The geology of gas storage in offshore salt caverns

by

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1 EXECUTIVE SUMMARY

This report discusses the potential use of offshore salt formations on the UKCS for the storage of liquefied natural gas (LNG). No gas is currently stored in salt formations offshore UK. In fact, in a worldwide survey by Kavernen Bau- und Betriebs GmbH only one other offshore storage site was identified (offshore Louisiana, USA). However, with the import of increasing volumes of LNG into the UK, this remains an option competing with the onshore cryogenic storage tanks at the five existing UK facilities.

In the North Sea, maps of the several Permian and Triassic salt formations were derived from the DTI's verbatim Well Stratigraphy database. In the East Irish Sea Basin, tables of the top and base of the Preesall Halite Formation have been derived from the BGS "stratigraphic surfaces database"; the various other Triassic salt units here had are not always distinguished on the company composite logs. Data from offshore BGS regional reports and the UKOOA lithostratigraphic publications have also been integrated into this report. A table summarising the distribution, thickness, depth of burial and age of all offshore salt occurrences is included.

The viability of gas storage in offshore salt deposits is likely to be controlled by a large number of factors, some geological, others logistical and economic. These include: (1) preferred water depth of 15-40 m, if moorings are to be used, (2) preferred close proximity to abandoned platforms and existing pipelines, if they are to be used (3) bedded salt needs to be over 1000 ft thick, (4) depth of burial should be less than 3000 ft, to avoid salt creep, (5) avoid salts with mudstone interbeds greater than 6 ft thick, (6) salt pillows, walls and plugs (as long as there is no associated fracturing) offer the double advantage of the top of the salt being near the surface and a very deep base, (7) depth of burial should be less than 1000 ft, to avoid gas outbursts, (8) potential oil and gas fields should be avoided, (9) faults should be avoided, (10) close proximity to existing wells minimises the possibility of facies changes in the potential storage area, and (11) dykes should be avoided.

Applying these concepts to the geology of the offshore UK, it seems likely that the most favourable locations for comparable gas storage facilities lie within the thick Preesall Halite Formation (Triassic) in the southern East Irish Sea Basin, close to existing infrastructure and to plugged and abandoned wells. The main depocentre of the East Irish Sea Basin contains the thickest salt, and mudstone interbeds decrease in dominance southwards. The many North Sea halite units are mostly buried to greater depths beneath overlying Mesozoic to Quaternary strata, and are probably unsuitable for this reason. Some salt diapirs rise to shallow depths in the Central and Southern North Sea and these sites warrant further investigation.

Based solely on geological criteria, large parts of the offshore Wessex Basin, Peel Basin, Solway Firth Basin, Cardigan Bay Basin and Forth Approaches Basin could also support such facilities. However, these areas currently have no infrastructure, and some have very few wells within the salt depositional area. Without knowing the economic viability of the various elements of the facility, the future competition with onshore facilities, and the total import of gas by this method, it is difficult to assess whether facilities could also be developed in such areas remote from existing infrastructure. The cost would inevitably be greater.

2 INTRODUCTION

In the light of proposals to develop an offshore gas storage facility in a salt cavern in the East Irish Sea, this report assesses whether this area is the only location in the UKCS where a project of this nature could be developed, or whether there are other possible offshore locations for salt cavern gas storage. In order to do this, it was important to understand the fundamental requirements (economic and physical) that make a salt formation suitable for gas storage within the UKCS and Territorial Seas, the type of rock sequence which could support a gas storage facility, where these sequences can be found, and at what depth. With the benefit of advice from companies involved in the search for both offshore and onshore sites, a summary of the types of offshore development proposed is presented in Appendix A, and Section 3 includes a list of the criteria that need to be present or avoided.

Naturally occurring rock salt, halite occurs in several of the UKCS Permo-Triassic basins (Fig. 1). The two of these basins with infrastructure, the East Irish Sea and the Southern North Sea, are assessed in detail. In the other offshore basins, where no infrastructure is present, a list of references is provided to aid future studies. However, the absence of infrastructure is not considered to be a limiting factor for this type of development (Andrew Stacey, Stag Energy, pers. comm.).

The main database used in the North Sea has been the Well Stratigraphy Access database of formation tops that has been entered verbatim from composite logs over the past 20 years of Geological Advice contracts by BGS for DTI. Company composite logs in the other UKCS basins have not consistently subdivided the salt-bearing strata, so that such an approach has only proved feasible within the North Sea.

Other valuable sources were the regional summaries of offshore areas published in the series of DTI-sponsored BGS offshore regional reports (Andrews *et al.* 1990, Cameron *et al.* 1992, Gatliff *et al*. 1994, Jackson *et al*. 1995, Johnson *et al*. 1993, Tappin *et al*. 1994), the UKOOA-sponsored BGS lithostratigraphic reviews (Cameron 1993, Jackson & Johnson 1996, Johnson *et al*. 1994) and the Millennium Atlas (Evans *et al*. 2003). It is noticeable and inevitable that these various databases do not provide consistent results, but a complete lithostratigraphic review of salt-bearing formations was outside the scope of this study. The thicknesses derived from composite logs are likely to be based on widely differing interpretations of what constitutes the top and bottom of a formation, and represent an evolving comprehension of the complexity and variations of the sequences, whereas the subsequent BGS studies have made a more consistent study of all the data then available. No seismic reflection data were used for this study. These data are likely to be used by prospecting companies to show the extent to which optimum conditions identified in wells can be extrapolated, to perhaps to identify where such optimum conditions occur near existing infrastructure.

Some basins with probable offshore salt are excluded for the present e.g. the inner part of the Severn Estuary, because there is no offshore drilling. This exclusion also applies to other basins which do not have an offshore well proving salt of sufficient thickness and purity.

3 PROBABLE FACTORS RESTRICTING THE POTENTIAL STORAGE AREAS

A distinction needs to be made between the requirements for mooring ships and platform facilities and those of subsurface storage. These may be at different locations, linked by pipeline. Because cryogenic temperatures increase the cost of pipelines, mooring and platform facilities will need to be sited together or nearby, reducing the need for a long pipeline connection.

(1) Distance from the coast: this is likely to be important for the mooring as the water needs to be at least 15 m (50 ft) deep, although shallow water is preferred for cavern construction. Current designs favour mooring in water depths between 15-40 m (50-130 ft). These isobaths are depicted for the East Irish Sea on Figure 13b; only a narrow coastal zone of the North Sea is shallower than 15 m (50 ft) water depth. Wave height restriction on offloading is 3-4 m (10-13 ft) according to the water depth (de Baan *et al*. 2003).

(2) Distance from infrastructure: not essential, but abandoned platforms could be converted and existing pipelines used.

(3) One of the most important factors is a requirement for a bedded salt over 1000 ft (300 m) thick.

(4) Depth of burial: salt creep (plastic movement when the salt is under stress) increases rapidly below 3000 ft (Favret 2003), and burial depths less than this are preferable.

(5) Purity of the salt: the number and thickness of interbedded clays or other impurities. Mudstone beds greater than 2 m thickness should be avoided. Beds other than rock salt are destined to collapse during salt extraction to collect on the bottom of the caverns.

(6) Where salt diapirism has produced salt pillows, walls and plugs of various shapes, this indicates that the salt has been mobilized subsequent to deposition. The limit of Upper Permian diapiric salt was mapped in the Southern North Sea by Jenyon (1986), and lies close to the 250 m contour of Stassfurt Halite indicated on Figure 20. Remobilisation of salt is not a problem as long as there is it is not associated with fracturing in the salt. Many salt domes in the southern USA have the double advantage of the top of the salt being near the surface and a very deep base. These salt domes provide the storage capacity for the US Department of Energy’s Strategic Petroleum Reserve. The geology of these structures favours vertical (bottle-shaped) cavern formation, and this has been the most common type of cavern used for gas storage (Dreyer 1982). In contrast cavern formation in bedded salt is likely to be more horizontal, providing sausage-shaped storage facilities.

(7) Gas outbursts: gas is known in the deeper USA Gulf region salt mines (mostly over 300 m depth to mine floor). It was also reported in the Cheshire mines (Redwood 1922), but this cannot be verified from the BGS archive records. Outbursts have been triggered by solution mining in the Werra district, Germany and are located near to faults that are relatively recent (Gimm & Pforr 1964). No recent faults are known to us in the UK offshore.

(8) Discovery wells: potential oil and gas fields should be avoided.

(9) Faults: wells that intersected faults or were sited near to faults should be avoided.

(10) Distance from existing wells: the risk of a change of salt character, or thickening of mudstone interbeds obviously increases with increasing distance from wells. Seismic reflection data may provide some evidence for lateral facies change, but will not necessarily eliminate the risk of lateral changes in salt characteristics. In the UKCS, exploration for potential cavern sites is probably not likely to be far from public domain wells, although a wide grid of seismic

data away from a well was looked at by Stag Energy (we were unable to replicate this, in the time available, for the current study).

(11) Dykes: areas with dyke swarms or sills probably should be avoided because the location of anastamosing sills or low-angle dykes is difficult to predict. East Irish Sea well 113/27-1 encountered dolerites of the Fleetwood dyke system (Jackson *et al*. 1987) beneath a thick Triassic Preesall Halite Formation in the East Irish Sea Basin. There is some indication that the velocity of the salt is higher just above the intrusion, and the mudstones beneath the intrusion clearly have a higher velocity. NW-SE trending dykes are also present in the Mid North Sea High area, off the Northumberland coast and E-W trending dykes may also be present farther north in the North Sea (Gatliff *et al*. 1994).

Basin	Formation	Age	Type or ref well	Unit thickness	Salt bed thickness	Purity	Depth of burial	Halokinesis	Comments and suitability for gas storage
East Irish Sea Basin	St Bees Evaporite Formation (Lower Halite Unit)	Late Permian	113/27-3	Average 285 ft		Scarce mud partings		Mild pillowing.	Too thin.
East Irish Sea Basin	St Bees Evaporite Formation (Upper Halite Unit)	Late Permian	113/27-3	Average 360 ft		Slightly argillaceous salt, with numerous mud partings			Too thin.
East Irish Sea Basin	Fylde Halite Member	Triassic	110/2-5	Up to 600 ft		Subordinate mud partings		Some local salt flow in Triassic generally.	Too thin.
East Irish Sea Basin	Rossall Halite Member	Triassic	110/2-6	Up to 490 ft		Subordinate, but persistent mud partings			Too thin.
East Irish Sea Basin	Mythop Halite Member	Triassic	113/27-3	170-800 ft	3-100 ft	Significant and laterally-persistent mud partings			Too thin.
East Irish Sea Basin	Preesall Halite Formation	Triassic	110/7-1	300-1800 ft		Some thin mud partings. The least argillaceous of the EIS Triassic salts.	Typically 1000-1500 ft; deepest proven by well is 4020 ft.		**The most favourable salt unit for gas storage on the UKCS.**

Basin	**Formation**	**Age**	**Type or ref well**	**Unit thickness**	**Salt bed thickness**	**Purity**	**Depth of burial**	**Halokinesis**	**Comments and suitability for gas storage**
East Irish Sea Basin	Warton Halite Formation	Triassic	110/13-8	900-3000 ft	Beds up to 40 ft thick.	Clean halite, with numerous, laterally-persistent mud partings.	Occurs up to ‘wet’ rockhead in places.		Too many shale partings.
Peel Basin	Undifferentiated	Late Permian	111/25-1	54 ft in one well.			At 4836 ft in well.		Too thin.
Peel Basin	Mercia Mudstone Group	Triassic	111/25-1	384 ft plus 591 ft units in one well.	Up to 85 ft thick.		Less than 700 ft in well.		Too thin.
Solway Firth Basin	Undifferentiated	Late Permian	112/15-1	200 ft in one well.			At 7486 ft in well.		Too thin.
Solway Firth Basin	Mercia Mudstone Group, probably Rossall, Mythop and Preesall	Triassic	112/15-1	2100 ft gross thickness.	Beds up to 90 ft thick.		Less than 500 ft in well.		Potentially good, but individual units may be too thin and little data available.
North Channel Basin	Undifferentiated	Late Permian	111/15-1	One 60 ft thick salt.			At 5181 ft in well.		Too thin.
North Channel Basin	Mercia Mudstone Group (3 salts)	Triassic	111/15-1	c.1000 ft of salt (total, net)		Low purity.	At 764 ft in well.		Individual units too thin. Also dolerite dyke/sill.
Central Irish Sea	Undifferentiated	Late Permian	None	Not proven, but likely.					Unknown potential.
Central Irish Sea	Mercia Mudstone Group	Triassic	108/30-1	Up to 60 ft thick.		No thick, clean halites.	At 1066ft in well.		Too thin.

Basin	**Formation**	**Age**	**Type or ref well**	**Unit thickness**	**Salt bed thickness**	**Purity**	**Depth of burial**	**Halokinesis**	**Comments and suitability for gas storage**
Cardigan Bay	Mercia Mudstone Group	Triassic	No wells	Maybe over 2000 ft (un-drilled).					Potentially good, but no well data.
St. George's Channel	Mercia Mudstone Group, with 3 separate salts	Triassic	106/28-1	Up to 2700 ft.				Salt walls and pillows.	Potentially good, but individual units may be too thin and little data available.
South Celtic Sea and Bristol Channel Basin	Mercia Mudstone Group	Triassic	93/6-1	1735 ft in one well.					No drilling or infrastructure in Bristol Channel.
Melville Basin	Melville Halite	Triassic	72/10-1A	Up to 2300 ft in swells.			At 6368 ft in well.	Two major salt swells.	Water depth (500 ft) too great and no infrastructure.
Offshore Wessex Basin	Dorset Halite	Triassic	97/12-1	1100 ft in one well.					Good.
Southern North Sea	Silverpit Evaporite Member	Early Permian	44/21-1	Up to 165 ft.			Generally more than 10,000 ft.		Too thin and too deeply buried.
Southern North Sea	Z1 (Werra)	Late Permian	49/26-4	Up to 66 ft.			Over 6000 ft in reference well.		Too thin and only very locally developed.

Basin	**Formation**	**Age**	**Type or ref well**	**Unit thickness**	**Salt bed thickness**	**Purity**	**Depth of burial**	**Halokinesis**	**Comments and suitability for gas storage**
Southern North Sea	Z2 (Stassfurt)	Late Permian	44/11-1	Well over 2000 ft in some diapirs.	Some units 1000+ ft in wells.		Only less than 3000 ft in wells 41/1-1 & 41/8-2. Average depth is c.7800 ft.	Large scale swells and diapirs.	Thick, but generally too deeply buried. Shallowest diapirs may have potential.
Southern North Sea	Z3 (Leine)	Late Permian	49/26-4	100 ft to 1000 ft.			Only less than 3000 ft in Q41.		Thick, but generally too deeply buried.
Southern North Sea	Z4 (Aller)	Late Permian	49/26-4	Up to 400 ft.			Only less than 3000 ft in Q41. Also at 2185 ft in 42/29-5.		Too thin.
Southern North Sea	Z5 (Grenzanhydrit)	Late Permian		c.20 ft	Sometimes a thin halite.				Too thin.
Southern North Sea	Main Rot Halite Member	Triassic	49/21-2	90-180 ft thick.			Thin interbeds.		Too thin.
Southern North Sea	Upper Rot Halite	Triassic							Too thin.
Southern North Sea	Muschelkalk Halite Member	Triassic	49/21-2	90-180 ft thick.			Thin interbeds.		Too thin.
Southern North Sea	Keuper Halite	Triassic	49/21-2	180-600 ft thick.	30-60 ft units.				Too thin.

Basin	**Formation**	**Age**	**Type or ref well**	**Unit thickness**	**Salt bed thickness**	**Purity**	**Depth of burial**	**Halokinesis**	**Comments and suitability for gas storage**
Central North Sea	Shearwater Salt Formation	Late Permian	21/11-1	Up to 6800 ft in wells, more in undrilled diapirs.			6 diapirs cut the base Miocene level and are within at least 1000 ms of seabed.		Generally far too deeply buried, but crests of diapirs are a possibility.
Forth Approaches Basin	Zechstein Group	Late Permian	26/8-1	700 to 3300 ft on net salt in wells.	Thickest units over 1000 ft.		Top Permian is at 1390 to 2580 ft in wells.	Pillows, but no diapirs.	Good. Not buried too deeply. May be suitable.
Northern North Sea	Shearwater Salt Formation	Late Permian	9/17-1A	Up to 670 ft.			At 11,420 ft in well.	Some halokinesis, but less so than in CNS & SNS.	Too deeply buried.
West Orkney Basin	West Orkney Evaporite Formation	Late? Permian	202/19-1	Up to 480 ft.	Thin beds, veins or dissemin-ated masses.		At 5765 ft and 8967 ft in two wells.		Beds too thin.

Table 1: Summary information relating to salt formations on the UKCS and their suitability for gas storage.

4 DISTRIBUTION OF SALT FORMATIONS

The salt formation limits have been assessed and described for each basin in which they occur. There are significant differences between basins (particularly nomenclature), and the relationship to existing infrastructure and potential shipping requirements makes it more logical to do this. The basins and sub-basins are grouped according to the BGS offshore regional report areas, and are covered in a clockwise manner beginning with the East Irish Sea. The halite members and formations are then described with the oldest first.

4.1 East Irish Sea Basin

Halite formations in the East Irish Sea Basin include the Lower and Upper Halite Units of the St Bees Evaporite Formation (Upper Permian), and up to five halites of Triassic age. There is a close relationship between the latter and laterally equivalent but thinner halites in the adjacent onshore basins of West Lancashire and Cheshire (Jackson *et al*. 1995). The uppermost Triassic Warton Halite occupies the basin lows only, having been removed from the highs by post-depositional solution, as in the Cheshire Basin. The Preesall Halite Formation contains the thickest, most widespread and cleanest salt sequence. The Mythop, Rossall and Fylde halites have thick interbedded mudstones.

4.1.1 St Bees Evaporite Formation

Late Permian in age, the St Bees Evaporite Formation is restricted to the northern half of the East Irish Sea Basin (Figs. 2, 3), being coeval with the Manchester Marls Formation of carbonates and/or mudstones and anhydrite that was deposited to the south (Jackson & Johnson 1996). The St Bees Evaporite Formation includes Lower Halite and Upper Halite units (Jackson & Johnson 1996) that were previously termed BS2 and BS3 cycles (Jackson *et al*. 1987).

The salt units of the St Bees Evaporite Formation are locally the purest of the East Irish Sea Basin, judging by their remarkably uniform character in the geophysical logs of well 110/8-2 (Fig. 4), where they are over 700 ft thick at a top depth of 8200 ft. The salt section is thinner in wells 113/26-1 and 113/27-3 (Jackson & Johnson 1996). It is also thinner in wells 110/3-2, and 112/25a-1 – in both wells it has been truncated at its base by faults (Fig. 4).

The Lower Halite Unit averages about 285 ft in thickness, with scarce mudstone partings, and it is affected by mild pillowing and halokinesis (e.g. well 110/8-2; Fig. 4). The Upper Halite Unit comprises an average of 360 ft of slightly argillaceous salt, with numerous mudstone partings (Jackson & Johnson 1996), and would not be suitable for gas storage.

4.1.2 Fylde Halite Member

The Fylde Halite Member of the Leyland Formation is restricted to the north and centre of the East Irish Sea Basin and is the oldest Triassic halite, lying just above the Ormskirk Sandstone (Sherwood Sandstone) hydrocarbon reservoir (Figs. 5, 6, 8, 10). It is differentiated from the overlying Rossall Halite by an upward increase in the number and thickness of mudstone interbeds (Jackson & Johnson 1996). The lowest 200 ft in well 113/26-1 is a relatively clean salt, with two thin interbedded mudstones (Fig. 10), but this component thins and disappears southwards (Jackson & Johnson 1996).

4.1.3 Rossall Halite Member

In areas where the Fylde Halite Member is absent, the Rossall Halite Member is the lowest salt in the Leyland Formation (Jackson & Johnson 1996) (Figs. 5-10). It is thickest west of Morecambe Field and north of well 110/3-2, probably reaching 350 ft, and thins southwards. It extends onshore into west Lancashire. Where fully developed in the north and centre of the basin it comprises four halites, separated by three laterally persistent mudstone interbeds (Fig.

11; well 110/2-6). Elsewhere it is quite variable in characteristics, but the clean salt beds are relatively thin compared to the Preesall Halite Formation (Jackson & Johnson 1996) – they are not thick enough to be ranked amongst the best of the subsurface storage prospects.

4.1.4 Mythop Halite Member

The Mythop Halite Member (Leyland Formation) is characterised by relatively thin salt beds, separated by mudstone beds up to 100 ft thick (Jackson & Johnson 1996) (Figs. 5-9, 12). It has the highest percentage of mudstone of any halite unit in the East Irish Sea Basin (Jackson & Johnson 1996), and for this reason is unlikely to be suitable for subsurface storage. It is about 1467 ft thick in well 110/3-2, and the depocentre may extend northwards to well 113/27-1 (727 ft thick). Well 113/27-3 has an atypically thick, halite-rich, unfaulted section in the north of the basin; the section illustrated for well 110/12a-1 is more typical (Fig. 12).

4.1.5 Preesall Halite Formation

The Preesall Halite Formation is the thickest and cleanest Triassic halite in the East Irish Sea Basin, and has been extensively logged geophysically. It ranges in thickness from 312 ft to 2034 ft (95-620 m) in wells (Jackson *et al*. 1997) (Figs. 5, 6, 8, 13a). Preesall Halite Formation tops and bases for available wells are listed in Table 1. In well 110/3-2 it is 1899 ft (580 m) thick, beneath casing at 1153 ft. Its middle section here is cleaner than the base, containing only four thin mudstones, up to about 6 ft thick, between 1930-2820 ft depth.

In well 113/27-1 the Preesall Halite Formation is about 1757 ft thick, with mudstone partings up to 50 ft thick (Jackson & Johnson 1996), but is intruded by the Fleetwood dyke system at the base, which is one of the risk factors best avoided. In well 113/28-1 it is 1342 ft thick, with the cleanest section between 4810 and 5100 ft.

D.I. Jackson (pers. comm.) considered that about 20 individual mudstone partings could be traced widely across the basin, and these thicken northwards (see correlation panels in Jackson & Howard 1996). It may be that the southern part of the basin is the optimum location for subsurface storage within this formation (Fig. 13b).

Well	Top Preesall Fm (sub-sea depth ft)	Base Preesall Fm (sub-sea depth ft)	Thickness (ft)
110/11-1	1039	1705	666
110/11-2	1496	1900	404
110/2-2	767	1396	629
110/2-4A	2175	2485	310
110/2-5	1043	1275	232
110/2b-9	1247	1877	630
110/3-1	1008	1330	322
110/3-2	1062	2961	1899
110/3b-4	1355	1634	279
110/6-2	511	1337	826
110/6b-1	1297	2219	922
110/7-1	1455	2774	1319
110/7-2	1627	2321	694
110/7a-4	305	502	197
110/8a-5	2054	2971	917
110/9-1	723	1177	454
113/27-1	404	2161	1757
113/28-1	3894	5236	1342

Table 2 Preesall Halite Formation thicknesses, East Irish Sea Basin. Data from BGS stratigraphic surfaces database.

4.1.6 Warton Halite Formation

The Warton Halite Formation (=Wilkesley Halite of the Cheshire Basin) is the least extensive of all the Triassic salts in the East Irish Sea (Figs. 5, 6, 8, 14). In well 110/7-2 it occurs between the casing and 1330 ft, and has mudstone interbeds of about 30 ft thickness. The Warton Halite Formation is probably present in well 113/28-1, between 520 and 836 ft. In well 110/13-8 it contains thin mudstone interbeds and is 882 ft thick (Jackson & Johnson 1996). Seismic data suggested to Jackson *et al*. (1997) that it is more than 3000 ft thick in undrilled parts in the north (Keys Sub-basin), but it thins southwards (Gogarth and Berw sub-basins).

Mudstone beds within this halite formation average about 10 ft in thickness, but they reach 40 ft thick in well 110/13-8 (Fig. 14). Thin higher velocity spikes are represented by beds of gypsum, anhydrite or dolomite in the latter well (Jackson & Johnson 1996).

4.2 Peel Basin, Solway Firth Basin and North Channel Basin

Basins to the north and west of the Isle of Man, the Peel Basin, Solway Firth Basin and North Channel Basin, also contain Triassic halites. There are no discoveries or infrastructure in these basins.

Jackson *et al*. (1995) suggested that the Solway Firth Basin may have Upper Permian halites at its centre, and well 112/15-1 subsequently drilled 200 feet of halite with thin beds of mudstone and anhydrite at the base of the Upper Permian. In the overlying Triassic section there are at least three halites in well 112/15-1, probably equivalents of the Rossall, Mythop and Preesall halites, and all include clean salt beds of about 90 ft thick between depths of 500-2600 ft in well .

The only well in the North Channel Basin, well 111/15-1, has one Upper Permian and three Triassic low purity halites that correlate with those in the Larne 2 borehole onshore in Northern Ireland, along with dolerite dykes.

In the Peel Basin, well 111/25-1 penetrated a 384 ft Triassic unit of interbedded salts and mudstones directly beneath the Quaternary, another 591 ft unit close below, probably a Rossall Halite equivalent unit, that includes relatively clean halite beds up to 85 ft thick, and a 54 ft unit of Upper Permian salts and mudstones at 4782 ft sub-sea. The only other well in the basin, 111/29-1, spudded in the Jurassic, and its Triassic section is badly faulted and contains no salt.

4.3 Central Irish Sea, Cardigan Bay, St. George's Channel, South Celtic Sea, Bristol Channel and Melville Basins

Although Upper Permian salt is not known in the Central Irish Sea Basin, this basin has more in common with the East Irish Sea Basin than the other basins to the south, so there is a possibility of its presence. There is sufficient drilling in the other basins to confirm that no Upper Permian salt is present in these.

Triassic halite beds do occur in the Central Irish Sea Basin, and are very variable in thickness. However, no thick, clean sections have been penetrated (clean halite up to a maximum of about 60 ft thick).

Based on evidence from seismic profiles, thick Mercia Mudstone Group sediments are present in the Cardigan Bay Basin, but no wells have yet sampled them. Lithologies are thought to be similar to the adjacent St. George's Channel Basin (see below). Around the basin margins, salt-bearing units may subcrop the sea bed/Quaternary.

A major salt unit occurs within the Mercia Mudstone Group of the St. George's Channel Basin, forming a salt wall against the controlling fault at the south-east of a major half graben (Tappin *et al.* 1994), and showing other signs of post-depositional salt movement (e.g. a salt pillow at well 103/2-1). In well 106/28-1 the salt unit is 2314 ft thick (at 5321 ft sub-sea), and in well 103/2-1 it is 2704 ft thick (at 4540 ft sub-sea). There are extensive mudstone intervals within the Mercia Mudstone Group in the southern basins, enabling three widespread Triassic salt units to be distinguished. In the Central Irish Sea the thickest, youngest halite might be equivalent to the Preesall Halite Formation of the East Irish Sea Basin.

Triassic salt is also found in the South Celtic Sea Basin (Evans 1990). Well 93/6-1 drilled 1735 ft of salt (at 3682 ft sub-sea), the topmost part of which appears to be purer judging by the geophysical logs (Evans 1990). This unit also extends into the outer part of the Bristol Channel Basin, where thicker mudstone interbeds are present, and it may also occur a short distance farther east in an offshore extension of the Central Somerset Basin, where it is thin and impure (Tappin *et al*. 1994).

The Melville Basin of the Western Approaches Trough contains a thick halite unit (the Melville Halite) in the Triassic Mercia Mudstone Group, at the same general level as that in the South Celtic Sea Basin (Evans 1990). Well 72/10-1A drilled 2313 ft of salt (at 6368 ft sub-sea) on one of two major salt swells in the basin (Evans 1990).

There is currently no infrastructure in any of these southern basins.

