower Limestone and Limestone Coal formations (Figures 45, 46) commonly have TOC values of 3-7.5%, with values between 9-30% measured in carbonaceous mudstones.

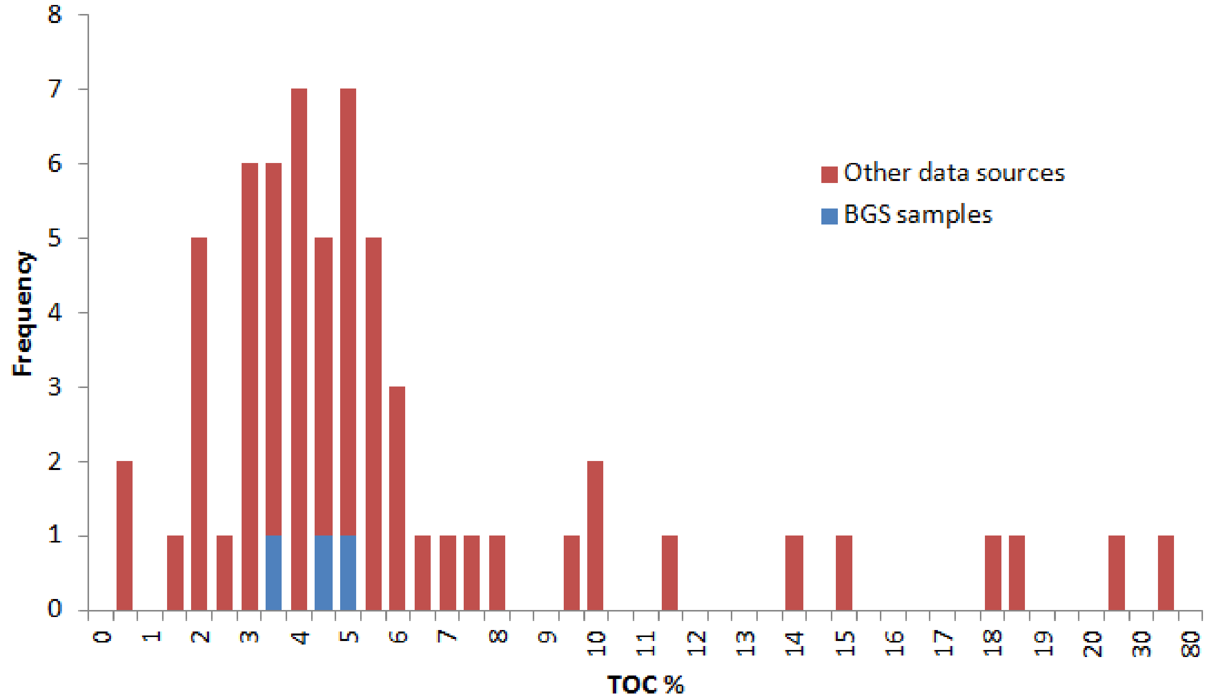


Figure 45 Histogram showing the distribution of TOC measurements (n=62) in the Lower Limestone Formation.

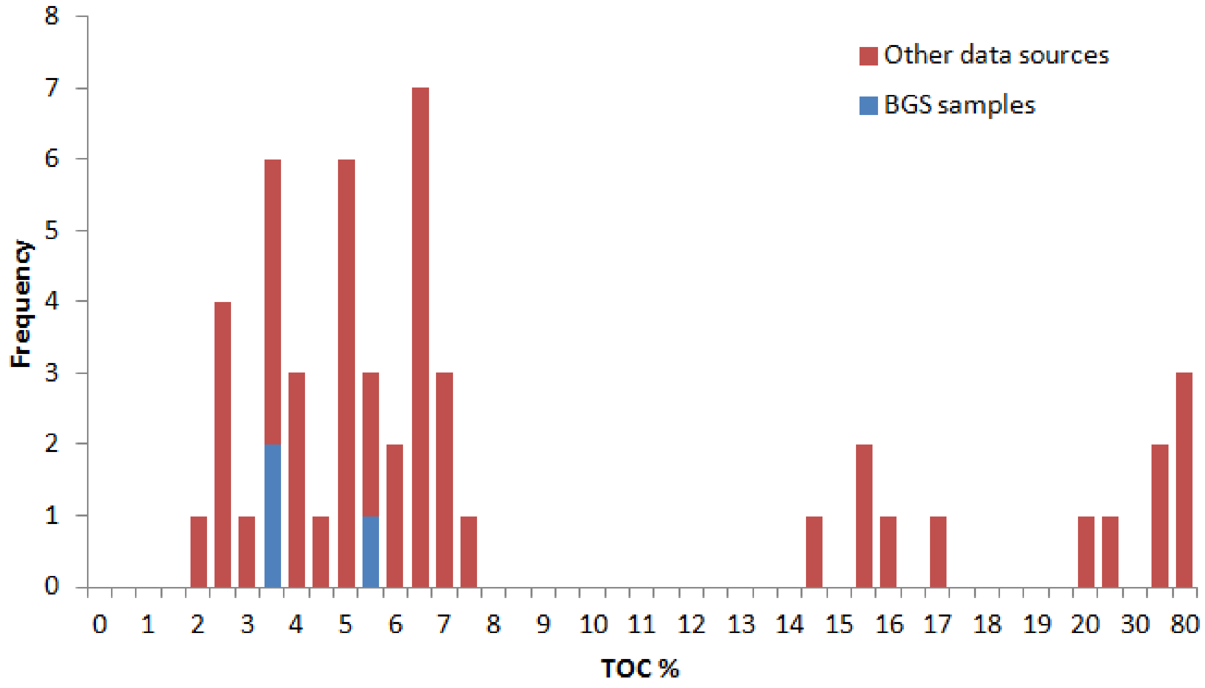


Figure 46 Histogram showing the distribution of TOC measurements (n=50) in the Limestone Coal Formation.

The Ballagan Formation near the base of the Carboniferous (Table 4) is a thick, mudstone-rich unit, widespread across the Midland Valley of Scotland, which merited initial consideration as a shale oil or gas resource. However, apart from one sample all measured TOC values are <2 % (Figure 47). As a result of the > 2% TOC criterion generally not being met, the Ballagan Formation was not considered further as a possible shale oil or gas resource.

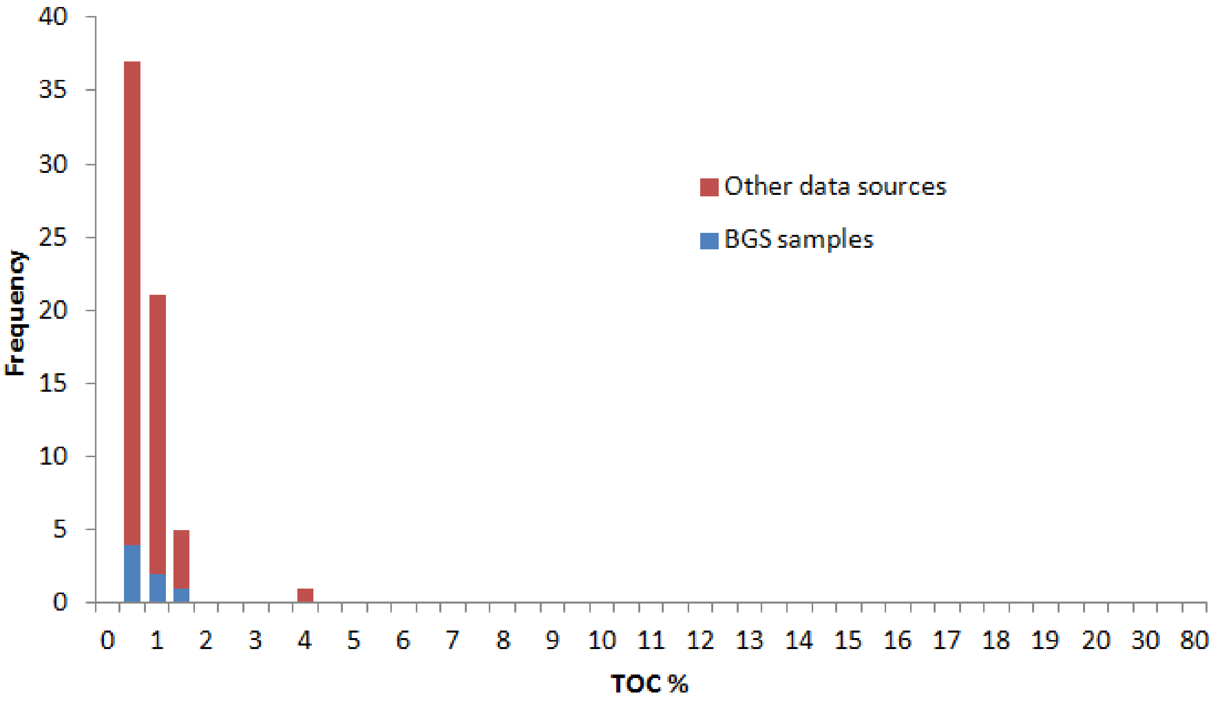


Figure 47 Histogram showing the distribution of TOC measurements (n=64) in the Ballagan Formation.

Comparing TOC sample data with well gamma logs highlights the organic richness of the Limestone Coal Formation, Lower Limestone Formation and the upper part of the West Lothian Oil-Shale unit in the Central Coalfield and Lanarkshire Basin areas. Sample values from thick shale intervals identified on the composite log consistently have TOC > 2%. It is clear that mudstone and other strata forming a large proportion of the sedimentary succession meet the > 2% TOC criterion for shale resource in this area, in addition to the highly organic-rich, much thinner oil-shales.

The Leven Seat 1 well located closer to the basin margin penetrates lower into the West Lothian Oil-Shale unit, where the succession of relatively thinly interbedded shale, sandstone and limestone exhibit lower, variable TOC contents, many < 2% TOC towards the base of the unit. Five samples from the Gullane Formation in Pumpherston 1 gave variable TOC values, three between 1-1.5% and two greater than 2%. Only one of the samples was from a shale layer greater than 50 ft thick, and it had a TOC of 3.23%.

TOC data from the Midlothian and Fife area wells are relatively sparse. TOC content at the base of the West Lothian Oil-Shale Formation and the Gullane Formation in Stewart 1 ranges from 1.19 – 3.48%, whereas two samples from the same intervals in Cousland 6 are 2.55 % and 0.11 % TOC. The TOC content of West Lothian Oil-Shale unit samples from Kelty Bridge 1 and Duloch 1 in Fife are variable at 0.29 – 3.48%, whereas those from Milton of Balgonie 1 and 3 are more akin to the Central Coalfield samples e.g. 3.43 – 4.87% TOC in Milton of Balgonie 3.

The Spilmersford well exhibits an attenuated sequence at the south-eastern basin margin, with thin shales within the West Lothian Oil-Shale unit (Aberlady Formation) and Gullane unit giving a wide range of TOC measurements from less than 1% to 56%. Samples from an attenuated sequence of West Lothian Oil-Shale unit (Pathhead Formation) in the Glenrothes well on the north-eastern basin margin have TOC < 2%. From the Lawmuir 1A well on the western basin margin, one sample of black mudstone from the West Lothian Oil-Shale unit (Lawmuir Formation) had a TOC of 2.09%, but the remaining samples had TOC < 1%.

In summary, the TOC analysis for the West Lothian Oil-Shale and Gullane units ties in with the known sedimentary facies and palaeogeography, with TOC values becoming lower towards the depositional basin margin and also towards the more thinly bedded, clastic-dominated Fife and Midlothian strata.

3.2.3 Well-log TOC analysis

Calculated TOC values have also been generated for five wells using the Δlog R (Passey) method on downhole logs (Passey *et al.* 1990; Appendix F). This method uses sonic, density, neutron and resistivity logs to calculate a continuous log-derived TOC curve down the well, which can be calibrated with sampled intervals. The analysis was limited to these 5 wells due to the poor availability of digital well logs, and only three of the westernmost wells were calibrated by TOC Rock-Eval sample measurements. Whilst this method produces a useful continuous assessment of TOC, there are limitations resulting from an assumed level of maturity, lack of a 'lean shale' calibration point and limited measured calibration points.

The western wells analysed (Craighead 1 and Bargeddie 1) showed more organic-rich shales with higher calculated wt% TOC and P/G (pay to gross= % shale with >2% TOC; Figure 48). The eastern wells (Carrington 1 and Straiton 1) had lower quality data that showed leaner shales giving lower calculated wt% TOC and P/G, however these wells showed discrete intervals of higher calculated TOC.

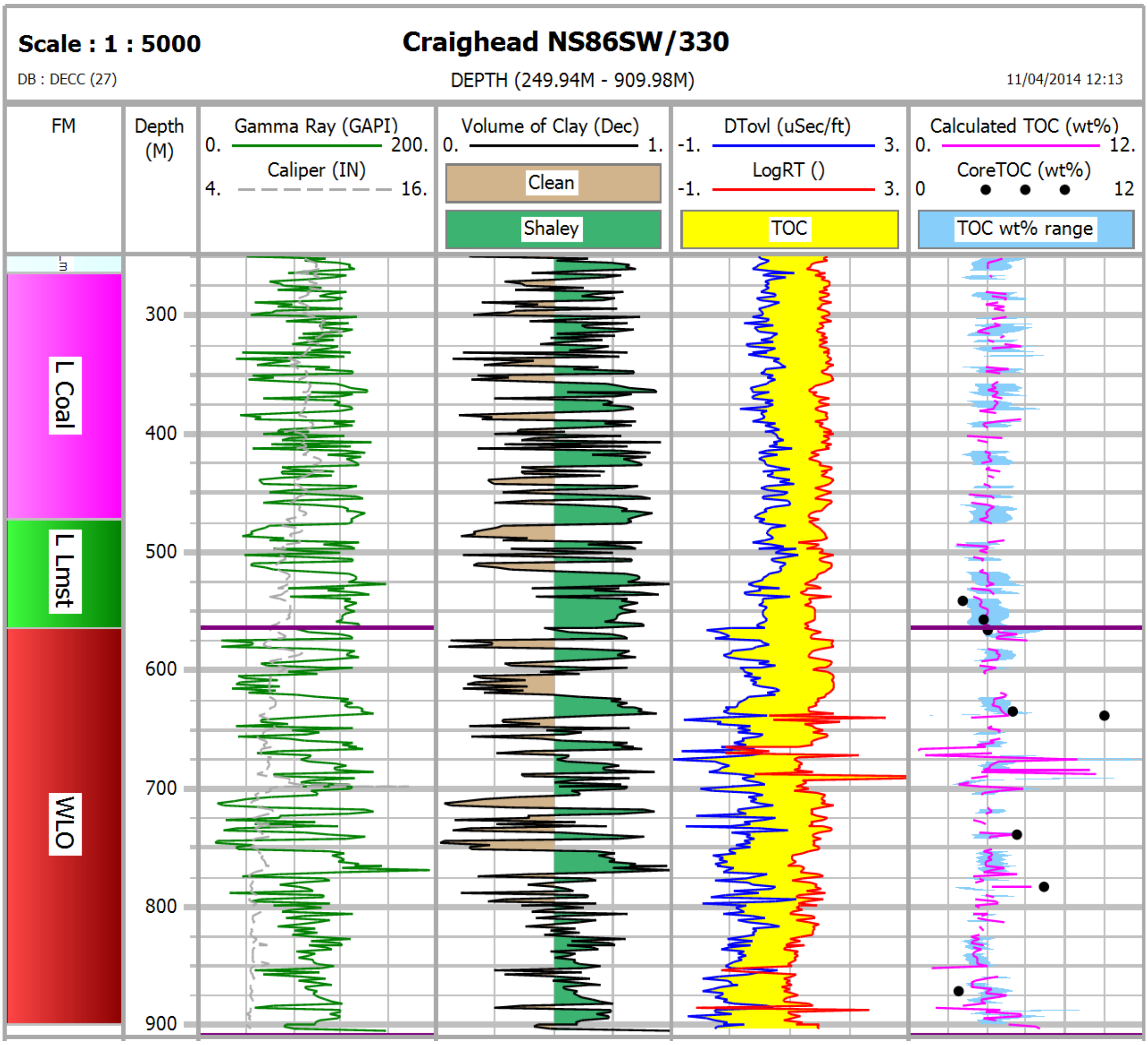


Figure 48 Example of well-log plot for continuous log-derived TOC from the Craighead 1 well. WLO = West Lothian Oil-Shale unit, L Lmst = Lower Limestone Formation, L Coal = Limestone Coal Formation.

The highest calculated wt% TOC units were the Limestone Coal Formation and Lower Limestone Formation, with an average calculated wt% TOC greater than 4% in organic-rich shales (e.g. Figure 48). The West Lothian Oil-Shale and Gullane units showed variability in calculated TOC; at certain intervals discrete TOC-rich shales were identified (see Appendix F). Overall, the well-log TOC analysis further highlights the presence of significant net thicknesses of shale with TOC contents well over the >2% TOC cut-off criterion.

3.2.4 Net organic-rich shale maps

Maps were compiled to input the spatial variability meeting the criterion 'percentage of shale with TOC greater than 2%' (Table 3) into the volumetric resource estimate calculation. The TOC dataset for some wells and formations in the west-central parts of the study area is good, though data points are widely spaced. For example, Bargeddie 1 in the Lower Limestone Formation and West Lothian Oil-Shale unit, Craighead 1 and Inch of Ferryton 1 from the Limestone Coal Formation to West Lothian Oil-Shale unit have good depth coverage. However, in central and eastern parts of the study area, the TOC dataset is sparse in all formations, with resultant high uncertainty in net organic-rich shale maps.

The percentages of shale with TOC >2% were estimated by visual inspection of the gamma log on wells with measured TOC values. Quantitative analysis of TOC values was attempted, but the limited number of samples combined with the large range of TOC values (< 1 to 80% TOC) meant this approach was unsuccessful. The well-log study (Appendix F) was used to give additional data points. However, the eastern wells are uncalibrated with measured TOC values. It is important to note that the percentage of shale > 2% TOC maps are constrained by at most 11 data points and thus have low reliability.

The value of '*percentage of shale > 2% TOC*' for the Limestone Coal Formation is constant at 100% as nearly all TOC measurements from across the study area have TOC > 2%. The Lower Limestone Formation shows greater variability, with virtually 100% of the shale > 2% TOC in the west, decreasing eastwards (Figure 49). A similar pattern is observed for the West Lothian Oil-Shale unit, though the high Milton of Balgonie 1 well TOC measurements increase the values into Fife (Figure 50).

