ORIGINAL ARTICLE

RESOURCE GEOLOGY · WILEY

Spatial and temporal distribution of hydrocarbon production on the UK continental shelf

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Abstract

Hydrocarbon production from oil and gas fields is controlled by a variety of interconnected factors with a hierarchy of significance that is, for the most part, difficult to untangle. This article documents and investigates the spatial and temporal distribution of key hydrocarbon field parameters on the UK Continental Shelf. Data have been compiled from publicly available sources for 424 fields. Variables are considered as "descriptive parameters," "control parameters" and "outcomes". Descriptive parameters are metadata such as field name, location, etc. Control Parameters include depositional environment, present depth of burial, porosity, permeability, reservoir formation pressure, reservoir temperature, average net-to-gross, number of fault populations, hydrocarbon API, field area, bulk rock volume, well density, number of wells (production and injection), well spacing, gas oil ratio, reservoir thickness, fluid saturation, compartmentalization (quantitated by number of observable non-communicating fault compartments), structural complexity (scaled from 0 to 5), field production strategy, trap type and stratigraphic heterogeneity. Outcomes are used to assess field performance and include final recovery factor (estimated), maximum production rate, and cumulative monthly production. Analysis of the database illustrates a number of empirical observations regarding hydrocarbon production on the UKCS. The Jurassic plays have been the most successful in the region in terms of total volumes produced while the Permian reservoirs of the SNS account for the majority of the gas. Most of the UKCS reservoirs record top depths between 2000 and 4500 m with good reservoir quality. The best reservoir quality is observed in reservoirs that were deposited within deep marine systems. The largest hydrocarbon reserves are found in the Northern North Sea basin in these deep marine (as well as paralic and shallow marine) reservoirs. Using the data from this article and affiliated data, potential exists for extracting insight beyond spatio-temporal distributions.

KEYWORDS
distributive statistics, oil field geology, production history, regional hydrocarbon geology, UKCS

1 | INTRODUCTION

The UK Continental Shelf (UKCS) has produced oil and gas for over 50 years (Band, 1991; Goffey & Gluyas, 2020) from a wide variety of reservoir types. There are over 450 oil and gas fields on the UKCS with reservoirs from Precambrian to Pleistocene in age (Gray, 2013). These represent a broad spectrum of predominantly clastic depositional environments, but also include fractured basement (Trice et al., 2019) and minor carbonates (Doornenbal et al., 2019). They cover a broad range of burial depths and include oil, gas and condensates. There is a variety of structural and stratigraphic trapping styles with varying degrees of structural complexity (Stoker et al., 2006). There is a wealth of publicly available data from this province which can be used to investigate the relative significance and importance of the different factors that govern reservoir performance. The aim of this contribution is to present a data overview that has been compiled for the majority of these fields (424). The data is used to summarize the distribution of the key parameters that may control production and to start to further investigate the interplay between these parameters. The data used here forms the basis for more detailed analysis in subsequent research from this project.

Hydrocarbon production is governed by a wide range of geological and engineering parameters (Izadmehr et al., 2017; Shepherd, 2009a, 2009b; Xu et al., 2015; Zeng & Liu, 2009). Geologically, this begins with the depositional environment and includes successive modification by diagenesis and structural overprint. Natural engineering parameters include temperature and pressure, which are related to burial depth and also fluid properties such as, density, viscosity and phase. Other engineering factors include development strategy, number of wells and others. Many of these parameters are interlinked and many interact with one another to either enhance production (e.g., increased pressure and reduced viscosity with increased depth) or to exhibit dissonance (e.g., increased pressure and decreased reservoir quality with depth).

Reservoir and field performance are measured by a series of parameters which include recovery factor, maximum production rates, initial production rates, water cut though time, plateau rate, and so on.

Given that there are multiple controlling factors and also multiple performance metrics, the challenge of unraveling the fundamental controls on production is not trivial but if successful can provide an improved understanding that can be used in a predictive manner in other, less mature, petroleum provinces.

The first step to addressing this problem is taken here by building a coherent multi-dimensional database (utilizing exclusively publicly available data). The importance of these parameters and their potential impact on production is discussed here.

There is a long history of trying to understand the relative importance of geological and engineering controls on reservoir performance (Kjønsvik et al., 1994; Manzocchi, Carter, et al., 2008; Manzocchi, John Matthews, et al., 2008; Weber & van Geuns, 1990). Some of these have focused on the geological (Manzocchi, Carter, et al., 2008; Manzocchi, John Matthews, et al., 2008; Skorstad et al., 2005) while others spotlight the engineering (Gurbanov et al., 2016; Matthews et al., 2008; Muggeridge et al., 2014) controls. A number of previous articles have attempted to look into both using statistical correlations, but they have traditionally struggled with the large numbers of parameters and the vast parameter space. Recent developments in multivariate analysis (Abid et al., 2018; Holgersson & Singull, 2020; Naik, 2018; Negi & Kadappa, 2010) and machine learning (Dramsch, 2020; Macleod, 2019) have provided an opportunity to explore this space. For example, Tian et al. (2018) analyzed geological controls on Eagle Ford shale production looking at a number of parameters including total organic carbon (TOC), average bed thickness, depth of burial, and limestone bed distribution which were correlated with regional production measured in the form of time-constrained cumulative production. Results generated showed certain consistencies including elevated production with increased depth of burial, bed thickness and TOC. Conclusively the study found TOC and depth of burial (as determinants of pressure and temperature maturation), among all other assessed factors, were of greatest significance to determining performance. Specifically, simple linear regression models were used to evaluate the relationship between geological parameters and production, following scaling and normalization before analysis of P-values and coefficients.

Fishman et al. (2008) examined producing reservoir formations of varying depositional environments and evaluated heterogeneity (captured as a variation coefficient) in production histories, attempting to draw conclusions on controls for future growth. Aside from depositional environment, other variables assessed include diagenetic alteration, trap type, reservoir quality, and so on. Engineering and technical considerations were not examined in that study. Results showed that geologic variability directly correlates with production heterogeneity; simple fluvial reservoirs being the least geologically complex reservoirs expressed the least amount of production heterogeneity and karst reservoirs expressed the greatest amount of production heterogeneity. Notably, this study concluded that geological variability is the primary control on production.

An alternative approach to this problem is through modeling synthetic reservoirs. Extensive studies by Manzocchi, Carter, et al., 2008, Manzocchi, John Matthews, et al., 2008 looked at geological and engineering parameters in synthetic shallow marine reservoirs (Skorstad et al., 2008). This approach was expanded to a range of clastic environments by Tveranger et al. (2008). A similar approach was taken by Hovadik and Larue (2010).

Recent advances in the analysis of large datasets (machine learning, processing, data mining, etc.), have revealed the power of interrogating very large volumes of data to reveal underlying trends. A similar approach was undertaken on a smaller dataset of fields from the Norwegian Continental Shelf by Aliyuda et al. (2020) who built a comparable database and analyzed it in a similar way. That project was limited to about 90 producing fields, while this current one includes a much larger dataset in excess of 400 fields.

The overarching aim of the wider project is to improve understanding of what controls reservoir performance and hence to potentially improve forecasting. This work provides an understanding of the distribution of parameters at play across the study area.

2 | APPROACH

The methodology for this project was to empirically analyze the production behavior of fields within the data-rich, mature hydrocarbon province of the United Kingdom continental shelf (UKCS). This region of the North Sea, similar to the adjacent Norwegian continental shelf (NCS), has been in production for over 50 years from a host of clastic and carbonate fields. There is a wealth of publicly accessible data available for these fields for both geological and engineering parameters.

The first stage of the analysis was to build a database that captured the key parameters for each of the fields. There are 467 fields in the UKCS (according to the UK Oil and Gas Authority and the UK National Data Repository databases), 424 of these were chosen for further study (Figure 1). Fields were selected to provide a representative cross section and also based on the availability of data.

Data that were compiled for each of these fields included descriptive parameters, data on the geologic controls, fluid properties, field development variables and measurements of field performance. As data were mined from the public domain, it was inevitable that there were limitations in data coverage and missing data points from certain fields. This article documents the development of the project database, parameters selected for assessment, the classification schema used and preliminary findings and observations from statistical assessment.