4.4 Offshore Wessex Basin

The Triassic Dorset Halite is the only salt formation known to occur in the offshore Wessex Basin. In the inshore part of the basin, the limits of the halite have been mapped by Smith *et al*. (2003). In the only offshore well in the Wessex Basin, 97/12-1, this halite is 1154 ft thick (at 4234 ft measured depth). Salt is mapped as being continuously present to the west, south of Sidmouth, but there are no wells there. The basin rapidly terminates east of Wytch Farm and Quadrant 98, and there is no salt in the latter area (Hamblin *et al*. 1992).

The English Channel (offshore Weald Basin) has a very thin Triassic Mercia Mudstone, if it is present at all, and no salt (Hamblin *et al*. 1992).

4.5 Southern North Sea (Gas Basin or Southern Permian Basin)

4.5.1 Permian halite members and formations

The Southern Permian Basin is bounded to the south by the London-Brabant Massif, to the west by the Pennine High, to the north by the Mid North Sea High, and it extends eastwards through Northern Europe.

4.5.1.1 Lower Permian

Through Early Permian times the Southern Permian Basin formed an asymmetric basin gently sloping from south to north (Cameron *et al*. 1992), within which were deposited a series of marginal fluvial and aeolian desert sandstone facies (the Leman Sandstone Formation). At the basin’s depocentre in the southern parts of Quadrants 43 and 44, these sandstones pass laterally into lacustrine clays and halites of the Silverpit Formation (Fig. 16) that attain a maximum thickness of 1115 ft (340 m); the halite-bearing section has been designated the Silverpit Evaporite Member (Johnson *et al*. 1994).

Well 44/21-1 proves a basal halite unit 165 ft (50 m) thick, although halite beds become thinner and less numerous both upwards and laterally from the basin’s depocentre (Rhys 1974, Cameron *et al*. 1992). Within the North Sea, therefore, early Permian halite beds are likely to be regarded as too thin to provide potential for developing underground gas storage facilities. They are potentially also too deep, being generally buried beneath more than 10,000 ft of post-Permian strata.

4.5.1.2 Upper Permian

The Upper Permian (Zechstein) succession represents a complex sequence of evaporite and carbonate rocks that underlie a substantial area of the North Sea and North-west Europe. They were deposited following a rapid marine transgression (the first of five) that introduced an abrupt basinwide facies change from the underlying Lower Permian desert strata. Each transgression was related to the temporary opening of a seaway between the Permian basins and the Boreal Ocean north of Norway (Ziegler 1982, 1990, Cameron *et al*. 1992). The opening and closing of this seaway was controlled by mainly eustatic changes in sea level within the Boreal Ocean and the development of the proto-Atlantic rift system (Smith, 1980, Cameron *et al*. 1992). During these times, the London-Brabant Massif and Pennine High continued to form the southern and western margins of the Permian depocentres, but the Mid North Sea High was inundated by the first transgression and remained partially or wholly submerged, providing connection between the northern and southern Permian basins of the North Sea thereafter (e.g. Jenyon *et al*. 1984, Cameron *et al*. 1992).

Over 3300 ft (1000 m) of Upper Permian sediment accumulated in the deepest parts of the southern Permian Basin, with evaporites forming the vast majority of the sediments. They crop out at sea bed to the north of Middlesborough, but are buried beneath 2300-8200 ft (700-2500 m) of younger sediments over most of the offshore area. Extensive salt movements (halokinesis) have deformed much of the Upper Permian and younger sediments, such that the thickness of the Upper Permian varies from 165 ft (50 m) or less in areas of almost total salt withdrawal to over 8200 ft (2500 m) in some of the major salt diapirs. Many of these salt diapirs and walls punch through the overlying Triassic sequences into Jurassic and Cretaceous rocks. The crests of two of the largest diapirs are now within 330 ft (100 m) of the sea bed.

The effect of the marine transgressions was to introduce a basinwide cyclicity to the Zechstein succession, with the second and subsequent cycles dominated by evaporites showing an upward transition from anhydrite to halite and then to magnesian or potassium salts. This reflected a general and gradual increase in the salinity of the basin due to evaporation, although in detail each cycle departs from the ideal sequence. They are referred to as the Zechstein Z1 to Z5 cycles, all five of which display lateral facies variations from the margins to the centre of the basin: carbonates developing around the margins, with anhydrites and in Z2-Z5 thick halites, basinwards.

4.5.1.2.1 Z1 Cycle

Halite has been encountered in the Werra Halite Member of the Z1 cycle in well 49/26-4 (Fig. 17) and two other offshore wells (Rhys 1974, Cameron *et al.* 1992). It is in the region of 66 ft (20 m) at its maximum, but was deposited only in one or two North Sea blocks in isolated salt pans within a marginal sabkha environment (Taylor 1980). It is unlikely to be regarded as a potential storage level.

4.5.1.2.2 Z2 Cycle

The Stassfurt Halite Formation represents the basinal accumulation of the Z2 Group (Figs. 19, 20) and is the equivalent to the Fordon Evaporites of east Yorkshire (Smith *et al*. 2003). The Hornsea onshore gas storage facility (Dean 1978, Dean *et al*. 1978, Dean 1985) on the coast of Yorkshire at Atwick, was established in the Fordon Evaporites in 1972 (Smith *et al*. 2003).

The Stassfurt Halite Formation comprises a complex series of evaporites, which filled, or nearly filled, the southern Permian Basin during the late stages of the second Zechstein cycle. The bulk of the Stassfurt Formation comprises halite – the main source of Zechstein salt structures. This halokinesis has disturbed the sequence across most of the basin. It is difficult to ascertain original thicknesses, but perhaps 1650 ft (500 m) of evaporites were precipitated in the central parts of the basin. In areas closer to the basin margin evaporites are between 330 and 820 ft (100 and 250 m) thick, thinning shorewards to between 80 and 200 ft (25 m and 60 m) over the outer edge of the Z2 carbonate-anhydrite shelf. Three evaporate sub cycles of the

Stassfurt Halite are recognised (Colter & Read 1980, Cameron *et al*. 1992). The two earliest cycles have lenticular geometries: thickening from the shelf over the slope, but thinning eastwards across the floor of the basin, restricting sedimentation of the uppermost cycle to the central parts of the basin (Fig. 20). The lowest cycle in the offshore wells is between 50 and 165 ft (15 m and 50 m) thick and may be absent in central parts of the basin. As in eastern England, the lowest cycle is mainly halite but contains thin bands of anhydrite towards the base. The middle cycle is up to 900 ft (275 m) thick, and is predominantly halite, with carnallite and shales appearing towards the top, giving characteristically spiky gamma ray profiles (Fig. 20). This is thought to represent complete evaporation of the Zechstein basin by the end of the middle cycle (Cameron *et al*. 1992). The upper cycle is over 330 ft (100 m) thick in the centre of the basin and shows an upward increase in halite, with the loss of anhydrite. It contains relatively few, thin impurities (wells 44/11-1, 47/8-1 and 48/13-2A, Johnson *et al*. 1994) (Fig. 19). At the top of the Z2 strata is a prominent, discontinuous and diachronous anhydrite between 3 and 80 ft (1 m and 25 m) thick that is found in around 70% of the offshore wells. Known as the Deckanhydrit Formation, it probably represents a solution residue formed as the less saline waters of the third major Zechstein marine transgression invaded the basin. Although in most areas the unit is too deeply buried to be considered suitable for gas storage, the crest of some diapirs may be suitably shallow.

4.5.1.2.3 Z3 Cycle

The Leine Halite Formation (Johnson *et al*. 1994) (Figs. 22, 23) represents the slightly thinner basinal accumulation of the Z3 Group and is the equivalent to the onshore Boulby Halite, in which various hydrocarbons, gases and chemicals have been stored on Teesside by ICI, the Northern Gas Board and other companies since the 1970s.

The Leine Halite Formation thickens progressively basinwards from less than 100 ft (30 m) near its boundary to a maximum of 1000 ft (300 m) at its depocentre (Figs. 22, 23). The formation is readily subdivided into a lower halite-dominated member and an upper potash-dominated member (Smith & Crosby 1979, Cameron *et al*. 1992) (Fig. 22).

The lower halite member thickens from 165 ft (50 m) on the Yorkshire coast to around 650 ft (200 m) in the centre of the southern North Sea and appears to have been deposited in a marginal salt belt more than 60 km wide (Cameron *et al*. 1992). The overlying potash member is absent in a zone 20 km wide around the margins of the Z3 evaporite basin, but thickens to 330 ft (100 m) in the basin centre. There appears to be some diachroneity between the two Z3 salt members and many offshore wells have penetrated a highly radioactive zone of concentrated potassium salts at the base of the potash member (Fig. 22).

The Leine Halite Formation is capped by the Roter Salzton Formation (Carnallitic Marl Formation onshore), the latter being virtually indistinguishable from the uppermost beds of the Leine Halite Formation. The Roter Salzton salt is relatively clean, especially in well 42/10a-1, where thin anhydrite beds are the main impurity (Johnson *et al*. 1994).

4.5.1.2.4 Z4 Cycle

A fourth Zechstein cycle contains the Aller Halite Formation, which again thickens progressively basinwards to about 400 ft (120 m, Cameron *et al*. 1992). The formation thins over the Cleaver Bank High at the UK/Netherlands median line in Quadrant 49, perhaps as a result of leaching, as it is close below the base Cretaceous unconformity. The Aller Halite and equivalent Sneaton Halite Formation onshore can be subdivided into two halite-dominated members and a potash-dominated member (Fig. 22). The lower halite member increases in thickness from around 65 ft (20 m) on the Yorkshire coast to 115 ft (35 m) in the centre of the southern North Sea and contains intercalations of anhydrite and mudstone. The middle potash member is up to 250 ft (75 m) thick in the basin centre, but diminishes to perhaps 105 ft (32 m) around the basin margins. The upper halite member thickens basinwards from the coast to a maximum of 65 ft (20 m) at the centre of the southern North Sea.

4.5.1.2.5 Z5 Cycle

The fifth Zechstein transgression, represented by the Grenzanhydrit Formation, is poorly developed across the Southern North Sea and represents a short-lived expansion of the basin. It has not been identified in many wells (Fig. 22), being only 20 ft (6 m) thick at most, sometimes containing a thin halite.

4.5.2 Triassic halite members

Most of the Upper Triassic of the southern North Sea forms the Haisborough Group, which comprises three formations: the Dowsing Dolomitic Formation, the Dudgeon Saliferous Formation and the Triton Anhydritic Formation (Cameron *et al*. 1992). The basal two formations contain four halite members of varying thickness, composition and extent.

4.5.2.1 Dowsing Dolomitic Formation

Near the base of the Dowsing Dolomitic Formation is the *Main Röt Halite Member* (Fig. 25), which is between 200 ft (60 m) and 260 ft (80 m) thick in most of the northern half of the Anglo-Dutch Basin (Figs 26 - 29). However, near some Zechstein salt structures it may be more than 330 ft (100 m) thick. The salt is reasonably pure, with only a few thin mudstone layers (Johnson *et al*. 1994). In the centre of the basin, the member comprises five evaporite cycles (Southworth 1987, Cameron *et al.* 1992). Each cycle has a thin but laterally continuous mudstone at its base, representing marine influence, with salts precipitated during a subsequent regression in restricted lagoons and shallow evaporite basins.

The Upper Röt Halite, Upper Röt Evaporite and Upper Röt Mudstone members were deposited during the second major marine incursion and subsequent regression. However, the Upper Röt Halite is restricted to the northern half of the Anglo-Dutch Basin, where it is only between 15 ft (5 m) and 35 ft (11 m) thick (Fig. 26).

The *Muschelkalk Halite Member* was deposited during the initial stages of a third marine regression and has a quite different areal distribution to the earlier halites of the Dowsing Dolomitic Formation (Fig. 26). Between 130 ft (40 m) and 200 ft (60 m) thick, it extends farther south towards the London Brabant Massif, but is absent from onshore eastern England (Fig. 30). There are numerous thin beds of red mudstones within the halite. The lowest halite beds are thinnest, having been precipitated in isolated lagoons, whereas at higher levels thicker halite beds accumulated in more widespread evaporite basins (Southworth 1987, Cameron *et al*. 1992). Wells 43/26-7 and 49/21-3 (Johnson *et al*. 1994) both show a reasonably clean salt, with very thin impurities in well 43/26-7 especially.

4.5.2.2 Dudgeon Saliferous Formation

The Dudgeon Saliferous Formation was deposited during a return to dominantly continental clastic facies across the North European Triassic Basin (Fisher 1986). The lower 330 ft (100 m) or so of the formation comprise red-brown mudstones, and above this the lowest salt bed within a succession of interbedded halites and red mudstones is taken as the base of the Keuper Halite Member. The top of the highest salt bed is taken as the boundary with the overlying Triton Anhydritic Formation (Rhys 1974, Cameron *et al*. 1992). The Keuper Halite Member records another return to dominantly subaqueous deposition in the centre of the southern North Sea. Beds of halite form up to 80% of the member in the centre of the Sole Pit Trough, where they are between 3 ft (1 m) and 66 ft (20 m) thick. However, the thinnest salt beds are laterally impersistent. The halite member thins to the north-west and north (Figs. 31, 32). The abundance of relatively thick mudstone beds in this member (Johnson *et al*. 1994) make it unattractive for gas storage.

4.6 Central North Sea

The Northern Permian Basin covered much of the area now occupied by the Central North Sea, extending north-westwards into the Moray Firth area, northwards into the Northern North Sea and eastwards as far as Scandinavia (Gatliff *et al*. 1994). It was a smaller basin than the southern Permian Basin.

4.6.1 Shearwater Salt Formation (Cameron 1993)

As in the Southern North Sea, shales, carbonates and evaporates were deposited across the Central North Sea following the rapid Late Permian transgression, with the Zechstein overlapping the Lower Permian desert strata to rest on pre-Permian rocks towards the basin margins. Across the central North Sea, Zechstein cycles Z1 and Z2 are identifiable, whilst Z3/Z4/Z5 are amalgamated (Gatliff *et al*. 1994). There is no formally defined subdivision of the succession on this basis, however. Halite units are generally restricted to the more central parts of the basin, being absent in some cycles and hence correlations with cycles in the southern North Sea are difficult, if not impossible.

No salt is present in the Permian (Zechstein) sequences of the highs within and adjacent to the UK Central Graben (e.g. Montrose High and area south of the Duncan-Argyll fields (Gatliff *et al*. 1994). Thick halites of the Shearwater Salt Formation are widespread elsewhere in the Central Graben, they extend across the West Central Shelf, and an embayment crosses the Mid North Sea High, where the formation is 1936 ft thick in well 37/12-1 (Johnson *et al*. 1994). In the area west of the Argyll field a salt dissolution front has been mapped (Figs. 33, 34). Permian Zechstein salt is present in wells 26/7-1 and 21/26-1 and thickens east to over 2600 ft (800 m) in well 21/11-1, although there are interbeds of mudstone of in excess of 300 ft in the latter. Nearer to the coast and at shallower depth the salt in 26/7-1 is also purer, although not in sections greater than 165 ft (50 m) thick. Salt walls surround the Devil’s Hole Horst, particularly on its eastern side, where they extend towards diapirs surrounding the Montrose High (Gatliff *et al*. 1994). Neighbouring wells often have negligible salt due to withdrawal.

Significant thicknesses of halite and/or potash-magnesium rich salts occur between the Auk/Argyll region and the northern margins of the Central North Sea (Figs. 33, 35). Although there is a correlatable anhydrite bed at the top of the salts, these are, however, difficult to correlate particularly where halokinesis has been significant. This is illustrated in well 21/11-1, where the basal 630 ft (192 m) of halite represents the Stassfurt Halite of the Southern North Sea, but the remainder of the halite-bearing section could comprise parts or all of cycles Z3 to Z5 (Fig. 35). Similar uncertainties are found in well 21/26-1 (Fig. 35).

Thick anhydrites have also been penetrated by well 26/7-1 in the Forth Approaches Basin, with halites developed in the upper part of cycle Z2 and in an amalgamated Z3 to Z5 succession (Fig. 35).

Considerable halokinetic movement of the Zechstein salt occurred during the Triassic and Jurassic periods, resulting in the development of numerous salt walls, diapirs, pillows and areas of salt withdrawal (Fig. 33). This has led to major lateral variations in salt thickness over very short distances (Figs. 33, 34). Salt walls appear more widespread than salt pillows, their orientation being variable. In the Forth Approaches Basin their trend is northeasterly, on the flanks of the Mid North Sea High it is E-W and in the West and East Central grabens they are parallel to the Mesozoic graben-bounding faults (Gatliff *et al*. 1994). Generally these orientations are related to sub-Permian faults. Salt diapirs appear restricted to the West and East Central grabens.

The Zechstein may be up to 2625 ft (800 m) thick over the Mid North Sea High, illustrating that by Upper Permian times it was largely inundated by a shallow carbonate sea. As alluded to, it has been suggested that deeper water links existed between the northern and southern Permian basins during this time. Connections along the site of the Central Graben and smaller ‘channel’ features over the high have been suggested and described by Jenyon *et al*. (1984)

and Smith & Taylor (1980). Thick halites have been recognised within these features, identified from N-S trending salt-solution fronts running across the high (Fig. 34).

No significant thickness of Triassic salt is present in the Smith Bank Formation of this area (Gatliff *et al*. 1994). North of the Mid North Sea High, the sedimentary basins are fault bounded and lack persistent halites. Gatliff *et al*. (1994) illustrated evaporites, including very thin salt in well 30/1c-3, in the Smith Bank Formation but none is recorded in the Skagerrak Formation (Fig. 36).

4.6.2 Forth Approaches Basin and south of Buchan

Salt is present in the Zechstein of the Forth Approaches Basin and over the Buchan Graben and the Aberdeen Platform (Fig. 39) connecting with the Shearwater Salt Formation of the Central North Sea area (Andrews *et al.* 1990, Gatliff *et al*. 1994). Here, thick basinal evaporites are preserved in a series of salt pillows, where the Zechstein locally reaches 3300 ft (1000 m). Salt diapirs have not been recognised here. The Zechstein comprises four evaporitic cycles, that in addition to the dominant salt, include potassium and magnesium salts and anhydrite (Andrews *et al*. 1990). Correlation with the classic five cycle division of the Zechstein in the southern North Sea has proved difficult, though it is likely that the thick halite-dominated succession in the south-east represents cycles Z1 to Z4 (Deegan & Scull 1977, Andrews *et al*. 1990). In wells, the Zechstein to buried to depths of 1390 ft to 2580 ft and may be suitable for gas storage.

4.7 Moray Firth

No Permian or Triassic salt is present in the Inner or Outer Moray Firth basins (Andrews *et al*. 1990).

4.8 Northern North Sea

Zechstein deposits have been proved in at least 15 wells in the Northern North Sea area (Johnson *et al*. 1993). The majority of penetrations have been in the southern and central part of the Viking Graben, with no halites yet proven north of wells 9/17-1 and 9/27-1 in the southern part of the Beryl Embayment (Fig. 40). In well 9/17-1, up to 70% (630 ft or 192 m) of the 900 ft (274 m) thick Zechstein sequence is composed of halite (Fig. 41), which has been suggested represents the Zechstein Z2 cycle (Taylor 1990).

Halokinesis is again evident here, though less so than in the Central and Southern North Sea.

4.9 West Orkney Basin

Thin salt beds are present in the Upper? Permian West Orkney Evaporite Formation (Ritchie *et al*. 1996), but would not be suitable for gas storage. Wells 202/18-1 and 202/19-1 found salt at depths of 5765 ft and 8967 ft respectively.

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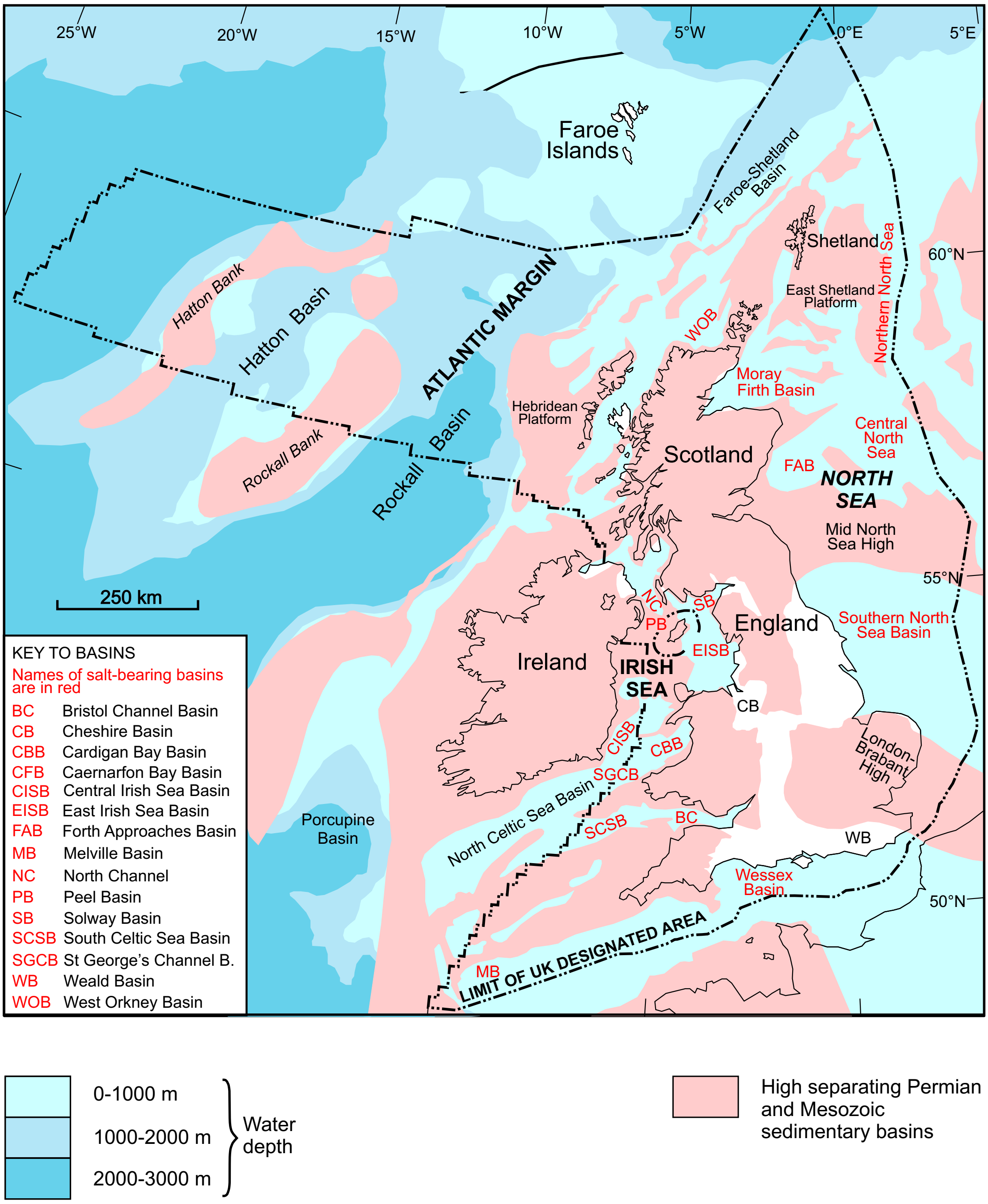


Figure 1 Location of salt-bearing basins on the UKCS.

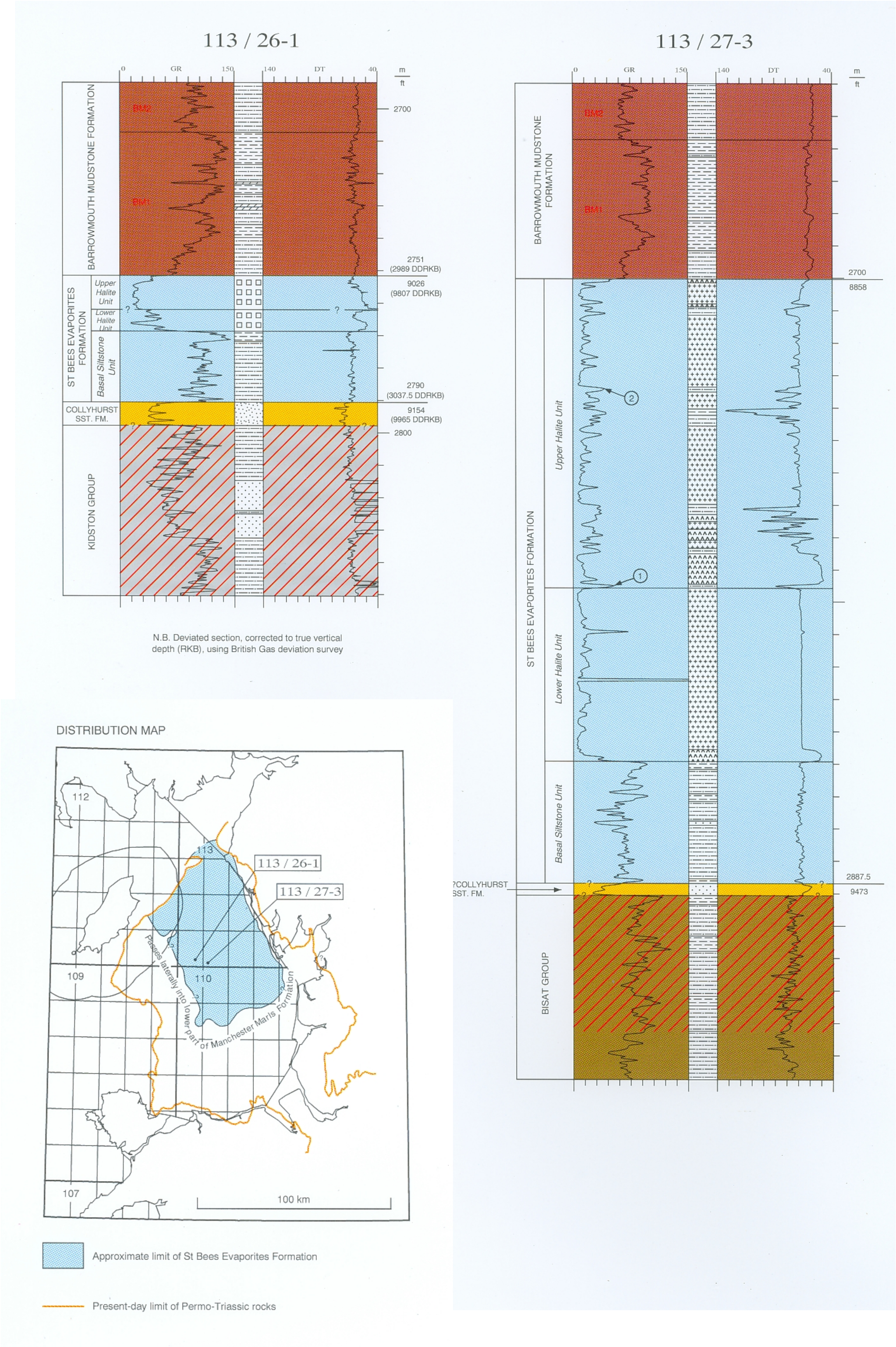


Figure 2 Distribution and selected well sections of the St Bees Evaporite Formation, East Irish Sea (from Jackson & Johnson 1996).