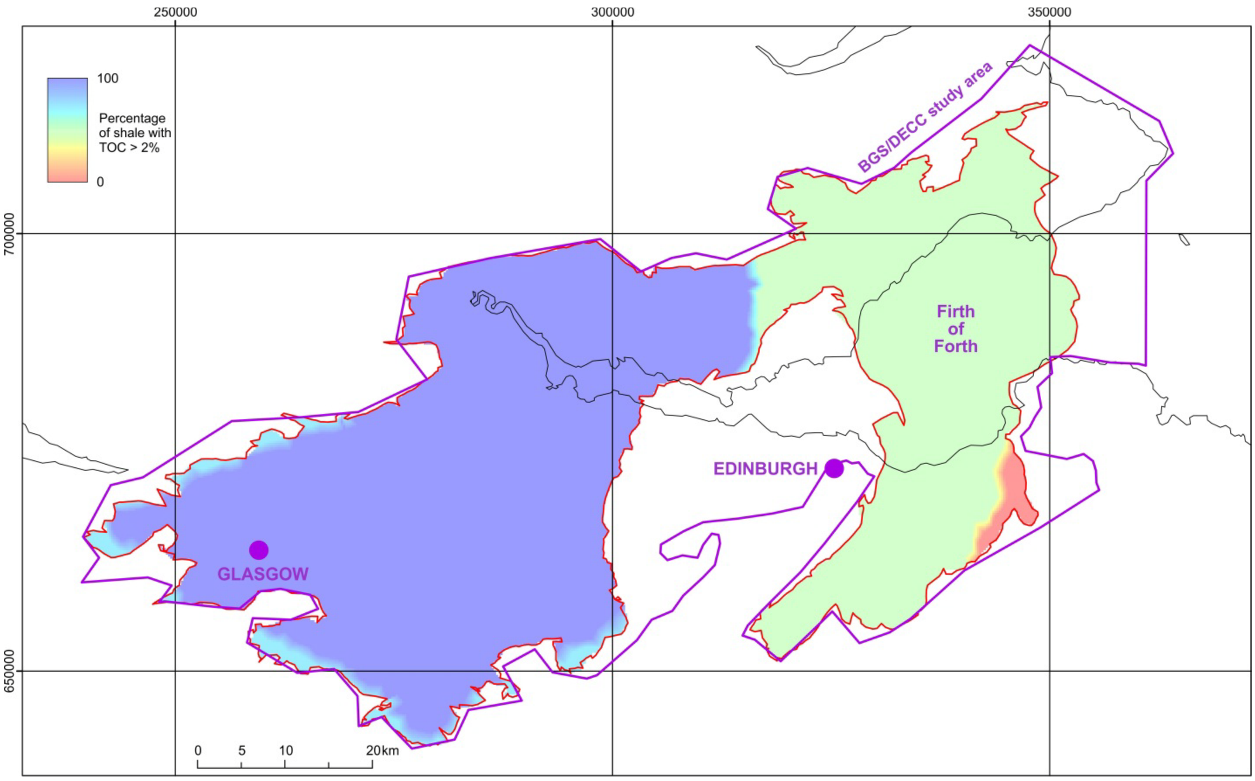


Figure 49 Percentage of shale with TOC >2% map for the Lower Limestone Formation

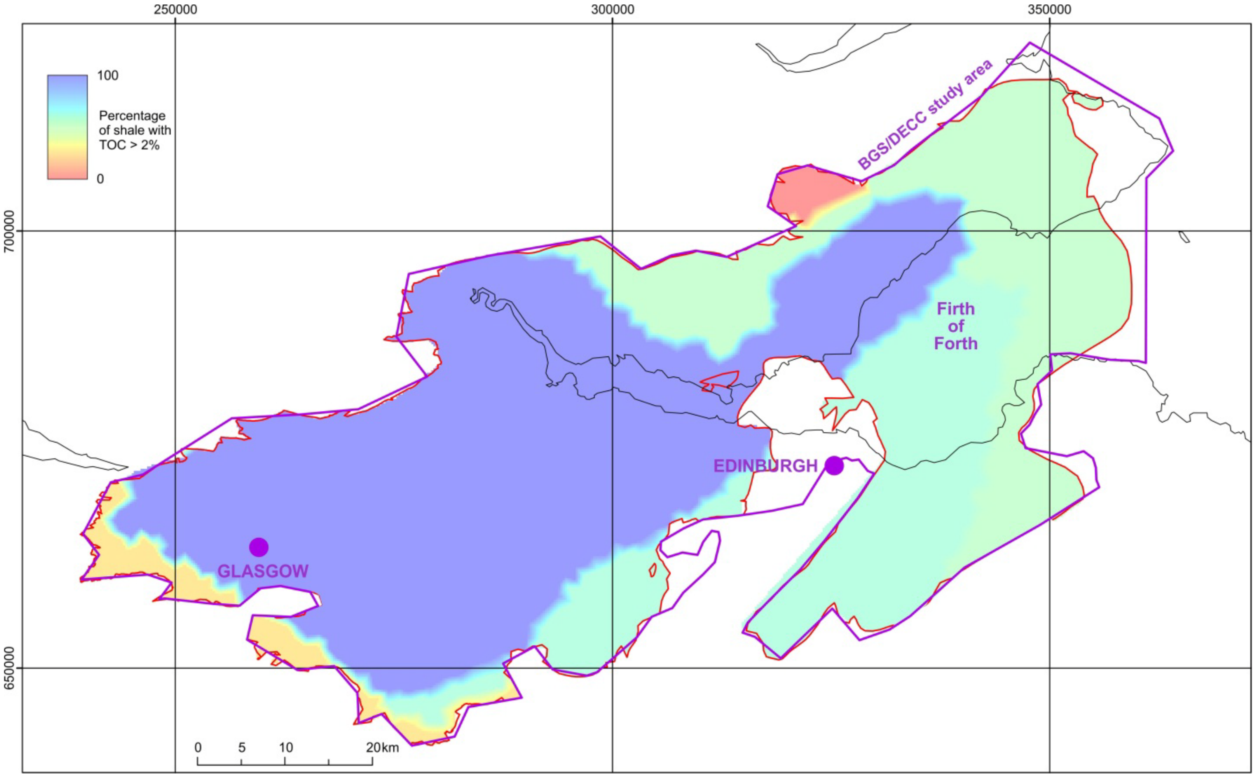


Figure 50 Percentage of shale with TOC > 2% map for the West Lothian Oil-Shale unit

A constant value of 50% TOC > 2% was used to represent the very limited measured TOC values and well-log analyses for the Gullane unit.

3.3 Kerogen type and hydrocarbon generation potential

Kerogen type influences the temperature and character of oil or gas generation during rock maturation. Type I kerogen is mainly algal (typically lacustrine) and amorphous and likely to generate oil, Type II kerogen is of marine origin, whereas Type III is composed of woody terrestrial source material that typically generates gas.

3.3.1 Previous work

A Van Krevelen diagram presented by Raymond (1991, p. 182) from 13 Fife outcrop samples highlighted a marked variation in elemental composition from different types of organic matter, ranging from Type I, Type II and Type III kerogens. More detail on the linking of chemical composition of organic material to rock type is given in Raymond (1991).

In the Leven Seat 1 well (Petrachem 1989), gas-prone kerogen types were found in the Limestone Coal Formation, mixed types in the Lower Limestone Formation and Inverclyde Group, with the West Lothian Oil-Shale and Gullane units containing mainly oil-prone kerogen types.

In the Inch of Ferryton 1 well (Petrachem 1986), kerogen types examined microscopically varied from predominantly oil-prone to predominantly gas-prone in the prospective units. In the Limestone Coal Formation, amorphous kerogens of vascular plant and algal origin, plus black wood were commonly observed, as well as structured kerogen in some samples. Amorphous kerogen was also common in Lower Limestone Formation and Strathclyde Group samples. At lower maturity levels the sedimentary rocks were interpreted as more oil prone, with the oil likely to have been generated ranging from light, paraffinitic to heavy paraffinitic, with some aromatic in character. The character is believed to indicate a significant terrestrial component. Hydrocarbon production values became generally poorer closer to the Midland Valley Sill, and it was suggested that intrusion had 'retorted' off oil-prone shales (Petrachem 1986).

Kerogen examined microscopically and by geochemical analysis from the Salsburgh 2 well showed Type III (gas prone) to Type II/I (oil prone) derived from a mixture of kerogen types in the Limestone Coal and

West Lothian Oil-Shale formations (Reach 2013). Increasing oil production values downward in Salsburgh 2 indicates some shales were actively generating oil at maximum burial, and this oil is mostly compositionally light, non-waxy (Reach 2013). These figures were obtained from pyrolysis of cuttings such that any volatile light hydrocarbons including gases between C1 and C13 will have been lost during drilling and cuttings sampling.

Geochemical analysis suggested the oil-shale bearing strata as the source rock for the conventional hydrocarbon accumulations and seeps across the Midland Valley of Scotland (Parnell 1984, 1988, Raymond 1991, Underhill *et al*. 2008).

3.3.2 Data synthesis

A more limited quantity of data was available to this study to assess kerogen type and generation potential than for TOC and vitrinite reflectance measurements. Seventy samples (50 BGS 2014, 20 company data) with oxygen index (OI) values are shown on a Van Krevelen plot (Figure 51), with a larger number of samples analysed for one or more of S1 and S2 and hydrogen index (HI) values.

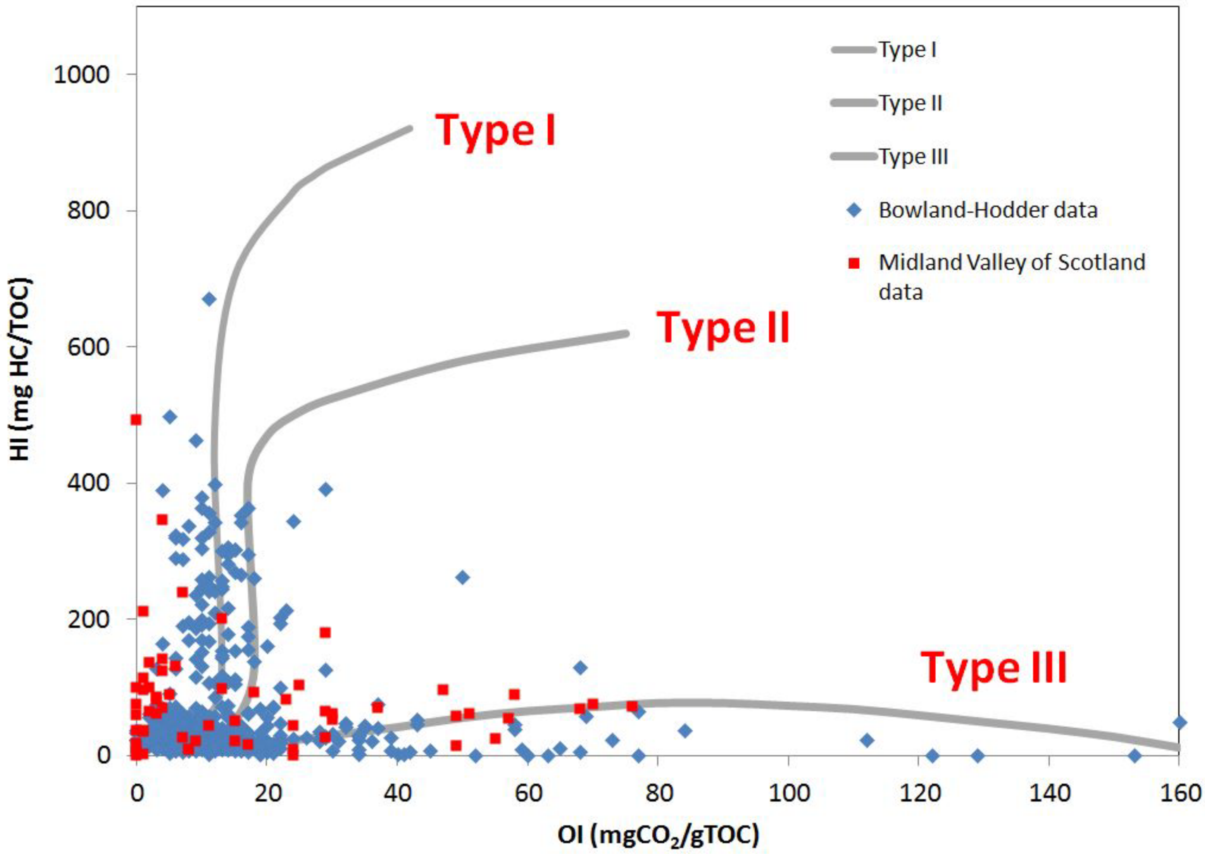


Figure 51 Van Krevelen plot showing all Midland Valley of Scotland samples, compared to Bowland-Hodder Shale samples in blue (Andrews 2013)

The Midland Valley of Scotland data exhibit a range of HI and OI values (Figure 51). Trends along the Type I and Type III curves can be picked out, suggesting that much of the kerogen is either lacustrine (Type I) oil-prone, or terrestrial (Type III) gas-prone. As with the Bowland–Hodder Shale data, many of the samples have low HI and OI values indicating sample maturity.

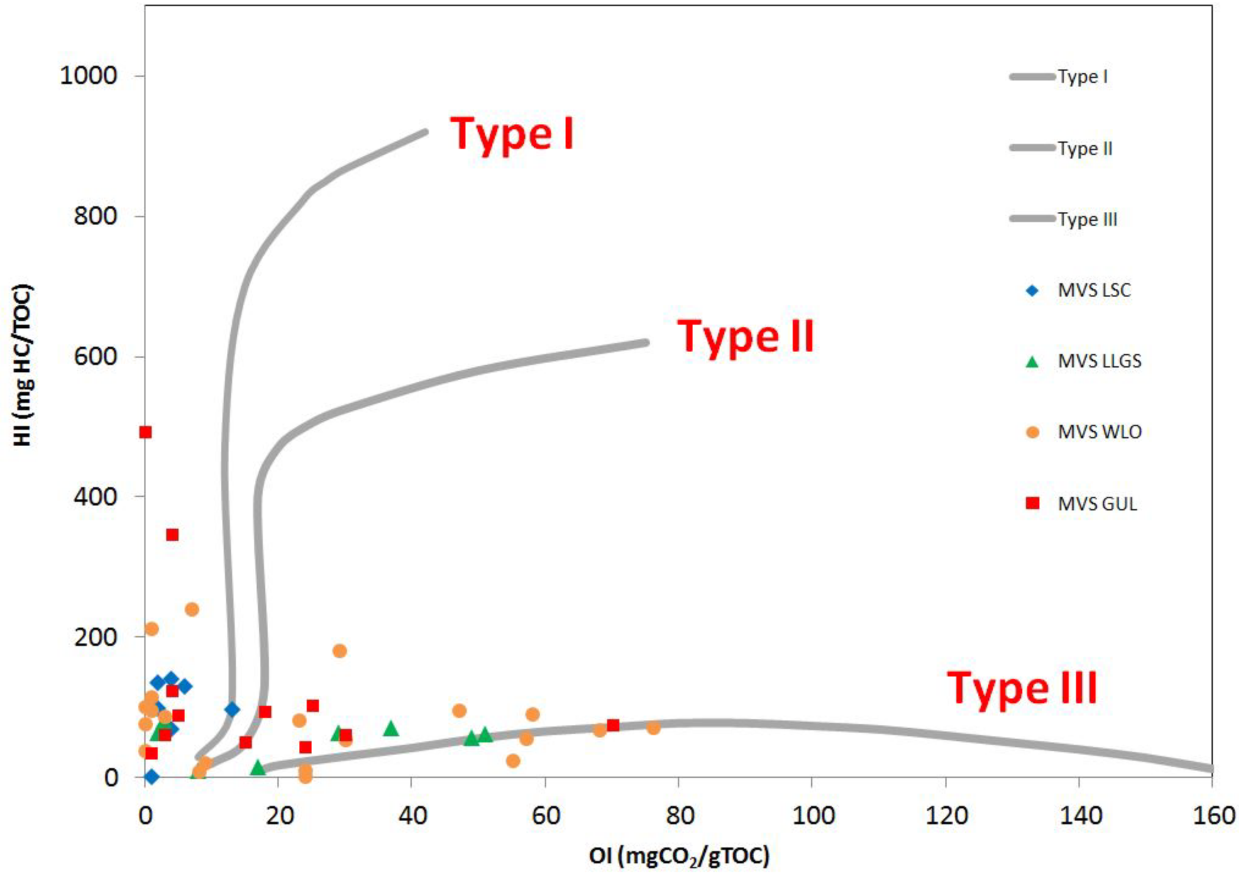


Figure 52 Van Krevelen plot showing all Midland Valley of Scotland (MVS) samples by stratigraphic unit. GUL = Gullane unit, WLO = West Lothian Oil-Shale unit, LLGS = Lower Limestone Formation, LSC = Limestone Coal Formation.

Examining the relatively small amount of data by stratigraphic unit (Figure 52) shows that Limestone Coal Formation samples are indicative of Type I kerogens, whereas Lower Limestone Formation samples are aligned with Type III kerogens. Samples from the West Lothian Oil-Shale and Gullane units plot within the range of Type I, Type II and Type III kerogens.

Taken together with previous work on kerogen type (see above) and the variability on the S2 vs TOC graph (Figure 56), it is not possible with the current dataset to identify particular units with a particular kerogen type; the regional picture is of mixed kerogen types. For example, there is evidence of Type II kerogens, but not at a specific level at regional scale.