Parameters are subdivided into "descriptive," "controls" and "outcomes." Descriptive parameters record factors such as field name, location, etc. Control parameters, which can be both quantitative and qualitative in nature
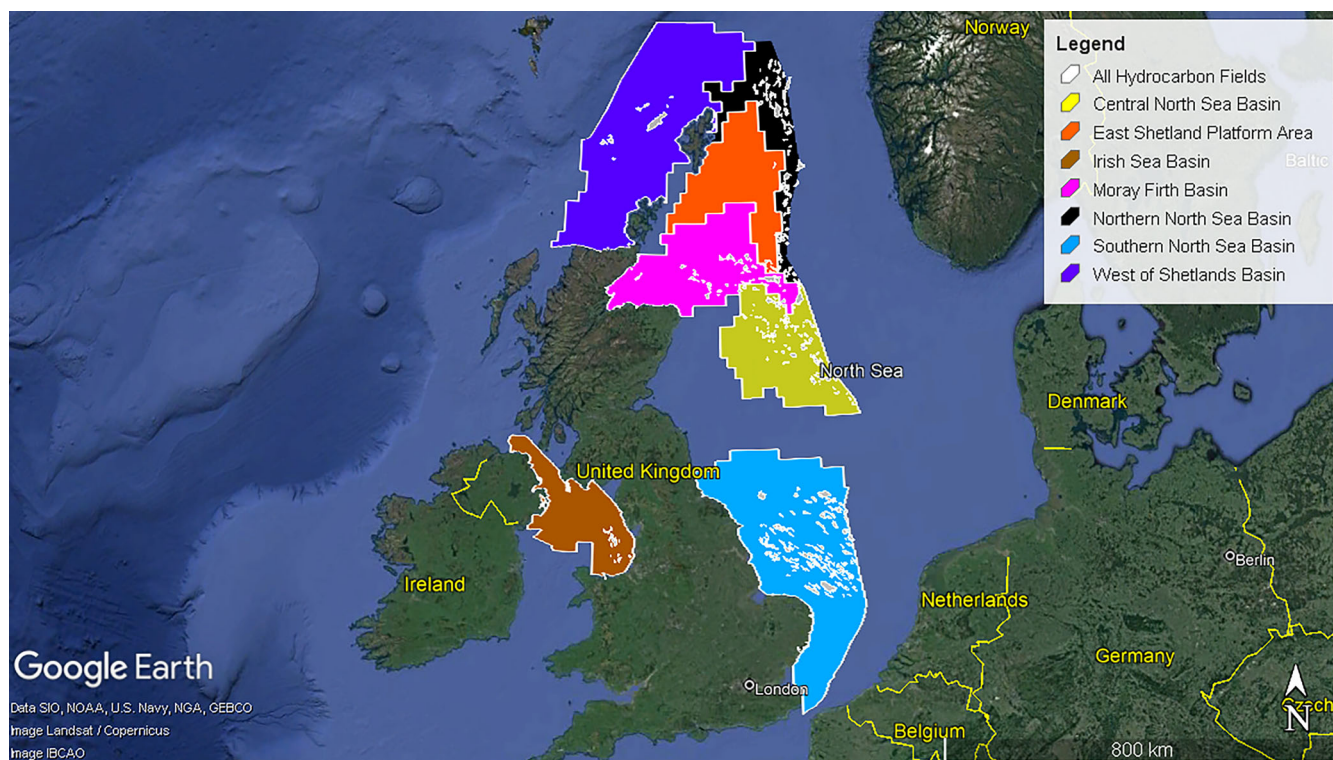

FIGURE 1 Map of UKCS Showing hydrocarbon fields with sedimentary basins highlighted. (Created with Google Earth Pro).

TABLE 1 Data distribution statistics for numerical variables grouped by controls (descriptive, geological and PVT) and outcomes.

	Variable	Observations	Mean	SE mean	StDev	Minimum	Q1	Median	Q3	Maximum
Geological	Stratigraphic heterogeneity	59	2.1	0.2	1.3	0.0	1.0	2.0	3.0	7.0
	Structural complexity	58	2.2	0.2	1.3	0.0	1.0	2.5	3.0	5.0
	Number of fault pops	58	1.9	0.1	1.1	0.0	1.0	2.0	3.0	5.0
	Number of fault compartments	59	2.0	0.4	2.7	0.0	0.0	0.0	3.0	15.0
	Top depth (m)	424	2709.1	40.1	826.0	652.3	2192.7	2632.8	3316.5	5364.0
	Net:Gross	59	0.8	0.0	0.2	0.5	0.7	0.8	0.9	1.0
	Max. thickness (m)	59	179.4	15.8	121.5	23.0	101.0	152.0	220.0	665.0
	Avg. porosity (%)	268	19.9	0.4	6.4	5.0	15.0	20.0	24.0	38.0
	Avg. permeability (mD)	261	771.0	91.0	1469.7	0.1	40.0	300.0	800.0	10000.0
	Bulk rock volume (10^6 m^3)	59	1710.0	542.0	4162.0	7.0	177.0	299.0	1300.0	28036.0
	Field area (km^2)	420	21.9	1.7	34.6	0.5	5.4	11.2	24.7	394.2
PVT	Reserves (oil): MMBOE	398	73.4	11.5	230.1	0.0	0.7	8.8	51.0	2904.5
	Reserves (gas): BCF	408	341.2	42.8	864.8	0.0	10.7	68.4	294.8	8488.4
	Reserve (hydrocarbons): MMBOE	410	128.1	14.6	295.6	0.0	11.0	36.8	114.3	3168.8
	In place volume (Mill. Sm^3)	59	13026.0	7258.0	55752.0	1.0	24.0	76.0	3511.0	397000.0
	Fluid density (gas gravity or oil API)	59	26.4	2.3	17.6	0.6	0.7	36.4	39.0	45.0
	GOR (m^3/m^3)	58	49351.0	17551.0	133666.0	14.0	43.0	130.0	29839.0	695733.0
	Pressure (bar)	58	328.5	14.4	109.6	77.6	244.7	336.1	414.0	517.5
	Temperature (°C)	58	98.8	3.3	25.0	30.0	87.8	105.1	113.9	147.2
	Water saturation (%)	58	29.9	1.5	11.8	5.0	20.0	30.0	40.0	50.0
Engineering	No. of prod. wells	395	10.8	1.2	24.4	1.0	1.0	3.0	9.0	226.0
	No. of injection wells	395	1.6	0.2	4.6	0.0	0.0	0.0	1.0	45.0
	Injector-producer ratio	395	0.1	0.0	0.3	0.0	0.0	0.0	0.2	2.0
	Well spacing (Km^2/Prod. Well)	394	5.2	0.3	6.3	0.0	1.3	3.0	6.4	53.5
	Well density (Prod. Wells/Km^3)	59	19.2	3.0	23.0	2.0	6.9	13.6	20.8	151.5
	Total number of months in production	423	171.2	5.7	118.1	0.0	70.0	159.0	249.0	526.0
Outcomes	Recovery factor (%)	238	52.5	1.5	22.4	6.0	35.0	50.0	74.0	97.0
	Maximum field rate Kboepd (oil or gas)	410	38.0	3.2	64.9	0.0	10.0	17.9	40.7	622.0
	Maximum field rate Kboepd (hydrocarbons)	410	44.7	3.6	72.3	0.0	11.5	21.8	47.0	679.6

TABLE 1 (Continued)

Variable	Observations	Mean	SE mean	StDev	Minimum	Q1	Median	Q3	Maximum
Monthly depletion Rate	59	0.0043	0.0003	0.0020	0.0016	0.0026	0.0040	0.0051	0.0105
Total produced volume (oil): MMBOE	410	65.6	10.6	215.2	0	0.4	5.6	38.6	2800
Total produced volume (gas): BCF	410	236.7	31.2	632.3	0	9	48	192	7000
Total produced volume (hydrocarbons): MMBOE	410	106.8	13.5	272.8	0	8.5	24.9	89.9	3200
Average cumulative monthly production of total hydrocarbons (MMBOE)	409	0.4194	0.0333	0.6735	0.0001	0.0943	0.1976	0.4584	6.3745

Note: Shows list of variables, number of observations, mean, standard error of mean, standard deviation, minimum, first quartile, median, third quartile and maximum.

TABLE 2 Tally of variables and number of observations for categorical (non-numerical) variables grouped by control types (descriptive, geological and PVT).

	Variable	Observations
Descriptive	Reservoir Group(s)/Formation (s)/Member(s)/Unit(s)	424
	Paleoclimate	59
	Reservoir age	424
	UKCS basin	424
Geological	Gross depositional environment	424
	Depositional environment	59
	Diagenetic impact	59
	Trap type	59
PVT	Fluid phase	424

are those which influence how a reservoir would perform over the course of its production lifespan. These are subdivided into geologic variables including sedimentological, structural, and stratigraphic characterization parameters, PVT parameters associated with the properties of the fluids and the reservoir as well as engineering variables such as field development strategy, drive mechanism, number of wells, and so on (Table 1). Outcomes are the measures of reservoir performance, including recovery factor, maximum well rate, average time factored cumulative production, and so on. An overview of the variables and rationale for their selection is discussed in subsequent sections. Tables 1 and 2 give a tally of variables and basic descriptive statistics.

3 | STUDY AREA: UK CONTINENTAL SHELF

A full summary of the history of oil and gas production on the UKCS is beyond the scope of this article. Brennand et al. (1998) provide a useful overview of all aspects of exploration and production, including the engineering advances and the legislative framework up to the mid-90s. Craig et al. (2018) also provide history up to the 2000s. A recent publication by Goffey and Gluyas (2020) provides a detailed up to date review. The following is a brief summary to set the scene.