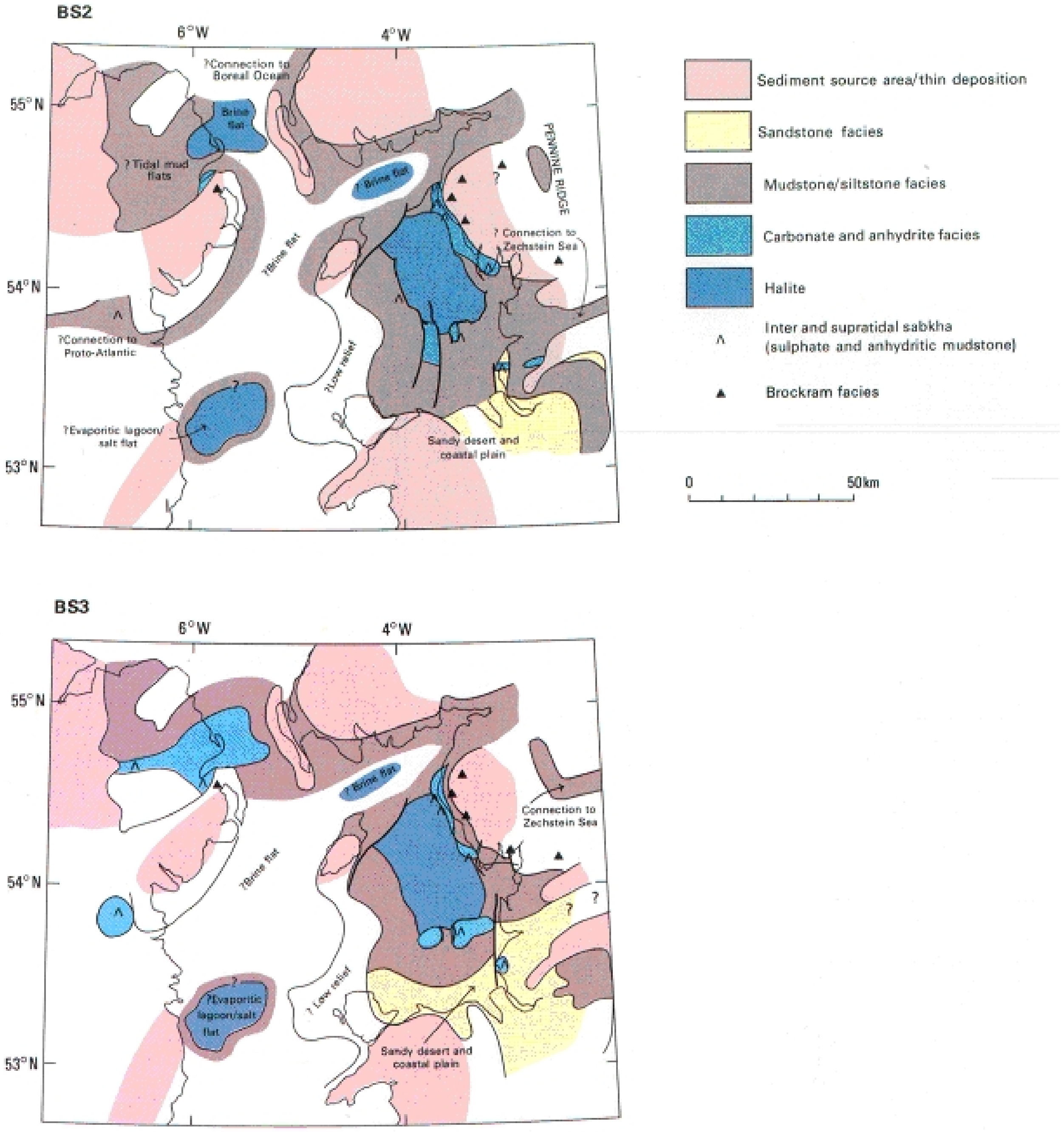
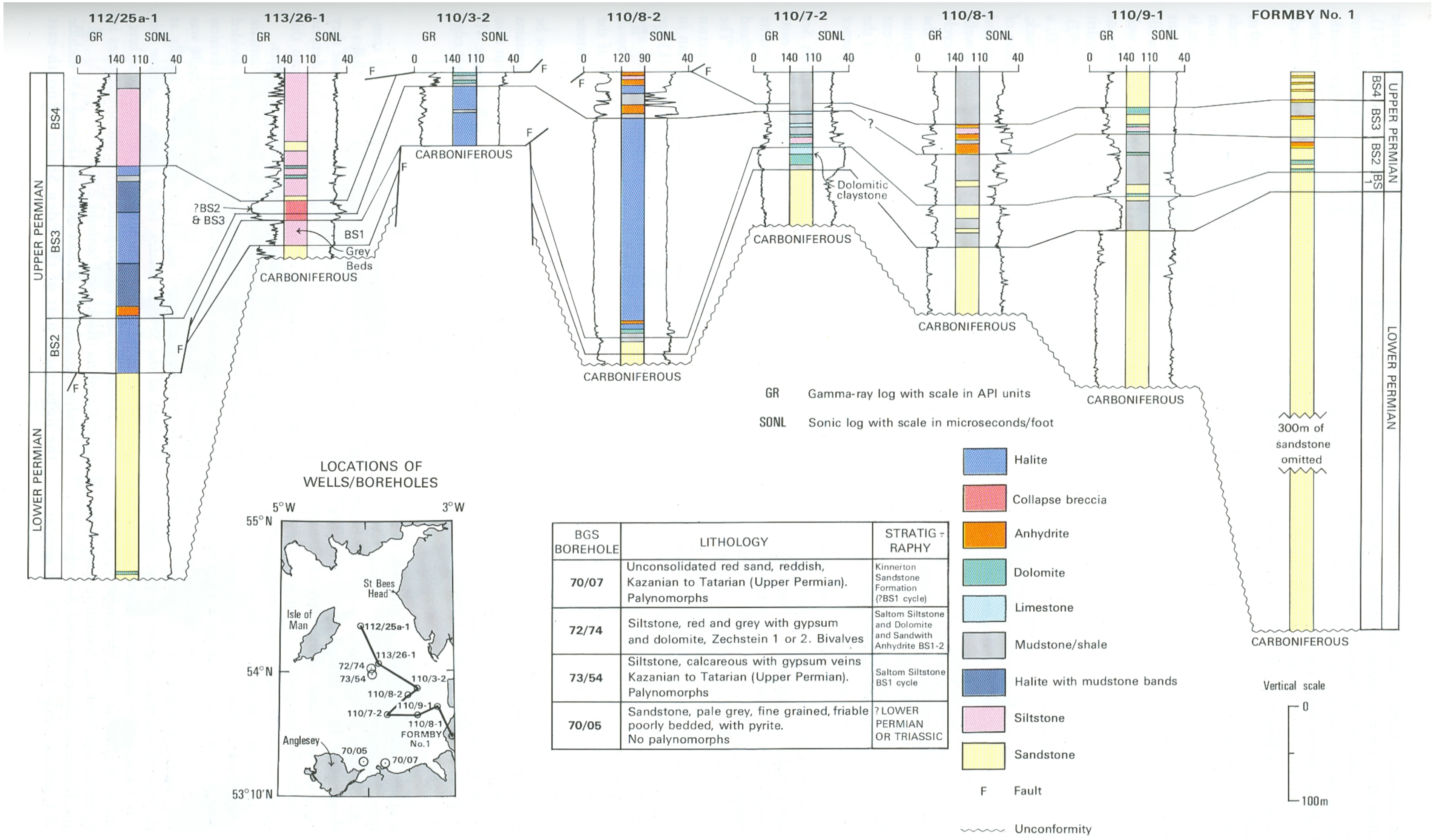


Figure 3 Palaeogeographic sketch maps showing the limits of the Late Permian Lower Halite Unit (BS2) and Upper Halite Unit (BS3), Irish Sea (from Jackson *et al*. 1995).



BGS BOREHOLE	LITHOLOGY	STRATIG - RAPHY
70/07	Unconsolidated red sand, reddish, Kazanian to Tatarian (Upper Permian). Palynomorphs	Kinnerton Sandstone Formation (?BS1 cycle)
72/74	Siltstone, red and grey with gypsum and dolomite, Zechstein 1 or 2. Bivalves	Saltom Siltstone and Dolomite and Sandwith Anhydrite BS1-2
73/54	Siltstone, calcareous with gypsum veins Kazanian to Tatarian (Upper Permian). Palynomorphs	Saltom Siltstone BS1 cycle
70/05	Sandstone, pale grey, fine grained, friable poorly bedded, with pyrite. No palynomorphs	? LOWER PERMIAN OR TRIASSIC

Figure 4 Correlation of Permian strata in the East Irish Sea Basin (from Jackson *et al*. 1995).

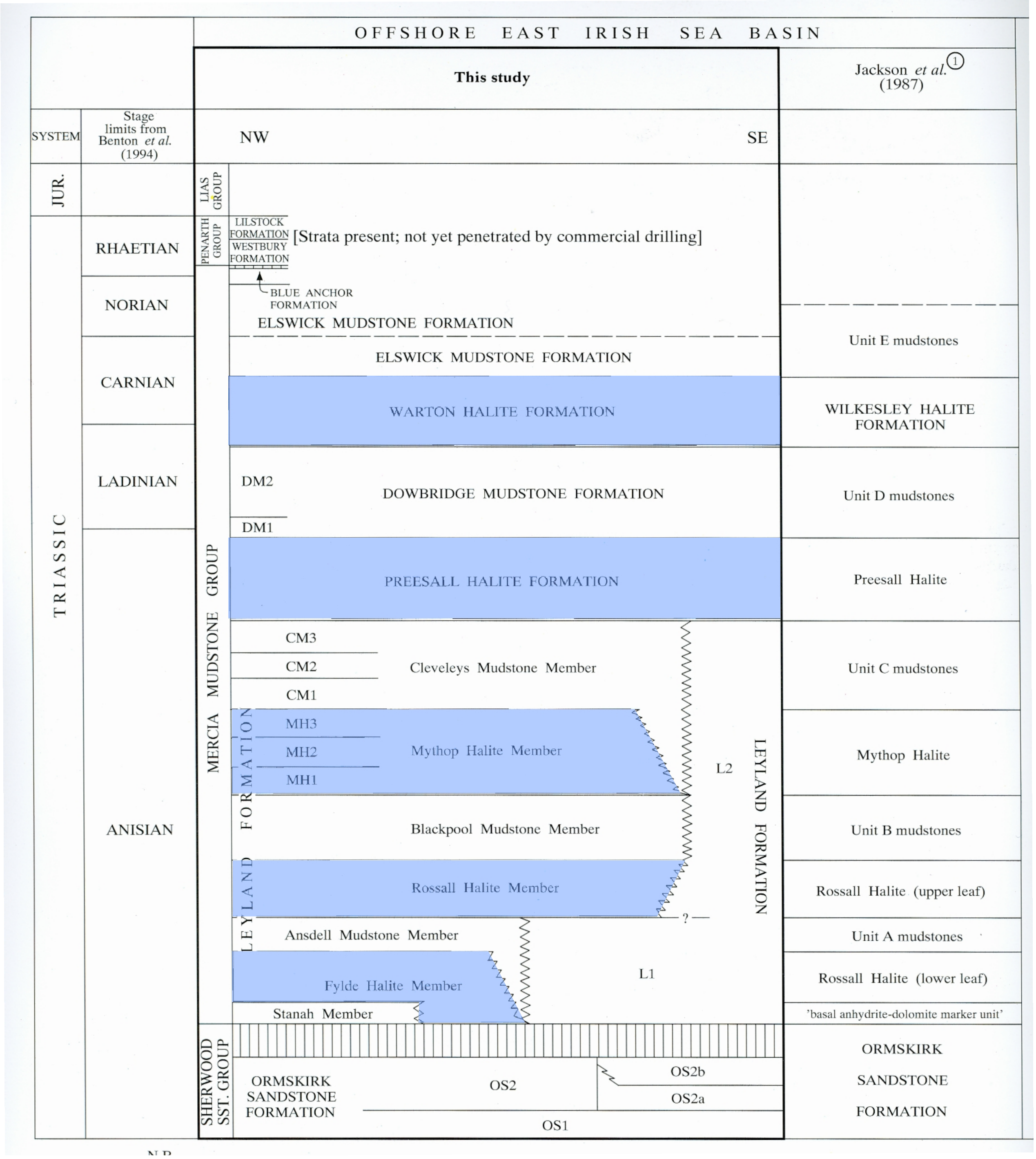


Figure 5 Halite units within the Triassic Mercia Mudstone Group, East Irish Sea (Jackson & Johnson 1996).

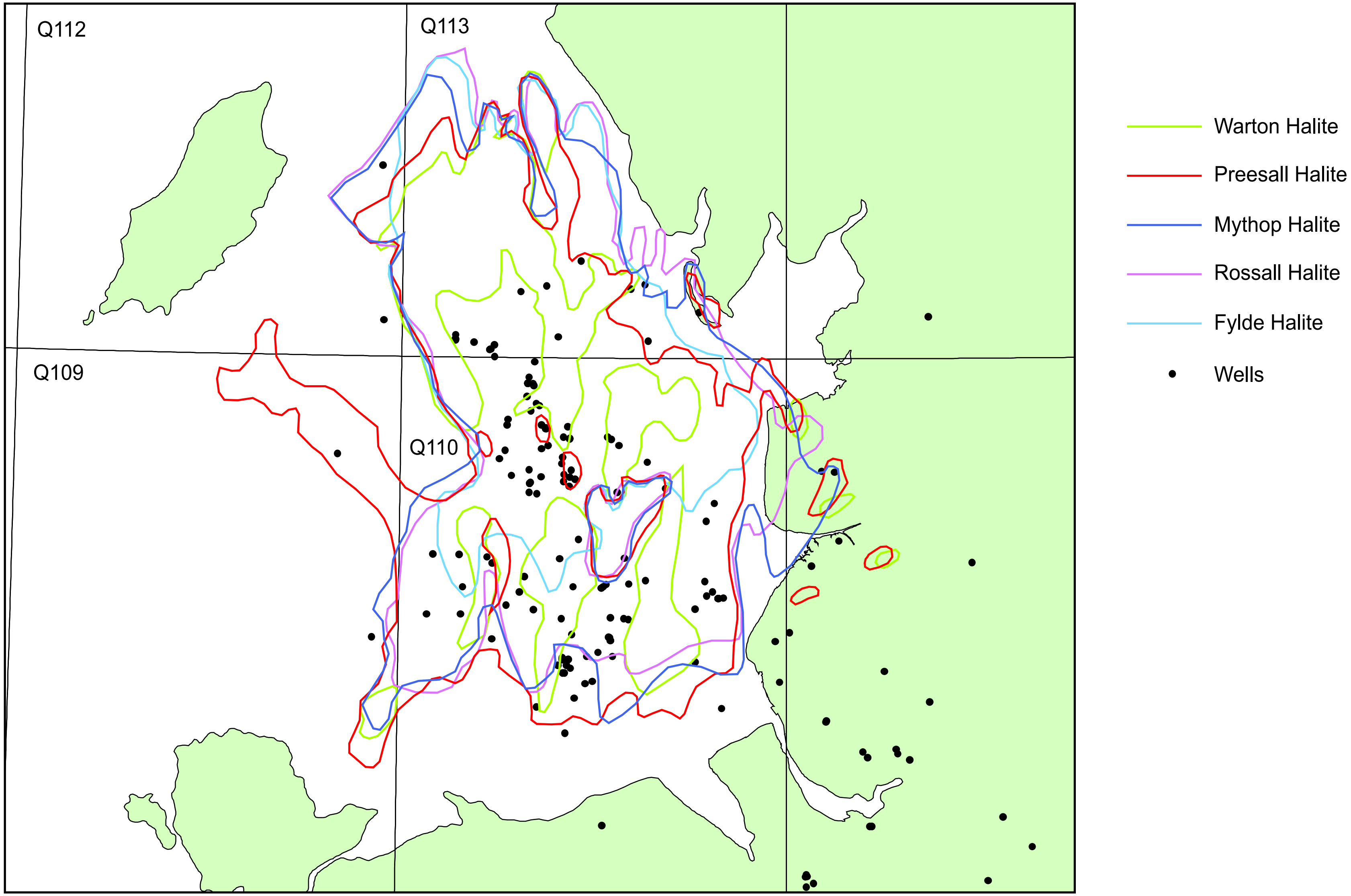


Figure 6 Limits of Triassic salt-bearing strata in the East Irish Sea Basin (from Jackson & Johnson 1996).

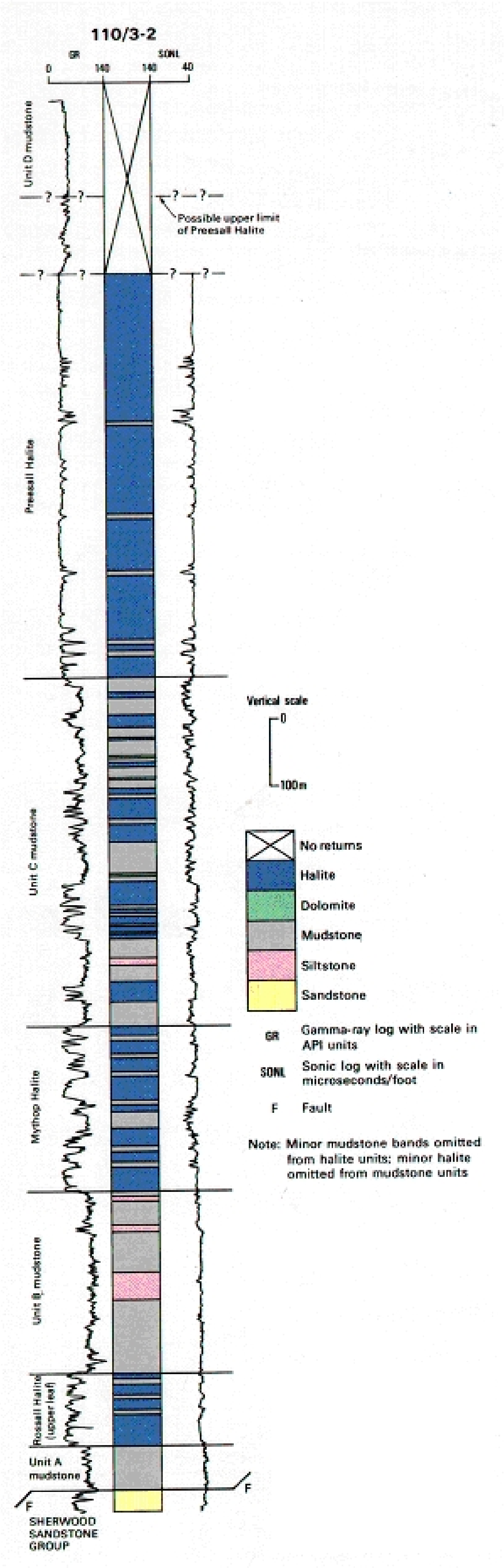


Figure 7 Well 110/3-2 illustrating the stratigraphy of the Mercia Mudstone Group, East Irish Sea (from Jackson *et al.* 1995).

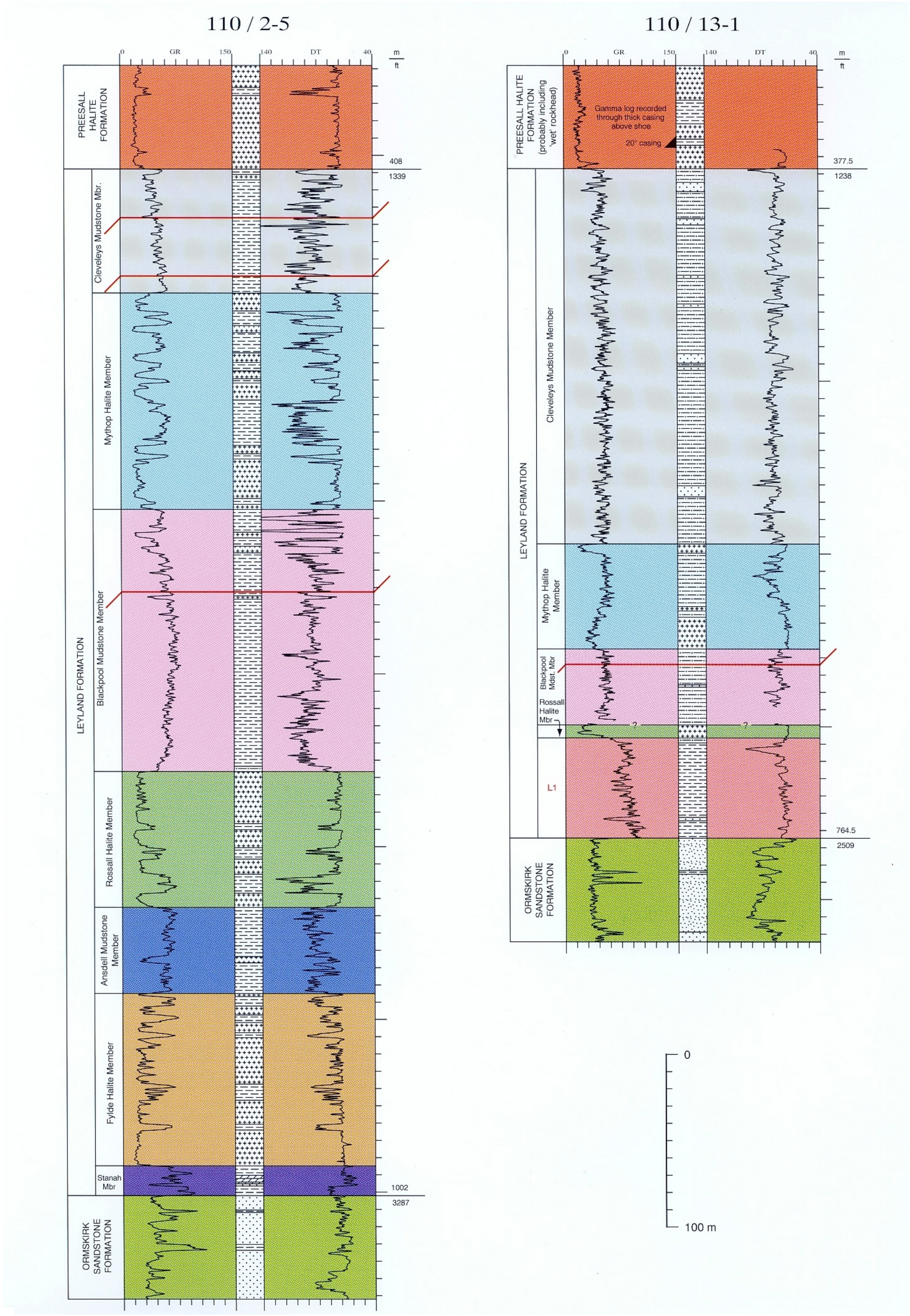


Figure 8 Example well sections through the Leyland Formation, East Irish Sea (from Jackson & Johnson 1996).

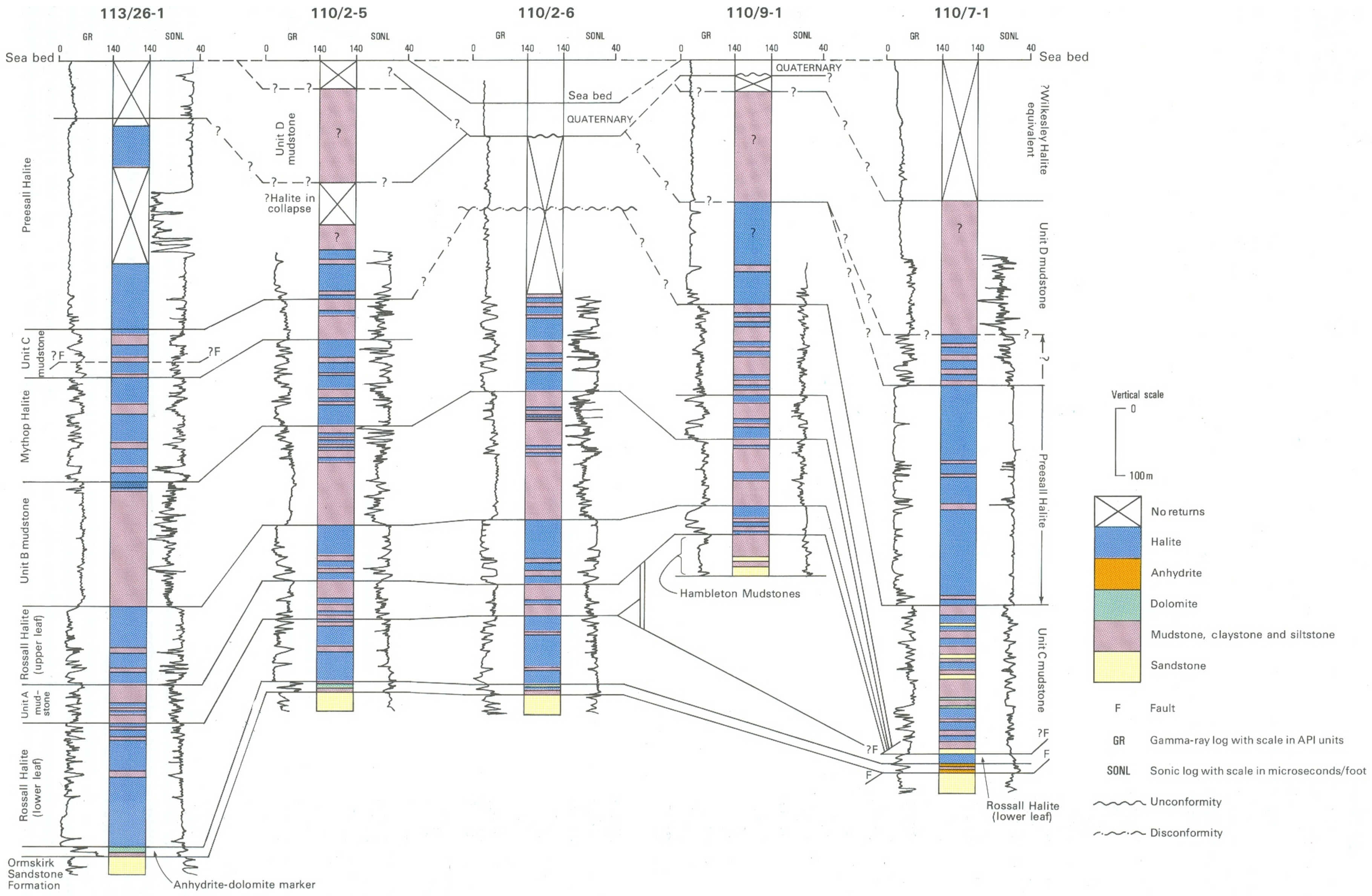


Figure 9 Correlation of Triassic salt-bearing strata, East Irish Sea (from Jackson *et al*. 1995).