3.4 S1 content and potential oil yields from S1 data

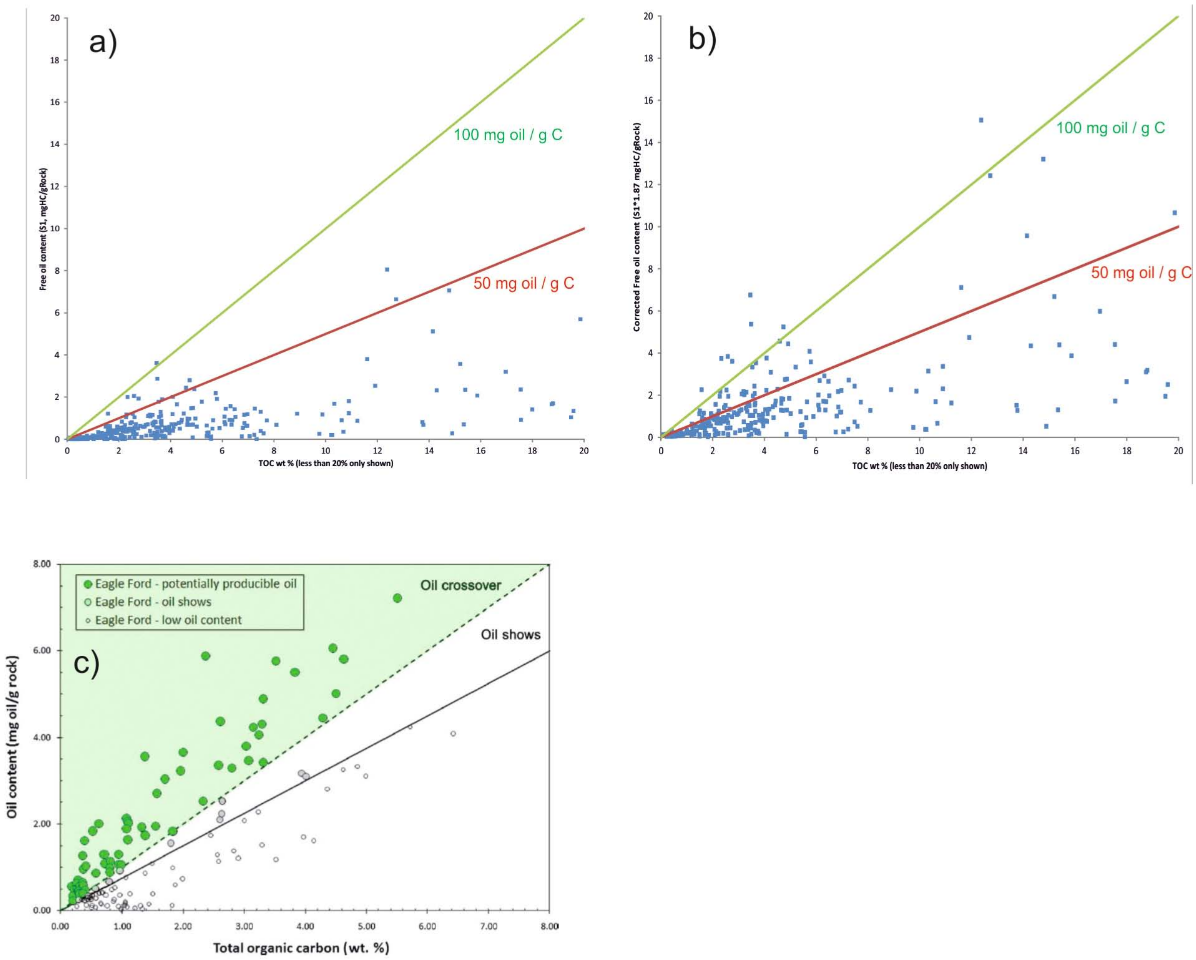


Figure 53 (a) Plot of TOC vs. S1 for all Carboniferous shales in the Midland Valley of Scotland with TOC < 20% (b) Plot of TOC vs. corrected S1, as above, but with an evaporative correction of 1.87 applied. (c) Comparative plot with data from the Eagle Ford Shale (Upper Cretaceous) in Texas (Jarvie et al. 2012).

The S1 value output from the Rock-Eval analysis is a measurement of the amount of free hydrocarbons already generated in the source rock and present in the sample as both 'free oil' in microscopic pore spaces and 'sorbed oil' in the kerogen. It is the free oil component that can potentially be extracted after fracture stimulation. Table 6 gives average S1 values for each prospective unit for oil mature, organic-rich samples.

	Average free oil content (S1) (mgHC/gRock)	Average corrected free oil content (mgHC/gRock)
Limestone Coal Formation	1.40	2.6
Lower Limestone Formation	0.57	1.1
West Lothian Oil-Shale unit	1.52	2.8
Gullane unit	0.29	0.6

Table 6 Summary of average S1 values for prospective shale with > 2% TOC and R_o between 0.6 - 1.1%. Corrected S1 values use the mean correction factor input to the Monte Carlo simulation of 1.87.

The correction of S1 for 'evaporative loss' is an important factor in converting the present-day S1 figures determined on legacy core material into data that are likely to pertain to the shales under reservoir conditions at depth. The loss of light oil from samples between down-hole collection and their analysis (often decades later) is commonly estimated to be 35% (a correction factor of 1.33), but it is highly dependent on organic richness, lithofacies, oil type, sample type and method of preservation (see Jarvie 2012b). Jarvie *et al*. (2012) warned that correction factors of over 5.0 may be necessary and Michael *et al*. (2013) showed that oil gravity has a major control on evaporative loss. A range of evaporative losses was input to the Monte Carlo simulation of oil-in place volumes and the P50 value of 1.87 was applied to Figure 53b (see Appendix A for detail, P50 value based on API of 40).

The oil saturation index (OSI) is a measure of the free oil from Rock-Eval-measured S1 in relation to TOC:

The oil saturation index (OSI) = (S1 x 100)/TOC, giving results in mgHC/gTOC

When the oil saturation index exceeds the sorption potential of oil in kerogen, potentially producible oil is likely to be present in the pore space. Experimentation suggests that the sorption potential for oil in kerogen is approximately 100 mg oil/g kerogen, so OSI values above 100 are taken to indicate the presence of potentially producible oil (Jarvie & Baker 1984, Sandvik *et al*. 1992, Jarvie 2012b).

Some of the Midland Valley of Scotland samples analysed have a corrected free hydrocarbon (S1) content of greater than 100 mg oil/ g C, with a more significant number having free oil contents between 50 and 100 mg oil/g C (Figure 53a,b). In the Weald area of southern England (Andrews 2014), a correlation between TOC and S1 suggested that most of the 'free oil' was bound within the kerogen. In contrast, the Midland Valley of Scotland data is scattered, suggesting that at least some free oil is present outside the kerogen.

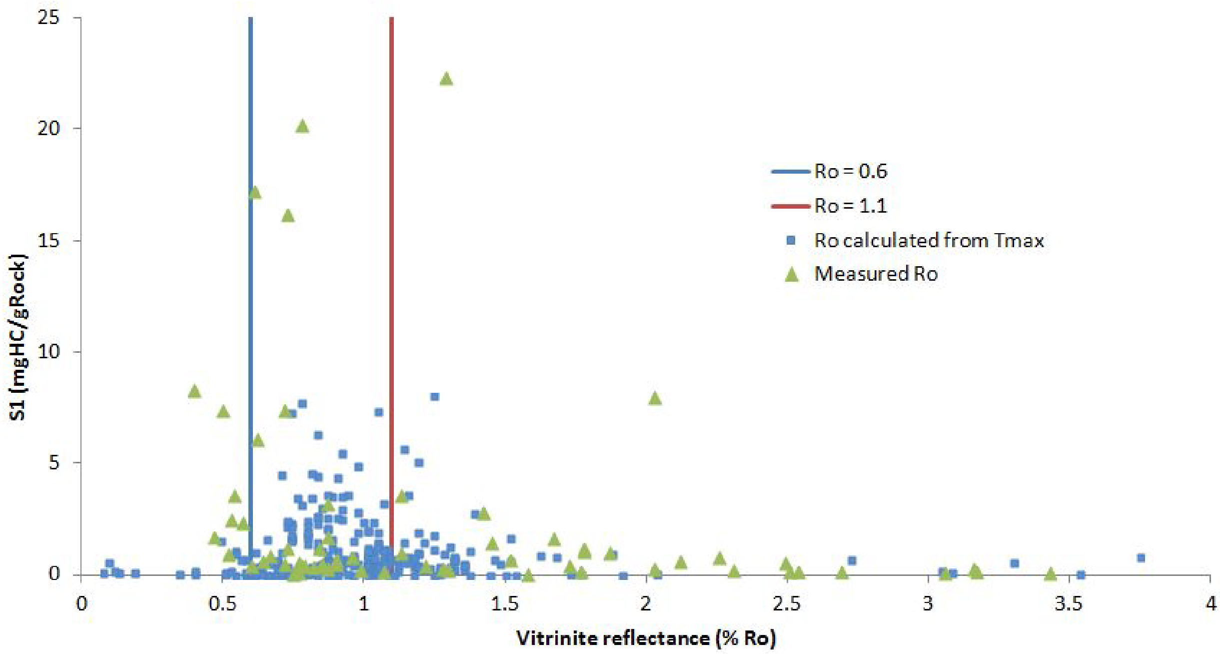


Figure 54 Graph of S1 against vitrinite reflectance (R_o, calculated and measured) for all prospective units

A plot of S1 against vitrinite reflectance shows that in general, samples within the oil window (maturity between R_o=0.6 and 1.4%) have higher 'free-oil' S1 values (Figure 54). In the Salsburgh 2 well there is a clear trend to increasing S1 and oil production index (=S1/(S1+S2)) values with increasing burial depth (Reach 2013).

3.5 Hydrocarbon generation potential – S2 values

The S2 value is a measure of the residual hydrocarbon available remaining in the sample, which could be released upon heating. It is a measure of the potential to generate hydrocarbons if maturation continued.

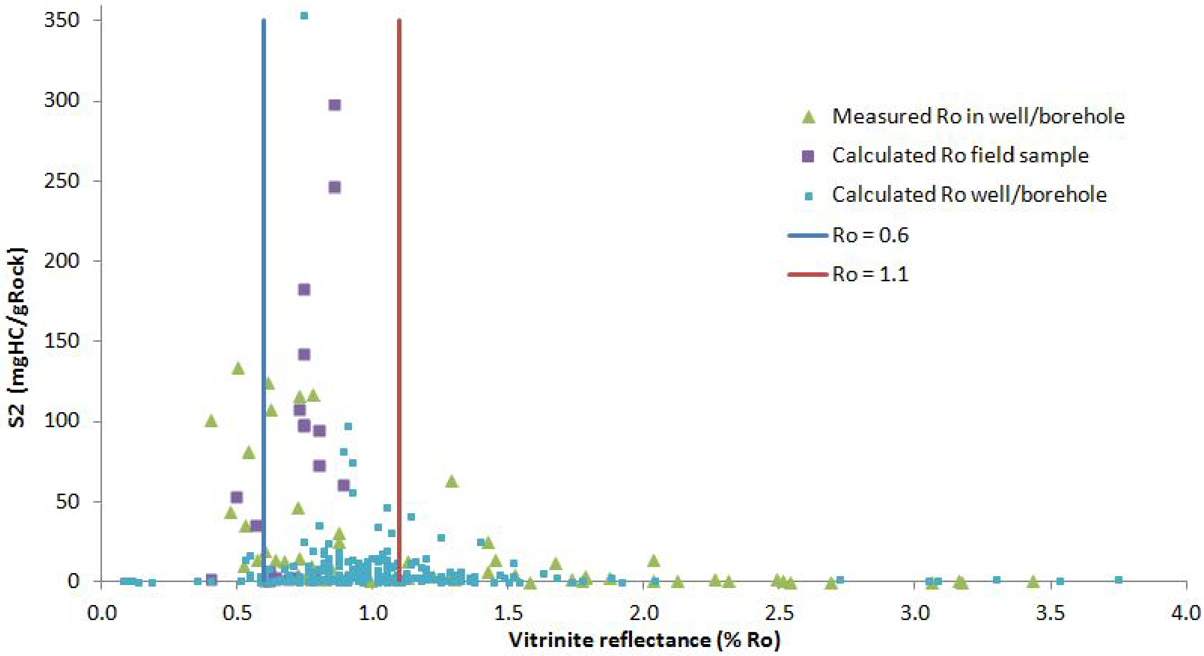


Figure 55 Plot of S2 against calculated and measured vitrinite reflectance (R_o) for all prospective units

On Figure 55, S2 has been plotted against vitrinite reflectance to assess the effect of maturity. Whilst the majority of the samples have relatively low S2 values, field (outcrop) samples and well/borehole samples of lower maturity generally show the highest S2 values. This suggests that some less mature or less deeply buried samples retain higher potential for hydrocarbon generation, whereas many of the more mature, deeply buried samples have lower potential for hydrocarbon generation, likely because they are already mature for oil or gas at the present time. These hydrocarbons have in all probability been already generated.

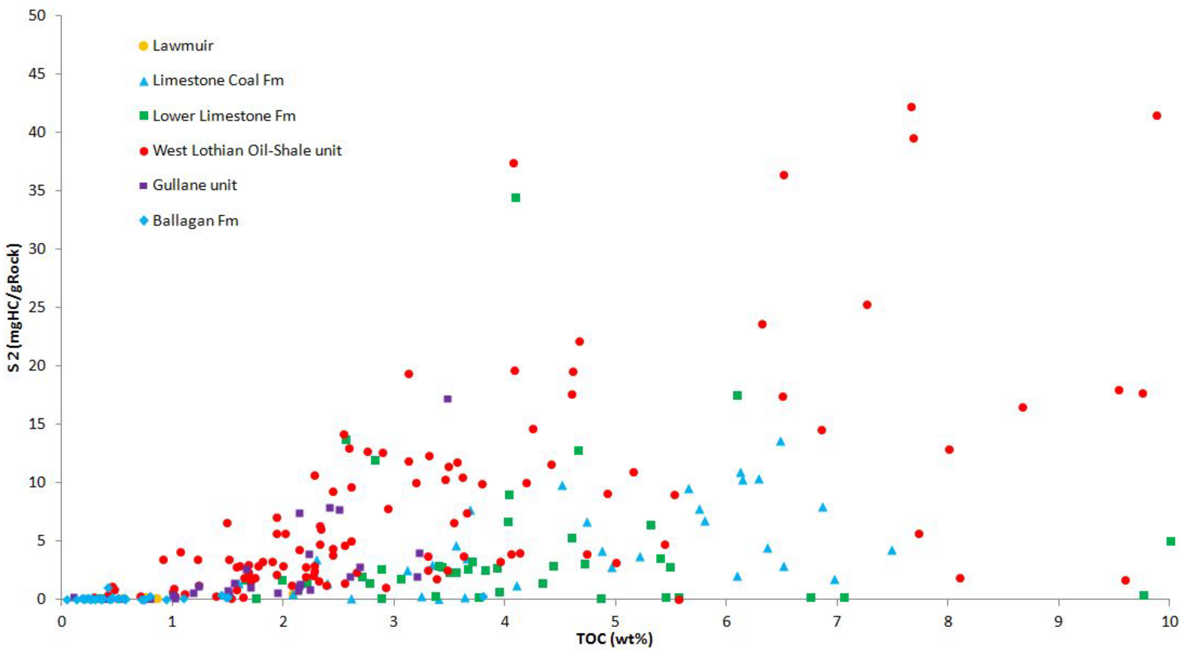


Figure 56 Graph of S2 versus TOC for samples less than 10% TOC, with stratigraphic units shown

Plotting S2 values against TOC illustrates the range of S2 values (Figure 56) relating to sample variability and maturity.

3.6 Thermal maturity and uplift

3.6.1 Previous work

Raymond (1991) determined and interpreted vitrinite reflectance measurements from over 1,000 borehole, well and field samples from the Carboniferous strata of the central and eastern Midland Valley of Scotland. She showed that:

- Numerous downhole borehole vitrinite reflectance analyses to depths of 8,000 ft, combined with organic geochemistry, proved hydrocarbon maturation of lacustrine oil-shales due to burial.
- The thermal effects of sill emplacement were found to be widespread around tholeiitic sills (Figure 58; see also Raymond & Murchison 1988, Murchison & Raymond 1989), but confined to the very close proximity around alkaline sills. This was explained by the intrusion of the tholeiitic sills into dry, consolidated sediments, whereas the alkaline sills were believed to have been intruded into wet, unlithified sediments that greatly restricted the thermal effects of the high-temperature magma. The tholeiitic Midland Valley Sill exerted a major influence on organic maturation within the lower Limestone Coal, Lower Limestone and upper West Lothian Oil-Shale formations in the central and eastern Midland Valley of Scotland.
- For a given stratigraphic level, the rank is higher in the Stirling-Clackmannan-Central coalfield basins than it is further to the east in the Fife-Midlothian Basin and its immediate surroundings. Numerous rank maps are provided in Chapter 5 of Raymond (1991). This general pattern is maintained throughout the Carboniferous succession. A greater regional palaeoheatflow in the central-western Midland Valley of Scotland was suggested than in the east, corresponding to an 'increased thickness of the volcanic pile' there.
- Vitrinite reflectance maturity data may have been suppressed by the presence of liptinitic and exinitic matter. Comparisons of coal rank with rank of sedimentary strata in the same borehole show a distinct separation of 0.2-0.3 %R_o (Raymond 1991 Chapter 5 Fig. 5.7, see also Figure 58 below) where there is a larger proportion of exinite observed.
- Rank maps at any one stratigraphic horizon show spatial variability due to variation in burial depth and locally due to igneous intrusion. Strata as shallowly buried as the Passage Formation show some areas with R_o>0.6% and more deeply buried strata such as the top of the Strathclyde Group ('Calciferous Sandstone Measures') have R_o>0.6% widely and R_o>1.1% locally (Raymond 1991, Chapter 5). Igneous intrusions create rapid variations in rank at some stratigraphic levels.

Vincent *et al*. (2010) examined aspects of basin thermal maturity and uplift in the Midlothian-Leven Syncline area of the eastern Midland Valley of Scotland, and deduced up to 1,900 m (6,230 ft) additional burial of Carboniferous strata compared to present day levels. This BasinMod analysis suggested deeply buried Strathclyde Group strata had reached the gas window (R_o=1.3%; Vincent *et al*. 2010). A similar schematic burial and uplift history was used by Underhill *et al.* (2008) to explain the generation of hydrocarbons in the Midlothian-Leven Syncline.

The vitrinite reflectance and burial history of the Lower Devonian Stonehaven (R_o=1.2%), Arbuthnott (R_o=0.9%) and Strathmore (R_o=1.3%) groups at outcrop on the northern side of the Midland Valley were examined by Marshall *et al.* (1994). These R_o values imply maximum burial of 9,800-16,400 ft (3,000-5,000 m) for the Stonehaven Group, which may have occurred during Late Carboniferous times. Lower R_o values of 0.5 to 0.7% are documented for Carboniferous rocks at outcrop in Fife, which are consistent with an estimated 6,560-9,840 ft (2,000-3,000 m) of previous burial (Marshall *et al*. 1994).

Well reports containing maturity data include Petrachem (1989) for Leven Seat 1 and Petrachem (1986) for Inch of Ferryton 1. In Leven Seat 1, the wide range of maturity levels recorded, with no steady increase in vitrinite reflectance and spore colour with depth, was believed to be as a result of increased maturation by extrusive and/or intrusive igneous activity. Measured R_o for the Limestone Coal Formation showed rocks too immature for oil generation but approaching onset at 0.55% (though contrast with calculated R_o on Figure 58 below). Deeper rocks were all within the oil window at the present day, with the Lower Limestone Formation R_o = 0.57 to 0.72%, West Lothian Oil-Shale and Gullane units 0.85-1%, and tentative Inverclyde Group (Pu palynomorph zonation) analyses gave 0.82-

0.85% R_o. The Petrachem (1986) report judged the lower strata to be mature for oil and gas generation at the present day.