In 1964 the UK government passed the UK continental Shelf act which set the legal framework for exploration and production. The following year BP discovered the West Sole field in the Southern North Sea. The play was a logical extension of the onshore discoveries in the Dutch Rotliegend, such as the super-giant Gronigen field,

discovered in northern Holland in 1959. Exploration extended northwards and intensified after the discovery of Ekofisk in 1969 by Phillips Petroleum in Norway. In late 1969 Amoco discovered Montrose, closely followed by BP's discovery of Forties which triggered a series of major finds including Brent (1971), Piper (1973), Beryl (1973), Britannia (1975) and numerous others. The North Sea continued to produce major discoveries through the later part of the 20th Century; although, discoveries after the 2001 Buzzard field have been much smaller. Production peaked in the late 1990's at around 1.9 million barrels per day. Outside the North Sea there has also been discoveries and production from the Irish Sea, with the discovery of the Morecambe Bay Gas field in 1976 and others such as Hamilton and Douglas subsequently. The other key outlying area on the UKCS is the area West of Shetland which is more remote and challenging than the North Sea. The major discovery is the Clair field which was discovered in 1977 but not brought on stream until 2005. Other producing fields WoS include Foinaven and Schiehallion.

As of December 2019, there were a total of 301 producing fields on the UKCS. These cover a wide range of geological play types with reservoirs from Precambrian basement to Pleistocene lithologies. With over 50 years of production and a wealth of data, the UKCS is an ideal dataset to empirically investigate controls on field performance.

4 | GEOLOGY OF THE UKCS

The UK continental shelf covers a total area of about 286,695 Km^2 (ogauthority.co.uk). It contains a number of different hydrocarbon systems with two main source rock intervals (Carboniferous coal measures and upper Jurassic, deep marine mudstones). There are reservoirs at each stage of the Phanerozoic from the Devonian (Alma, Buchan, Clair and Stirling fields) through to the Pleistocene (Aviat shallow gas reserves). There are also reservoirs in fractured Lewisian basement (Trice et al., 2019). This study features seven main reservoir intervals from Carboniferous through to lower Paleogene (Figure 2).

The UKCS is subdivided into seven major regions (Figure 1). A brief description of these follows.

- West of Shetland (WoS): Geologically complex basin located on a rift margin setting; situated between Northern Scotland and the Faroe Islands (Rippington et al., 2015; Stoker, 2016) This area is heavily impacted by the presence of volcanic rocks and is the least explored area of the UKCS (Schofield et al., 2015).
- East Shetland Platform (ESP): Broad structural high consisting of a series of North-East trending fault blocks and forming the western boundary of the Viking Graben (Platt & Cartwright, 1998)
- Northern North Sea (NNS): This is the northern arm of the North Sea rift basin and is largely comprised of the Viking Graben (Johnson et al., 1993). It contains numerous large fields including the iconic Brent field.
- Moray Firth (MF): This is the western arm of the tripartite rift system extending from the southernmost reach of the Viking graben to coastal UK. It is made up of a series of well-defined grabens and half grabens which form the inner (NE trending) and outer (NW trending) Moray Firth sub-basins (Andrews et al., 1990). It includes a few significant fields like Beryl, Beatrice and Buzzard.
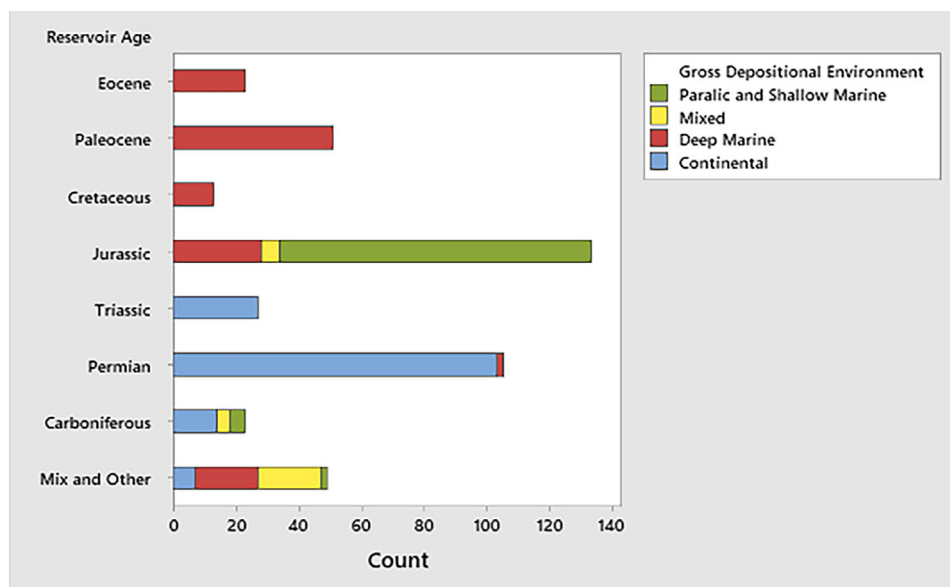

FIGURE 2 Bar chart showing number of fields in a given lithostratigraphic stage, categorized by gross depositional environment.

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- Central North Sea (CNS): This is the southern extent of the tripartite rift system and extends SSW. It includes a series of structural highs which divide it into eastern and western troughs. The central graben extends from its intersection with the outer Moray Firth and south Viking grabens to its abutment near the Dutch coast (Gatliff et al., 1994). A key aspect of the Central Graben is the presence of highly mobile Zechstein Salt which significantly impacted sea-floor topography and accommodation creation during the Triassic and Jurassic.

- Southern North Sea (SNS): This basin is separated from the CNS basin by the Mid North Sea High. The SNS is part of a different petroleum system to the basins to the north with gas from Carboniferous coal measures trapped in mainly Permian continental reservoirs with subordinate Carboniferous and Triassic reservoirs. The basin is characterized by halokinetic deformation and NW trending faults. The tectonic history of the SNS basin is complex with several distinct phases of subsidence, uplift, extension and inversion (Balson et al., 2001; Doornenbal et al., 2019; Jackson & Mulholland, 1993; Kent, 1967).

- East Irish Sea (EIS): This basin lies to the west of mainland Britain. It is comprised of Triassic extensional basin-fill with arid fluvial and eolian deposits. The source rocks are Carboniferous coal measures. It has also had a complex structural history with two different structural regimes operating in the northern and southwestern portions of the basin. (Jackson & Mulholland, 1993; Knipe et al., 1993).

Detailed descriptions of the geological history of each of the basins is beyond the scope of this introduction. Glennie (1998) provides an excellent account of the North Sea. Other relevant sources include the numerous "Barbican" Volumes (Geological Society of London, Petroleum Geology Conference series 1–8), the Millennium Atlas (Evans et al., 2003), the 25th and 50th year anniversary volumes of the Geological Society of London Memoirs (volumes 14—Abbotts, 1991 and 20—Gluyas & Hichens, 2003) and numerous other Geological Society of London Special Publications (e.g., Bowen, 1992; Duxbury et al., 1999; Glennie, 1997; Goffey & Gluyas, 2020). A very brief summary of the geological history of the region since the Caledonian orogeny is provided below.

Following the Caledonian orogeny, the area of the present day UKCS straddled the equator, and thick Carboniferous coal measures were deposited in association with large fluvial deltaic systems (Underhill, 2003). These are especially important for the SNS and EIS as they provide the source rocks and locally important reservoir intervals (Gautier, 2005; Pharaoh et al., 2016). To the

north, they are typically too deeply buried to be of significance today (Glennie, 1998). The late Carboniferous Variscan orogeny created a series of basins in the southern part of UK (Leveridge & Hartley, 2006) and, in combination with northward drift provided rain shadow to much of the area resulting in the development of large deserts (Sweet, 1999). In the Permian, these conditions resulted in significant deposits of eolian and fluvial strata which created major reservoirs in the SNS, CNS and EIS (Glennie, 1986). The late Permian was characterized by the formation of extensive evaporite deposits of the Zechstein super group (Clark et al., 1998). These provide minor reservoirs and more significantly the seal for the Permian reservoirs (Glennie & Provan, 1990). The Zechstein deposits were also a major mobile substrate which controlled the distribution of reservoirs and structures in the CNS (Smith et al., 1993). Triassic rifting coupled with mobilization of the Zechstein salt created accommodation for major Triassic fluvial systems which form reservoirs in the Central Graben and the southern part of the Viking Graben (Gray et al., 2019).

Lower Jurassic deposits are largely absent on the UKCS, primarily due to major Cimmerian uplift and erosion. This has traditionally been associated with formation of a thermal dome at the North Sea triple junction (Underhill & Partington, 1993). In that model, collapse of this dome created accommodation for the deposition of the major middle Jurassic reservoirs, especially the northwards progradation of the Brent Delta along the Viking Graben (Fjellanger et al., 1996) and the deposition of shallow marine reservoirs in the Central Graben and MF. More recent work by Quirie et al. (2019) has the lack of a prominent dome and a greater emphasis on the role of long-lived inherited lineaments in controlling both lower Jurassic unconformities and the creation of the North Sea triple junction.

A major phase of upper Jurassic rifting led to the drowning of the shallow marine reservoirs and deposition of the Kimmeridge clay formation, a basin-wide deep marine, organic rich mudstone interval, that extends across the CNS, NNS and MF basins. Similar aged organic-rich deposits extend from the south of England up to the Barents Sea in Norway.