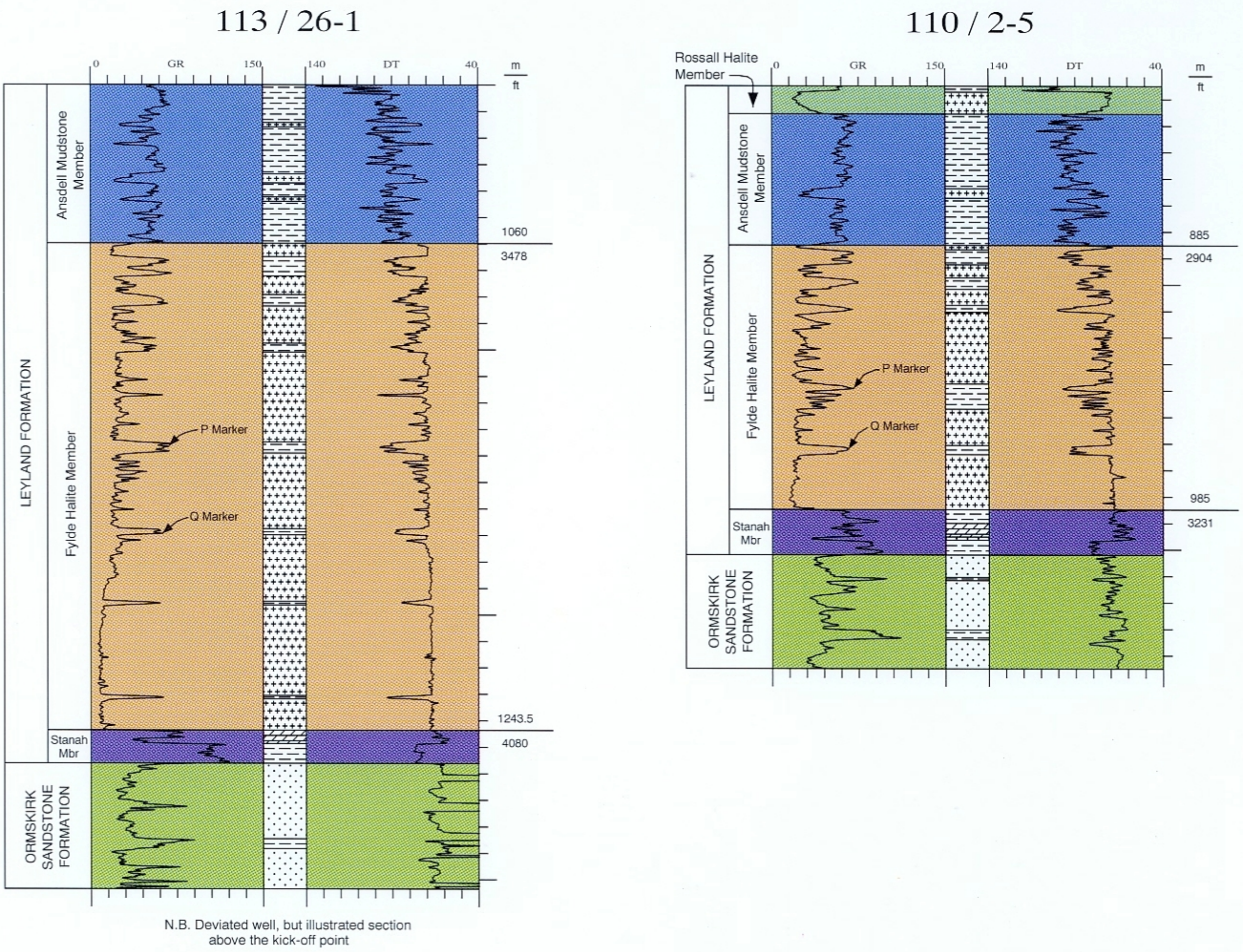
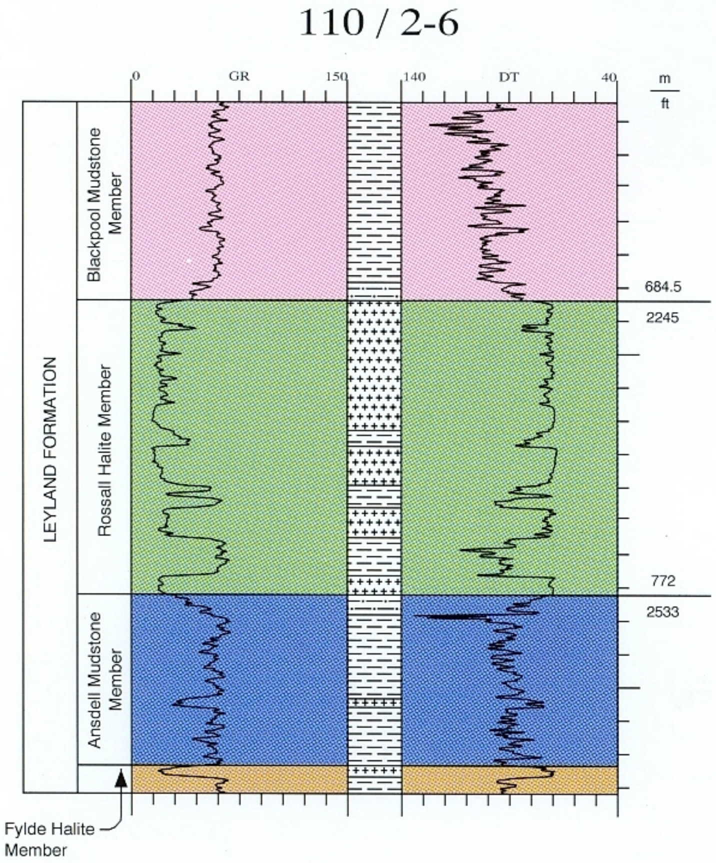


Figure 10 Example well sections through the Fylde Halite Member, East Irish Sea (from Jackson & Johnson 1996).



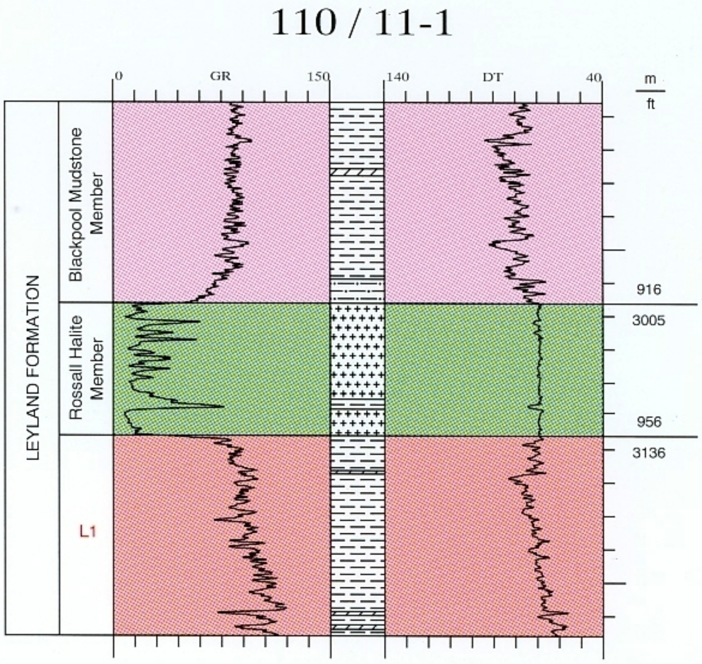


Figure 11 Example well sections through the Rossall Halite Member, East Irish Sea (from Jackson & Johnson 1996).

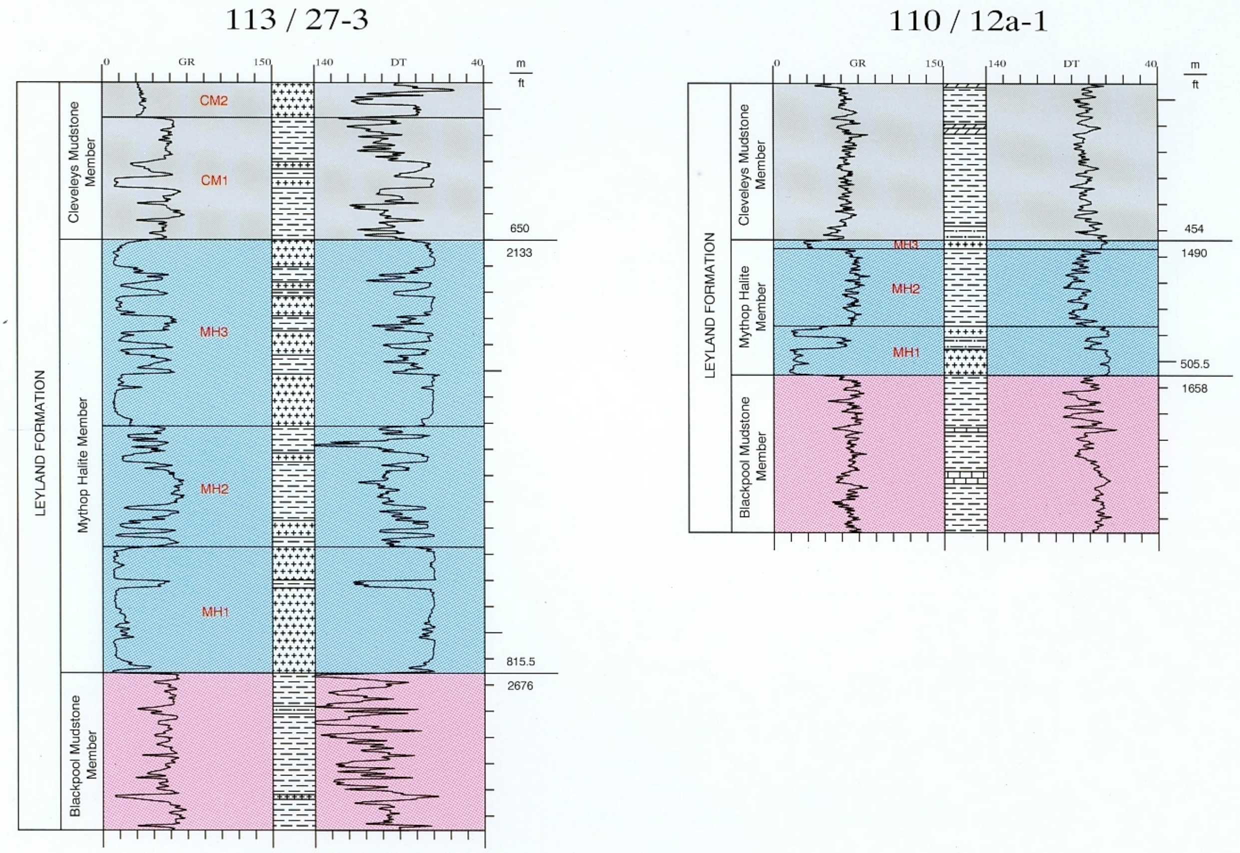


Figure 12 Example well sections through the Mythop Halite Member, East Irish Sea (from Jackson & Johnson 1996).

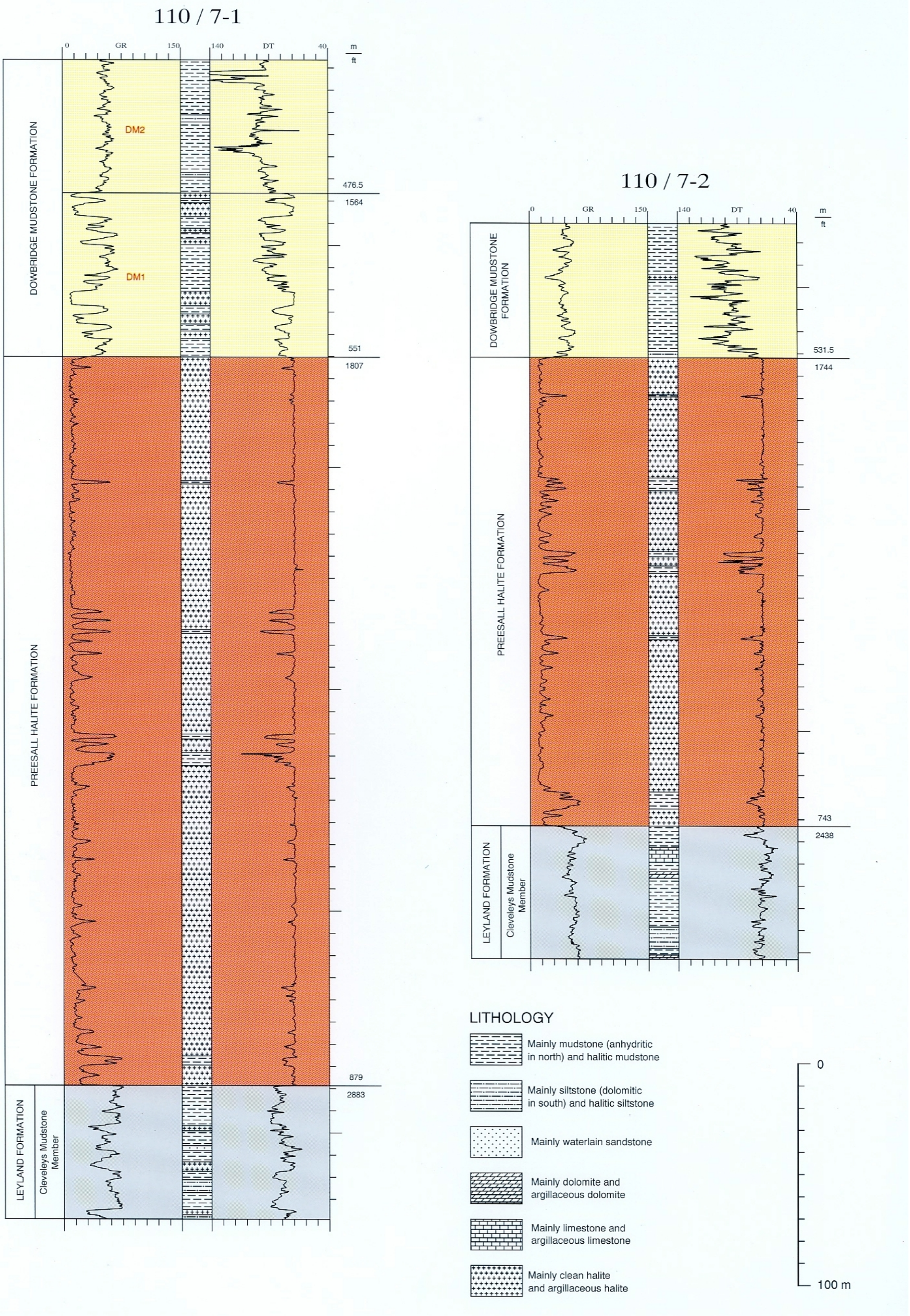


Figure 13a Example well sections through the Preesall Halite Formation, East Irish Sea (from Jackson & Johnson 1996).

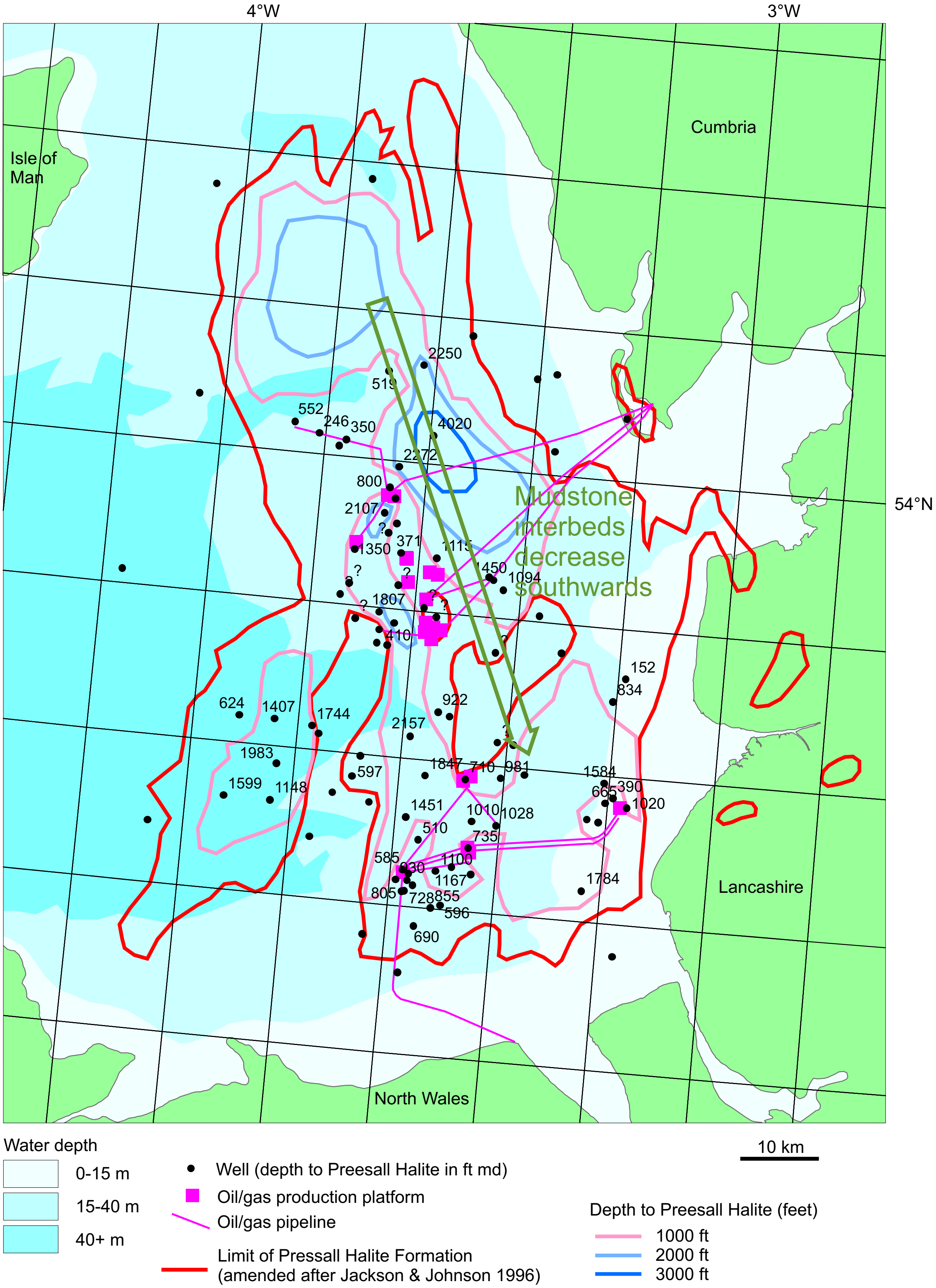


Figure 13b Summary information relating to the suitability of the Preesall Halite Formation for gas storage, East Irish Sea.

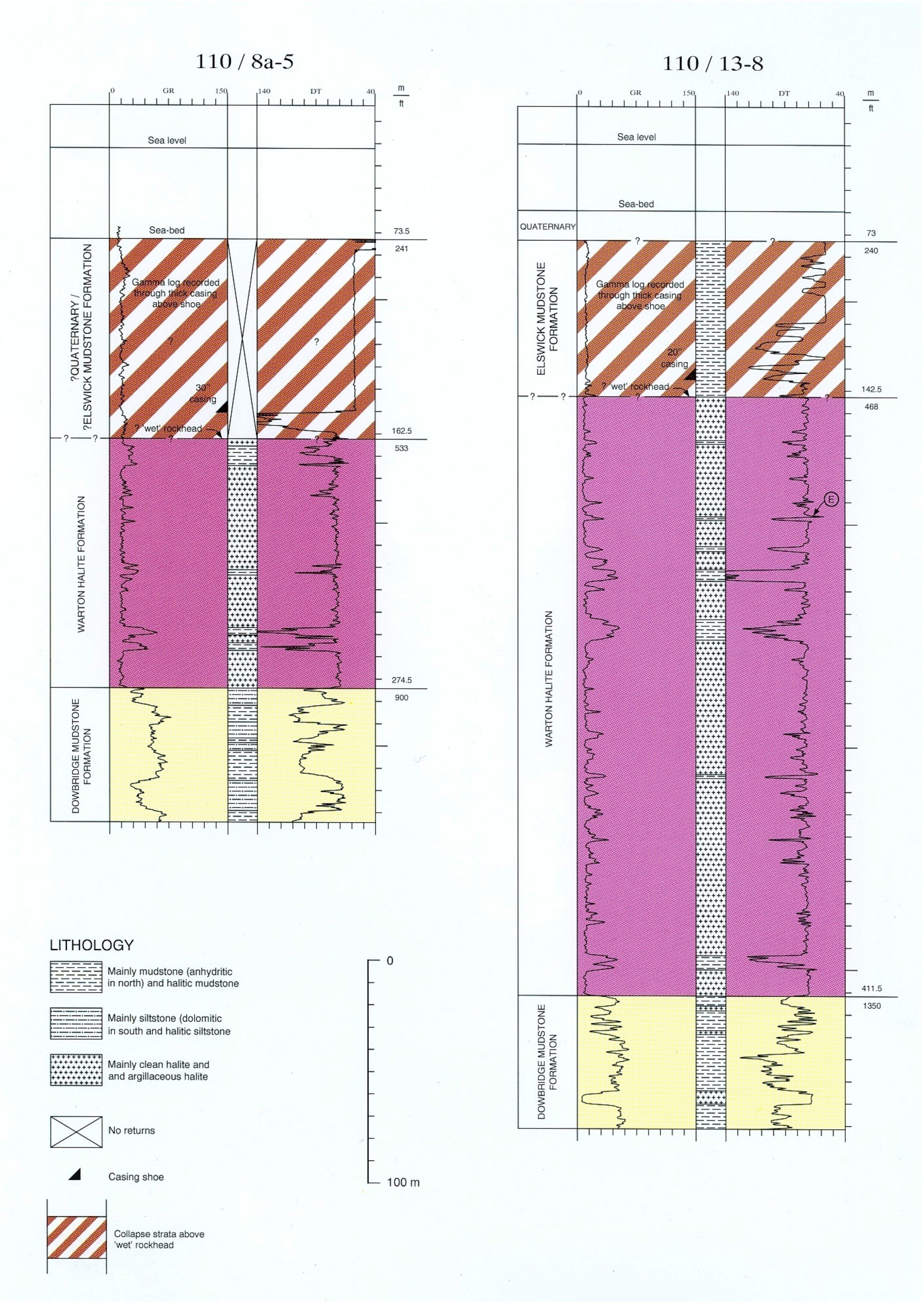
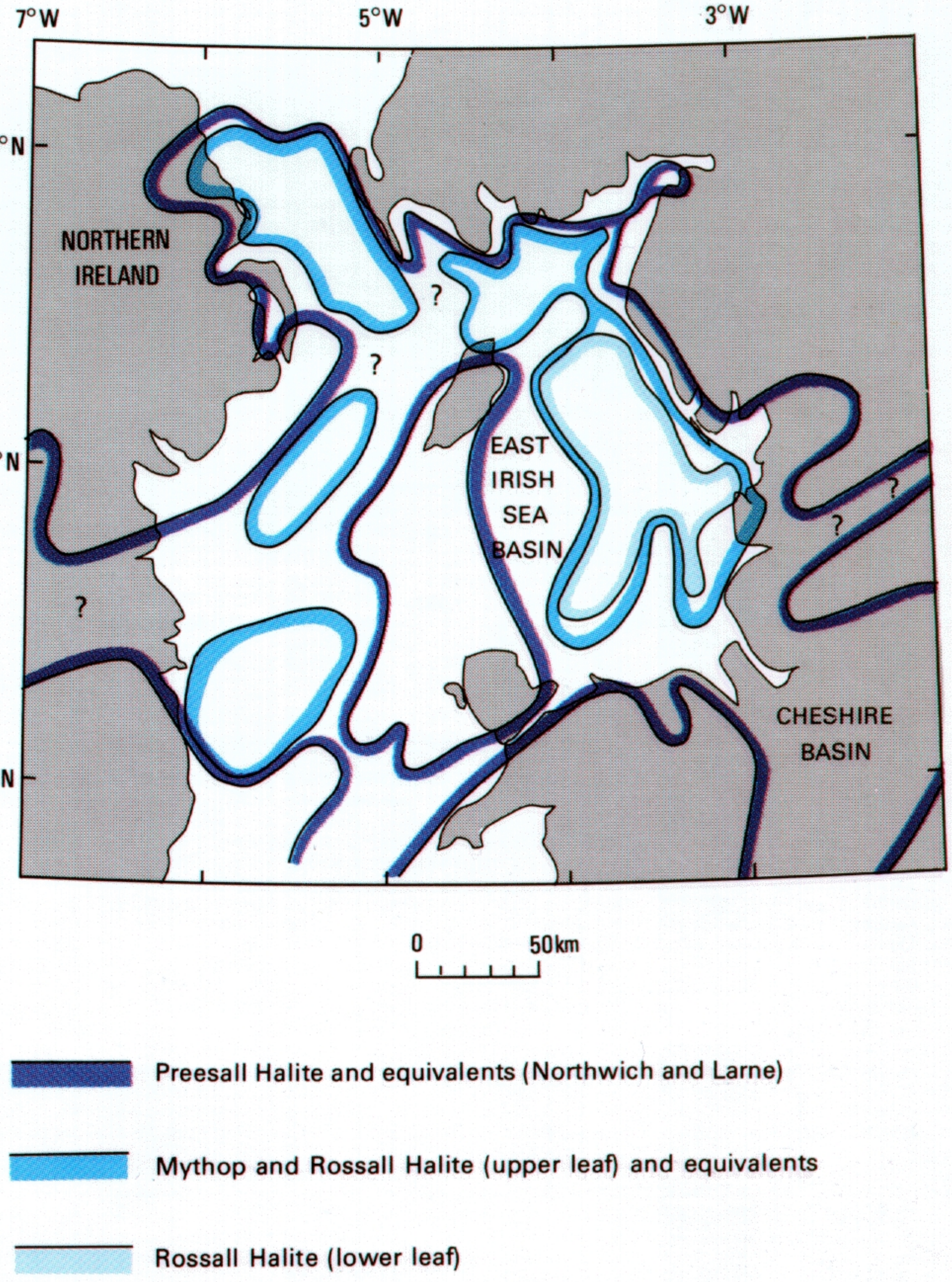


Figure 14 Example well sections through the Warton Halite Formation, East Irish Sea (from Jackson & Johnson 1996).



The Wilkesley Halite Formation (not shown) is present in the Cheshire Basin and has correlatives in basins farther south (Worcester and Wessex). It extends into the East Irish Sea Basin but a direct equivalent has not been identified in Northern Ireland.

Figure 15 Depositional limits of halites in and surrounding the East Irish Sea (from Jackson *et al*. 1995).

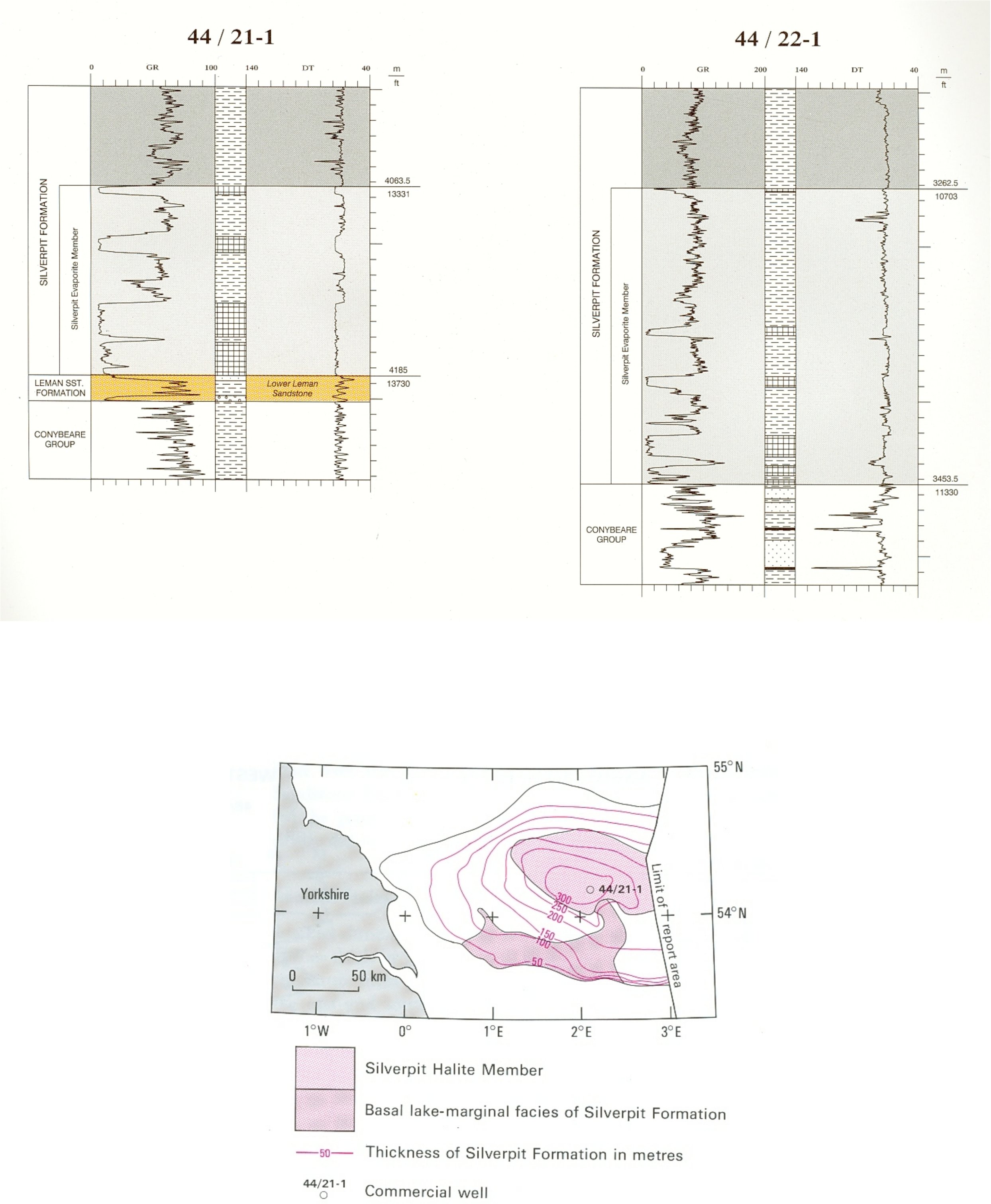


Figure 16 Well sections through the Silverpit Evaporite Member, Southern North Sea (Johnson *et al*. 1994) and its distribution and thickness (Cameron *et al*. 1992).