Vitrinite reflectance and spore colour data from Inch of Ferryton 1 (Petrachem 1986) show immature Coal Measures (0.54% R_o) and upper Passage Formation strata. The lower Passage Formation (0.6%) and Upper Limestone Formation (0.64-0.9% R_o) strata to 1,959 ft (597 m) were mature for liquid hydrocarbon. Upper Limestone Formation strata (0.73-0.81% R_o) and Limestone Coal Formation strata (0.87-0.9 R_o) to 2,739 ft were mature for oil and gas generation. Limestone Coal Formation below 2,739 ft (835 m; 1.45 -1.7% R_o) were mature for wet gas and methane generation only. The effects of the Midland Valley Sill can be clearly seen in the vitrinite reflectance data, with values up to approximately 3 % R_o in the vicinity of the sill (Figure 58).

A similar burial-maturity pattern was observed from the Salsburgh 2 well, being early mature for oil from surface to early mature for gas at depths of around 3,000 ft (915 m; Reach 2013) with approximately 5,580 ft (1.7 km) of uplift since maximum burial (Vincent 2013).

3.6.2 Analysis of datasets

Over 1600 vitrinite reflectance measurements have been collated and examined from the Carboniferous strata of the Midland Valley of Scotland. The majority of these data come from Raymond (1991). There are also a smaller number of measurements from well reports (e.g. Petrachem 1986, 1989).

Obtaining valid R_o data is not straightforward. Measured R_o values can be lower (suppressed) or higher (enhanced) than expected for a given depth of burial. In the past, the selection of primary vitrinite on which to carry out the analysis may have been less standardised that it is now. Vitrinite may be scarce or absent, and many samples have elevated R_o that may result from the erroneous selection of other organic macerals.

T_{max} is also indicative of the level of maturity, and a conversion formula is widely used to derive calculated R_o (although this relationship was derived specifically for the Barnett Shale). T_{max} becomes less reliable when TOC is low or when S2 < 0.5; it also suffers if there has been severe recycling of organic macerals.

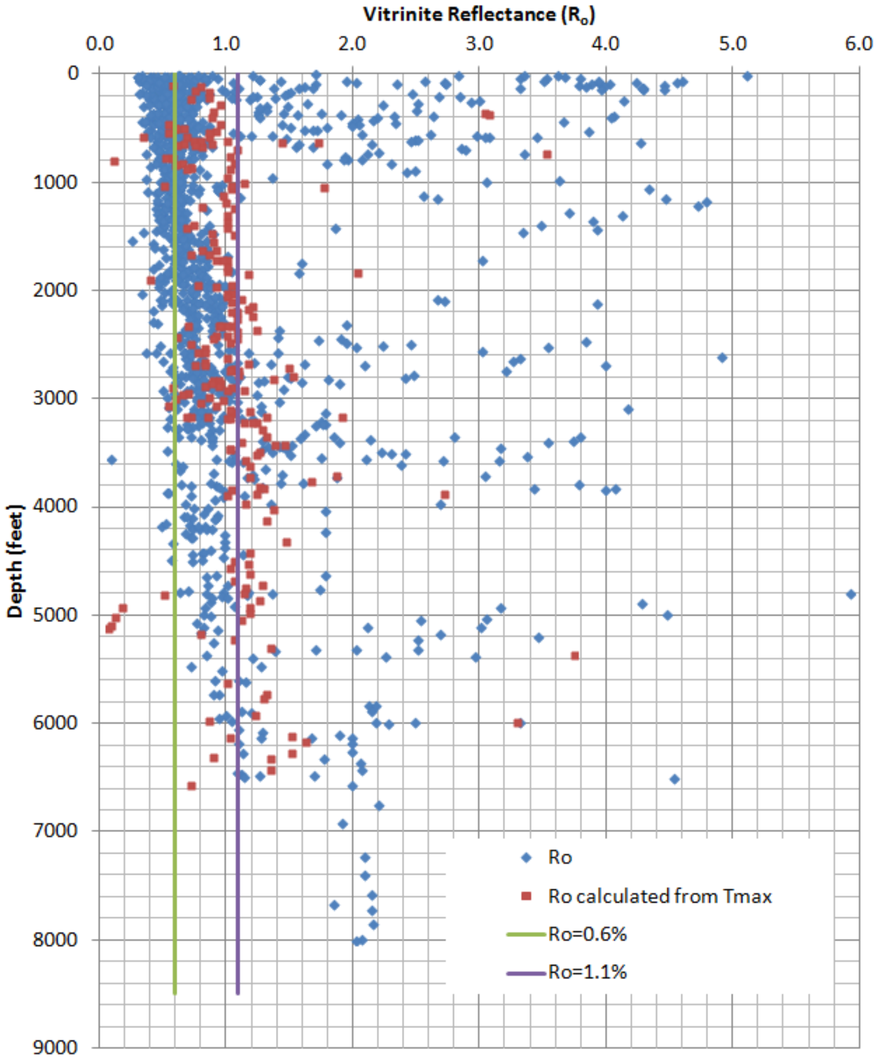
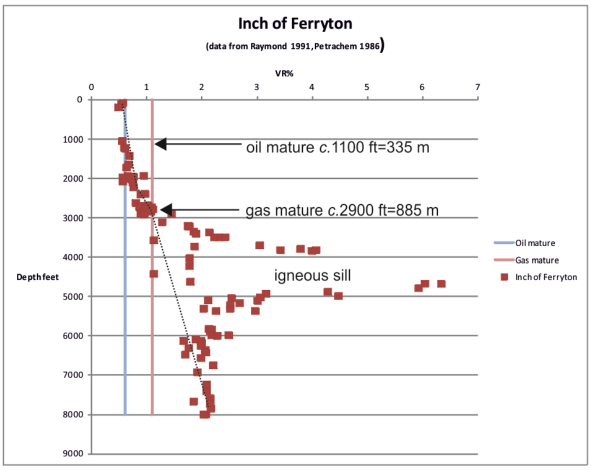


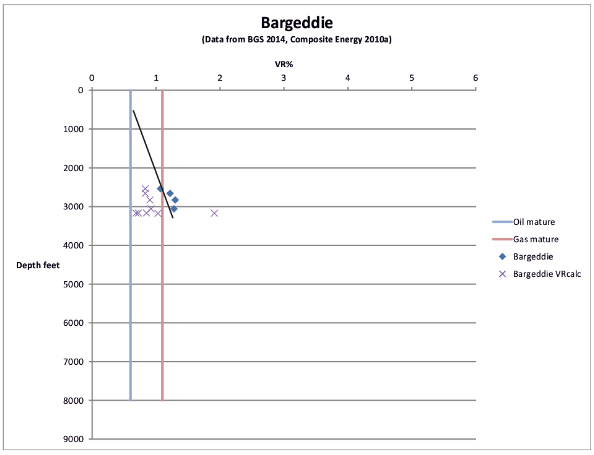
Figure 57 Graph of measured vitrinite reflectance R_o and calculated R_o against present day sample depth. Oil mature R_o > 0.6%, gas mature at R_o >1.1%, after Charpentier and Cook (2011).

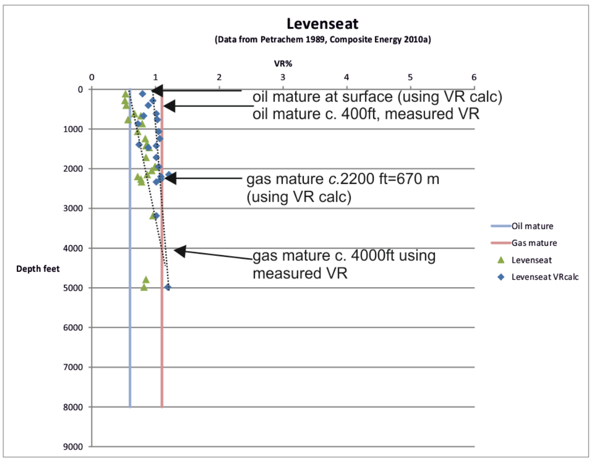
Figure 57 shows that many R_o measurements plot between the 0.6 and 1.1% R_o values indicative of maturity for oil, whilst a significant proportion are over 1.1% R_o indicative of maturity for gas. High values over 3% R_o are likely to be post-mature and may have been affected by local heating from igneous intrusions. The calculated R_o values generally appear to be slightly higher at a given burial depth than the R_o measured values, perhaps in response to the vitrinite suppression suggested by Raymond (1991). Some calculated R_o values are lower than measured R_o values. It has been shown that T_{max} may not be a reliable maturity parameter in Type I kerogen source rocks as oil generation occurs abruptly and rapidly over a narrow interval (Espitalie 1986). This may be a cause of mismatch between calculated and measured R_o in the Midland Valley of Scotland.

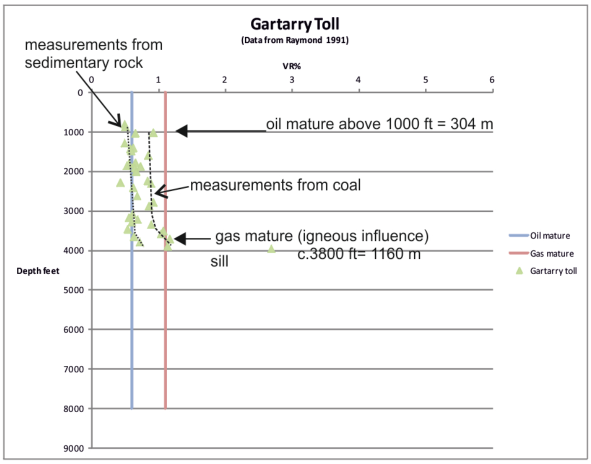
In this study, cut-offs of oil maturity at R_o > 0.6% and gas maturity at R_o >1.1% were used after Charpentier and Cook (2011, Table 3). There is evidence that Type I kerogens commence oil generation at R_o>0.7%, whilst Type II and Type III kerogens commence at R_o >0.5% (Tissot & Welte 1978). As the Midland Valley of Scotland kerogen types are mixed, R_o > 0.6% seems a reasonable threshold for the onset of the oil window.

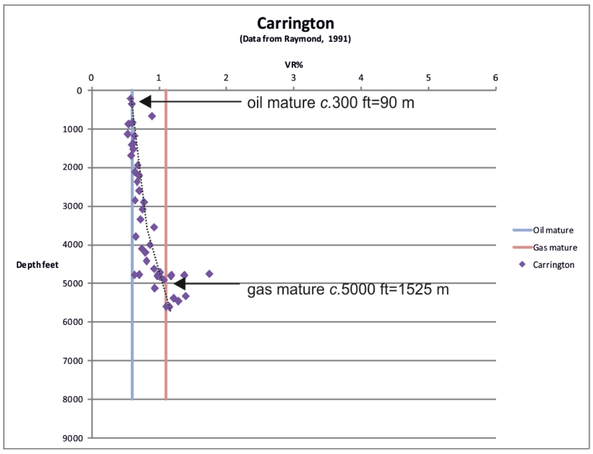
Plotting the maturity data on a well by well basis allows oil mature (R_o =0.6%) and gas mature (R_o =1.1%; Figure 58) current-day depths to be estimated. The graph for Gartarry Toll borehole using Raymond (1991) data has been included to illustrate the effect of vitrinite suppression. The graphs for the Inch of Ferryton 1 and Milton of Balgonie 1 wells illustrate the increase in rank adjacent to tholeiitic sill intrusions.

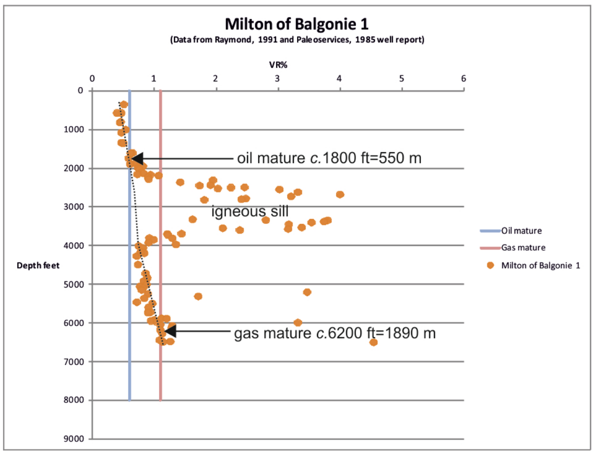

Inch of Ferryton
(data from Raymond 1991, Petrachem 1986)
VR%
Depth feet
oil mature c.1100 ft=335 m
gas mature c.2900 ft=885 m
igneous sill
Oil mature
Gas mature
Inch of Ferryton

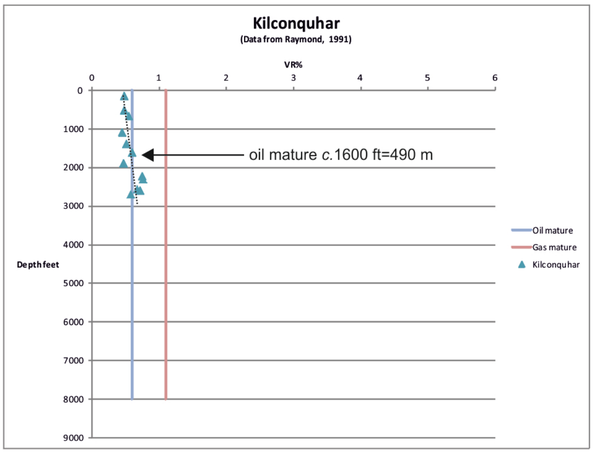

Bargeddie
(Data from BGS 2014, Composite Energy 2010a)
VR%
Depth feet
Oil mature
Gas mature
Bargeddie
Bargeddie VRcalc

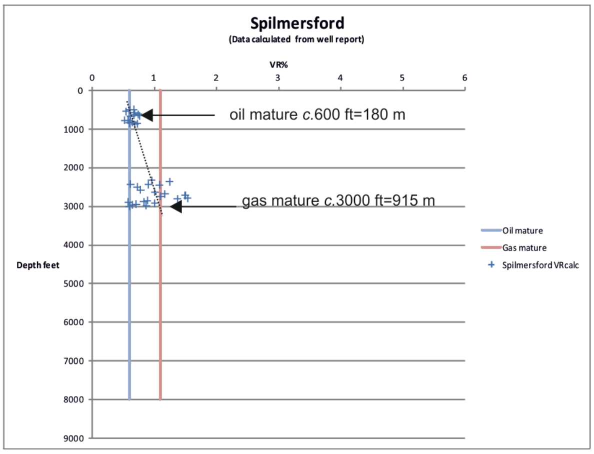

Levenseat
(Data from Petrachem 1989, Composite Energy 2010a)
VR%
Depth feet
oil mature at surface (using VR calc)
oil mature c. 400ft, measured VR
gas mature c.2200 ft=670 m
(using VR calc)
gas mature c. 4000ft using
measured VR
Oil mature
Gas mature
Levenseat
Levenseat VRcalc


Gartarry Toll
(Data from Raymond 1991)
VR%
Depth feet
measurements from
sedimentary rock
oil mature above 1000 ft = 304 m
measurements from coal
gas mature (igneous influence)
sill
c.3800 ft= 1160 m
Oil mature
Gas mature
Gartarry toll


Carrington
(Data from Raymond, 1991)
VR%
Depth feet
oil mature c.300 ft=90 m
gas mature c.5000 ft=1525 m
Oil mature
Gas mature
Carrington


Milton of Balgonie 1
(Data from Raymond, 1991 and Paleoservices, 1985 well report)
VR%
Depth feet
oil mature c.1800 ft=550 m
igneous sill
gas mature c.6200 ft=1890 m
Oil mature
Gas mature
Milton of Balgonie 1


Kilconquhar
(Data from Raymond, 1991)
VR%
Depth feet
oil mature c.1600 ft=490 m
Oil mature
Gas mature
Kilconquhar


Spilmersford
(Data calculated from well report)
VR%
Depth feet
oil mature c.600 ft=180 m
gas mature c.3000 ft=915 m
Oil mature
Gas mature
Spilmersford VRcalc

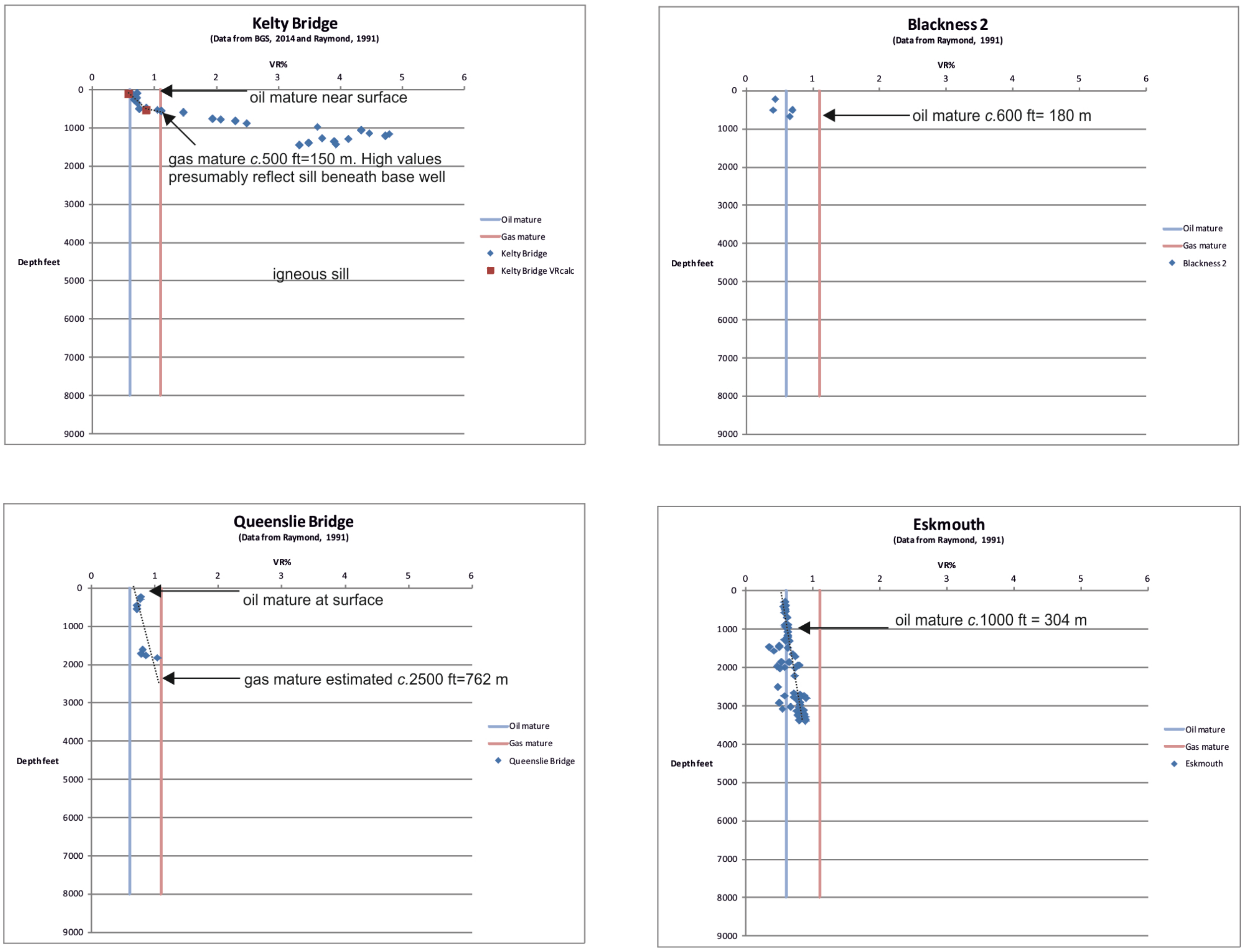


Figure 58 Vitrinite reflectance plotted against drilled depth below KB elevation for various wells and boreholes. Values for oil and gas mature current day drilled depths have been estimated from the correlation lines.