In the CNS, shallow marine sandstones were initially deposited on the newly forming fault terraces and in salt pods before they were also drowned by the continued rift related transgression (Howell et al., 1996).

Rifting continued into the lower Cretaceous but eventually slowed and died. A series of major deep water turbidite systems sourced from the UK mainland, filled the inherited rift topography especially in the Central Graben (e.g., Britannia) providing locally important reservoir intervals. The upper Cretaceous was marked by global

sea-level high-stand and the formation of thick chalk deposits across the UK and UKCS.

Palaeogene uplift of the UK mainland and ESP associated with opening of the Atlantic and potentially underplating (Nadin et al., 1997) lead to a massive influx of coarse-grained deep-water sediments to the North Sea basins, depositing a series of deep-water fans that would provide major turbidite reservoirs such as Forties.

The Neogene was a period of tectonic quiescence across the region, although continued subsidence led to further maturation of the source rocks and the filling of traps. Quaternary glaciation resulted in the deposition of proglacial deposits that host very minor accumulations of low-pressure biogenic gas (Rose et al., 2016).

The petroleum system of the UKCS can be summarized as follows:

- Source: Carboniferous coal measures serve as the main source rock for the gas fields of the southern Permian basin while Jurassic Kimmeridge clay is the major source for oil fields in the Northern basins (Glennie, 1998). Other minor source rocks occur throughout the region.
- Reservoir: There is a wide spectrum of reservoir ages (Devonian to Quaternary) and depositional environments, with every clastic depositional environment from eolian to deep marine represented. This makes the UKCS ideal for a study that is aimed at comparing different depositional systems as reservoirs.
- Trap: A variety of trap types are present including structural and stratigraphic examples. The majority are structural, associated with rifting, inversion and locally salt (Munns et al., 2005).
- Seals: The major seals are the Zechstein Salt in the SNS and upper Jurassic to lower Cretaceous, syn- and

post-rift mudstones north of the Mid North Sea High. Cretaceous and Palaeogene deep water systems are encased in marine mudstones. Detailed accounts of North Sea Petroleum systems including sealing lithologies can be found in Evans et al. (2003) and Gray (2013).

The UKCS is ideally suited for a study on geological controls on production because there are several hundred fields with a long production history and a wide spectrum of geological parameters which potentially influence production performance.

5 | BUILDING THE DATABASE

In order to attempt to unravel the importance of different controlling parameters on production, data on those parameters were collected and catalogued. A similar study was undertaken on the Norwegian Continental Shelf by Aliyuda et al. (2020), whose methodology for the characterization of controlling parameters has been modified for this study and is described below.

A formula for determining oil in place was also plugged into an excel sheet and used to fill in data gaps where possible in a few instances; STOOIP = 7758 (bbls/acre-ft) × Field Area (acres) × Thickness (ft) × Porosity (fraction) × Oil Saturation (fraction) × Oil Shrinkage (1/Bo).

Parameters have been subdivided into descriptors, controls and outcomes as described previously and summarized in Figure 3. These are discussed in more detail below.
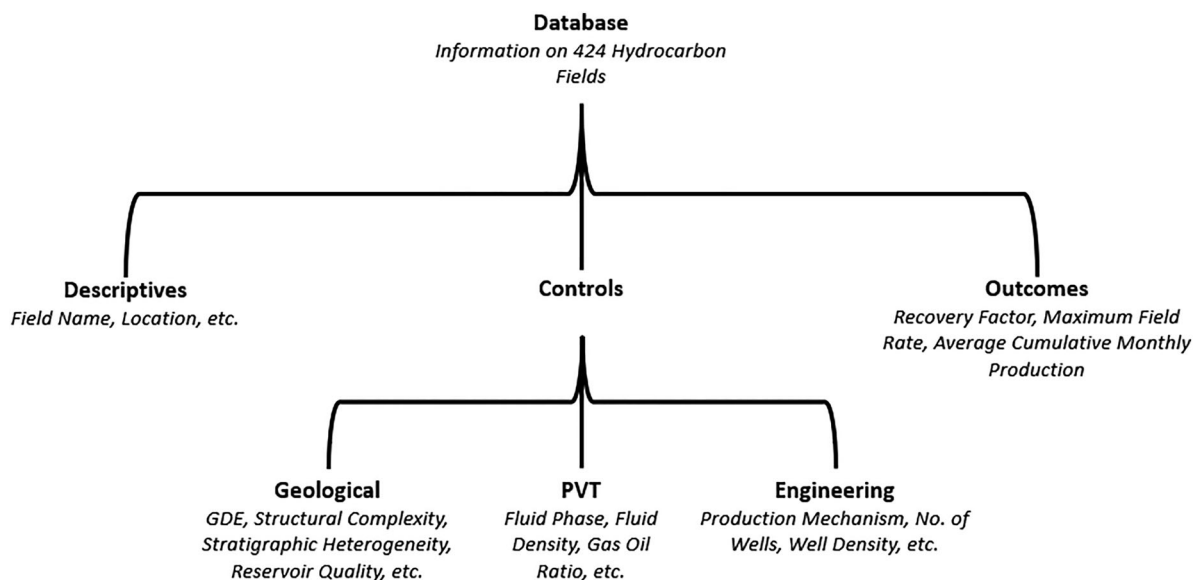

FIGURE 3 Summary of parameters within the database.

6 | DESCRIPTIVE PARAMETERS

These are parameters in the dataset that are important for describing the field, but they have no impact on the production behavior of the field. They include the following:

- Field Name: From UK Oil and Gas Authority (www.ogauthority.co.uk)
- Geographic Location: From UK Oil and Gas Authority (www.ogauthority.co.uk)
- Reservoir Lithostratigraphy (Group/Formation): Available from Abbotts (1991), Warren and Smalley (1994), Glennie (1998), Evans et al. (2003), Gluyas and Hichens, (2003), Goffey and Gluyas (2020) and other relevant sources including www.energist.io, the "Barbican" Volumes (Geological Society of London, Petroleum Geology Conference series 1–8) and other Geological Society of London Special Publications.
- Reservoir Age: From Knox and Cordey (1993) and the British Geological Survey (www.bgs.ac.uk).
- Paleoclimate: From the (Scotese 2002), PALEOMAP project (www.scotese.com).

7 | STRATIGRAPHIC AND STRUCTURAL CONTROLLING PARAMETERS

7.1 | Geological controls

The geology of a reservoir includes the sedimentology and the structural geology, both of which can influence production characteristics (Manzocchi, Carter, et al., 2008; Manzocchi, John Matthews, et al., 2008; Tveranger et al., 2008). The sedimentology is parametrized by defining the gross depositional environment (GDE) of the reservoir units. This is divided into continental, shallow marine and deep marine. For further granularity, the GDEs were subdivided into depositional environments (DE). The GDE and DE directly control the architecture and geometry of the flow units and barriers/baffles within the field. The scheme here follows that used by Aliyuda et al. (2020) and is based upon the schema implemented in the SAFARI database (www.safaridb.com). It is outlined in Table 3. See Knox and Cordey (1993) and BGS Lexicon for source information.

The SAFARI schema extends to depositional sub-environments (SEs) and architectural elements (AEs); however, these were not used here because most fields contain multiple SEs and AEs, and the available production data is at the field scale and not granular enough to distinguish the impact of these. A few fields contain more than one GDE, in this case, where determinable only the most volumetrically abundant one was used for simplification of classes during analyses. Figures 4 and 5 show the proportion of GDEs across the region and by basin.

Examples of oil fields with multiple GDEs where the dominant producing reservoir would be listed based on supporting references for statistical analysis include the Argyll field where there are multiple reservoirs, but the pressure connected continental reservoirs have been most volumetrically prolific (Tang et al., 2020). In the Beryl field an estimated 78% is produced from the Paralic and Shallow marine reservoirs (Karasek et al., 2003; Knutson & Munro, 1991) and so it is classed as such for analysis. For the Brent field over 70% of in place volumes and 90% of recoverable reserves are in the Paralic and Shallow marine GDE (Struijk & Green, 1991; Taylor et al., 2003). Important to note that Transitional formations/reservoirs encapsulating continental coastal and shallow marine environments such as the Banks group/Statfjord formation in fields such as the Brent field were classed as Paralic and Shallow marine based on existing UK lithostratigraphic research (Richards et al., 1993; Roe & Steel, 1985). In the Chanter field which is recorded

TABLE 3 Summarized SAFARI Classification Schema down to depositional environment level (safaridb.com).