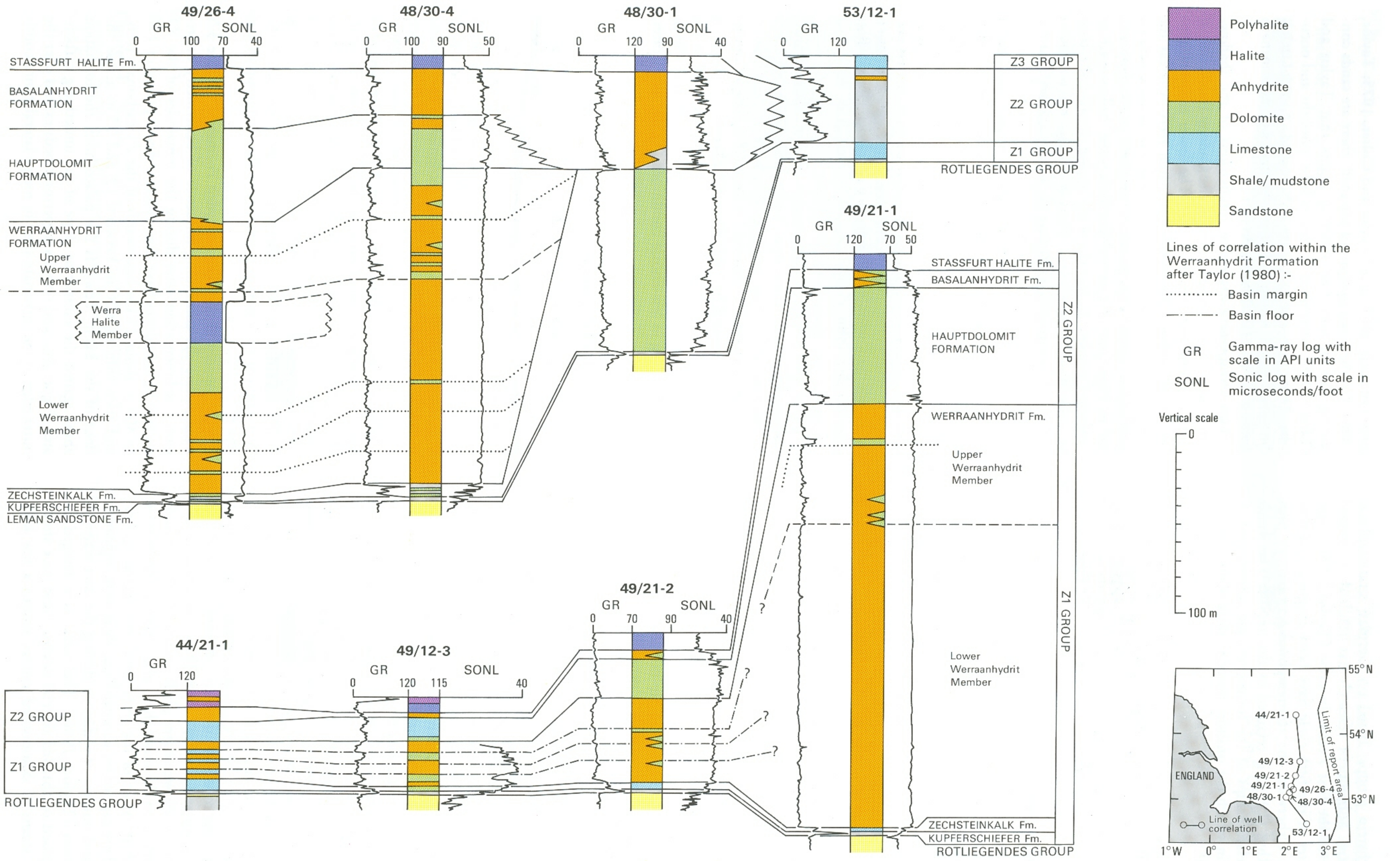


Figure 17 Correlation of carbonate and anhydrite formations in the Z1 and Z2 groups, Southern North Sea (from Cameron *et al*. 1992).

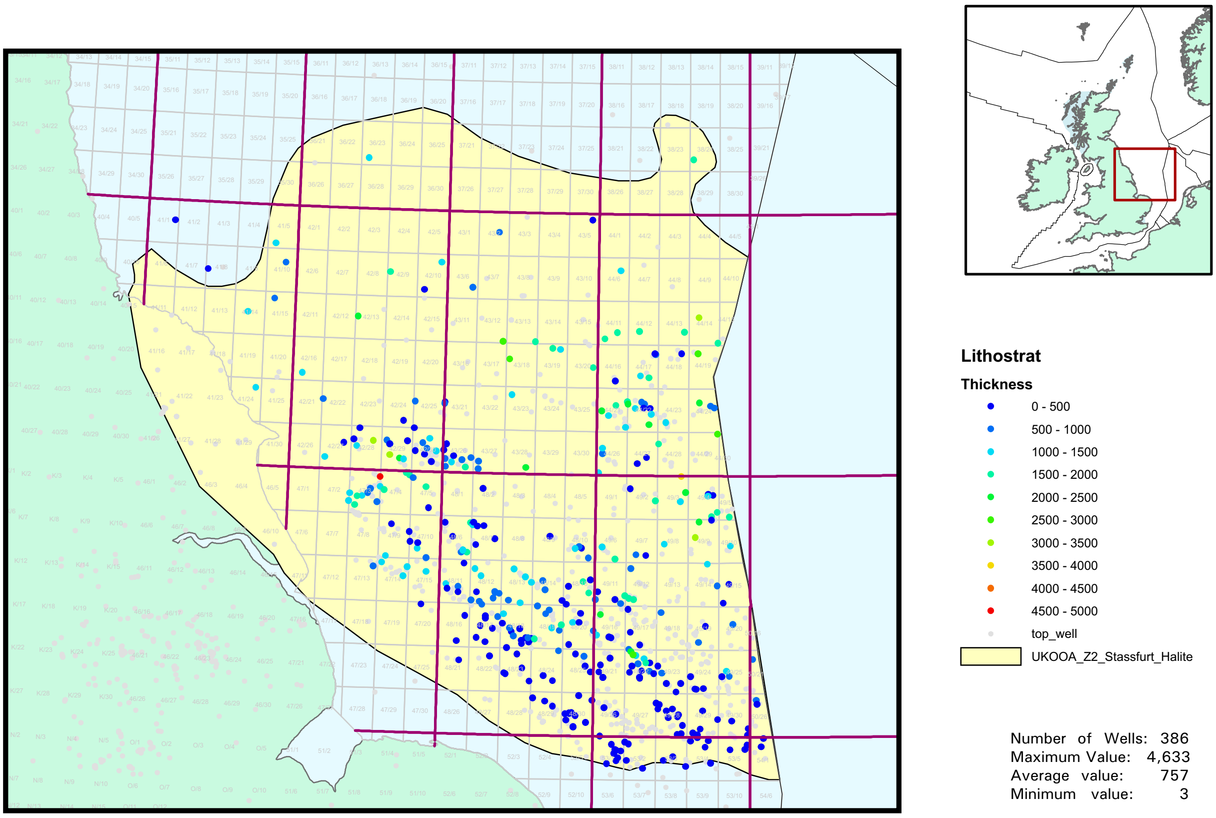


Figure 18 Distribution and thickness of the Stassfurt Halite Formation in the Z2 Group, Southern North Sea from WellStrat database.

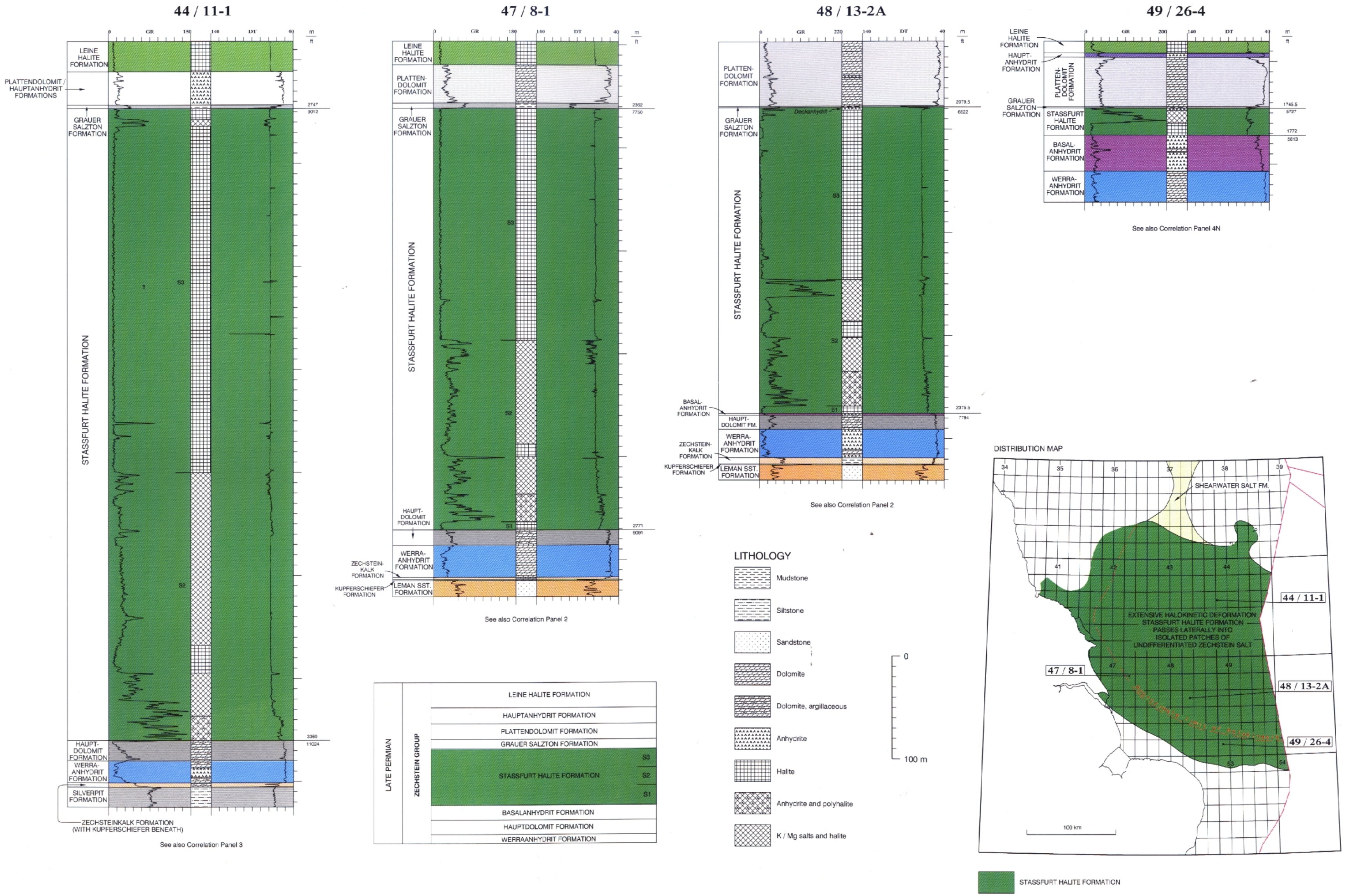


Figure 19 Stassfurt Halite distribution and correlation, Southern North Sea (from Johnson *et al*. 1994).

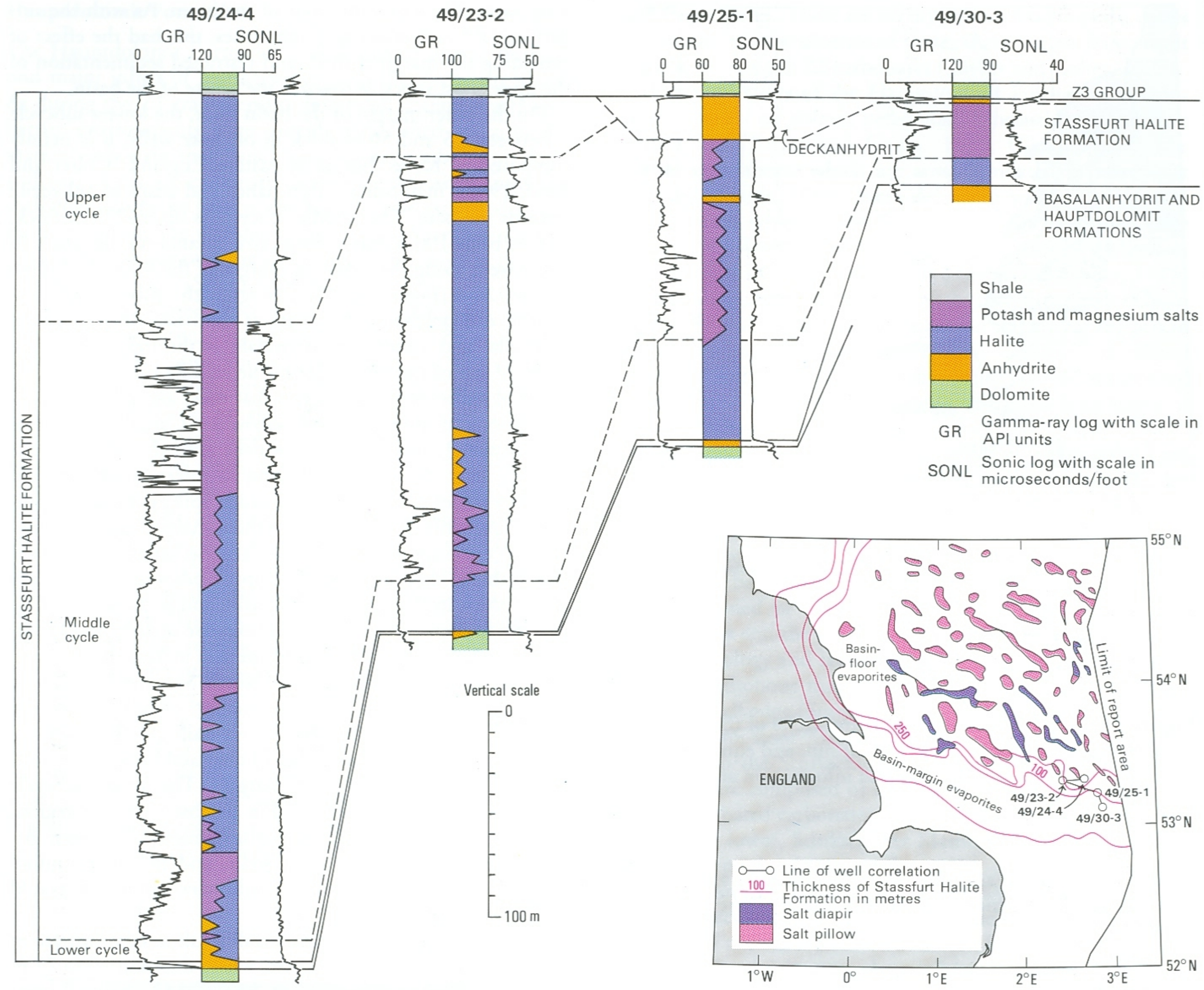


Figure 20 Well correlation of Z2 evaporite cycles on the southern margin of the Zechstein basin (from Cameron *et al*. 1992).

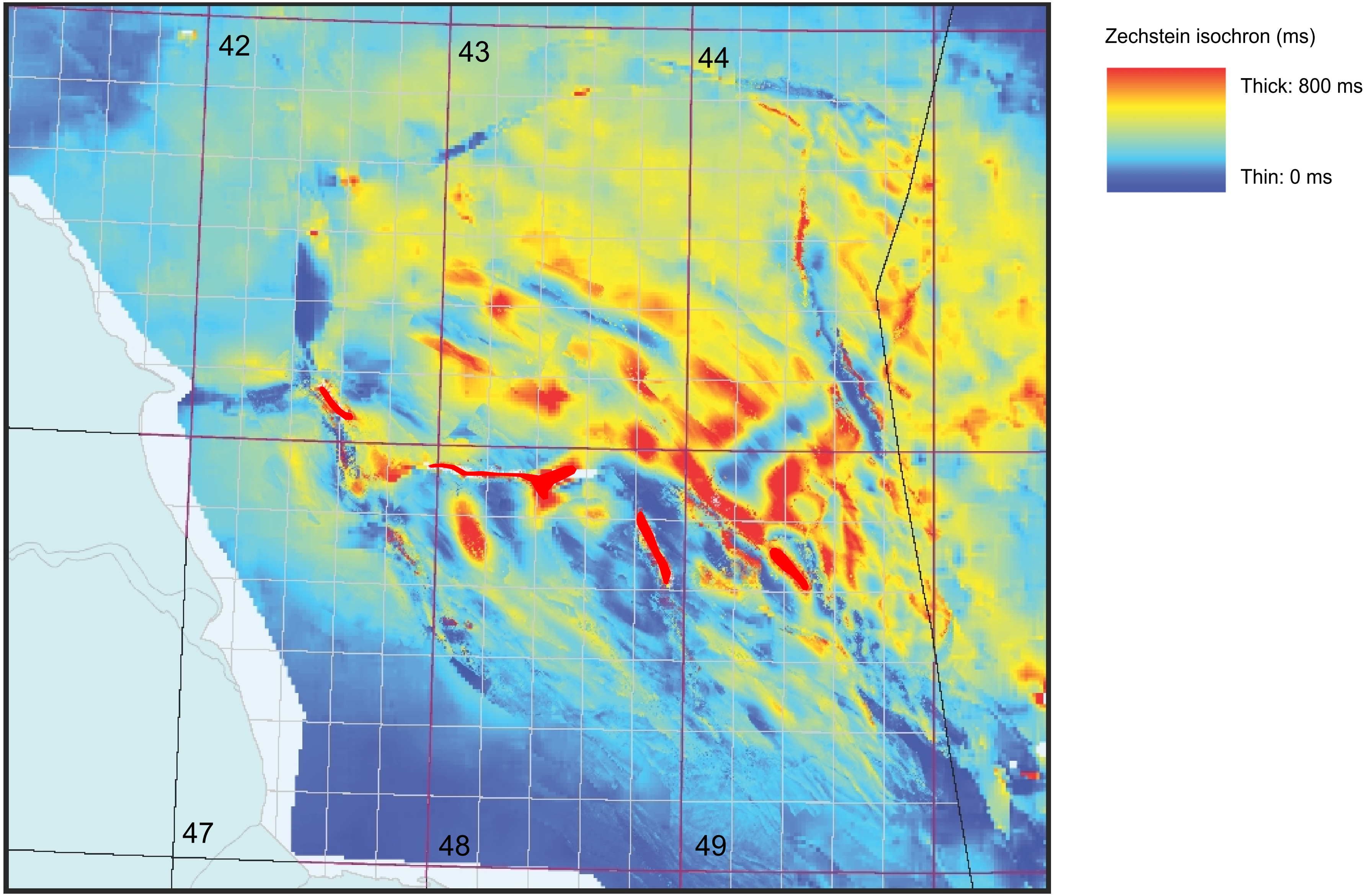


Figure 21 Total Zechstein isochron based on PGS North Sea Digital Atlas and interpretation of PGS MegaSurvey seismic data.

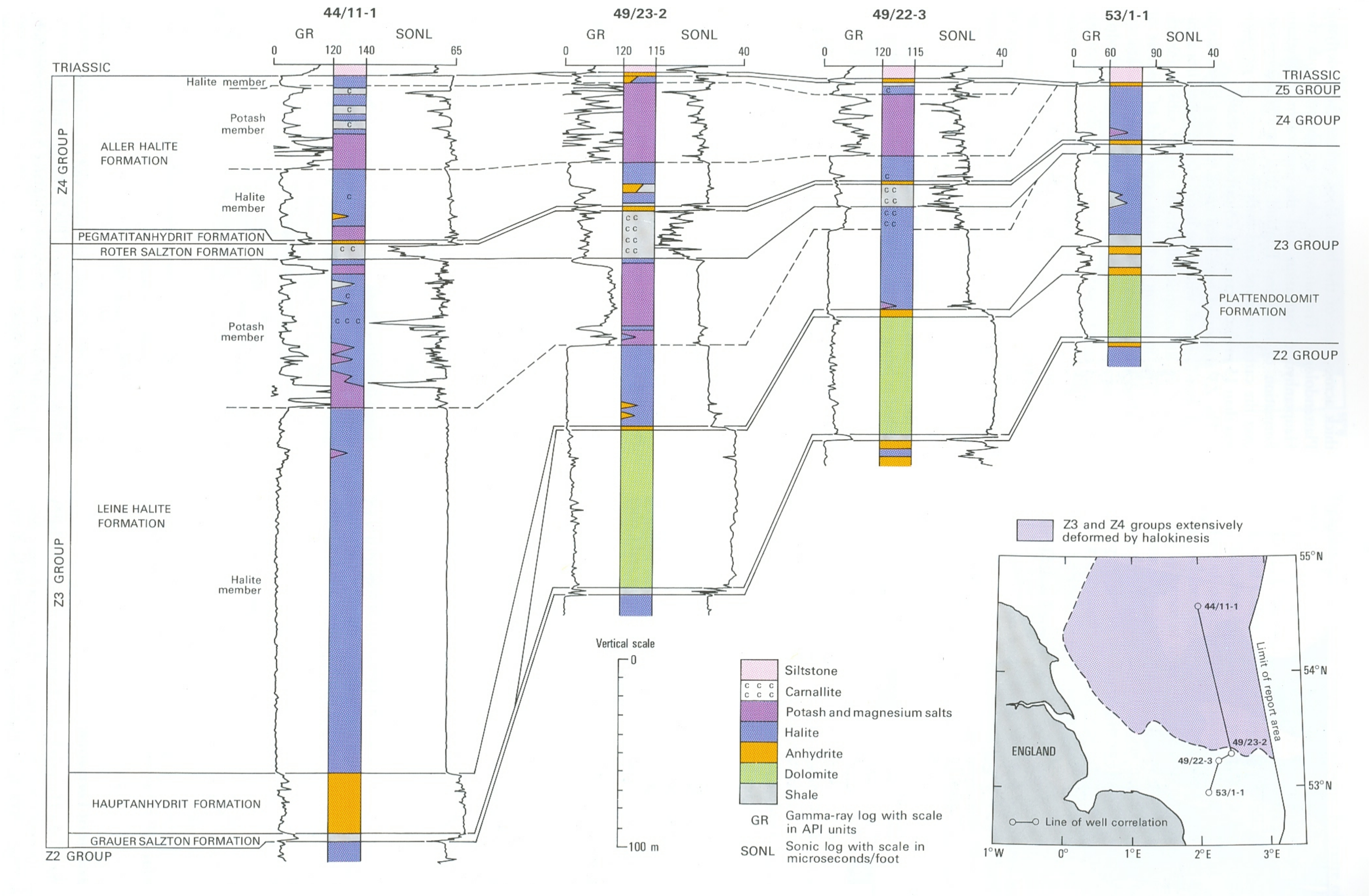


Figure 22 Well correlation of formations in the Z3, Z4 and Z5 groups, Southern North Sea (from Cameron *et al*. 1992).

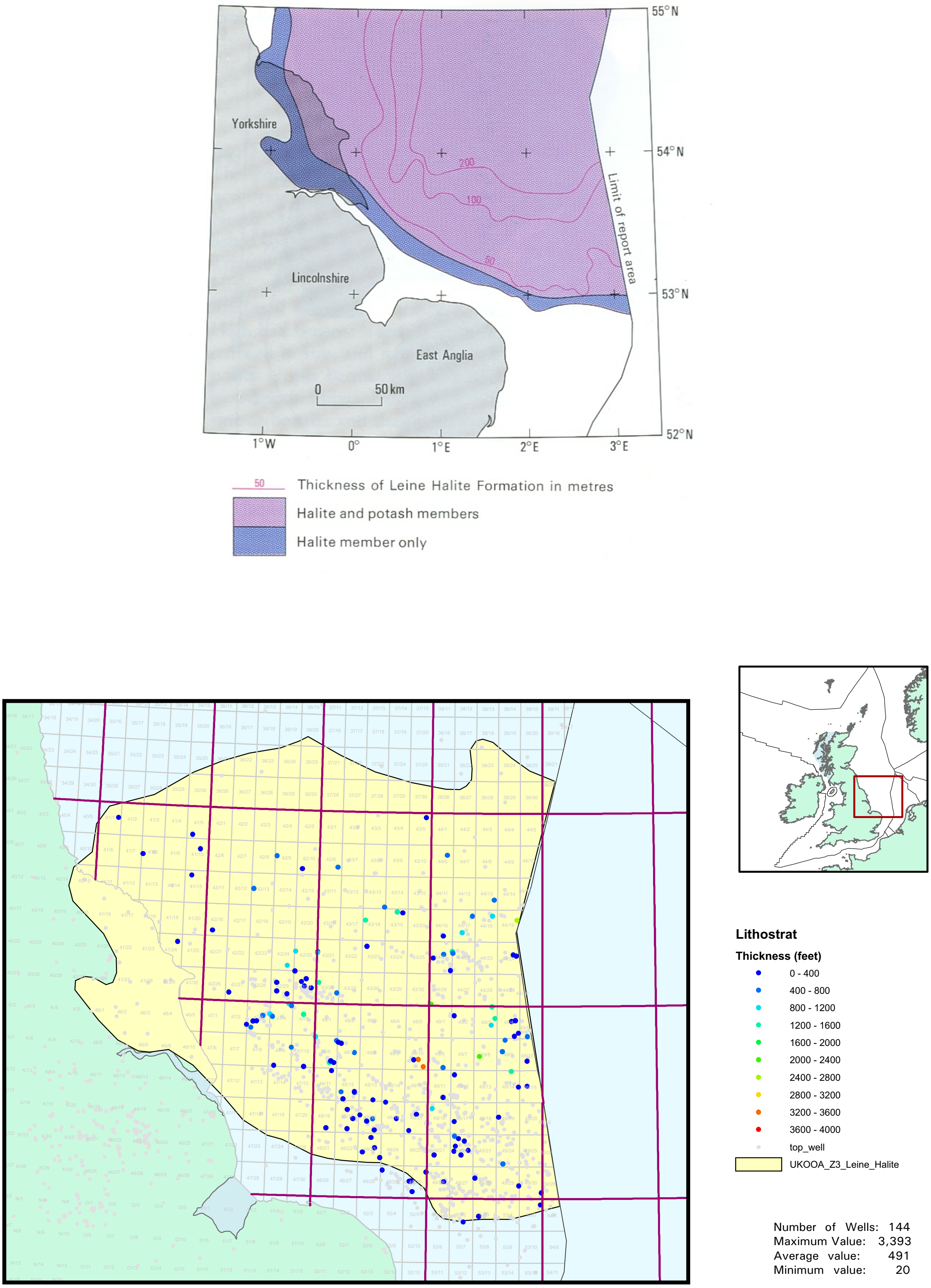


Figure 23 Distribution, thickness and lithology of the Leine Halite Formation in the Z3 Group, Southern North Sea (from Cameron *et al*. 1992) and from WellStrat database.