The graphs shown on Figure 58, plus rank maps from Raymond (1991 Chapter 5) have been used to interpret current day depth surfaces relative to Ordnance Datum to R_o=0.6% (onset of oil maturity) and R_o=1.1 % (onset of gas maturity), as input to the mature shale resource volume estimates. Preference was given to the regional burial trend rather than to locally high maturity values due to igneous intrusion. Whilst this method underestimates the rock volumes mature for oil and gas local to intrusions, it is balanced by the fact that strata immediately adjacent to intrusions are commonly overmature (R_o up to 6%; Figure 58). The maps are constrained by a relatively small number of data points (13 for gas mature, 21 for oil mature) and have low reliability.

Given the complex variation in rank resulting from igneous intrusion plus differential burial, uplift and erosion (Raymond 1991, Chapter 5) the depth-maturity surfaces are a regional simplification. It was not possible to quantify the complex local effects of igneous intrusions throughout the succession at regional scale. Between the main Central Coalfield and Midlothian-Leven basins, the area north of the Forth Estuary shows complex variations in maturity relating to intrusion and small sub-basins (e.g. Westfield), and here the depth-maturity maps are poorly constrained. The West Lothian area to the south of the Forth Estuary is poorly constrained due to lack of data. In the Firth of Forth, it has been assumed that the maturity depth follows the burial depth. The depth-maturity maps (Figures 59, 60) show that:

- Depths of oil and gas maturity are shallower in the Central Coalfield basin than Midlothian-Leven Syncline.
- Some strata are mature for oil at surface or at depths of only a few hundred feet, particularly in the Central Coalfield area
- Strata at depths suitable for shale resource exploitation are likely to be oil and/or gas mature

- Areas at present day basin margins and between the Midlothian–Leven Syncline and Clackmannan Syncline are assumed to have experienced significantly more uplift than in the basin centre, resulting in shallower depths for oil and gas maturity.

Future and local scale studies should examine in more detail the volumes and depths affected by heating from igneous intrusions and the resultant influence on hydrocarbon prospectivity.

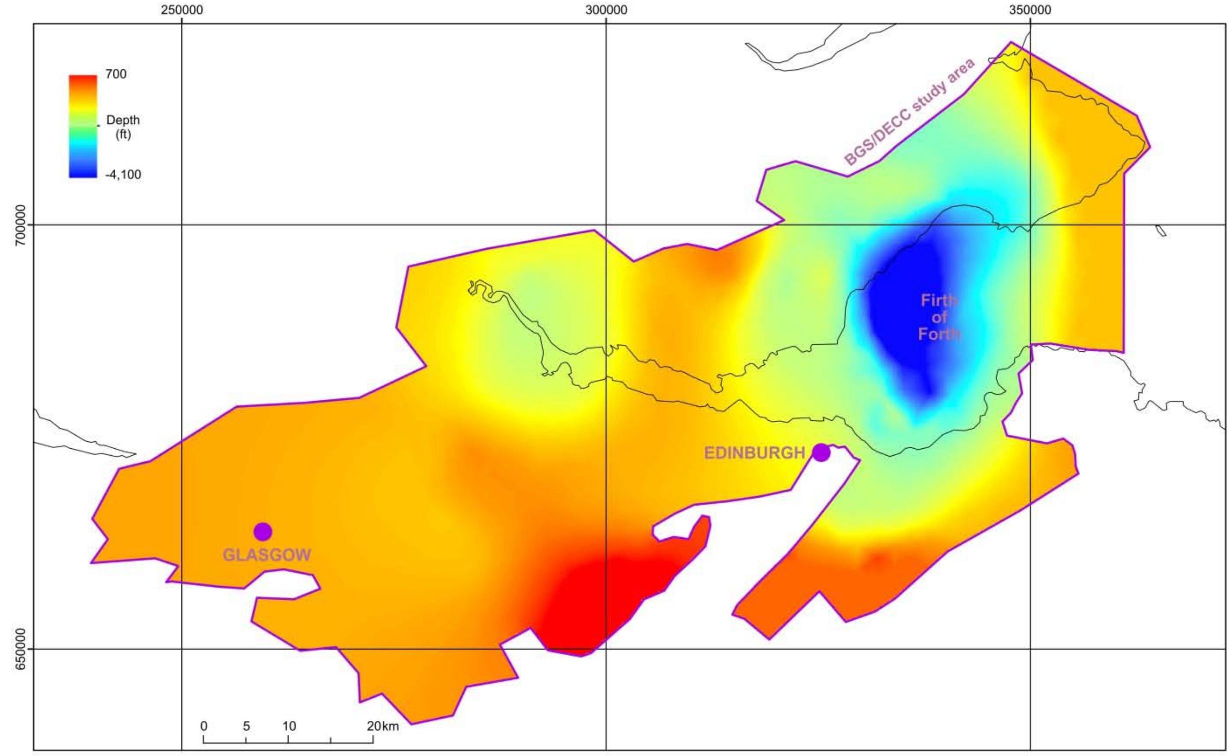


Figure 59 Simplified regional overview of estimated depth to R_o =0.6 (oil mature) in feet referenced to Ordnance Datum (note the depth scale is different from the depth to R_o =1.1 image).

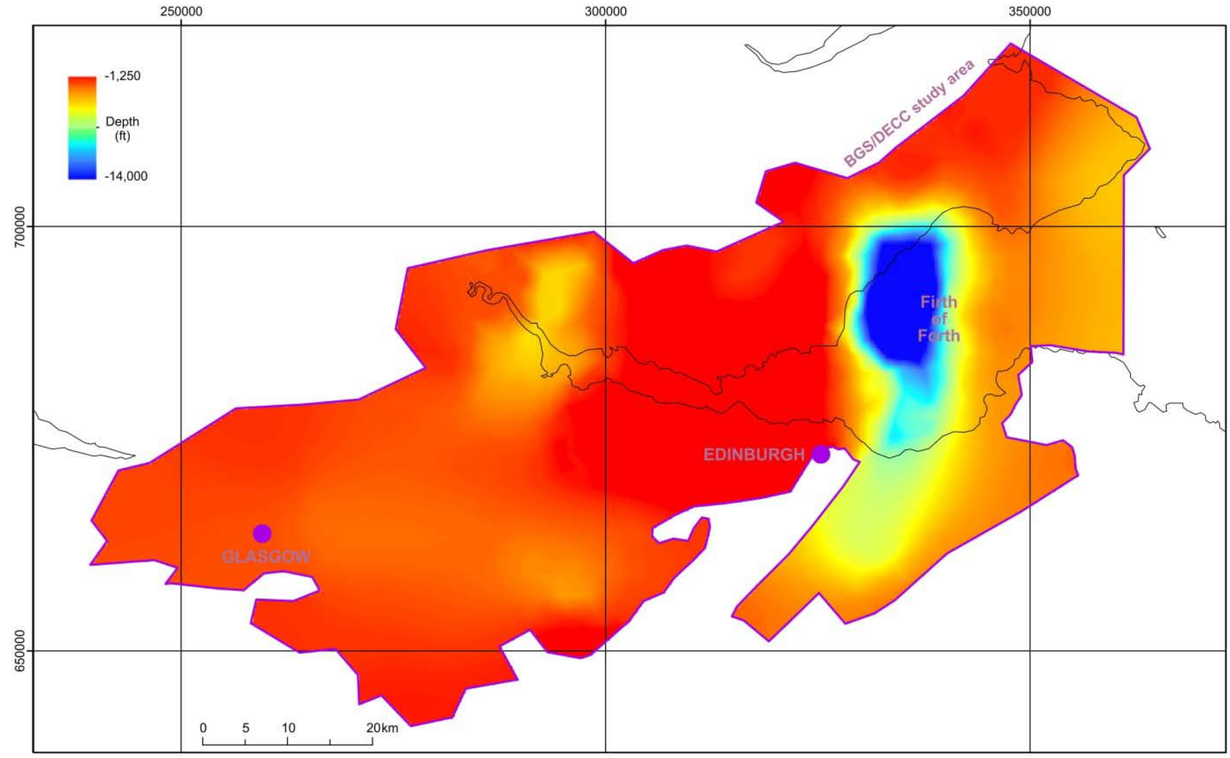


Figure 60 Simplified regional overview of estimated depth to R_o =1.1% (gas mature) in feet referenced to Ordnance Datum (note the depth scale is different from the depth to R_o =0.6 image).

The amount of uplift and erosion indicated by the observed burial-related maturity on selected boreholes is of the order of 6,000 ft. Vincent *et al.* (2010) calculated 6,000 ft (1.9 km) in the Midlothian-Leven Syncline and Vincent (2013) estimated 5,500 ft (1.7 km) of uplift from the Salsburgh 2 well using thermal basin modelling in BasinMod (Platte River Associates Inc. Software). Reach (2013) estimated between 5,900-6,000 ft (1.8-1.9 km) of uplift in the Central Coalfield using extrapolated depth-maturity plots.

3.7 Mineralogy

BGS mineralogical analyses were carried out on the same 50 sedimentary rock samples analysed for Rock-Eval. Whole-rock and clay mineral X-ray diffraction (XRD) techniques were used, with the detail provided in Appendix E.

Whole-rock powder XRD analyses reveal an average composition of approximately 59% phyllosilicates/clay minerals, approximately 9% carbonate minerals and approximately 32% QFP (quartz, feldspar and pyrite). There is however a wide range in compositions (Figure 61), including in samples with TOC>2%.

The mineralogical compositions of many of the Midland Valley of Scotland samples are considerably more clay mineral-rich and carbonate-poor than typical USA unconventional gas- and oil-producing shales. In the USA, shales with low proportions of clay minerals (generally less than 50%; Bowker 2007, Jarvie 2012a, Hart *et al*. 2013) are targeted to allow successful fracture stimulation. Whilst shales are relatively clay-rich, layering with brittle sandstone, limestone or ironstone in the Midland Valley of Scotland succession (see Figure 31) may make the rock more suitable for hydraulic fracturing.

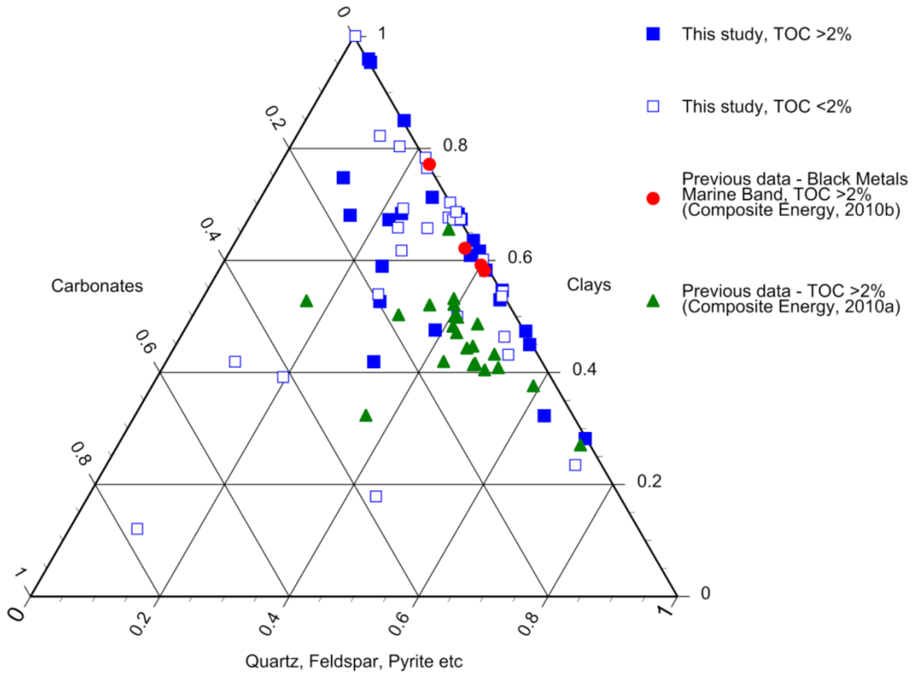


Figure 61 Triplot to illustrate the whole-rock mineralogy of the Midland Valley samples compared to previous commercial analyses, differentiated on the basis of TOC content.

In the Midland Valley of Scotland samples, less than 2 µm clay mineral assemblages are generally composed of various amounts of illite, illite/smectite (I/S), kaolinite and an intermediate Fe/Mg chlorite. Most samples contain an *R*1-ordered I/S (approximately 85% illite) with a more evolved *R*3-ordered I/S (approximately 92% illite) identified in many of the deeper samples. Clay mineral maturity is suggestive of burial depths representing the Light Oil/Wet Gas and Wet Gas/Dry Gas transition maturity zones, in agreement with vitrinite reflectance information synthesised in section 3.6.

4 Calculating gas mature and oil mature shale volumes

4.1 Resource estimation method

Figure 62 gives an overview of the method used in this study to calculate mature shale gas and shale oil volumes. Depth models were used to define gross volumes for the units of interest, which were then truncated by the mining-related depth cut-off (section 4.1.1 below) or 1,000 ft depth cut-off (section 4.1.2 below) and oil and gas maturity–depth surfaces. The net mature volumes were then calculated by multiplying the gross volumes by percentage shale (or percentage shale > 50 ft; Figures 28, 29, 34-37, 39, 40) and percentage TOC (Figures 49, 50).

It was not possible with the data available to estimate separate resource volumes of particular shale units stacked within the Midland Valley of Scotland succession. The approach taken was to use a 'net' percentage of shale, and percentage of shale greater than 50 ft, through the prospective interval (see section 2.9.1).

Using net mature shale volumes derived from the percentage shale contours and TOC> 2% gives an **upper bound** to the resource volume because some shales are too thin to meet standard criteria (Table 3). The volumes derived from percentage shale contours and TOC > 2% were input to the Monte Carlo simulation as **P10**.

Using net mature shale volumes derived from the percentage shale contours > 50 ft and TOC >2% gives a **lower bound** to the resource volume because this approach excludes stacked strata that taken together would meet standard thickness criteria. The volumes derived from percentage shale contours >50 ft and TOC > 2% were input to the Monte Carlo simulation as **P95**.

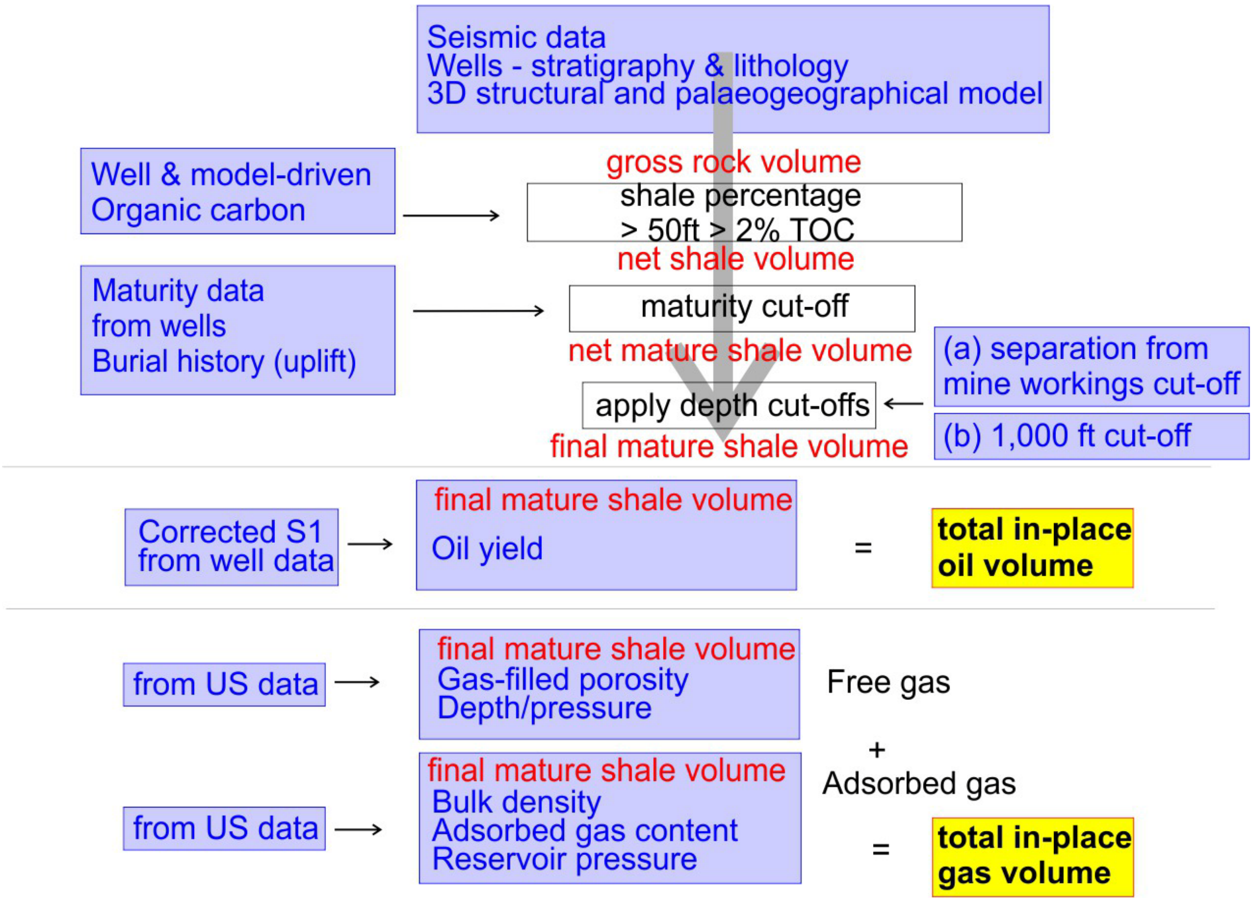


Figure 62 Overview of method used to calculate mature shale gas and shale oil volumes

4.1.1 In-place resource estimation incorporating a mining-related depth cut-off

Previous DECC/BGS resource estimation studies have used different depth cut-offs to this study. Less than 5,000 ft (1,500 m) after Charpentier & Cook (2011) was used for the northern England Bowland-Hodder shale gas study (Andrews 2013;) and less than 3,300 ft (1,000 m) as adopted by USEIA (2013) was used for the southern England Weald shale oil study (Andrews 2014), assuming that lower pressures encountered at shallower depths are not conducive to flow rates. However, there are examples of shallower, commercially produced hybrid plays, such as the Bakken Middle Member in south-western Manitoba (average depth to producing zone 2,867 ft (874 m), Lefever *et al.* 1991) and the shallow Antrim biogenic gas play (average depth 1,400 ft (430 m), USEIA, 2011 p. 102) The USEIA also summarise the average depth of the Niobraran shale oil resource at 1,000 ft (305 m, USEIA, 2011 p. 102). That is, shale gas and shale oil economic resources are documented from the USA from shallower depths than the USEIA (2013) 3,300 ft (1,000 m) used in that global assessment.