SAFARI classification schema						
Gross depositional environment	Continental				Paralic and shallow marine	Deep marine
Climate filter	Polar	Warm Temperate	Equatorial	Arid		
Depositional Environment	Lacustrine	Lacustrine	Lacustrine	Lacustrine	Fluvial dominated	Slope
	Alluvial	Alluvial	Alluvial	Alluvial	Wave dominated	Basin Floor
	Erg/Eolian			Erg/Eolian	Tidal dominated	
					Shelfal	

Note: Climate filter applied using paleoclimate reconstructions of Scotese, PALEOMAP Project (www.scotese.com).
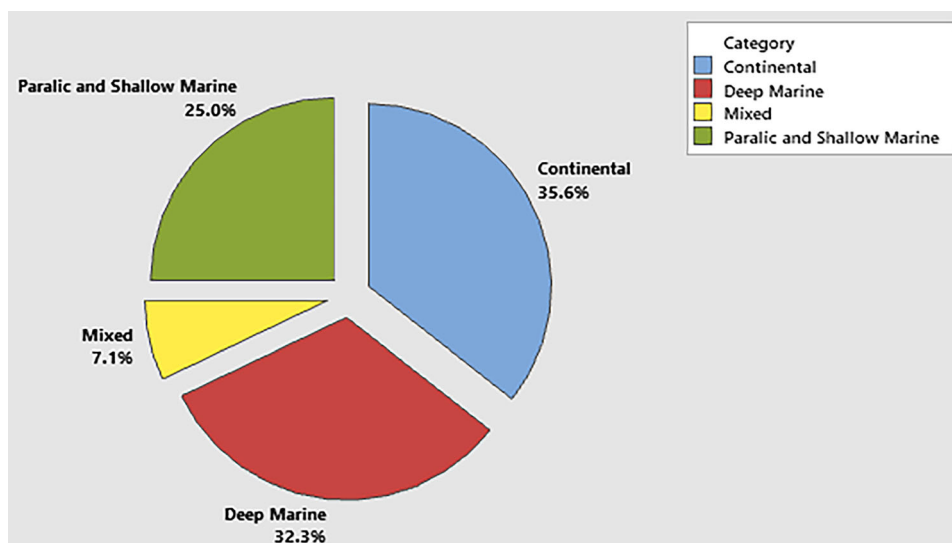
FIGURE 4 Pie chart showing proportions of reservoir GDE across the UKCS.
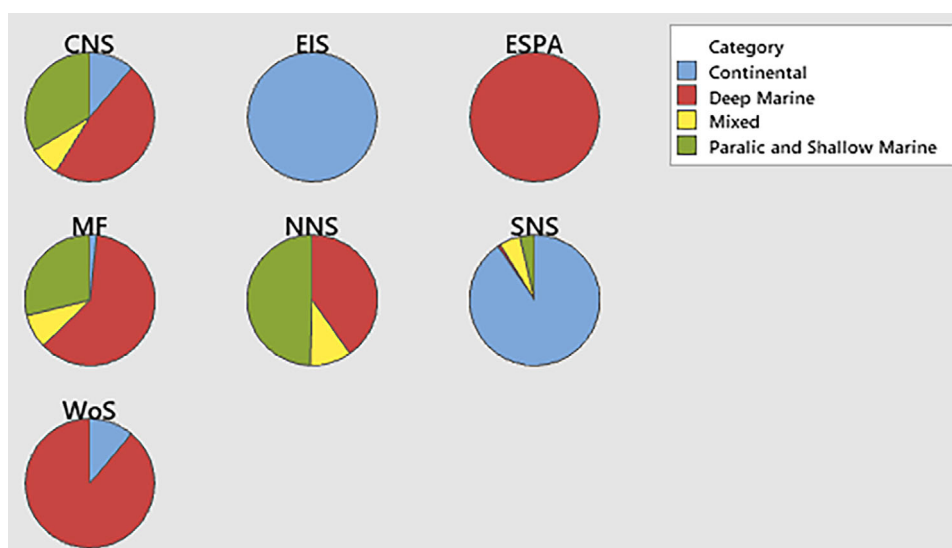

FIGURE 5 Pie charts showing proportions of reservoirs by GDE distributed by basin.

as an oil field the oil is hosted almost exclusively in deep marine GDE while the associated gas is hosted almost exclusively in the shallow marine reservoir (Schmitt, 1991) and so it is recorded as a deep marine GDE for oil field statistical analysis. The Claymore field also has a mix of GDE but 95% of Oil in place is in Deep marine GDE reservoirs and so it is classified as such for analysis (Harker & Green, 1991). In the Crawford field, the reservoirs were transitional from continental to shallow marine (Glennie, 1998; Yaliz, 1991) and thus classified as paralic and shallow marine. In the Dunbar field over 80% of in place volumes are located in the Paralic and Shallow Marine reservoirs (Ritchie, 2003) and so it is classified as such. For the Fulmar field, over 80% of in place oil is in Paralic and Shallow marine GDE, hence qualifying it for that classification (Kuhn et al., 2003; Stockbridge & Gray, 1991). For the Highlander field, 90%

of recoverable reserves are in Paralic and Shallow Marine reservoir (Whitehead & Pinnock, 1991) and it is classed as that for analysis. In the Maureen field, in-place volumes, reserves and produced volumes are overwhelmingly from the deep marine GDE (Chandler & Dickinson, 2003; Cutts, 1991) and so it classed as such for analysis. In the Saltire field, the primary reservoir is Paralic and Shallow marine, so it is classified as such for analysis (Casey et al., 1993). In the Statfjord field, over 80% of production has been from the Paralic and Shallow Marine reservoirs (Gibbons et al., 2003) so it is classed as such for analysis.

In addition to characterizing the GDE and DE, a simple metric that describes "stratigraphic heterogeneity" was also used for each field. This refers to the vertical and lateral variability in lithofacies within the reservoir (Manzocchi, Carter, et al., 2008; Manzocchi, John

Matthews, et al., 2008; Tyler & Finley, 1991). This metric is controlled by depositional environment but is also influenced by other parameters such as rates of accommodation creation, sediment source parameters and other factors. The matrix is considered on an inter-well to field wide scale (500–5000 m) and is based on interpretation of the well data, depositional environment, and other published information. The matrices of Tyler and Finley (1991) and Hiatt (2000) as seen in Figure 6 were used to define a score between 0 and 8 for a field (Figure 7).

With these variations in depositional stacking patterns and connectivity accounted for, an added layer of qualitative scrutiny was imposed in the form of a "diagenetic impact" designation (low, moderate, or high) based on literature review and core photograph assessment from the British Geological Survey (BGS) records. Morad et al. (2010) discuss the effect of diagenesis on stratigraphic heterogeneity. To determine and corroborate GDE literature on lithostratigraphy was relied upon, including Knox and Cordey (1993) and the British Geological Survey (www.bgs.ac.uk) as well as Lyell Memoir special publications on various fields.

7.2 | Structural complexity (scaled from 0 to 5)

Faults and fractures influence the flow of fluids in reservoirs (Harris et al., 2005). Jolley et al. (2007), describes structurally complex hydrocarbon accumulations as those in which the density of faults and fractures control the trapping mechanism, production considerations and field performance.

The degree of structural complexity is typically a qualitative expression. Fields are described as "structurally complex" but there is no generally accepted scalar metric to describe what that means. There have been previous attempts to quantify the impact of different structural complexities on production behavior (e.g., Manzocchi, Carter, et al., 2008; Manzocchi, John Matthews, et al., 2008; Tveranger et al., 2008; Yunxia et al., 2008).

Manzocchi, Carter, et al. (2008), Manzocchi, John Matthews, et al., 2008) applied a matrix based on fault density and fault transmissibility to describe structural complexity but also recognized that fault orientation and number of fault populations were also key factors.

The limited data available in the current study to the various fields precludes a detailed analysis of the structure or its complexity. To produce a metric for the statistical analysis, a simple semi-quantitative approach was followed.

In this schema (Figure 8) each field was assigned a value from 0 to 5 based on fault density, fault throw and estimated level of compartmentalization. Description of the scale values and illustrations are as follows:

0—No intra-reservoir faulting;
1—Minor faults with throw less than reservoir thickness;
2—Non-sealing faults with throw greater than reservoir thickness;
3—Minor compartmentalization occurs (a few compartments);

FIGURE 6 A juxtaposition of vertical and horizontal heterogeneity in typical sedimentary facies (not accounting for potential for diagenetic alteration) (Adapted from Hiatt, 2000).

		Lateral Heterogeneity		
		Low	Moderate	High
Vertical Heterogeneity	Low	Wave-dominated delta front, Barrier core and shoreface, Sandy strand plain	Channel-mouth bar, Muddy strand plain, Mixed-load meander belt	Fluvial-dominated delta front, Back barrier lagoon, Suspended-load meander belt
	Moderate	Cross-bedded sand sheet, Aeolian dunes, Wave-modified delta front	Alluvial fans, Shelf bars Fan delta, Distal shoreface, tidal estuary fill	Braided channel bedload, Tide-dominated delta front
	High	Turbidite lobes, Turbidite sheets, Shelf sand sheets	Coarse-grained meander belts, Sandy tidal flats, Braid delta lobes	Turbidite channel fill, Estuary

4—Extensive compartmentalization;

5—Very complex (heavily compartmentalized).

7.3 | Trap type

Hydrocarbon traps are spatial configurations of rock (reservoir and seal) that allows for economically consequential accrual of oil and gas (Biddle & Weilchowsky, 1994). There are four recognized types of traps namely, structural, stratigraphic, hydrodynamic and combination traps.

Structural traps are those developed as result of compactional, gravitational, tectonic and or diapiric action on reservoir-seal assemblages ultimately expressed as fault or fold structures (Gluyas & Swarbrick, 2004).