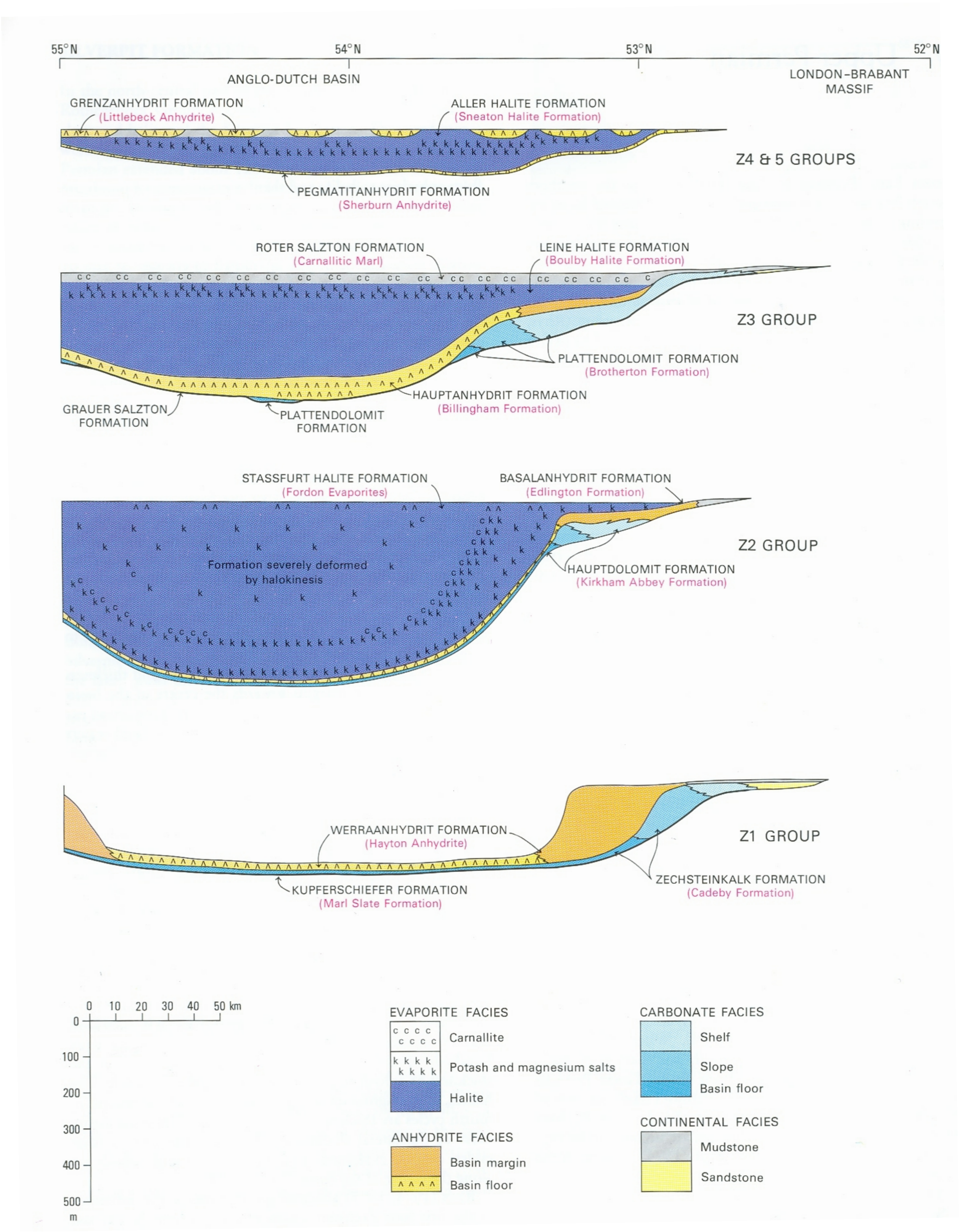


Figure 24 North-south sections showing successive cycles in the Upper Permian sediments of the Southern North Sea (from Cameron *et al*. 1992).

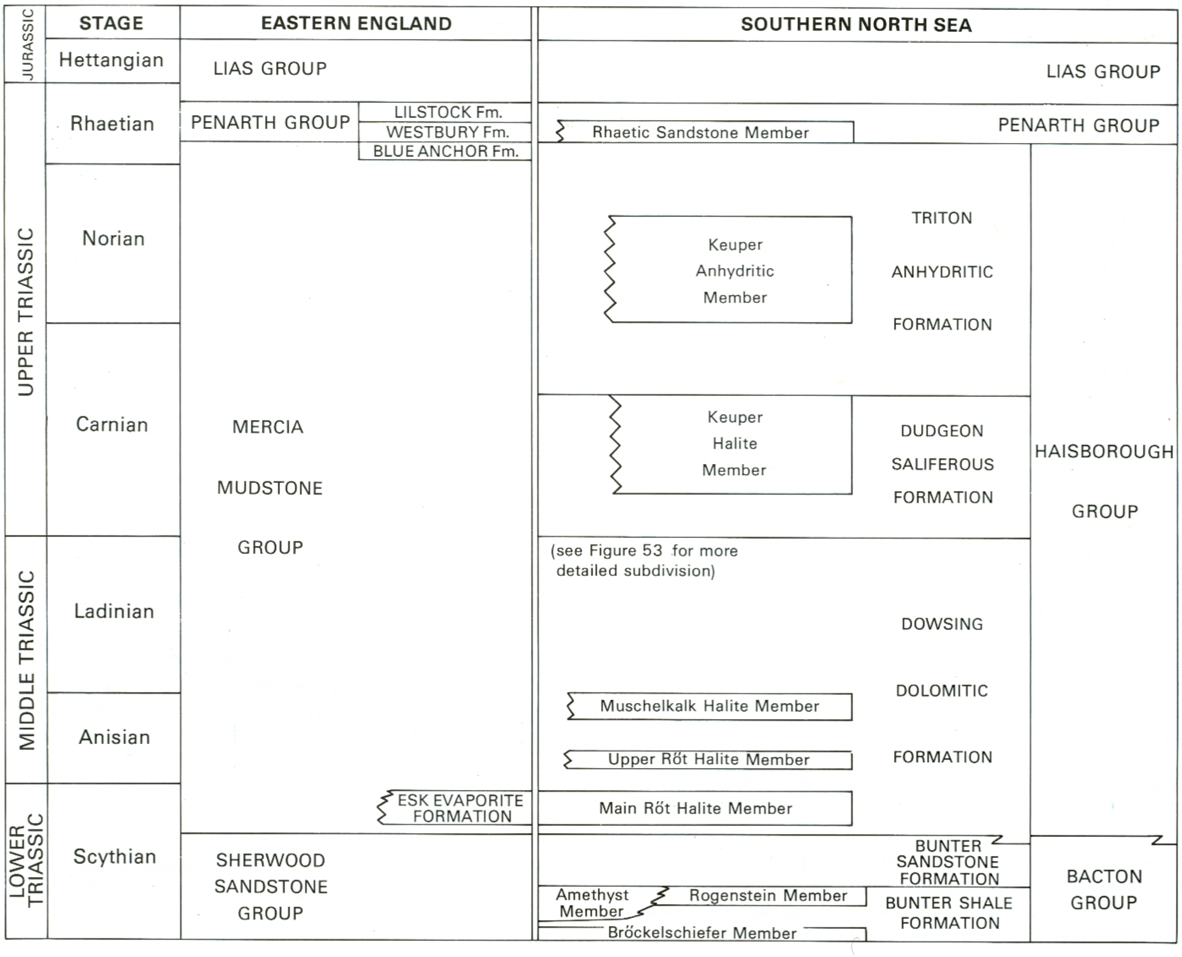
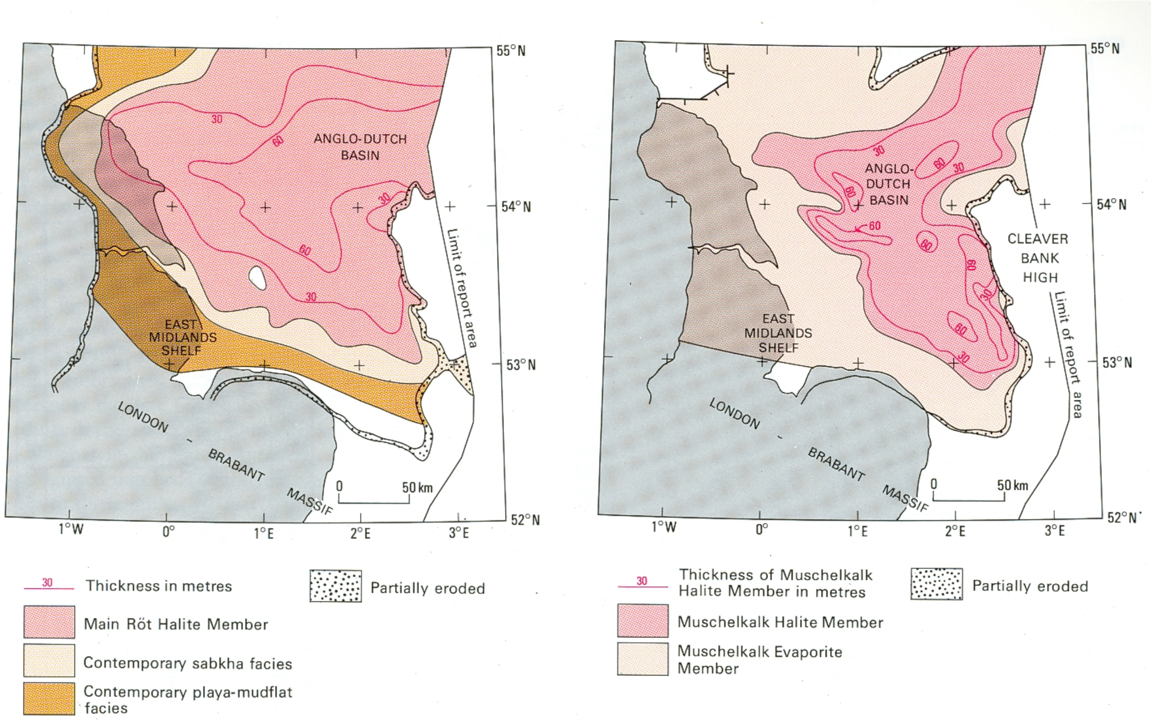
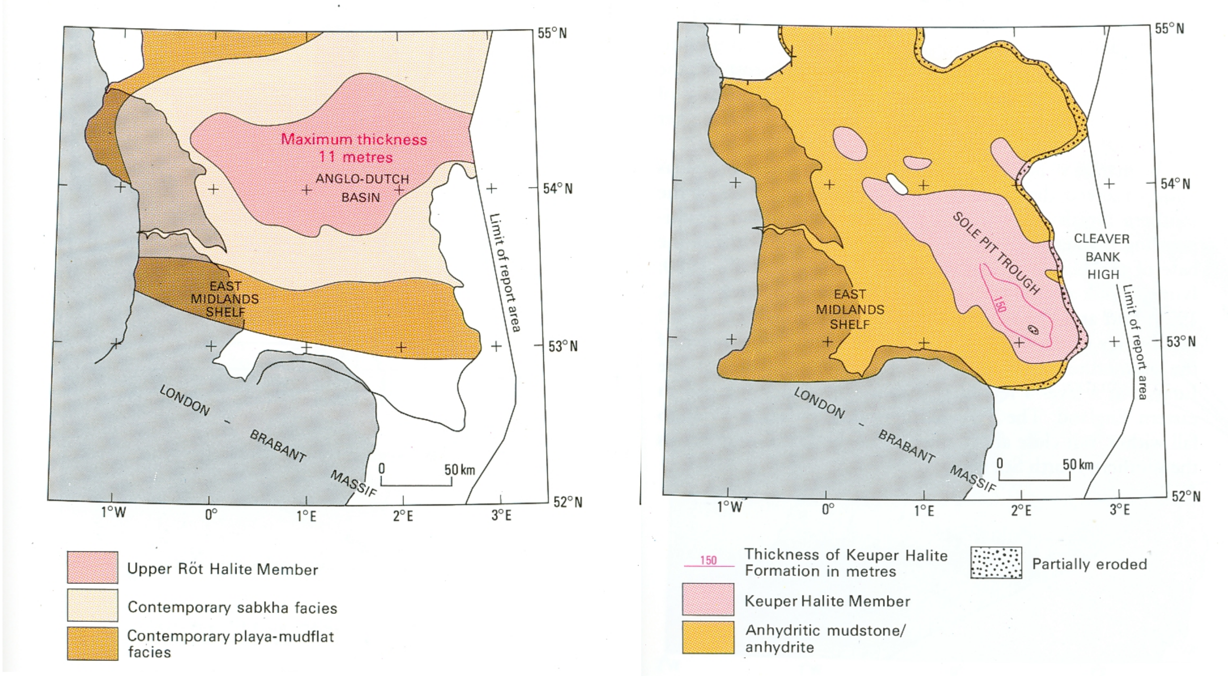


Figure 25 Triassic lithostratigraphy of eastern England and the Southern North Sea (from Cameron *et al*. 1992).



(a) Main Rot Halite

(c) Muschelkalk Halite & Evaporite



(b) Upper Rot Halite

(d) Keuper Halite Member

Figure 26 Distribution, thickness and facies of the Triassic salt units, Southern North Sea (from Cameron *et al*. 1992).

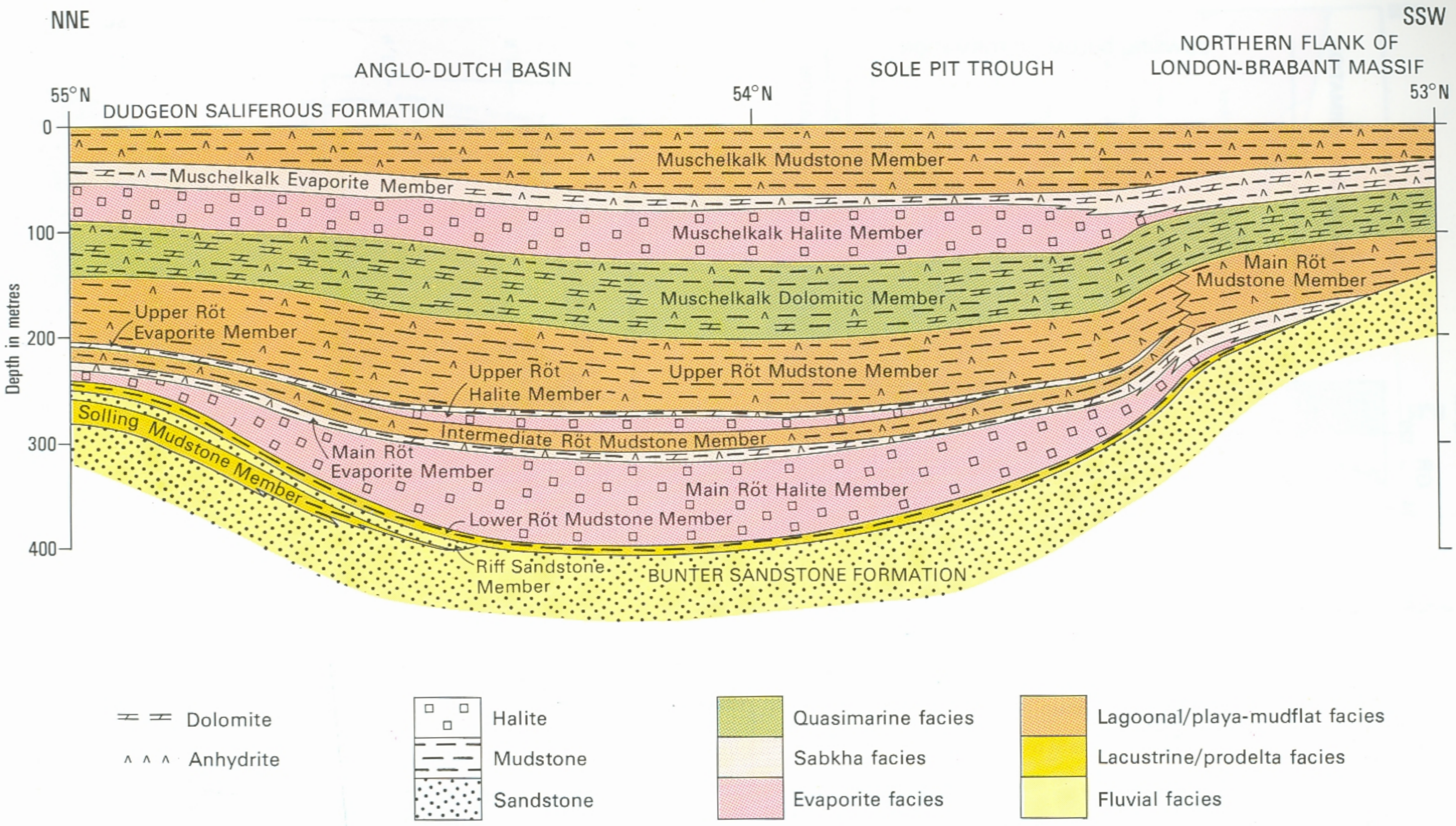


Figure 27 Schematic profile through the Dowsing Dolomitic Formation, Southern North Sea (from Cameron *et al*. 1992).

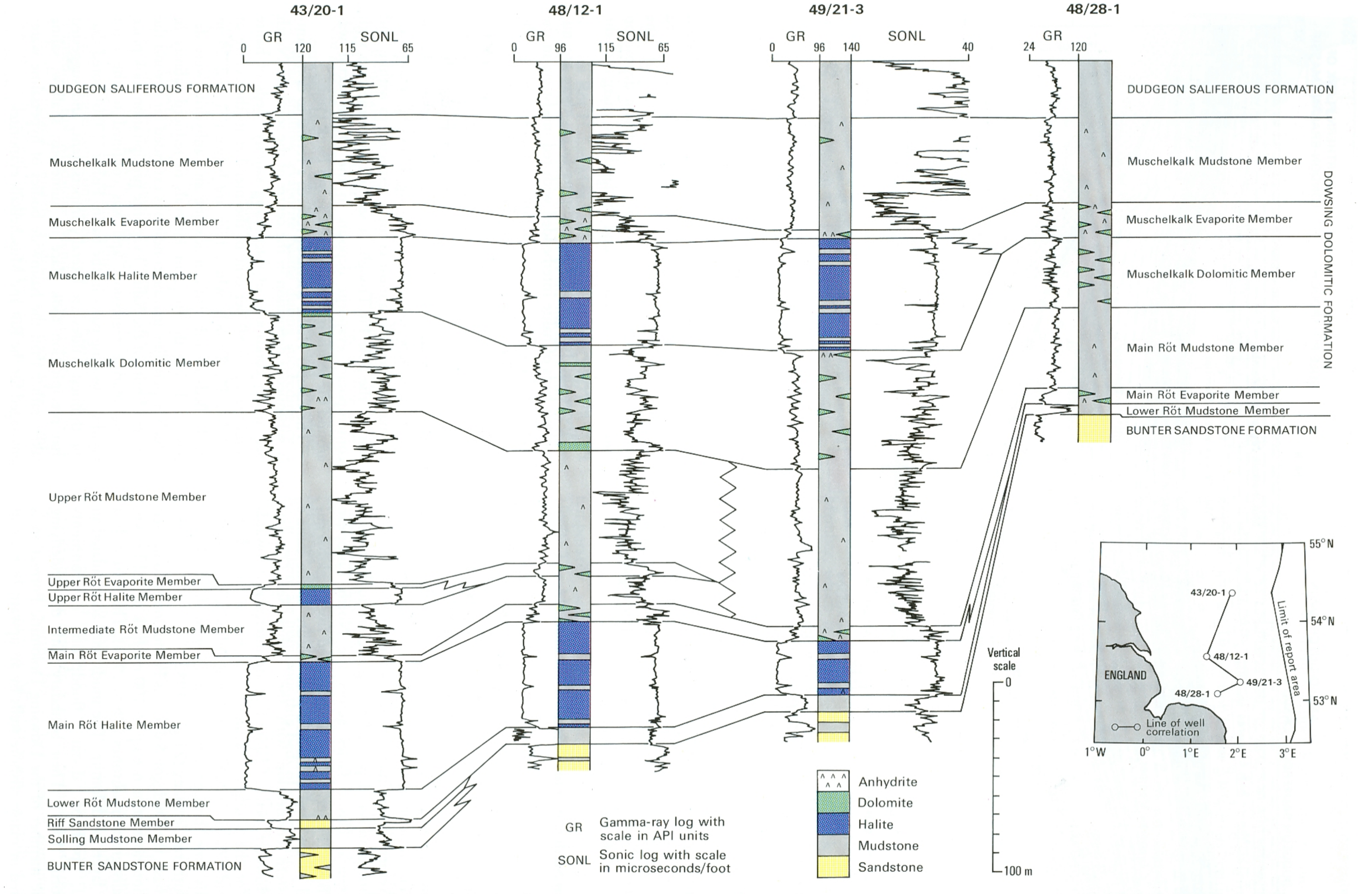


Figure 28 Correlation of the Dowsing Dolomitic Formation, Southern North Sea (from Cameron *et al*. 1992).

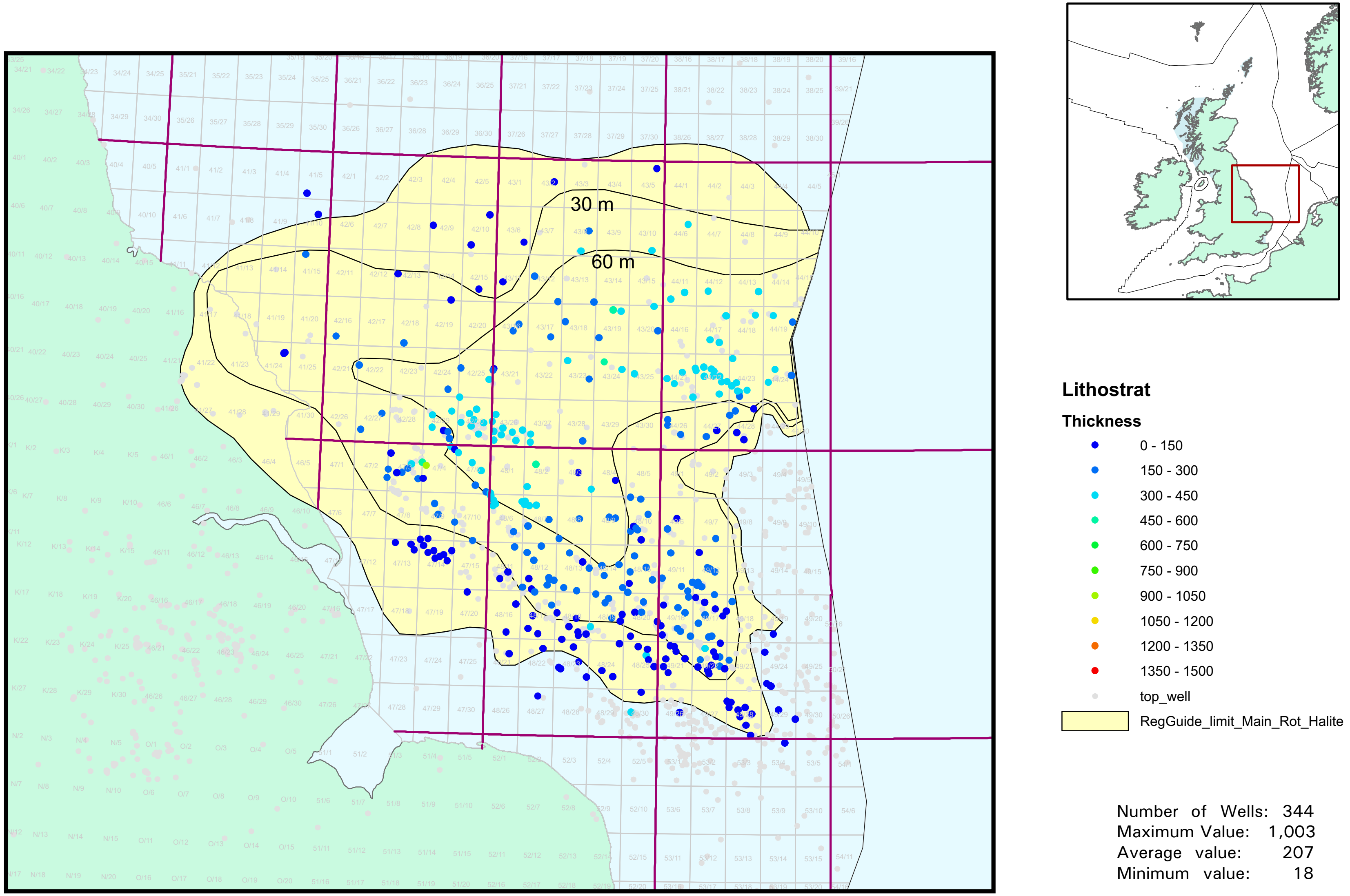


Figure 29 Distribution and thickness of the Main Rot Halite, Southern North Sea (limit and isopach from Cameron *et al*. 1992).

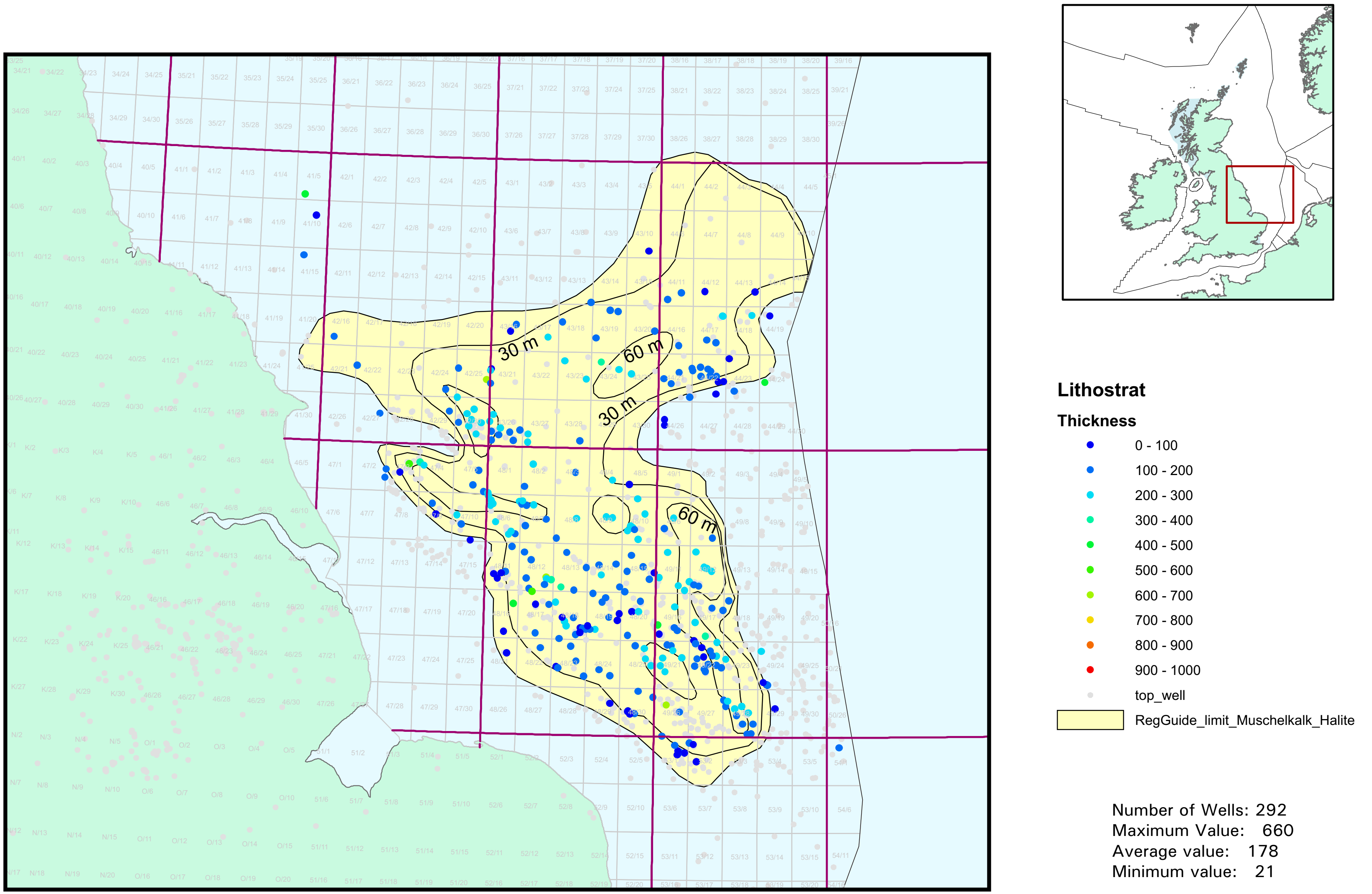


Figure 30 Distribution and thickness of the Muschelkalk Halite, Southern North Sea (limit and isopach from Cameron *et al*. 1992).