The mature shale intervals of the Midland Valley of Scotland are relatively shallowly buried, but another depth-related factor is of great importance. Abandoned deep coal mines are widespread across the areas of the Midland Valley underlain by strata with shale resource potential.

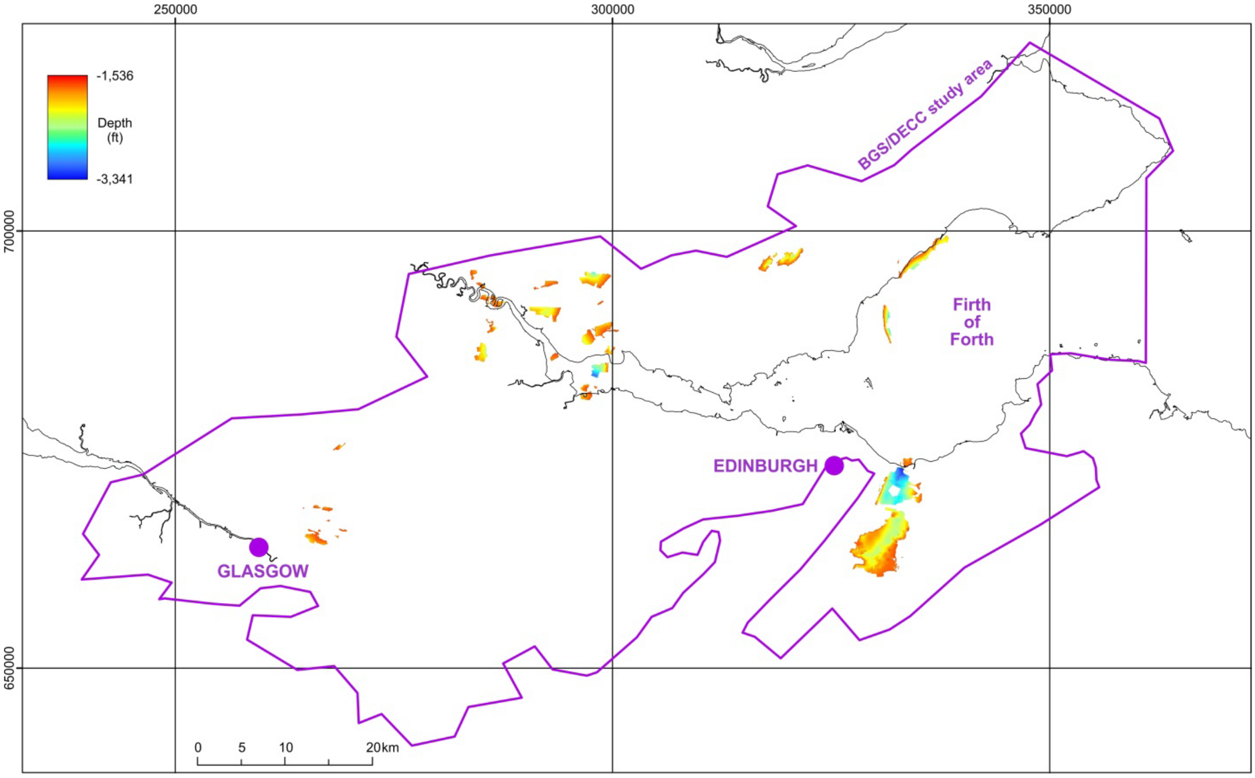


Figure 63 Extent and deepest depth of mine abandonment plans greater than 1,640 ft (500 m) relative to Ordnance Datum based on data licensed from The Coal Authority, plus mine abandonment plan information collated by BGS in the Firth of Forth.

The depths of the historic mine workings are commonly shallower than 1,640 ft (500 m) below Ordnance Datum, but a significant number are between 1,640 ft (500 m) to 3,380 ft (1,030 m) deep. The extent and depth of abandoned coal mining workings deeper than 1,640 ft (500 m) was licensed from The Coal Authority, and a deepest-mining contour map was produced (Figure 63). Outside 'areas of mining deeper than 1,640 ft (500 m) ', a cut-off of 1,640 ft (500 m) was set (Figure 64). Note that mineshafts and roadways which accessed the deep workings have not been included. Mineshafts can be deeper than the coal seams which were worked and any future local study should additionally consider these localised features.

In the USA (Kentucky, Pennsylvania and West Virginia), the hydraulic fracturing of the Marcellus shale is undertaken beneath active coal mines. However, the separation distance is large, approximately 7,500 ft (2,200 m) and hydraulic fracturing of the shale is not covered by specific coal-mine related regulation. In the USA, regulations are in place to ensure special casing/plugging of wells through coal-bearing intervals, for coal pillars to be left around oil/gas wells, well plans to be available to coal operators and extra documentation for when mining is within 300 ft (90 m) of a well (e.g. Coal and Gas Resources Coordination Act implemented as Pennsylvania code http://www.pacode.com/secure/data/025/chapter78/chap78toc.html).

The situation is different in the Midland Valley of Scotland, where the abandoned deep mined strata of the Limestone Coal Formation are much nearer the deeper prospective shale units within this same formation (e.g. Black Metals Member and Johnstone Shell Bed). Thus, a buffer or vertical separation zone was cut from the top of the potential rock volume in the resource calculation to ensure separation from the abandoned coal mines and shafts.

The thickness of the vertical separation zone would ideally be based on evidence of the height of stimulated hydraulic fractures observed in the Midland Valley of Scotland, and failing that on geomechanical studies using Midland Valley of Scotland rock properties, stress fields and existing fault patterns. However, there is no Midland Valley of Scotland specific data available at the current time. Published plots of simulated fracture heights on various shales in the USA show maximum fracture heights of around 1,640 ft (500 m), with the majority being much smaller than that (Fisher & Warpinksi 2011). An experienced US shale gas operator, Consol Energy, provided DECC and BGS with microseismic evidence on hydraulically fractured wells in the Marcellus and Barnett shales to indicate that a vertical separation zone of the order of 1,000 ft (305 m) would be a reasonable first estimate (Consol Energy pers. comm.). A summary of simulated fracture heights worldwide gave a probability of 1% for a vertical extent > 1,150 ft (350 m) (Davies *et al*. 2012), though the approach was purely statistical and blind to local geology (Davies *et al*. 2013).

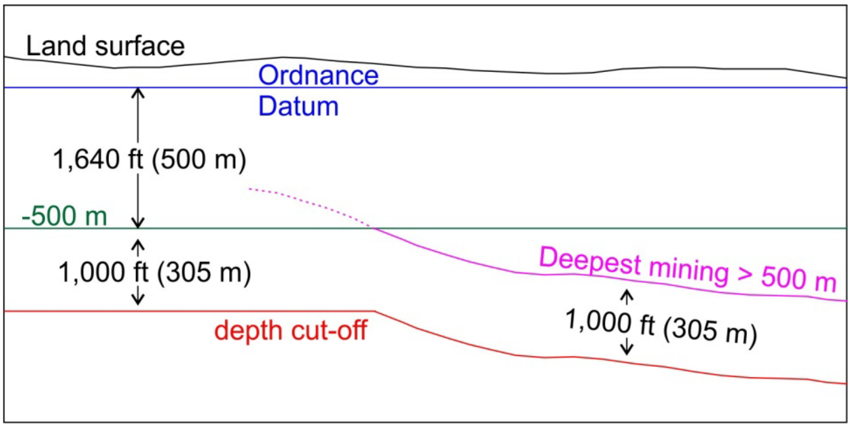


Figure 64 Sketch illustrating the depth cut-off used in the resource calculation

For the best technical case in this study, a 1,640 ft (500 m) plus 1,000 ft (305 m) vertical separation zone below the depth of abandoned coal mines was excluded from the shale in-place resource estimation (Figure 64); a minimum depth cut-off of 2,640 ft (805 m) below Ordnance Datum. Specific Midland Valley of Scotland geomechanical and fracture growth height studies are required to give a more robust figure for the vertical separation. As such, this vertical separation distance cannot be used to guide for exploration, well testing or regulation; it attempts to accommodate a reasonable vertical separation taking into account the heights of the majority of simulated fracture heights documented globally, but without being overly conservative for an in-place resource estimation in an area with no simulated fracture data. Figure 65 is a map of the mining-related depth cut-off calculated from the deepest coal mine workings from the Coal Authority data.

The depth cut-off of 2,640 ft (805 m) is well below the maximum depth of 1,310 ft (400 m) below ground level of groundwater bodies defined in the UKTAG report on the Water Framework Directive (http://www.wfduk.org/resources%20/defining-and-reporting-groundwater-bodies), but area-specific hydrological analysis would need to be considered as part of any hydraulic fracturing plan (see section 2.3).

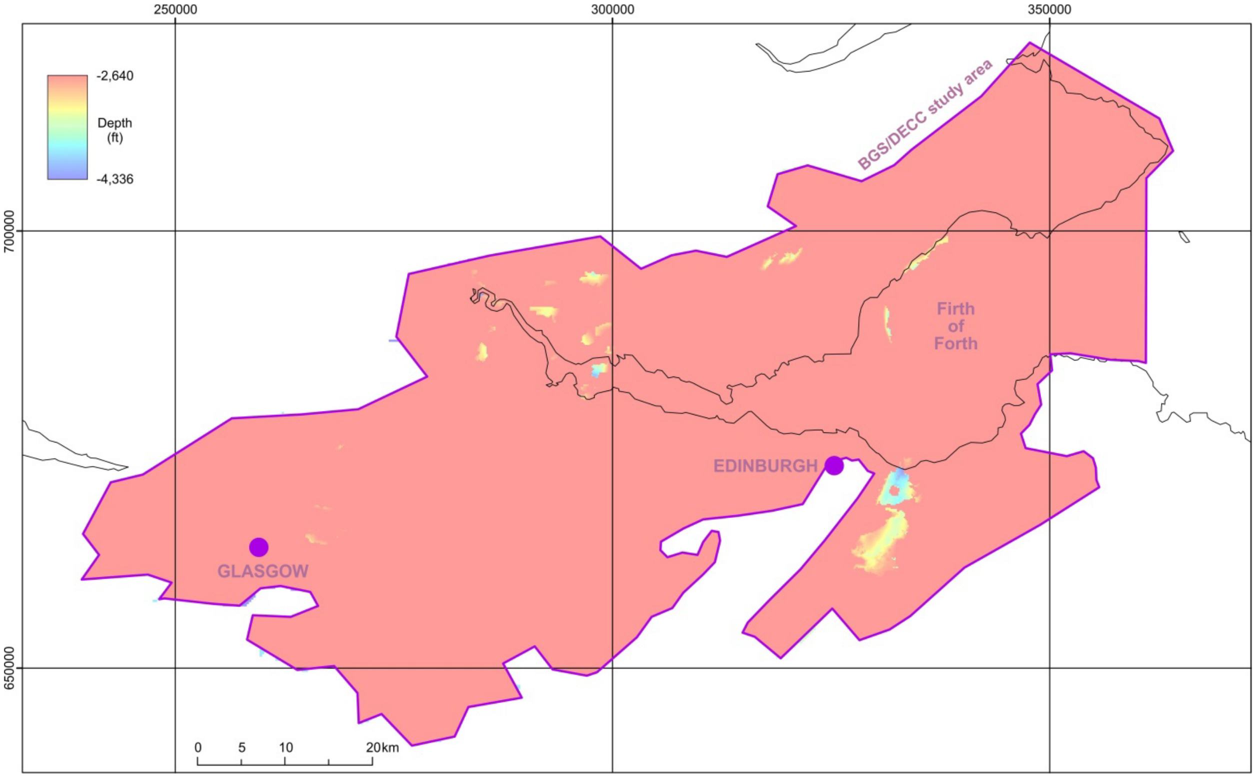


Figure 65 Mining-related depth cut-off map for the study area. Strata shallower than the depths shown here were not included in the best technical case resource estimation, see text for discussion. The red colour is the depth cut-off at 2,640 ft (805 m) below Ordnance Datum.

4.1.2 Sensitivity test of in-place resource using a 1,000 ft (305 m) depth cut off

A sensitivity test for shale oil- and gas-in-place using a simple horizontal depth cut off of at 1,000 ft (305 m) below Ordnance Datum was also examined. This 1,000 ft depth was chosen as the shallowest worldwide example of a shale play found, the Williston-shallow Niobraran play in the USA, has an average depth of 1,000 ft (USEIA, 2011). However, in the Midland Valley of Scotland historic deep mining at depths below 1,000 ft is of significant extent, with an areal extent larger than that shown below 1,640 ft (500m, Figure 63). For this reason, the sensitivity test at 1,000 ft depth cut-off, is not believed to be the best technical case. Further information is given in Appendix A.

4.2 Results

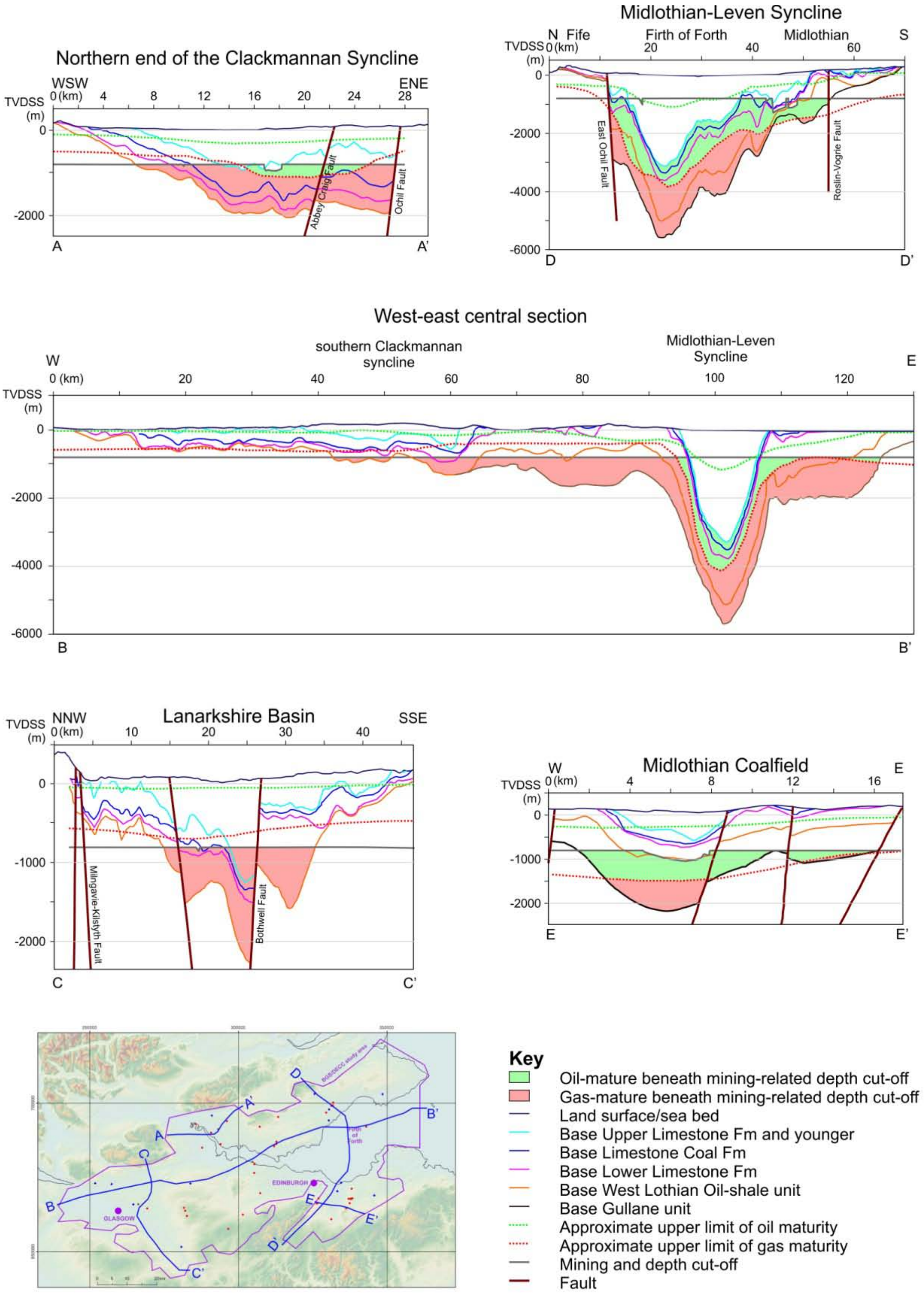


Figure 66 Cross-sections showing maturity and mining-related depth cut- off surfaces as output from the 3D geological model. Note each cross-section has a different horizontal and vertical scale. The modelled surfaces appear irregular and with considerable relief due to the high vertical exaggeration of the section and because smaller faults have been excluded from the model.

Cross-sections (Figure 66) highlight the relatively shallow nature of the mature oil and gas volumes in the subsurface of the Midland Valley of Scotland, together with the complex geological structure. The mining-related depth cut-off truncates the mature volumes upwards, such that in some areas, such as the Lanarkshire Basin section all of the strata within the oil-mature volume have been excluded.