Stratigraphic traps are those resulting where hydrocarbon retention is caused by Sudden or gradational stratigraphic constrictions and terminations of reservoir lithology as a result of unconformity; with no structural deformation attendant in trapping mechanism (Hyne, 2003).
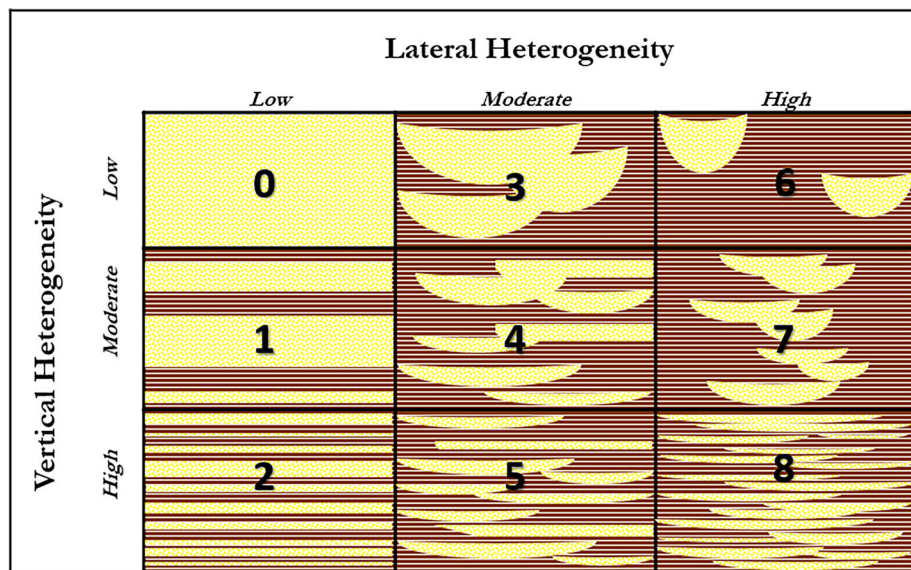
FIGURE 7 Scaling applied for stratigraphic heterogeneity rating as derived from Hiatt, 2000 and Tyler and Finley (1991). 0 being the least heterogeneous and 8 being the highest level of heterogeneity.
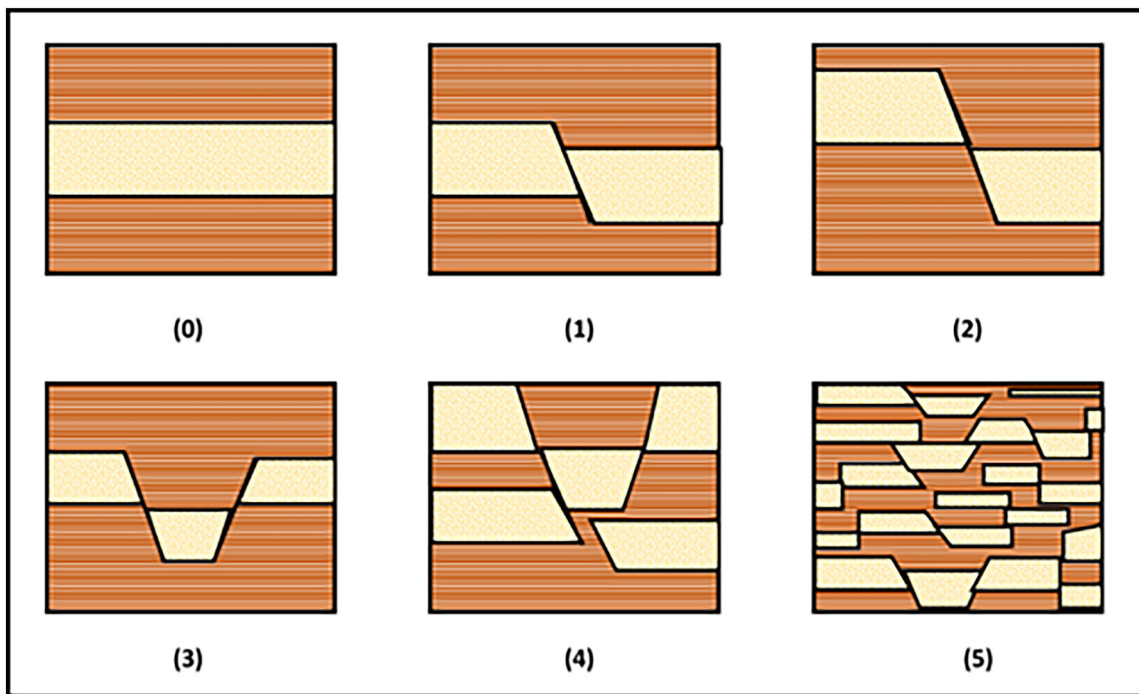
FIGURE 8 Illustration of scale values (from 0 to 5) for structural complexity.

Hydrodynamic traps occur when there are inclinations in hydrocarbon-water contacts due to fluid motion and accompanying pressure differences (Hubbert, 1953). Combination traps are traps which include elements of more than one of the aforementioned trapping mechanisms.

As relates to depositional environment, trapping mechanisms could be the result of depositional and diagenetic processes especially stratigraphic traps (Vincelette et al., 1999).

This study will highlight the type of trapping mechanism at play in the fields under study and assess possible patterns emerging from correlations of trap type, depositional environment, and reservoir performance. Data for this were obtained from the Lyell Memoirs 14 and 20.

7.4 | Depth of burial

For the purpose of this study, depth of burial is defined as the depth to the top of reservoir structure. This property is important because it is related to several other reservoir properties which enhance performance, such as temperature and pressure and a number of parameters that degrade performance, such as cementation and compaction (Worden et al., 2018). The value used refers to the present-day depth of burial. It is also recognized that many fields have been buried more deeply and have undergone one or more period of uplift. Ideally the maximum depth of burial would also have been recorded however these data were not readily available for many of the fields. Depth of burial for fields in the study area were obtained from literature (e.g., Abbotts, 1991; Gluyas & Hichens, 2003) and Oil and Gas Authority GIS files.

7.5 | Field size (area and in-place volume)

Two parameters which reflect the field size are included in the database and the analysis. The map view area is simply the plan view extent of the field and is easy to obtain and measure as there are numerous published maps. The second parameter is the published estimate for the in-place volumes which is also available for 62 of the fields (See Lyell Memoirs 14 and 20). These parameters were included because a number of authors including Hook et al. (2014) have suggested that there is a positive correlation between field size and performance metrics, suggesting that larger fields perform better. Field sizes obtained from literature (e.g., Abbotts, 1991; Gluyas & Hichens, 2003) and Oil and Gas Authority GIS files.

7.6 | Reservoir quality (porosity and permeability)

Porosity as defined by fluid occupiable volume in the reservoir rock, and permeability being the ability of said reservoir rock to transmit such fluid; both make up the basic properties of reservoir quality. In any field there will be a wide range of values for these properties, however such data were not readily available. It is however common for authors and commons to publish average values of both these properties and that was the data that were used. It is also recognized that permeability is highly dependent on scale (Nordahl & Ringrose, 2008), which is not captured in this measurement. Though some permeability values appear to be extremely high (up to 10,000 md), literature supports the occurrence of such values and peer reviewed research corroborated it's use for example with permeability values in the Heron field (McKie & Audretsch, 2005) and the Harding field (Beckly et al., 2003; Jayasekera & Goodyear, 1999; Zhang & Green, 2009). Values were properly researched referencing geological society memoirs and other literature. Nevertheless, for thoroughness, data packages and statistical analysis were created for both complete data as representative of geological reality and outlier excluded data as a consideration for mitigating errors. full details of outlier filtered comparative analysis was excluded from this document for conciseness, as no significant differences were observed.

7.7 | Average net-to-gross (NTG)

NTG is defined as the proportion of gross rock volume to formation thickness hosting hydrocarbon fluids. This parameter is a key part of the calculation of in-place volume and is also a key component of reservoir heterogeneity which in turn impacts the economically recoverable reserves (Egbele et al., 2005). Data for NTG is drawn from a variety of peer reviewed publications covering the large number of fields.

NTG is partially controlled by depositional environment, but it is also influenced by diagenesis and burial. Previous authors have suggested that it is a key control of reservoir performance. The majority of previous work on this issue has focused on fluvial systems for example, Aitken and Flint (1996) and Abdullayev et al. (2012). Larue and Hovadik (2006) quantified the relationship with modeling studies. Richards and Bowman (1998) considered the relationship between NTG and depositional environment and the significant role that NTG along with architectural element geometry play on reservoir

performance. It has not been systematically compared to production data from a range of different fields. In the same vein, data for bulk rock volume and maximum reservoir thickness were also recorded. Values for NTG were obtained from the Lyell Memoirs (Abbotts, 1991; Gluyas & Hichens, 2003).

7.8 | Number of fault populations

A fault population can be defined as a cluster of faults within an area of interest, grouped on the basis of orientation, proximity, span and or displacement (Needham et al., 1996). This parameter does not consider the nature of faults, whether sealing or non-sealing or their frequency.