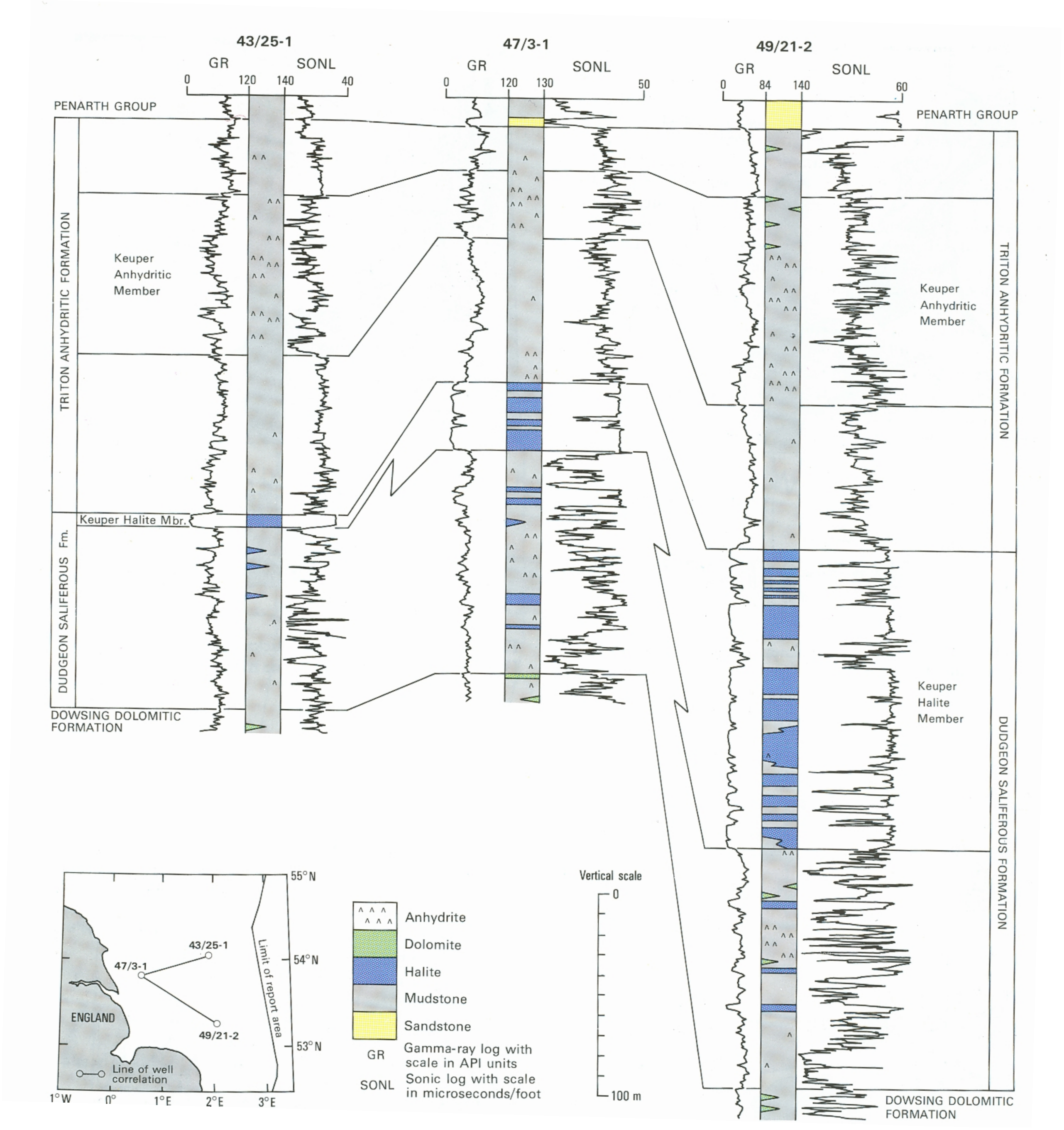
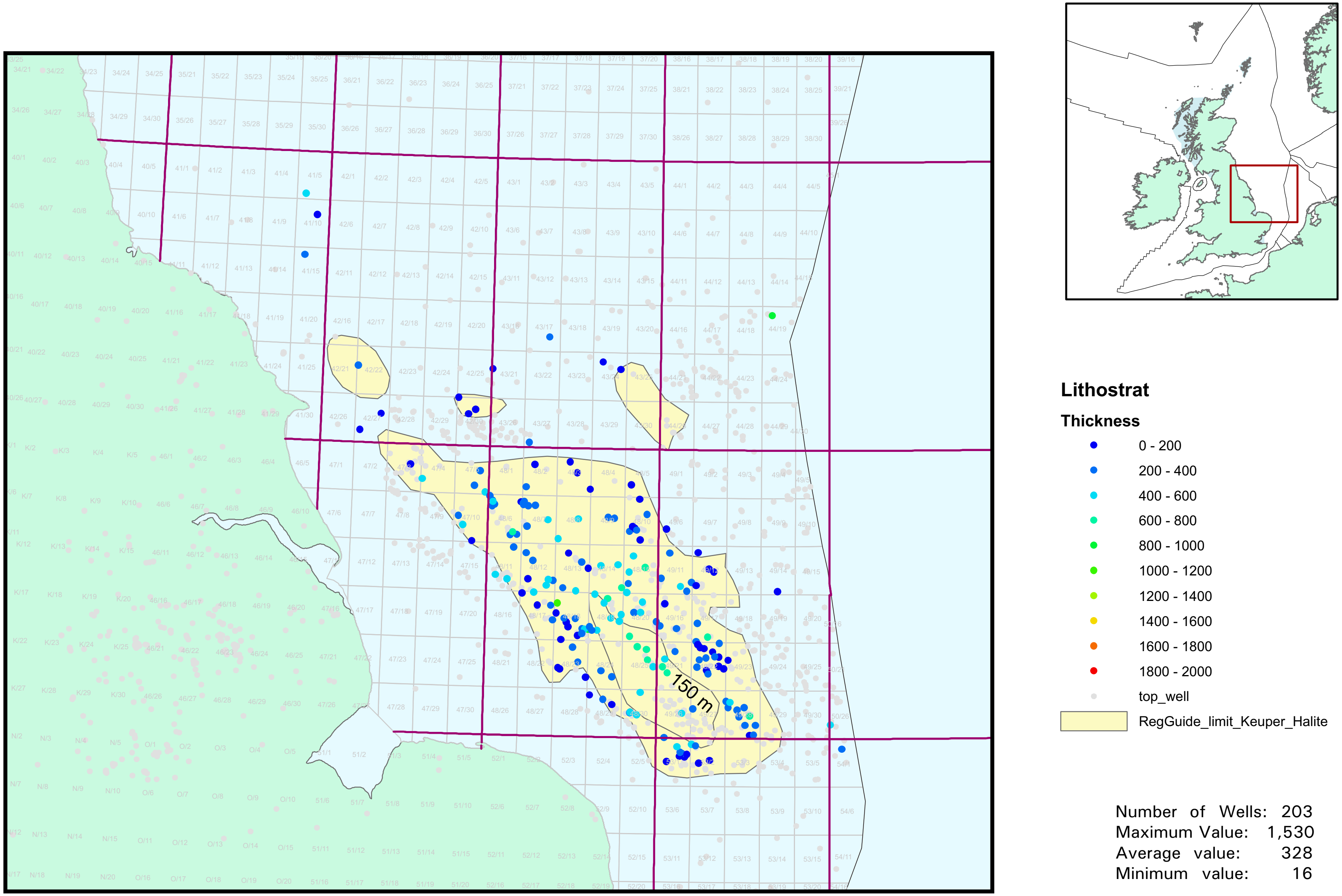


Figure 31 Correlation of the Dudgeon Saliferous Formation, Southern North Sea (from Cameron *et al*. 1992).



Number of Wells: 203
Maximum Value: 1,530
Average value: 328
Minimum value: 16

Figure 32 Distribution and thickness of the Keuper Halite, Southern North Sea (limit and isopach from Cameron *et al*. 1992).

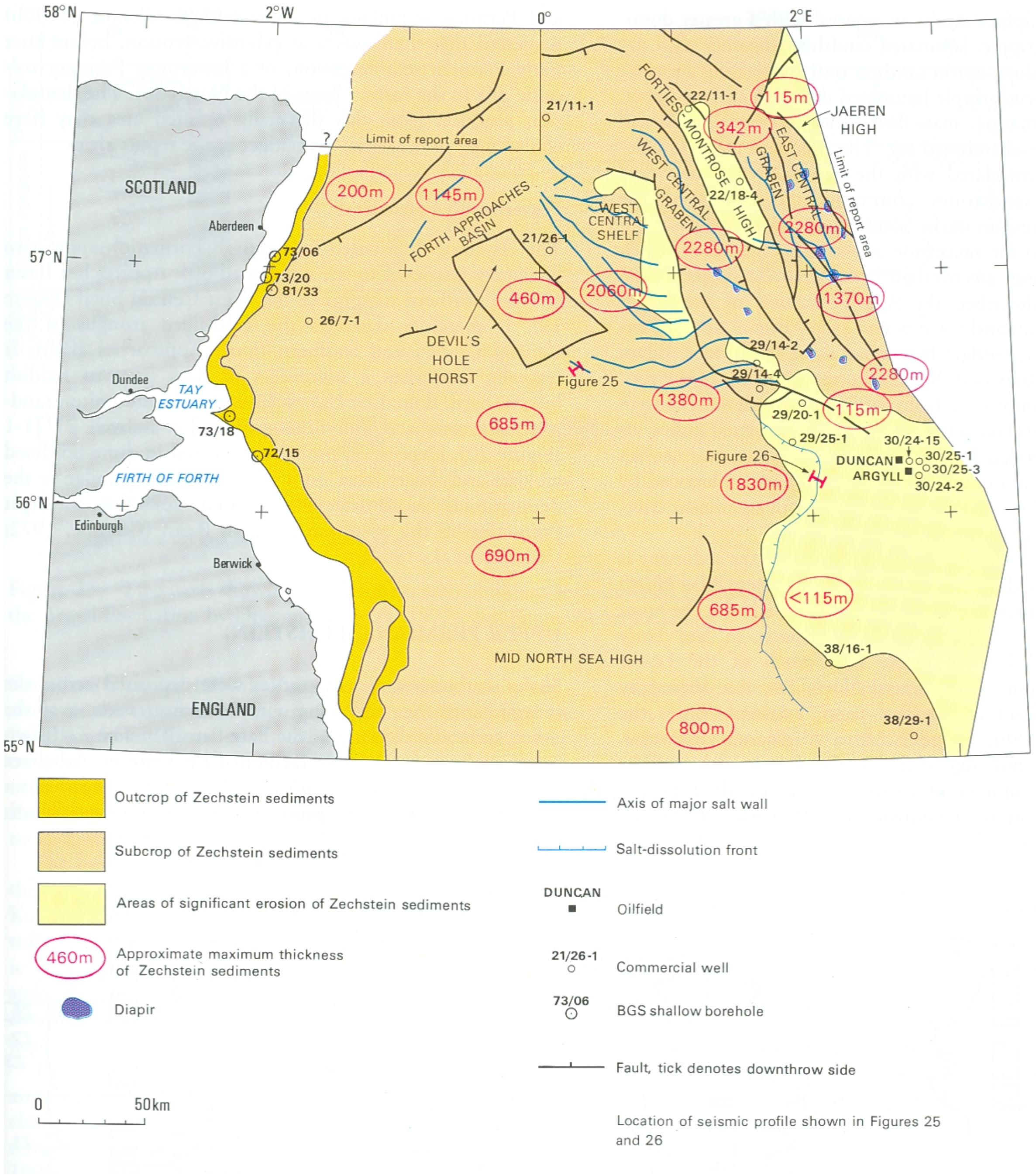


Figure 33 Distribution and thickness of Upper Permian sediments, Central North Sea (from Gatliff *et al*. 1994).

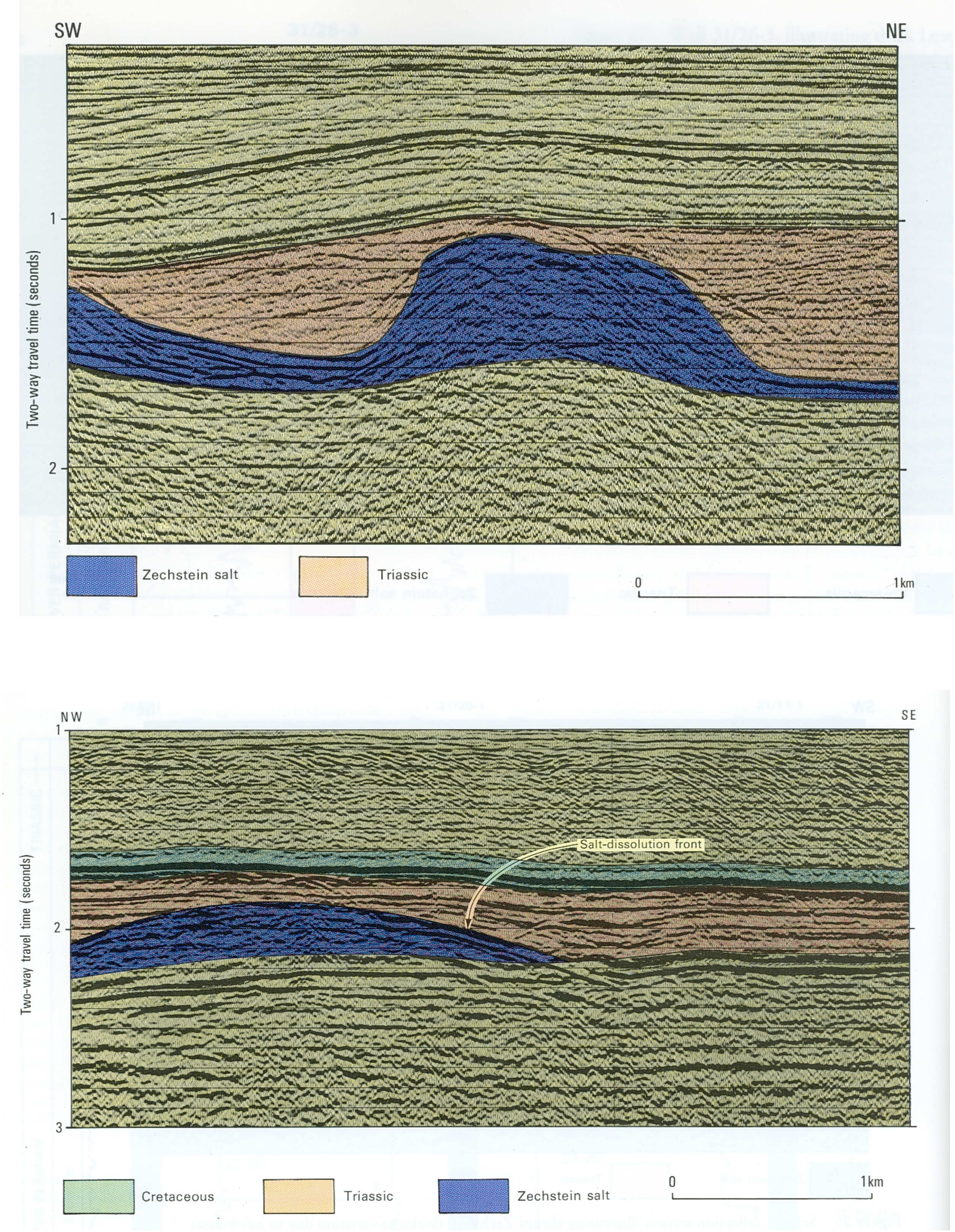


Figure 34 Seismic sections illustrating (a) abrupt thickness variation due to halokenesis in the Central North Sea and (b) the N-S trending salt dissolution front that runs across the Mid North Sea High (from Gatliff *et al*. 1994).

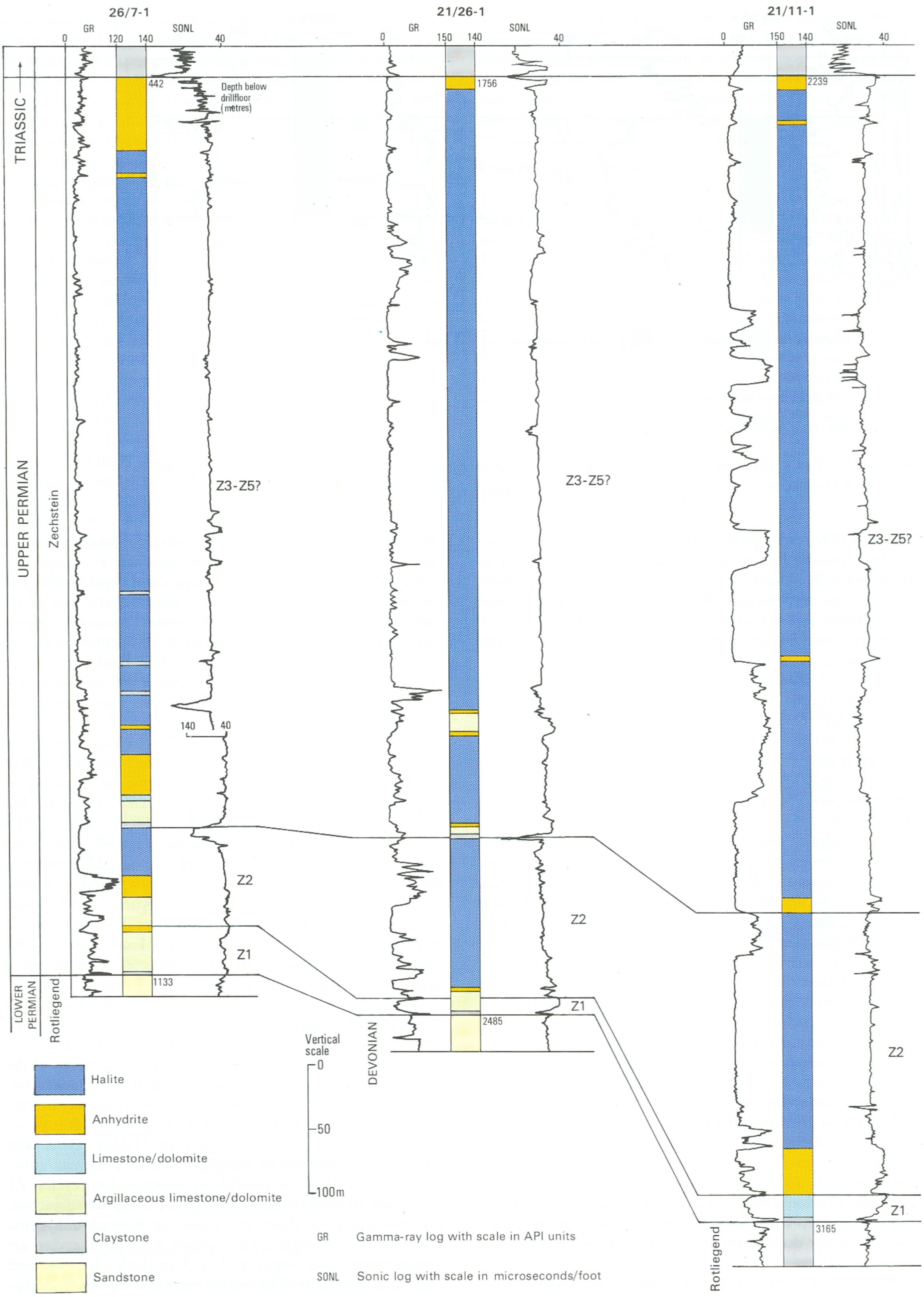


Figure 35 Selected wells showing Zechstein successions with thick halites and their subdivisions into cycles of Upper Permian sediments, Central North Sea (from Gatliff *et al*. 1994).

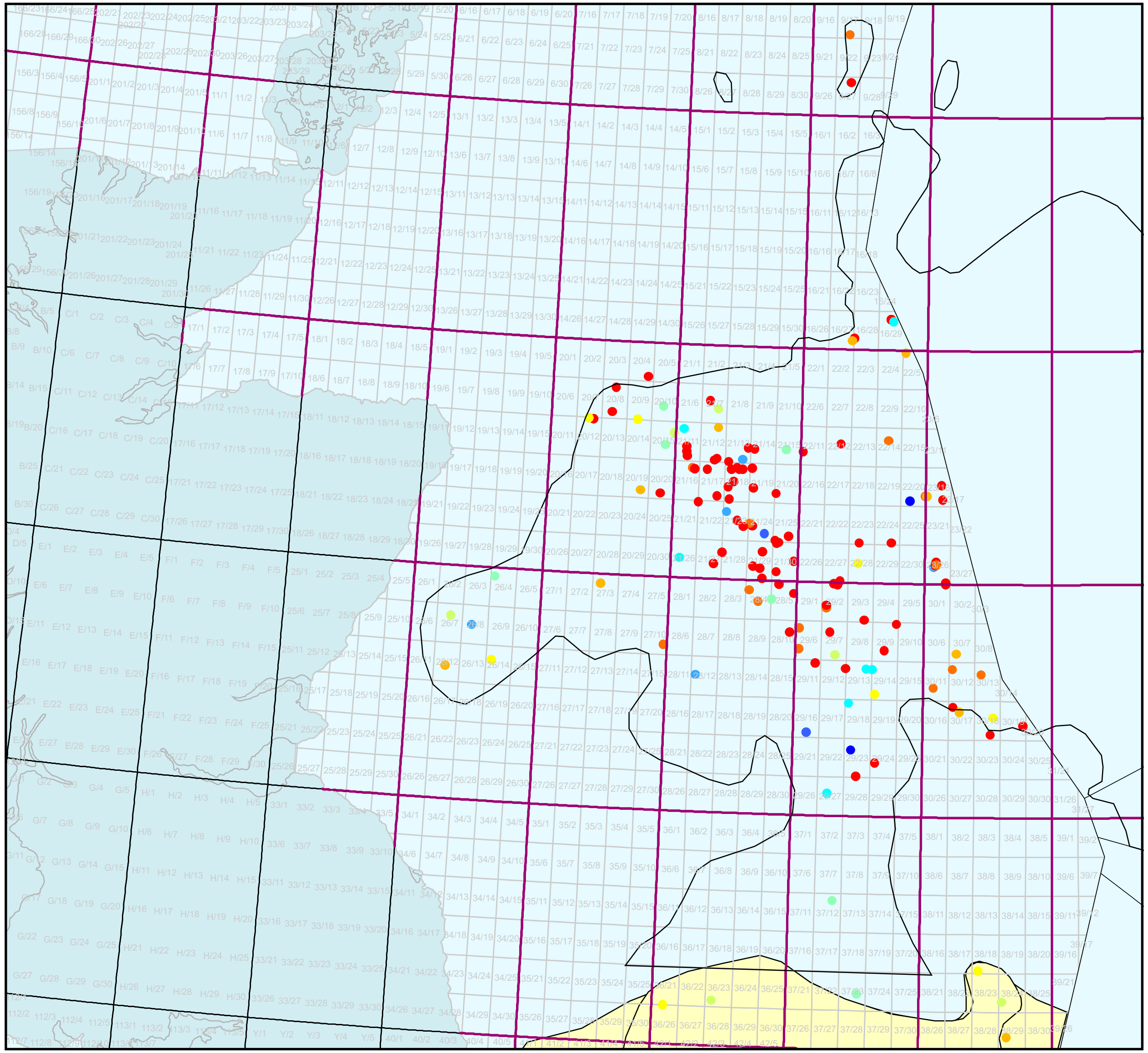


Figure 36 Total salt thickness, Central North Sea (black line = limit of Shearwater Salt Formation from Evans *et al*. 2003).

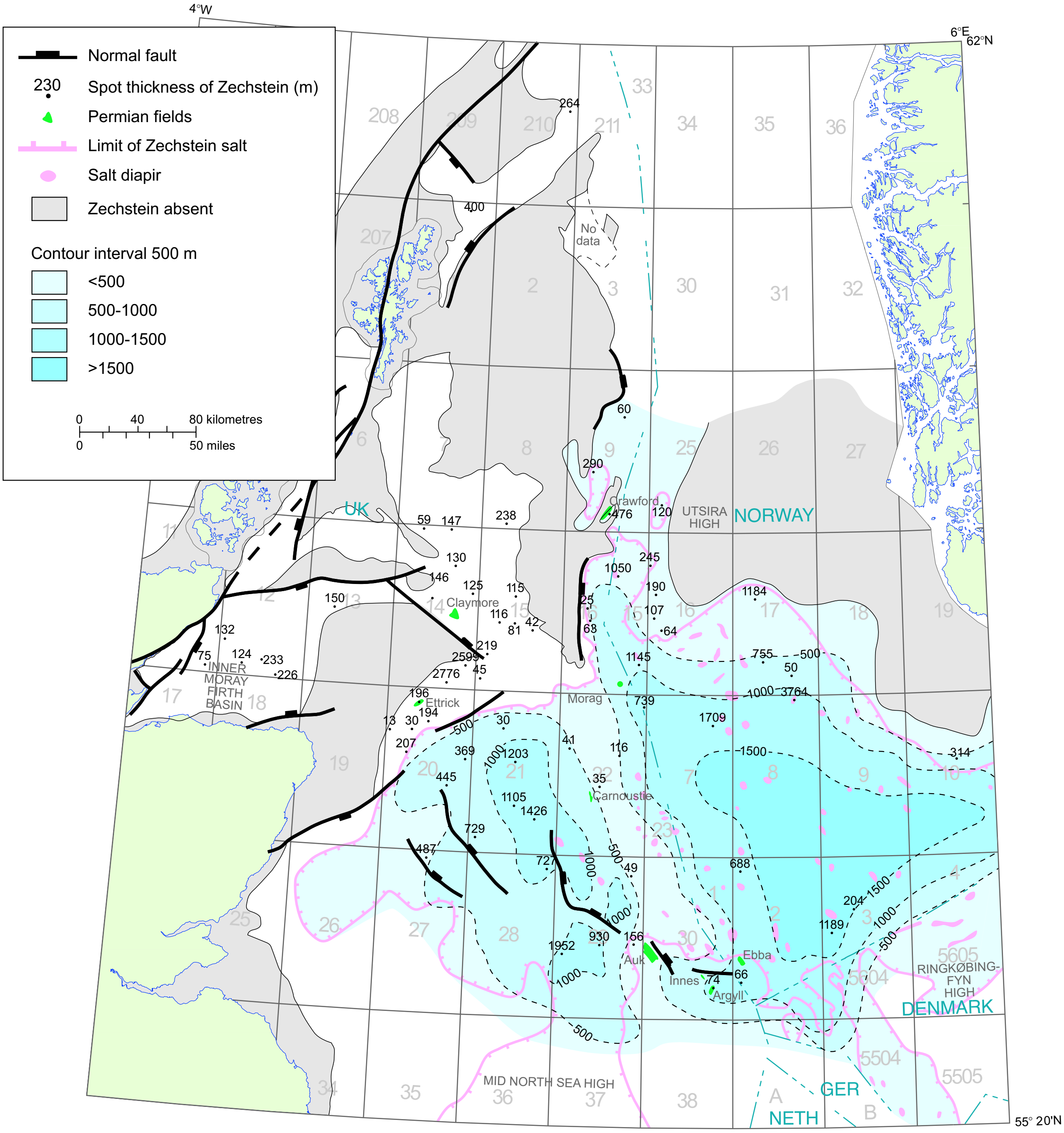


Figure 37 Thickness and distribution of Upper Permian, Central and Northern North Sea (Evans *et al*. 2003)

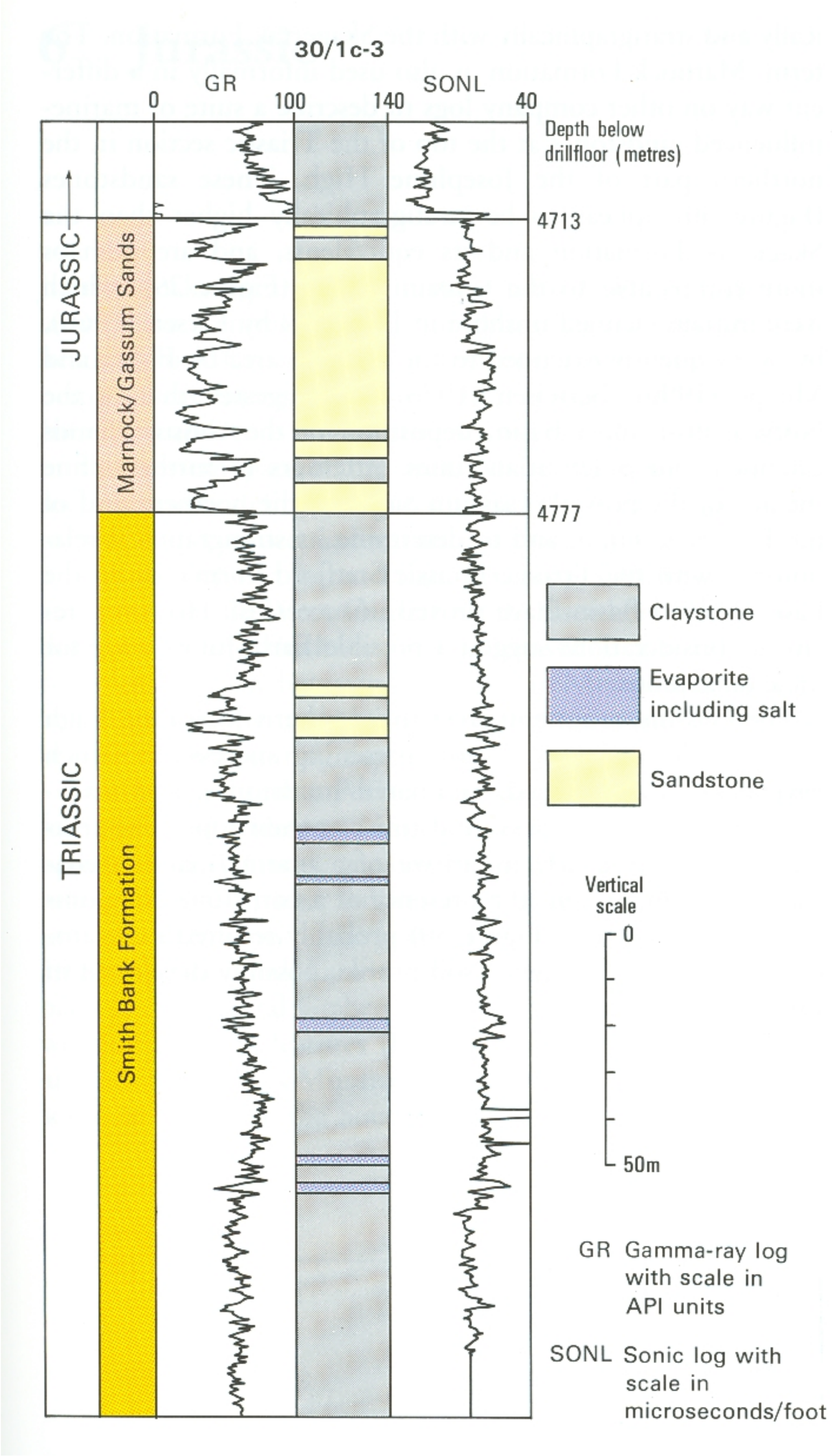


Figure 38 Thin salts within the Smith Bank Formation. Well 30/1c-3, Central North Sea (from Gatliff *et al*. 1994).