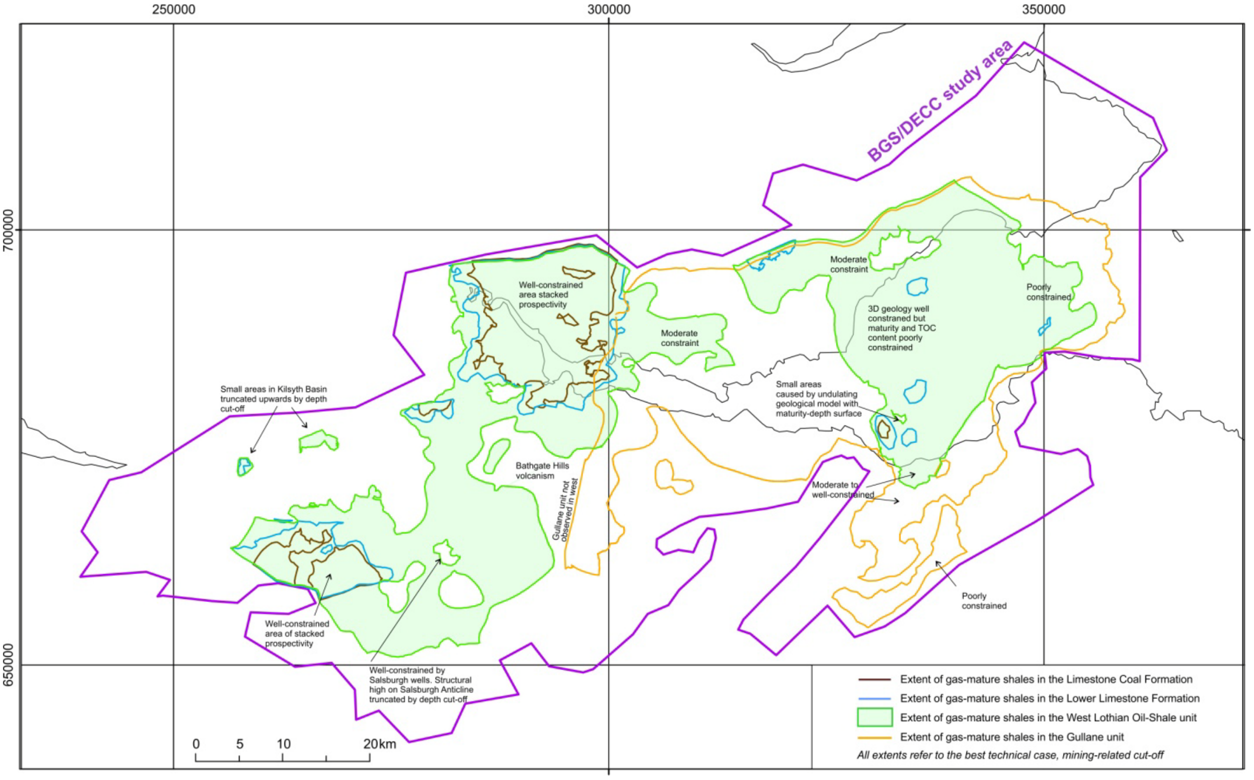


Figure 67 Summary of areas prospective for shale gas in the Limestone Coal and Lower Limestone formations, West Lothian Oil-Shale and Gullane units using the best technical case, mining-related cut-off

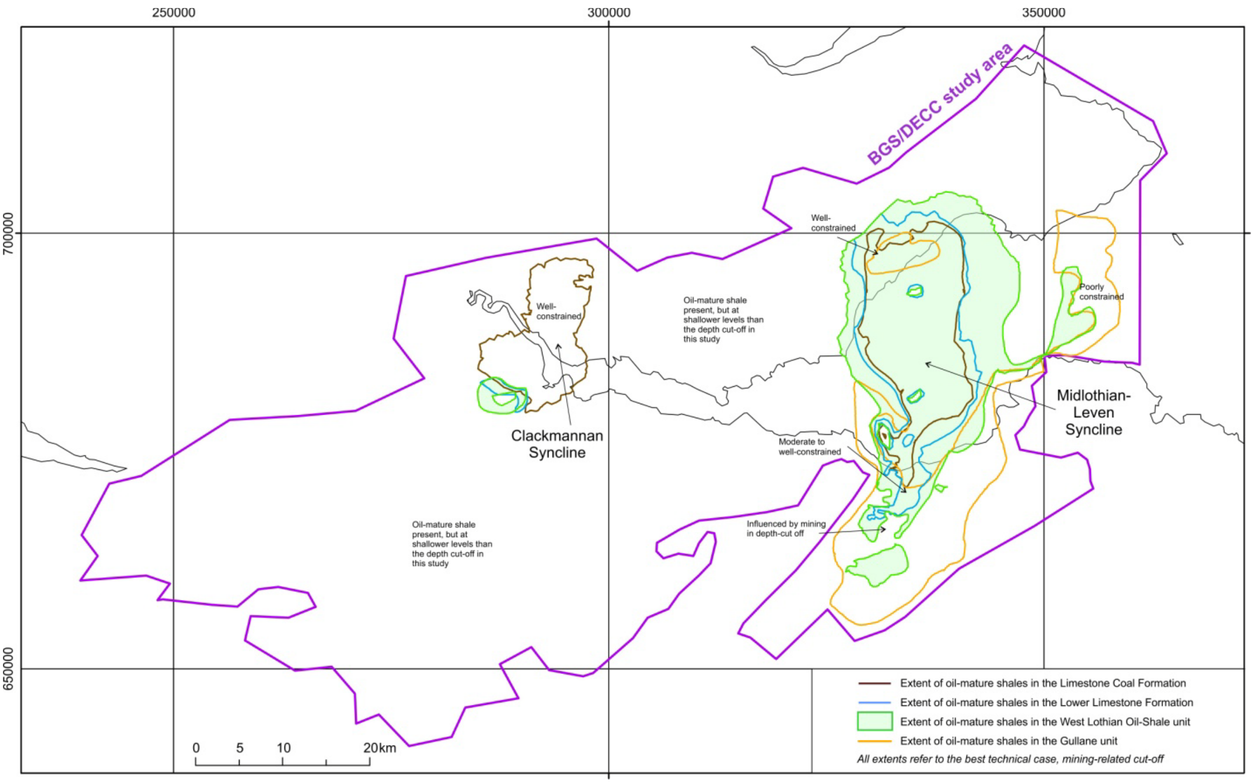


Figure 68 Summary of areas prospective for shale oil in the Limestone Coal and Lower Limestone formations, West Lothian Oil-Shale and Gullane units using the best technical case, mining-related cut-off

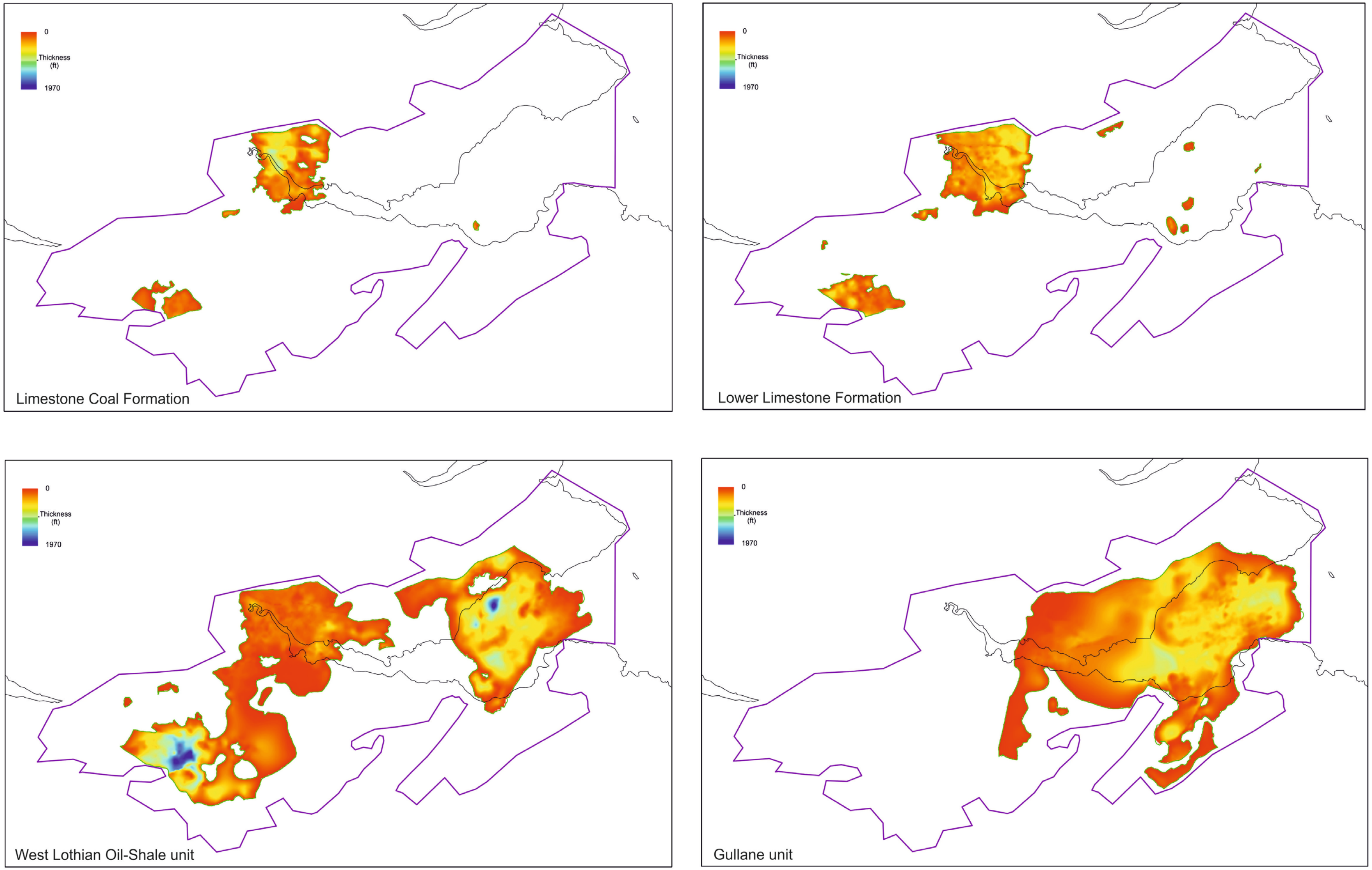


Figure 69 Net mature thickness and distribution of potential shale gas units in the Midland Valley of Scotland using the best technical case, mining-related cut-off.

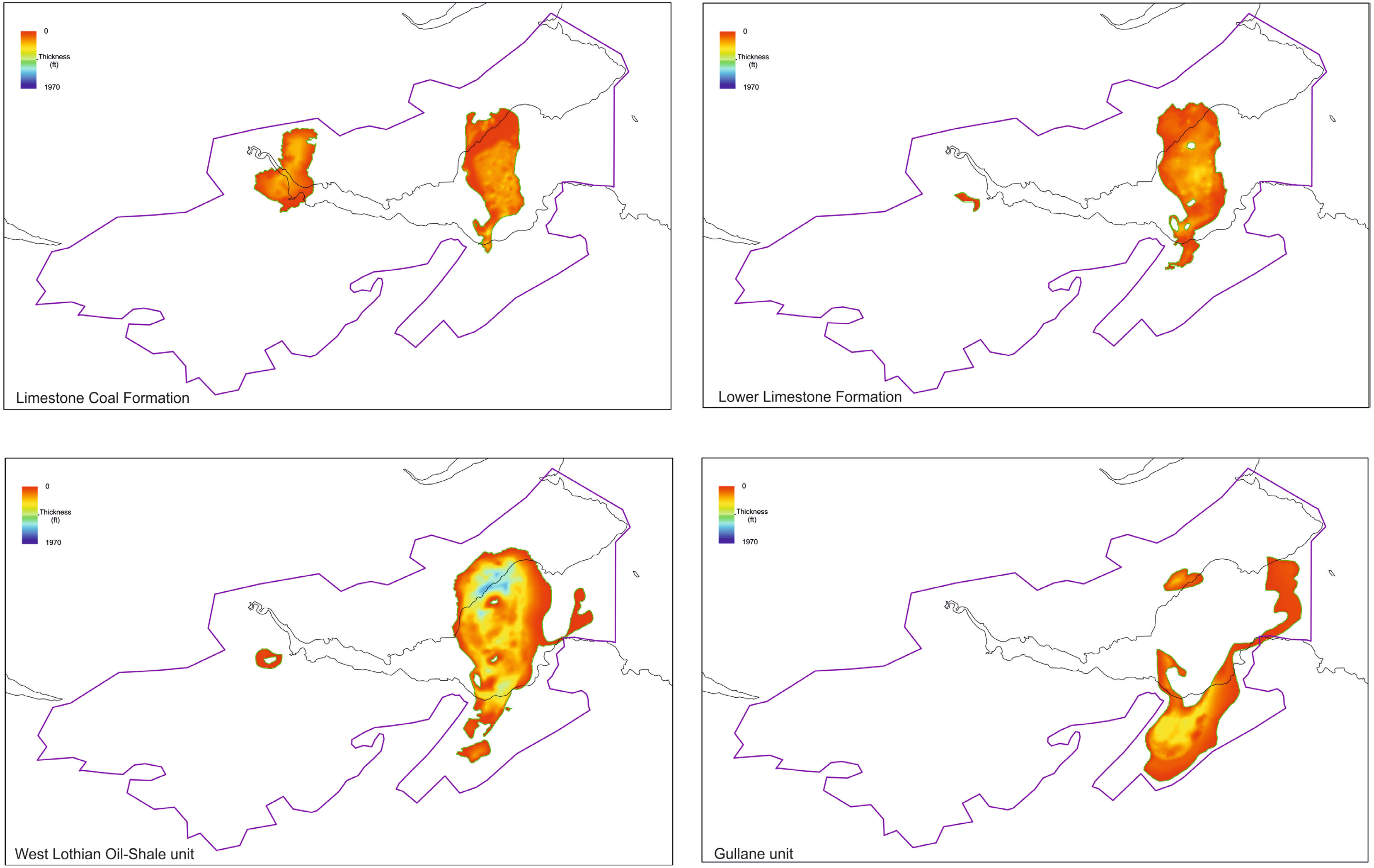


Figure 70 Net mature thickness and distribution of potential shale oil units in the Midland Valley of Scotland using the best technical case, mining-related cut-off.

Using the mining-related depth cut-off, the spatial extent of shale oil prospectivity is limited to the northern end of the Clackmannan Syncline and to the Midlothian-Leven Syncline across the Firth of Forth (Figure 68). In the northern Clackmannan Syncline, the net mature volume is dominated by the Limestone Coal Formation where net mature shale thicknesses of up to 400 ft (120 m) are estimated through the heterogeneous succession (Figure 70). In the Midlothian-Leven Syncline, the bulk of the net mature shale thickness is situated offshore where the Limestone Coal Formation, Lower Limestone Formation and West Lothian Oil-Shale unit are in the oil window, and considerable net mature shale thicknesses of up to around a thousand feet in the West Lothian Oil-Shale unit are estimated (Figure 70). The geological depth surfaces are moderately well constrained here by good quality seismic data tied to the Firth of Forth well, however the percentage of shale, TOC content and maturity values of the net mature shale volume are much more poorly constrained. Areas of onshore shale oil prospectivity occur in Midlothian and Fife in all four units, these are reasonably well constrained by data and parts of these areas occur beneath abandoned deep (> 1,640 ft or 500 m) coal mines. The tongue of West Lothian Oil-Shale unit and Gullane unit shale oil prospectivity extending offshore north-eastwards into the Firth of Forth (Figure 70) is very poorly constrained by data and relatively thin and should be considered speculative.

The oil-mature rock volume present from near surface or a few hundred feet depth is significantly truncated by the mining-related depth cut-off used. The effect of the mining-related depth cut-off is particularly striking over the southern and western Central Coalfield where shale-rich, oil-mature strata are present, but at shallower levels than allowed by the mining-related depth cut-off.

The spatial extent of shale gas prospectivity covers much of the Central Coalfield, together with the Midlothian-Leven Syncline and areas of Fife and West Lothian between these two basins (Figure 67). The prospective areas for the Limestone Coal and Lower Limestone formations in the northern Clackmannan Syncline and Lanarkshire Basin, as well as in small areas along the Kilsyth Basin are well constrained, with net mature shales approaching up to a thousand feet through the heterogeneous succession (Figure 69). These units are largely immature for shale gas in the eastern part of the study area.

The West Lothian Oil-Shale unit makes a large contribution to the overall shale gas prospective volume, being widespread over the Central Coalfield and Midlothian-Leven Syncline and reaching net mature shale thicknesses of over 1,000 ft (305 m) (Figure 69). In the Lanarkshire Basin, net mature shale thickness is estimated based on seismic interpretation and high TOC, high shale percentage strata proven in the Bargeddie 1 well, making a significant contribution to the volume estimation (Figure 69). However, there is no data on the lithology or TOC content of the thick unit identified on seismic data away from the well, resulting in a less well constrained volume estimate than for the overlying units in this area.

The deepest buried, Gullane unit shale gas prospective area is extensive in the eastern part of the study area where this unit is proven. The geological constraint on the base of the Gullane unit is very poor, so whilst the net mature shale thicknesses of up to 650 ft (200 m) present in the Firth of Forth (Figure 69) make a large contribution to the shale gas volume, that volume has a high degree of uncertainty.

4.3 Estimated resource volumes

DECC has not previously addressed in-place shale gas and/or oil resources in the Midland Valley of Scotland and no shale oil or shale gas drilling has yet been carried out in this area. Following detailed work undertaken by BGS in 2013-14, the first oil in-place and gas in-place resource estimation can now be made for the various shale units beneath the Midland Valley of Scotland. The details of the calculation are presented in Appendix A.

Previously published shale gas volume estimates in the Midland Valley of Scotland are restricted to Dart Energy's PEDL 133 license with an estimated 4.4 tcf of shale gas GIIP. They estimated recoverable prospective shale gas resources to be 119 bcf in the 'Black Metal Shale' and 536 bcf in the 'Lothian (Broxburn) Shale' (http://www.dartgas.com/page/Europe/United_Kingdom/PEDL133/).

USEIA (2013) considered the Midland Valley of Scotland as part of the 'north UK Carboniferous shale region' along with the Bowland-Hodder Shale of northern England and did not give any specific resource volume for Scotland.

The figures given below are for the best technical case of potentially exploitable shale oil and shale gas.

This study estimates that the **total in-place gas resource** for the Carboniferous shales across the Midland Valley of Scotland beneath the mining-related depth cut-off described in section 4.1.1 is **49.4 – 80.3 – 134.6 tcf** (1.40 – 2.27 – 3.81 tcm) (P90 – P50 – P10).

It is also estimates that the **total in-place oil resource** for the Carboniferous shales across the Midland Valley of Scotland beneath the mining-related depth cut-off described in section 4.1.1 is **3.2 – 6.0 – 11.2 billion bbl** (421 – 793 – 1,497 million tonnes) (P90 – P50 – P10).