The number of fault populations was determined primarily from published top structure maps and cross sections from Lyell Memoirs (Abbotts, 1991; Gluyas & Hichens, 2003).

7.9 | Number of fault compartments

Jolley et al. (2010), in a comprehensive article on reservoir compartmentalization describe compartmentalization as the separation of parts of an otherwise unitary hydrocarbon pool into an aggregate of discrete fluid/pressure units due to the effect of sealing boundaries (whether static or dynamic). Fault sealing occurs in the event of the abutment of reservoir formations against non-reservoir rock, across a fault plane and or with drastically reduced porosity and permeability due to clay/shale smear in the fault zone (Vrolijk et al., 2016).

For this study, fault compartmentalization characterized as the number of observable non-communicating fault compartments is assessed using published literature and available structural maps and seismic data mostly found in the Lyell Memoirs.

Previous work relating compartmentalization to depositional environment includes Ainsworth's (2006) article where depositional architecture is discussed as a control for fault sealing and resultant compartmentalization.

Other studies He et al. (2002), Fox and Bowman (2010), and Smalley and Muggeridge (2010) have effectively shown that not only does compartmentalization affect field development planning but it also has a recognizable impact on reservoir performance. A detailed analysis of the structure of the individual fields is beyond the scope of this study and the impact of structure on production has been extensively studied elsewhere (see Manzocchi et al., 2011 for review).

8 | PVT AND FLUID PROPERTIES

Beyond the geological properties, other subsurface parameters are related to the nature of the fluids in the field, including phase, density and gas-oil ratio. Information on these parameters is widely available and has been included in the assessment as they are assumed to play an important role in field performance (Freyss et al., 1989). They include all the factors typically described as PVT parameters (Sim, 1993).

8.1 | Fluid phase

The phase simply describes whether the main reservoir fluid is oil, gas or condensate. In the case of the fields that contain multiple fluid phases, they were recorded based on classification by the UK Oil and Gas Authority and main hydrocarbon produced as determined by volumes.

8.2 | Fluid density (API and gas gravity)

Fluid density is measured differently dependent on fluid phase. For oil, density is measured in API (American Petroleum Institute) gravity using degrees (°) as the unit of measurement, assigning a numerical value (10–50) for "heavy" or "light" with higher API representing lighter oil. For gas, density is measured as gas gravity; a ratio of molar mass of the gas divided by the molar mass of air. This value typically falls between 0.55 and 1.5. Workers like dos Santos et al. (2014) discuss how fluid density affects flowability, pipeline transportation and production/ enhanced oil recovery considerations. Data for this was obtained from the Lyell Memoirs.

8.3 | Temperature

Recorded reservoir temperature is for the most part a function of the local geothermal gradient (Ren et al., 2020) with possible attenuation by drilling mud (Dowdle & Cobb, 1975). Temperature affects the viscosity of the fluid. In addition, it also influences formation volume factor, gas-oil ratio, etc (Dake, 1978). Temperature is also shown to have an effect on reservoir quality in terms of poroperm, resistivity and capillary pressure of host formations (see Sanyal et al., 1974 for detailed discussion).

A few researchers have examined the effect of temperature on hydrocarbon recovery for very specific settings/ circumstances (Comberiati & Zammerilli, 1982; Doranehgard & Siavashi, 2018; Hamouda & Karoussi, 2008; Li & Li, 2016), however there appear to be no broad

empirical studies on the subject for comparative inference. Temperature data is found in the Lyell Memoirs (Abbotts, 1991; Gluyas & Hichens, 2003) and British Geological Survey reports (e.g., Holloway et al., 2005).

8.4 | Pressure

Various measures of reservoir pressures are accounted over the course of field life, including fluid pressure, initial reservoir pressure, average reservoir pressure, abandonment pressure, and so on (Satter & Iqbal, 2016a; Satter & Iqbal, 2016b). This study utilizes initial reservoir pressure, which typically refers to pressure at discovery prior to any production or injection. This intrinsic energy is an important factor as it, along with fluid phase and other considerations, determines the method of production/drive mechanism that would be employed over the course of field life (Renpu, 2011) and potentially the rates of production along with overall reservoir performance (Tiab & Donaldson, 2016).

Hategan and Hawkes (2007) highlight the importance of initial pressure in appropriately estimating recoverable reserves. Pressure data is found in the Lyell Memoirs (Abbotts, 1991; Gluyas & Hichens, 2003) and British Geological Survey reports (e.g., Holloway et al., 2005).

8.5 | Gas-oil ratio (GOR)

GOR can typically be examined as either instantaneous or cumulative and sometimes dissolved solution (gas solubility).

Instantaneous GOR refers to the ratio of produced gas measured in standard cubic feet (scf) to oil measured in stock tank barrels (stb) in a specific instant, while cumulative GOR refers to the ratio of total produced gas (scf) to total produced oil (stb) over time. Solution GOR on the other hand equates the propensity of gas to dissolve or escape from oil with PVT changes.

Ahmed and McKinney (2005) as well as Ahmed and Meehan (2012) dissect the intricacies of the topic in greater detail including equations for determining GOR as well as the relevance of GOR in predicting reservoir performance. For this study, cumulative GOR was preferentially used. Busahmin and Maini (2010) discuss how GOR affects recovery factor and production rate in the context of heavy oil reservoirs, observing a decrease in oil recovery with increasing GOR. Data for GOR is also available in the Lyell Memoirs (Abbotts, 1991; Gluyas & Hichens, 2003) and specialist publications for example, PGS (1996).

8.6 | Water saturation

Water saturation is the proportion of water in a unit rock volume relative to other fluid content (Sam-Marcus et al., 2018) and forms a key part of the calculation for in place hydrocarbon volumes (Iscan, 2021). For this study, the value was expressed in percentage terms. It affects both the amount of porosity available for hydrocarbon and also the relative permeability. This parameter functions intricately in conjunction with others to affect other controls and outcomes such as capillary pressure, water cut, rates of production, recovery, etc (Li & Li, 2014). Several authors discuss the impact of saturation on recovery and production behavior under very specific circumstances including Kazemi et al. (2015), Zaeri et al. (2018) and Ma et al. (2020). Data for water saturation is available in the Lyell Memoirs (Abbotts, 1991; Gluyas & Hichens, 2003).

9 | DEVELOPMENT AND ENGINEERING

In addition to the geological and fluid related parameters, there are a series of factors that influence production behavior and are based upon decisions taken during development and operation of the field. These are mechanical implementations and technical decisions made regarding the most economically efficient way to produce the hydrocarbons from the reservoir formations. They are also influenced by prevailing and forecast economics, available technologies, and operator preferences. The parameters recorded in the database are discussed below.

9.1 | Production mechanism

This parameter accounts for the hydrocarbon recovery techniques applied to the field. Typically, recovery methods are classed either as primary, secondary, or enhanced (Vishnyakov et al., 2020).

Primary recovery techniques are those which rely on naturally occurring pressure, buoyancy, fluid mechanisms and gravity, acting on the reservoir to drive fluids to the well bore. Some examples of primary drive mechanisms include rock and liquid expansion drive, depletion drive, combination drive, water drive, gravity drainage drive and gas cap drive (Ahmed & Mckinney, 2005). Recovery factors associated with primary recovery techniques are typically low, often between 10% and 30% of in place volumes (Satter & Iqbal, 2016a; Satter & Iqbal, 2016b).

Secondary recovery production processes involve artificially supplementing existing reservoir pressure and fluid action using motorized pump and lift mechanisms as well as injections of various fluids for the purpose of maintaining pressure within the reservoir and/or sweeping hydrocarbons toward the well bore (Viswanathan, 2017). Secondary recovery techniques are the most common in the North Sea and may improve recovery factor to 50% or more (Guerithault & Ehlig-Economides, 2001).

Tertiary or enhanced/improved oil recovery (EOR/IOR) techniques are those techniques employed when primary and secondary recovery techniques no longer prove economically effective (Ahmed, 2010). These techniques rely on changing the properties of fluids in the reservoir by heating (Speight, 2015), or introduction of chemicals that do not naturally occur in the reservoir such as surfactants (Al Shalabi & Sepehrnoori, 2017). These techniques may raise recovery to as high as 65% (Tunio et al., 2011).

Ahmed and Meehan (2012) comprehensively discuss drive mechanism as a factor in predictivity of reservoir performance. Prospecting available records, specific production mechanisms employed for the various fields were recorded, for example, aquifer drive, Pressure depletion, water/gas injection and gas lift. These methods were either employed individually or in combination. Data for this property was predominantly acquired from the Lyell Memoirs (Abbotts, 1991; Gluyas & Hichens, 2003) and lists the drive for the reservoir e.g., aquifer, pressure depletion, volumetric expansion, and so on.

9.2 | Well controls (number of wells, well spacing and well density)

The number and spacing of wells (both production and injection) within a field is a key development decision and it is also a key component in the cost of the development (Gurbanov et al., 2016). In this study, the total number of wells, including production and injection were obtained from public records. These are used to calculate the well density both in plan-view (wells per km2) and with respect to the reservoir volume (wells per km^3). There are a wide number of other factors that are also relevant such as well trajectory, well bore length within the reservoir, well completions etc. Unfortunately, these data are not systematically available for most of the fields.