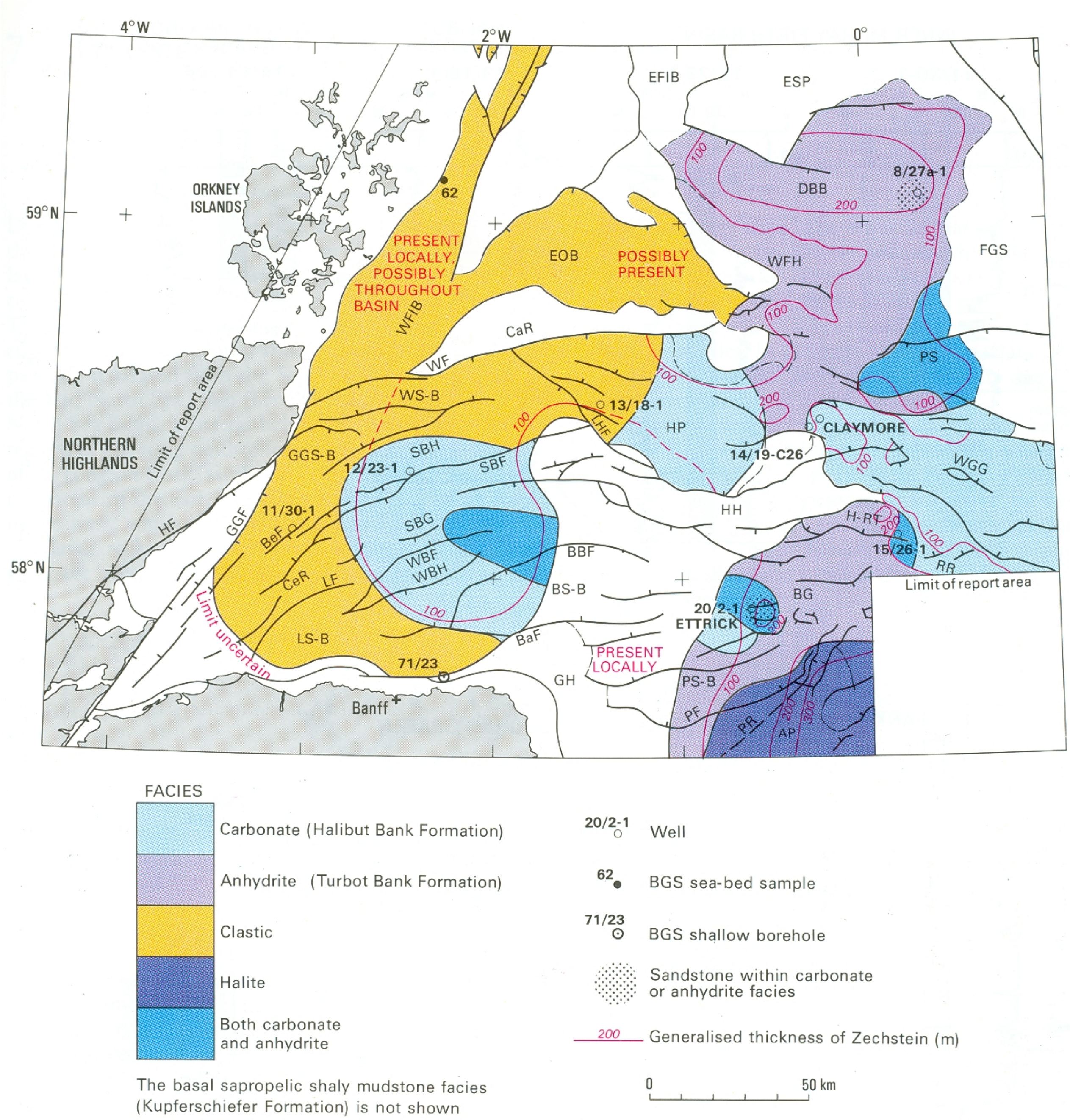


Figure 39 Facies and thickness of Upper Permian sediments, Moray Firth (from Andrews *et al*. 1990).

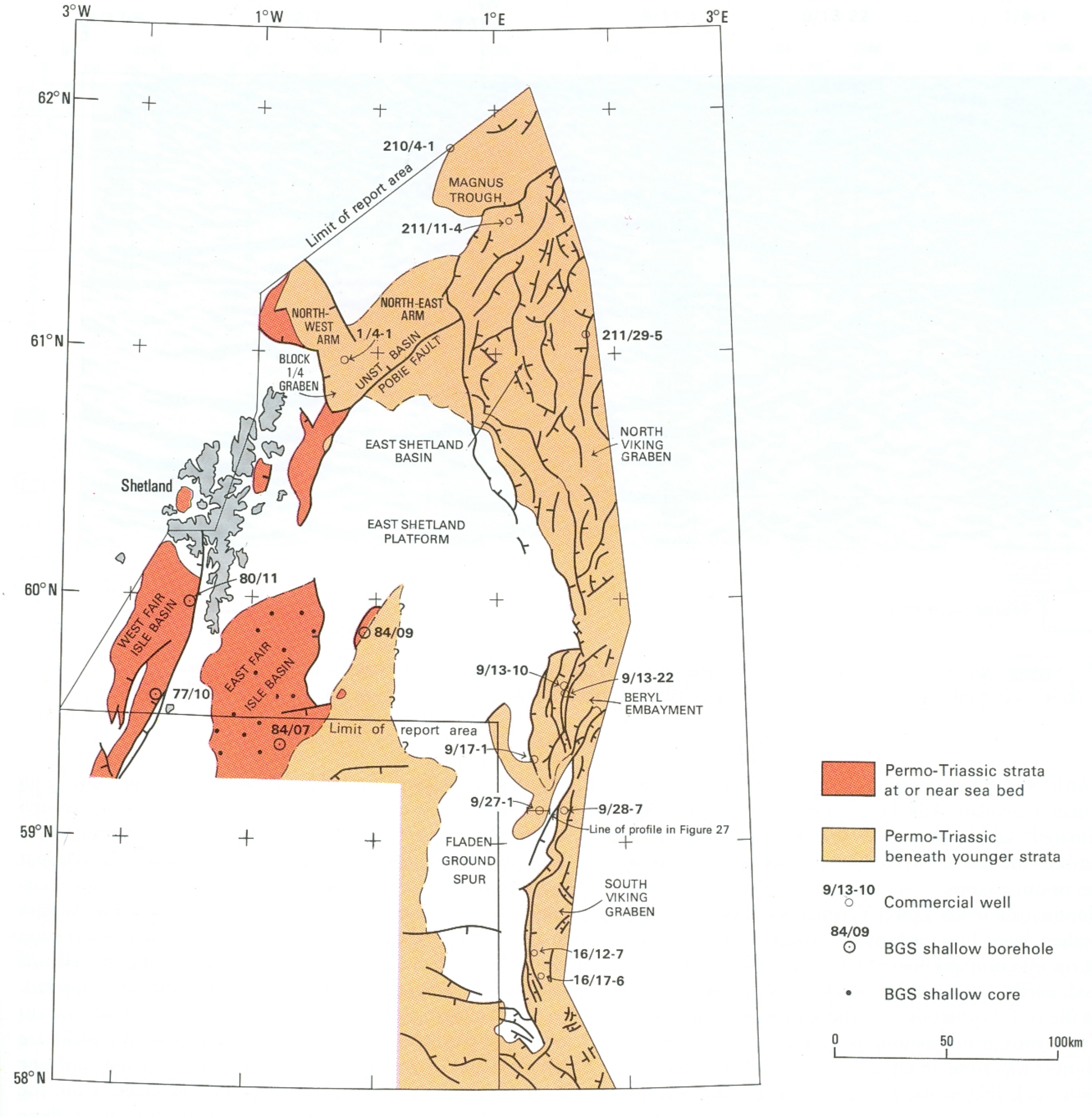


Figure 40 Distribution of Permo-Triassic strata in the Northern North Sea (from Johnson *et al*. 1993).

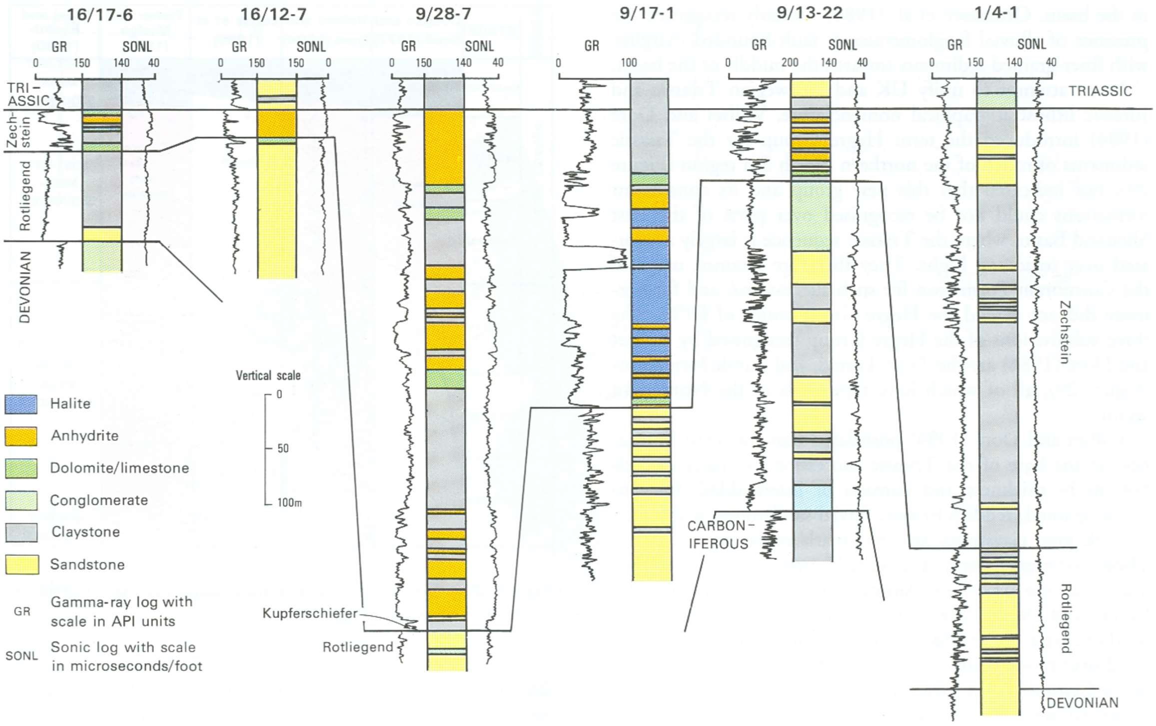


Figure 41 Well correlation of Permian successions, Northern North Sea (from Johnson *et al*. 1993).

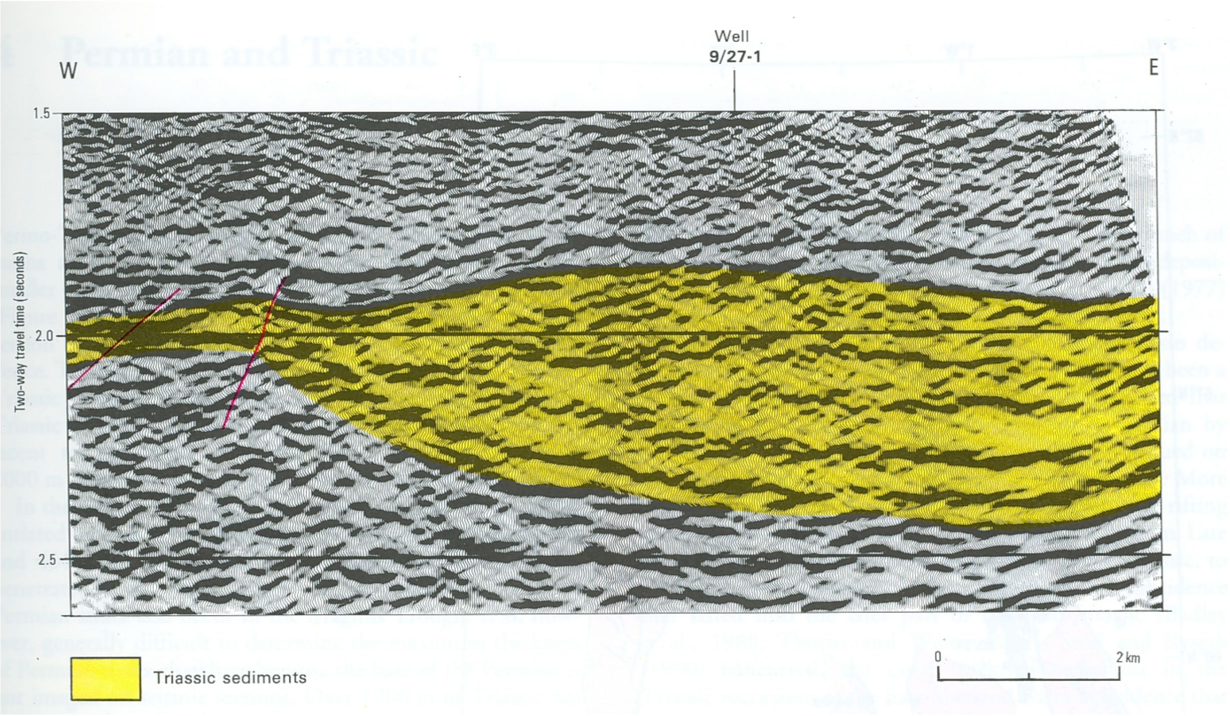


Figure 42 Seismic section through well 9/27-1 illustrating a pod of Triassic sediment formed by local salt withdrawal (from Johnson *et al*. 1993).

Appendix A: OFFSHORE MOORING-PLATFORM-SUBSURFACE STORAGE SCHEME

Andrew Stacey has given the following details of the Stag Energy scheme, which we have been able to expand by the use of references and websites.

The innovative system combines the import of LNG (until now stored in onshore locations in surface cryogenic tanks), processing the gas to normal temperature, and underground offshore gas storage. The cavern will be filled up and emptied quickly, ready for the arrival of the next tanker. The cost of the scheme is likely to be about $500 million, making the use of existing offshore infrastructure more marginal to the total expenditure. Various engineering components of similar models of such schemes were tested by the US Department of Energy (McCall 2004). The scheme's advantages over conventional LNG storage are the higher volumes which can be stored, and the high injection and withdrawal rates. There is no need for an increase in expensive and unwelcome onshore surface tanks, which causes public opposition. Also ship-manoeuvring conditions are less congested than at port facilities.

Mooring for tankers is likely to be a weather-vaning type, rather than a fixed mooring because of variable and severe winds in UK waters. De Baan *et al*. (2003) illustrated a shallow water depth terminal designed to function in waters between 15-40 m deep. The 15 m and 40 m isobaths in the Irish Sea are depicted on Figure 6. Wave height restriction on offloading is between 3-4 m according to the water depth (de Baan *et al*. 2003). Because of the design of the whole scheme it is evident that factors important in the siting of the mooring-terminal are likely to be different to those governing the siting of the subsurface cavern storage.

LNG is dispensed from the tanker, at low pressures (atmospheric) and at a temperature of -160°C. This cannot be injected directly into the salt formation. The ship unloads in 12-15 hours, at a rate of 10,000 m³/hr in the American model.

A platform will include accommodation and control rooms (unlikely to use existing abandoned platform), containing high pressure pumps which achieve cavern injection pressures (in excess of 2400 psi), and re-gasification equipment for the warming of the gas by heat exchanger, in the patented Bishop process. This could use seawater according to McCall (2004), but is not permitted in the USA according to Andrew Stacey (personal communication). Probably UK waters are too cold to do it this way, so ambient air could be used. As this is also colder than in the Gulf of Mexico, waste heat from the plant could be added.

Distance between the mooring and platform will not be more than 3 km, because cryogenic gas needs expensive insulated pipelines. Only sufficient LNG to keep the cryogenic equipment at the correct temperature between tanker arrivals need be stored (McCall 2004). Caverns could be sited nearer to the shore in water shallower than 15 m.

A joint US government-industry initiative to decrease LNG import costs by applying salt cavern gas storage technologies is moving closer to commercial feasibility. The research project, which is led by Conversion Gas Imports (CGI) and co-sponsored by US Department of Energy and several energy companies, has developed a core terminal design based on CGI's Bishop Process for unloading and vaporizing LNG directly into underground salt caverns.

CGI has calculated that for the US Gulf coast a 1.4 Bcf/day LNG, Bishop Process re-gasification and pressurization system coupled with a salt cavern storage scheme would cost between $480-650 million. The completion time is estimated at 30 months. CGI also calculated that 12 Bcf of natural gas storage could be created this way in a 12 month period for around $40 million. Cavern storage therefore can be created in roughly two thirds of the time needed to build equivalent cryogenic, LNG, onshore, storage tanks and at one fifth of the cost. Furthermore, the 'send out' rates of natural gas from caverns to consumers can be effectively 'instantaneous' compared with gas-fired heating to re-gasify LNG from tanks, approaching 3 Bcf/day, limited only by the capacity of the pipeline distribution grid. CGI believes it is technically feasible to construct a 50 Bcf salt cavern terminal with send out rates of 5 Bcf/day. For UK conditions several factors may alter these estimates. Notably, slower brine disposal rates may be needed to disperse the brines and the re-gasification process may be slower due to lower air and sea temperatures compared to the US Gulf Coast.

The most important factor for the cavern location is the suitability of the salt formation. Requirements are bedded salt over 300 ft (up to 1000 ft) thick, free from faults, fractures and with high net/gross salt (no mudstone bands thicker than 2 m). In the Gulf of Mexico salt domes are used, where the top salt is less than 1000 ft below sea level.

In the UKCS, exploration for potential cavern sites is probably not likely to be far from public domain wells, although a wide grid of seismic data away from a well was looked at by Stag Energy (we were unable to replicate this, in the time available, for the current study).

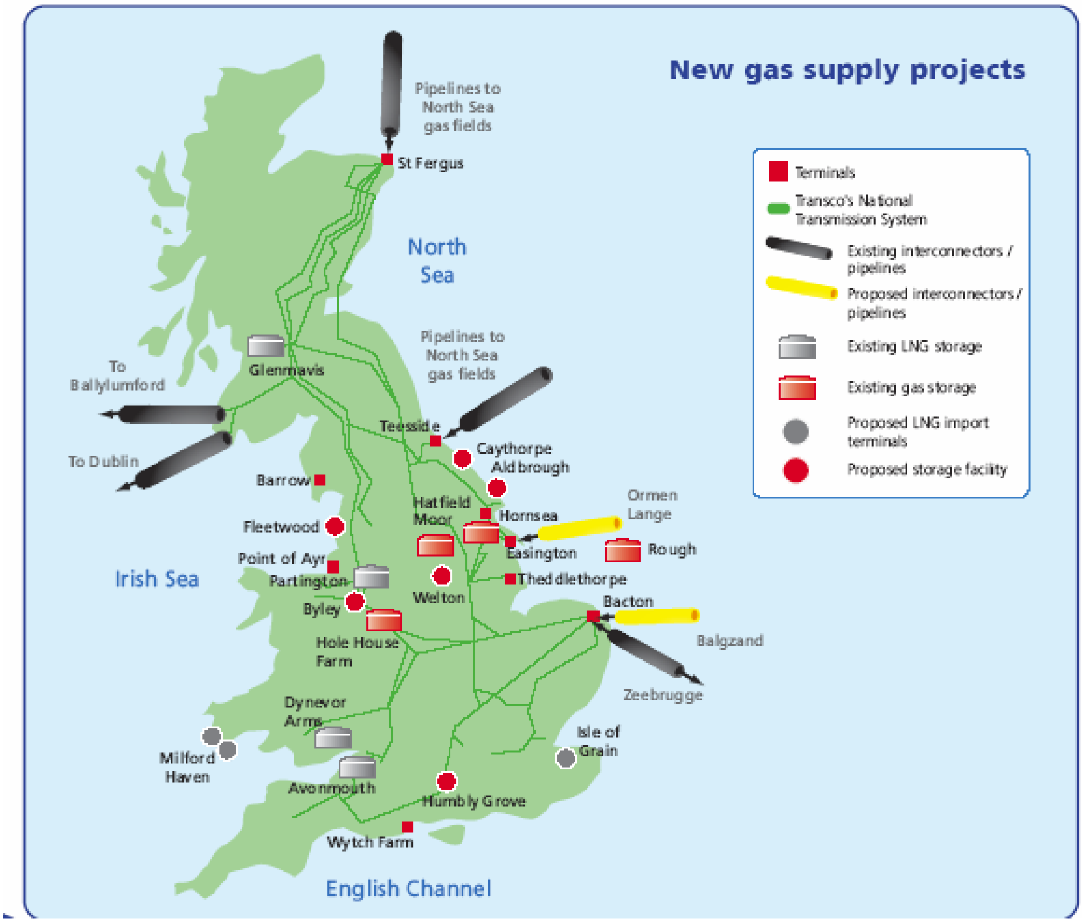
Engineering of the cavern (from Gaz de France techniques, precedents in offshore Louisiana) uses two wells and a nitrogen blanket to prevent upward dissolution, producing a horizontal sausage-shaped cavity (100-200 m wide). Favret (2003) prefers diesel oil or LPG instead of nitrogen, because the cavern shape can be controlled more closely. Another possibility is to begin storing gas in the upper part of the cavern while solution mining is still proceeding in the lower part. This might reduce the rate at which brine is produced but lengthen the engineering phase of the project.

Brine discharge would be through a multi-nozzle pipe to seawater with ambient salinity returning after 100 m from the discharge (US Gulf model). This part of the process is a disadvantage for an offshore cavern, because there is no commercial option (as far as we can see) to make usable the salt from the brine. Large amounts of water (7-9 m^3 per m^3 solution mined) are required, resulting in a salt concentration of 260-310 kg/m^3 (Favret 2003).

From the above it is possible that the terminal and platform could be located in deeper water, outside the area of the subsurface salt. Additional non-geological factors for the terminal are relatively shallow water (about 100 ft in the Vermilion Block; McCall 2004) and proximity to gas pipelines.

Dreyer (1982) predicted, initially for Germany because its natural gas reserves were relatively low at that time, that LNG would be increasingly imported by tanker from overseas. This situation now applies also to the UK with its diminishing gas reserves. There are several new projects connected with this change. Whessoe is building conventional surface LNG storage at Waterston, near Milford Haven and applications are in to build on Anglesey and another near Milford Haven. A new terminal has been built and another converted from peak shaving, both at the Isle of Grain, to complement those over 20 years old at Partington and Avonmouth. Centrica are also reported to be considering refurbishment of the Canvey Island tanks for LNG imports (17 July 2005).

The same import situation also applies to the USA, where Crystal Energy are converting Platform Grace to become a LNG import terminal called Clearwater Port, off California but without subsurface storage and seven other developments are in progress, including some with subsurface storage, mostly offshore Louisiana. These USA developments could represent a model for the licensing and monitoring duties of various bodies in the UK, although some of the environmental factors are likely to be different. For example the air and sea temperatures are considerably lower in the UK compared to offshore California and Gulf of Mexico, which may affect the re-gasification method.



Existing and proposed gas storage facilities in the UK (onshore only).

APPENDIX B: IMPORTANT DESIGN FACTORS OF CAVERNS

The main design factors of engineered caverns were listed by Hardy *et al*. (1983) and Istvan & Querio (1983):

- In-situ stress field (loss of volume through creep)
- Creep increases rapidly below 3000 ft (Favret 2003).
- Cavern dimensions and shape
- Cavern spacing (stability and flexing)
- Pressure gradient (determining optimum minimum operating pressure limits)
- The maximum allowable operating pressure was between 0.016-0.019 Mpa per metre depth but SMRI research at Etrez, France suggests that 0.019-0.021 Mpa per metre is a reasonable pressure, which permits an increase in working gas capacity of about 15% (Favret 2003).
- Injection-withdrawal cycle
- Temperature (plastic flow)
- Mechanical properties of salt and any other lithologies present
- Sump area for storage of insolubles
- Salt roof thickness (stability).
- Cap rock characteristics

Other important engineering factors, including leach water supply and brine disposal, present different problems at offshore locations.

APPENDIX C: PLANNING

Existing legislation was not designed to regulate offshore salt caverns. A possible solution is to extend the Minerals Policy Statement 1 (MPS1): Planning and Minerals Annex 4 to the offshore. We have made these suggestions separately in the consultative draft, which has recently been circulated to the British Geological Survey (Office of the Deputy Prime Minister 2005). However we have been told that the ODPM remit limit is median high water.

We also understand that DEFRA is preparing a marine spatial planning regime, by a Marine Bill, and it would seem highly appropriate that any policy on the development of offshore mooring-platform facilities-salt cavern construction for LNG import and storage be included within this regime.