	Total gas in-place estimates (tcm)			**Total gas in-place estimates (tcf)**		
Shale Gas	**Low (P90)**	**Central (P50)**	**High (P10)**	**Low (P90)**	**Central (P50)**	**High (P10)**
Limestone Coal Formation	0.04	0.09	0.17	1.4	3.2	6.1
Lower Limestone Formation	0.10	0.18	0.31	3.7	6.3	10.8
West Lothian Oil-Shale unit	0.46	0.92	1.89	16.2	32.6	66.7
Gullane unit	0.36	0.91	2.07	12.5	32.0	73.2
Combined	1.40	2.27	3.81	49.4	80.3	134.6
	Total oil in-place estimates (million tonnes)			**Total oil in-place estimates (billion bbl)**		
Shale Oil	**Low (P90)**	**Central (P50)**	**High (P10)**	**Low (P90)**	**Central (P50)**	**High (P10)**
Limestone Coal Formation	42	106	221	0.32	0.79	1.65
Lower Limestone Formation	35	78	153	0.26	0.59	1.15
West Lothian Oil-Shale unit	192	542	1,241	1.44	4.07	9.26
Gullane unit	13	32	70	0.10	0.24	0.53
Combined	421	793	1,497	3.2	6.0	11.2

Table 7 Estimates of the total potential in-place shale oil and shale gas resource in the Carboniferous Midland Valley of Scotland study area beneath the mining/depth cut-off described in section 4.1.1, breakdown by unit. Note that the 'combined' resource figures are the result of a separate Monte Carlo simulation; they are not the sum of the four subdivisions.

The contributions made by the four stratigraphic units are summarised in Table 7 and Appendix A gives the details of the calculation. The prospective volumes are located in the centres of the geological structures known as the Midlothian-Leven Syncline, the Clackmannan Syncline and the Lanarkshire Basin (Figures 72, 73).

A range of values is presented based on a Monte Carlo analysis (Figure 71 and Appendix A) to give a measure of the uncertainty in the resource estimation.

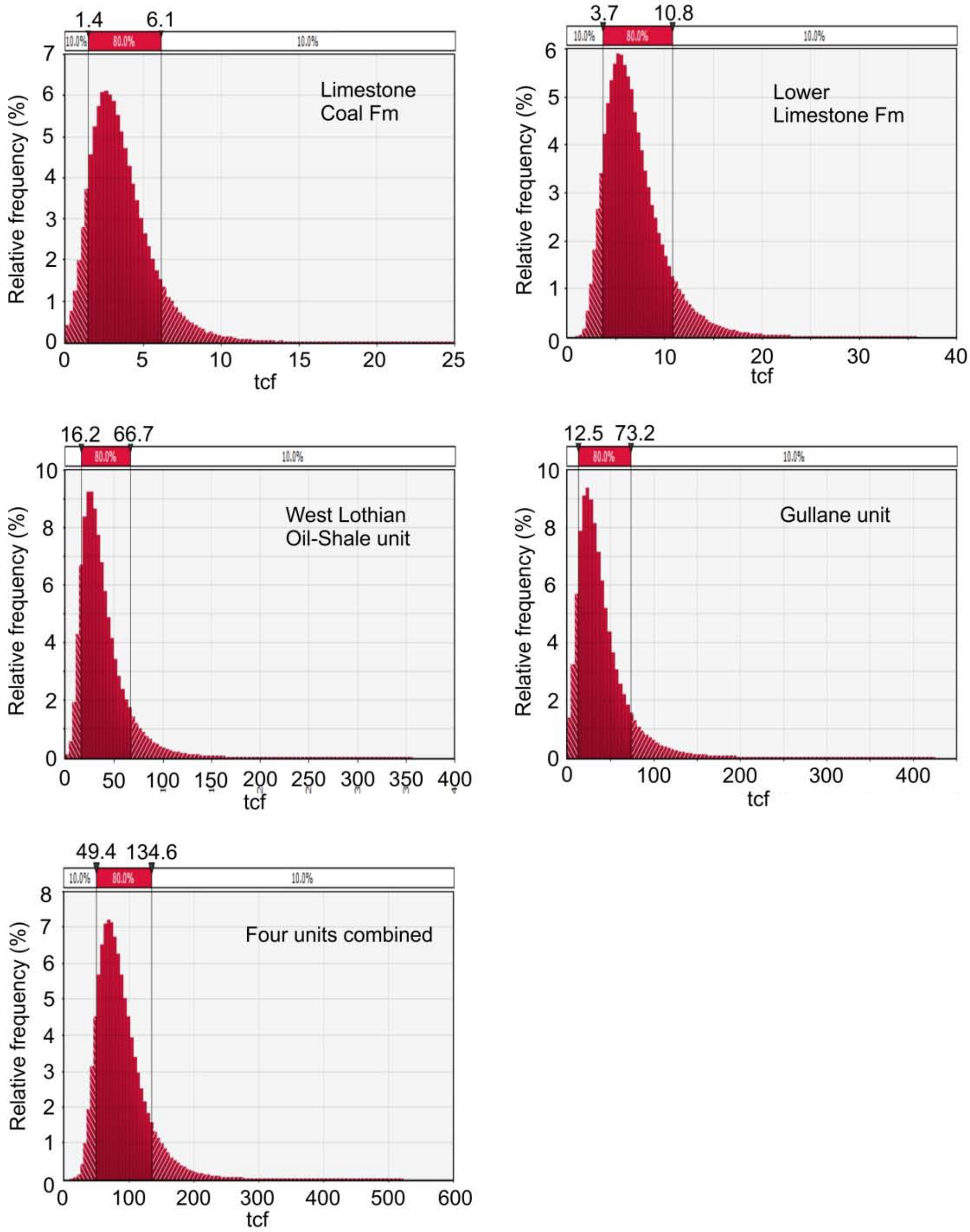


Figure 71 Probabilistic distributions representing the results of a Monte Carlo analysis for the in-place resource estimation of shale gas in four Carboniferous shale units of the Midland Valley of Scotland (separate and lastly combined). Distributions for shale oil are included in Appendix A.

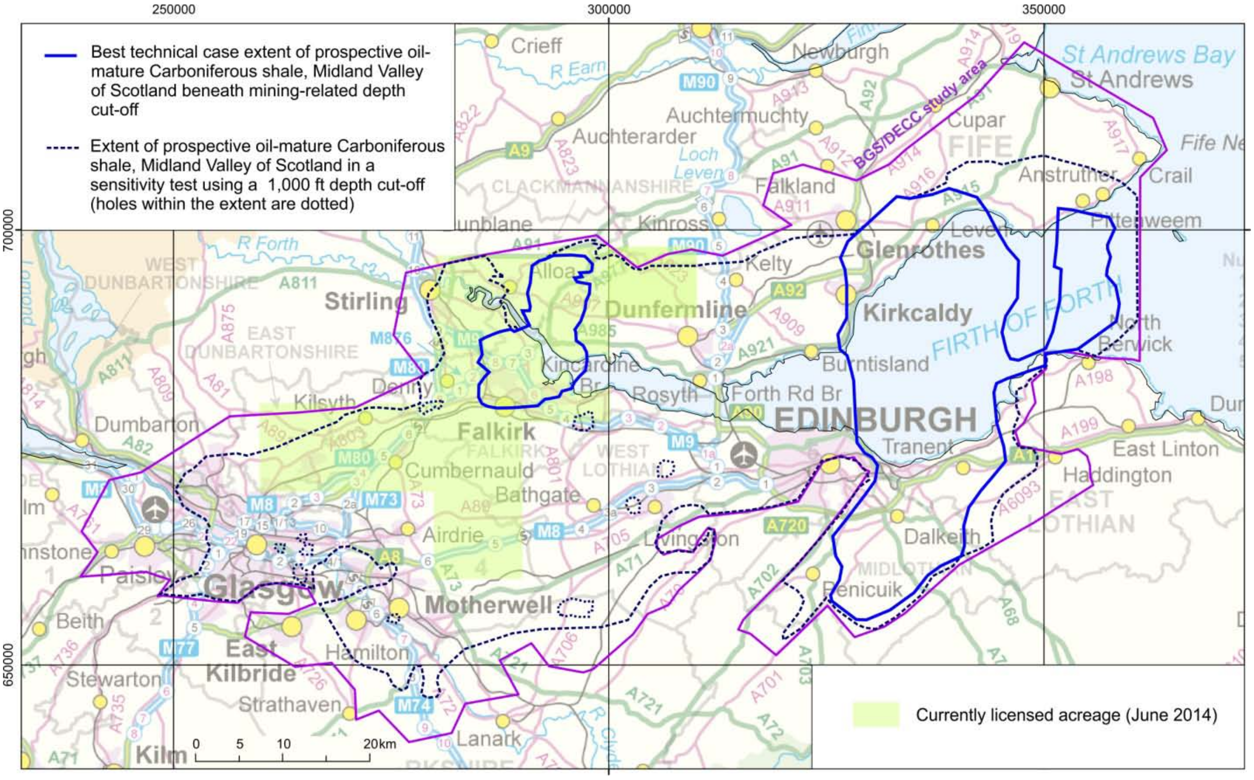


Figure 72 Summary of areas considered prospective for shale oil (blue) beneath a mining-related depth cut-off in the Carboniferous shales of the Midland Valley of Scotland. Study area in purple. Ordnance Survey data © Crown copyright 2014

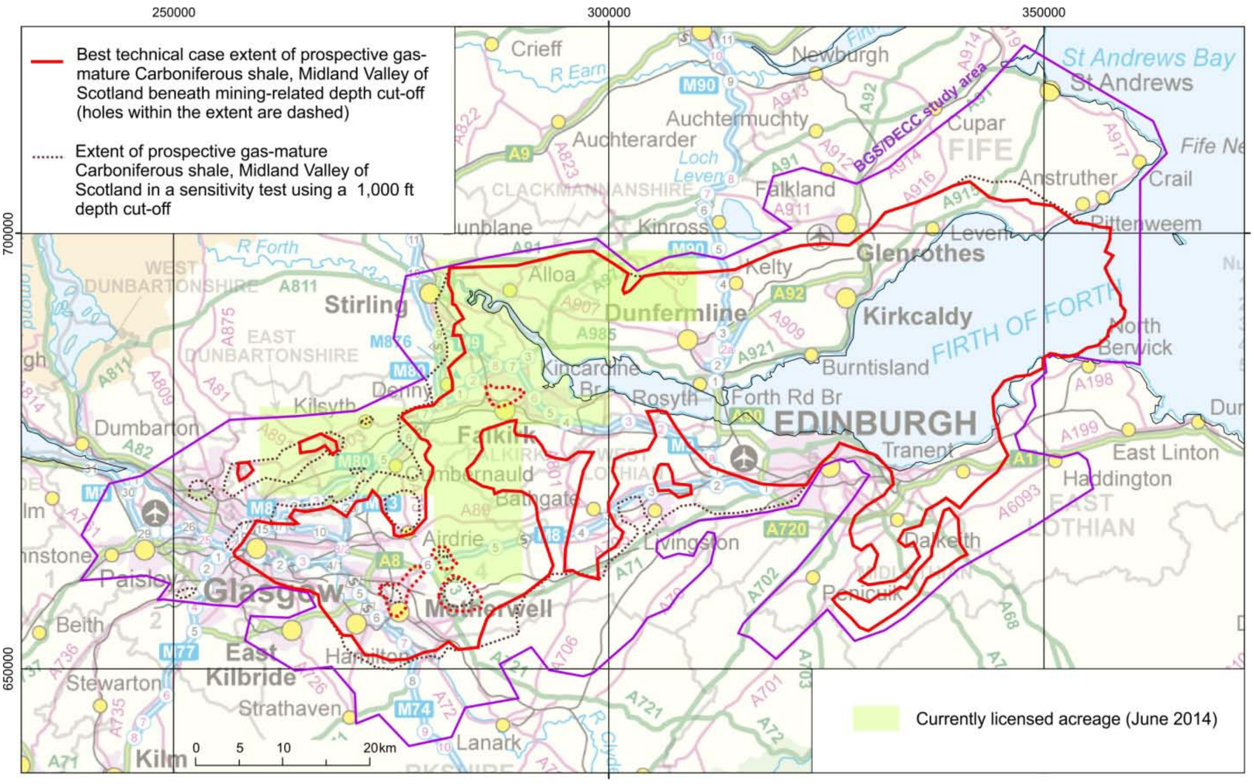


Figure 73 Summary of areas considered prospective for shale gas (red) beneath a mining-related depth cut-off in the Carboniferous shales of the Midland Valley of Scotland. Study area in purple. Ordnance Survey data © Crown copyright 2014

Within the prospective areas presented in Figures 72 and 73, the net mature shale thickness, quality (TOC, shale bed thickness etc.) and reliability of the estimation is highly variable, dependent on data availability and geology. For example, the prospective area for shale gas to the south-east of Penicuik and Dalkeith contains thin net mature shale (modelled at less than 164 ft, 50 m) and the geological criteria are poorly constrained due to lack of data (see also Figures 67, 68) .

The prospective extent maps presented here have been produced at a regional scale by application of a suite of criteria described in detail above. Additional data, amended criteria, local-scale assessments and developments in science and technology are likely to refine these extents.

In this populated area of central Scotland, regulatory, environmental and societal considerations have not been incorporated into this geological resource assessment.

5 Conclusions

The Midland Valley of Scotland has a long history of coal and hydrocarbon extraction which has fuelled the industrial development of Scotland. By the turn of the 20th century, over 100 oil-shale works extracting and heating immature oil-shale to extract oil had operated. While there is currently only one gas field in the area, the Airth coalbed methane field, numerous conventional oil and gas wells have been drilled, some of which produced hydrocarbons in the past. These discoveries, together with a small number of natural seeps, attest to the presence of an active petroleum system, of which the mature, organic-rich shales described in this study are the source rock.

Four Carboniferous stratigraphic units contain mature organic-rich shale at suitable depths for prospective shale oil and shale gas: the Limestone Coal Formation, Lower Limestone Formation, West Lothian Oil-Shale unit and Gullane unit. Historic coal mine workings are present over some of the prospective area and abandoned deep coal workings within the uppermost Limestone Coal Formation are within a few hundred feet of the prospective shale units within this same formation. A buffer or vertical separation zone was applied to the top of the potential rock volume in the resource calculation to ensure separation from the abandoned coal mines. Volcanism and post-depositional intrusive magmatism enhance lithological complexity. Faulting is observed on numerous orientations and scales, bounding and within, the prospective Carboniferous succession but is complexity is not adequately resolved from currently available 2D seismic data.

The lacustrine, fluvio-deltaic and shallow marine depositional environments in which the Carboniferous Midland Valley of Scotland shales were deposited exerted a strong control on their thickness, character and prospectivity. In contrast to the deeper marine Bowland-Hodder shale of northern England and to many USA marine shales, there are relatively few global analogues. The alluvial/lacustrine Green River Formation of the Uinta Basin, USA has some similarities.

The total organic carbon (TOC) content of the Midland Valley shales is high (2-6% and often up to 20%). A range of kerogen types is indicated with oil-prone Type I (amorphous algal or lacustrine) and gas-prone Type III (non-marine woody) kerogens being most common, but mixed and Type II kerogen (marine) also present, indicating periodic marine influence. Additional sampling is required to characterise intervals of particular kerogen type; the current regional picture is of variable and mixed kerogens in the prospective shale units. Some of the Midland Valley of Scotland samples analysed have a corrected free hydrocarbon (S1) content of greater than 100 mg oil/ g C, with a more significant number having free oil contents between 50 and 100 mg oil/g C, indicative of some free oil present outside the kerogen.

As a result of significant burial, uplift and erosion, the Carboniferous shales are mature for oil generation from shallow current day depths over much of the study area, and gas-mature shales occur at current day depths from about 2,300 ft (700 m) below the surface. These are shallow maturity depths when compared to those of the UK Bowland-Hodder Shale of northern England, Jurassic shales of the Weald and many commercial plays in the USA. Locally, maturation is enhanced by igneous intrusion.

The mineralogy of Midland Valley of Scotland Carboniferous shales is variable; on average they are more clay mineral-rich and carbonate-poor than typical USA unconventional gas- and oil-producing shales.

However, brittle sandstone, limestones and ironstones are interbedded with the shales such that a 'hybrid' play could be an exploration target in the stacked lithologies.

Whilst the seismic and well datasets available are of limited distribution and variable quality, the data presented clearly show that the Midland Valley of Scotland Carboniferous shale resource contains high TOC shales mature for shale oil and shale gas. However, the relatively complex geology and relatively limited amount of good quality constraining data, together with a generally more clay-rich mineralogy than USA shale plays result in relatively high uncertainty for the Midland Valley of Scotland shale gas and shale oil resource. Lack of measured values for key parameters input to the resource estimation, such as adsorbed gas content, result in the use of USA values. These input values may not be characteristic of Midland Valley of Scotland shales, but are the best estimates currently available.

This study has identified the potential for a significant volume of gas- and oil-mature shale to be present in four mature shale intervals beneath a mining-related depth cut-off: a **total in-place gas resource** of **49.4 – 80.3 – 134.6 tcf** (1.40 – 2.27 – 3.81 tcm) and a **total in-place oil resource** of **3.2 – 6.0 – 11.2 billion bbl** (421 – 793 – 1,497 million tonnes).

Unconventional gas and oil from the Midland Valley of Scotland have the potential to add to the UK resource base, but with only limited well control and no flow testing from the shale rocks within the basin, it is not yet possible to make an estimate of the amount of shale oil and shale gas that might ultimately be recoverable.

Appendix A Midland Valley of Scotland resource calculation

Appendix B Additional detail on Midland Valley stratigraphy, magmatism, tectonism and oil and gas shows.

Appendix C Well and borehole interpretations and correlations

Appendix D Results of BGS 2014 Rock-Eval analysis

Appendix E Results of BGS 2014 XRD mineralogy analysis

Appendix F Well log TOC study

6 Glossary

Unit/abbreviation	Full name
API	standard (American Petroleum Institute) measure of natural gamma radiation typically in a borehole
bcf	billion (10^9) cubic feet
Bg	gas expansion factor
ft	foot/feet
ft^3 or scf	(standard) cubic foot/feet
GIIP	gas initially in place
HIo	original hydrogen index
HIpd	present-day hydrogen index
km	kilometre(s)
km2	square kilometre(s)
m	metre(s) (1 m = 3.28084 ft)
m^3	cubic metre(s) (1 m^3 = 35.31467 ft^3)
Ma	million years before present
mD	millidarcy
MPa	megapascal(s) (1 MPa = 145 psi)
mcfd	thousand (10^3) cubic feet of gas per day
mmcfd	million (10^6) cubic feet of gas per day
$mile^2m$	a volume occupying an area of 1 square mile with a thickness of 1 metre (1 $mile^2m$ = 2,589,988 m^3)
Ordnance Datum (OD)	0 ft / 0 m defined by the Ordnance Survey as mean sea level at Newlyn in Cornwall.
R_o	vitrinite reflectance (in oil) (%)
tcf	trillion (10^{12}) cubic feet
tcm	trillion (10^{12}) cubic metres
TOC	total organic carbon (%)

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