Liu and Jing (2017) discuss in relatively sufficient detail the reasons for and effects of proper consideration in well spacing density and production-injection well ratios. Well data was obtained from the National Data Repository and the UK Oil and Gas Authority.

10 | PERFORMANCE MEASURES

This is data that tells us how well a reservoir or field will or has performed, in terms of the rate or volume of production. Below is a list of indicators for field/reservoir performance that are publicly available for most of the fields. Majority of the data were taken from the production records of the UK Oil and Gas Authority. Production data used terminates in 2017.

10.1 | End of life recovery or estimated recovery factor

The recovery factor (RF) of a hydrocarbon accumulation is the percentage volume of recoverable hydrocarbons from the total in-place volumes; a value that is largely dependent on applied recovery techniques, reservoir characteristics and fluid properties. Sustakoski and Morton-Thompson (1992) discusses the technicalities of properly determining recovery factor.

Certain fields in this study have ceased production so the RF is simply calculated from the produced volumes and the estimated in-place volumes. For the remaining fields which are still in production, the RF is a forecast. Fortunately, it is a relatively common parameter for companies to attempt to predict and estimates of the predicted RF for fields were found in the public domain. It was not possible to QC these estimates without further data, and they were used as found in the Lyell Memoirs, BGS reports and other published literature.

10.2 | Plateau/ maximum field rate

The production plateau records the stable rate at which the field produced prior to decline. It is a function of the number of wells, the performance of those wells and the deliverability of the reservoir formation. It is sometimes also limited by facilities and ullage. It is measured in barrels of oil equivalent per day. Records were found in the Lyell Memoirs (Abbotts, 1991; Gluyas & Hichens, 2003) and with the Oil and Gas Authority.

10.3 | Average monthly depletion rate

The depletion rate is the rate at which recoverable reserves are extracted from a reservoir or field over time. This is not to be confused with decline rates which measure difference in the rate of extraction of hydrocarbons from a pool, from one time-period to the next, for

example, between year 1 and year 2 of field life (Sorrell et al., 2009). Depletion rate can either be defined as a function of ultimate recoverable reserves (URR) or remaining recoverable reserves (RRR).

Mathematically, depletion rate of URR is the proportion of ultimately recoverable reserves produced within a given timeframe expressed as a simple ratio or in percentage terms. Similarly, depletion rate of the RRR is the fraction of remaining recoverable reserves produced within a given period (Hook et al., 2014). Notably Hook et al. (2014) assessed 880 fields and noted that field size appears to be

inversely correlated with depletion rate; finding that larger fields typically experience lower depletion and decline rates—acknowledging the controls of geological constraints as well as economic and technological factors.

In the current project, monthly production figures over the course of the field life were used. Monthly URR depletion rates were then calculated, and the results averaged to obtain average monthly depletion rate of URR, as a measure of reservoir performance.

Control parameters would be juxtaposed against the average monthly depletion rate of URR and assessed for

FIGURE 9 Total produced volumes (up to 2017) versus basin, stacked and color coded by fluid phase.
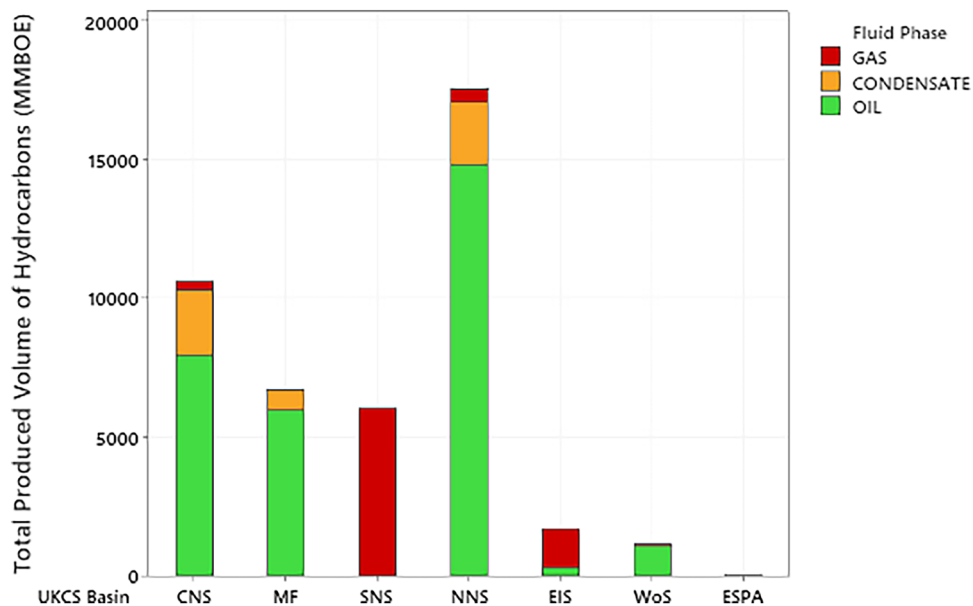
FIGURE 10 Total number of fields versus basin, stacked and color coded by fluid phase.
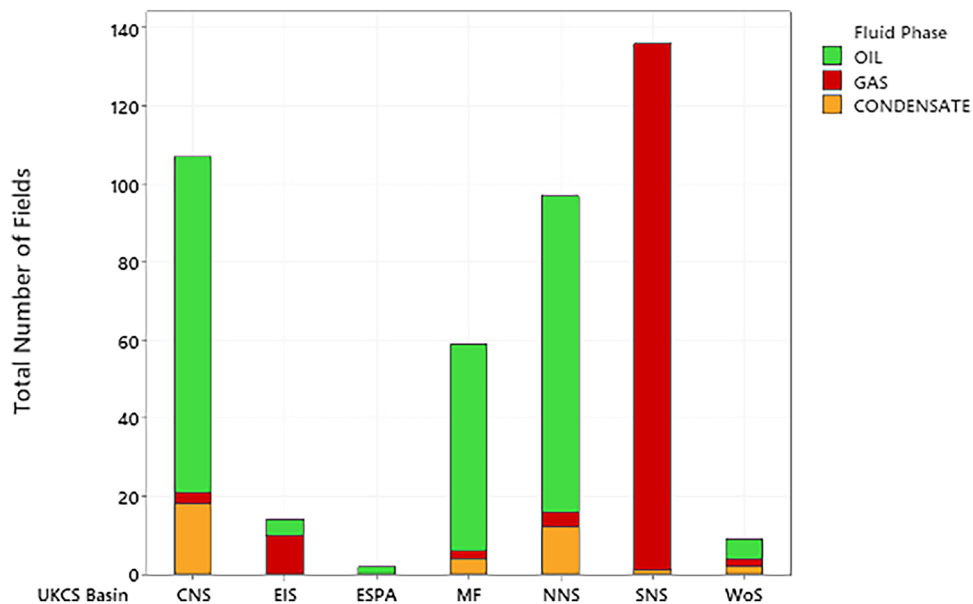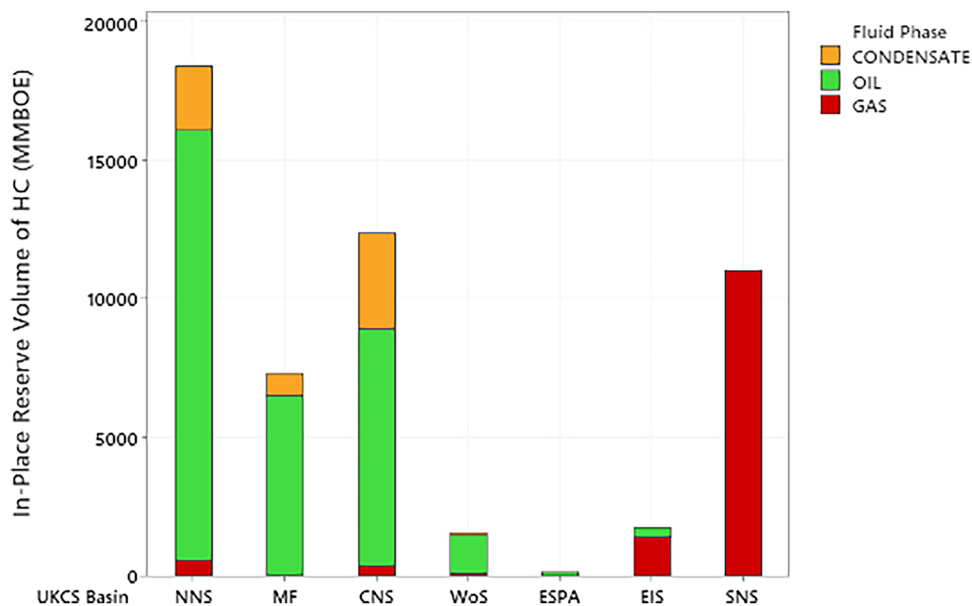
FIGURE 11 Total in-place reserve volumes (deduced using decline curve analysis) versus basin, stacked and color coded by fluid phase.
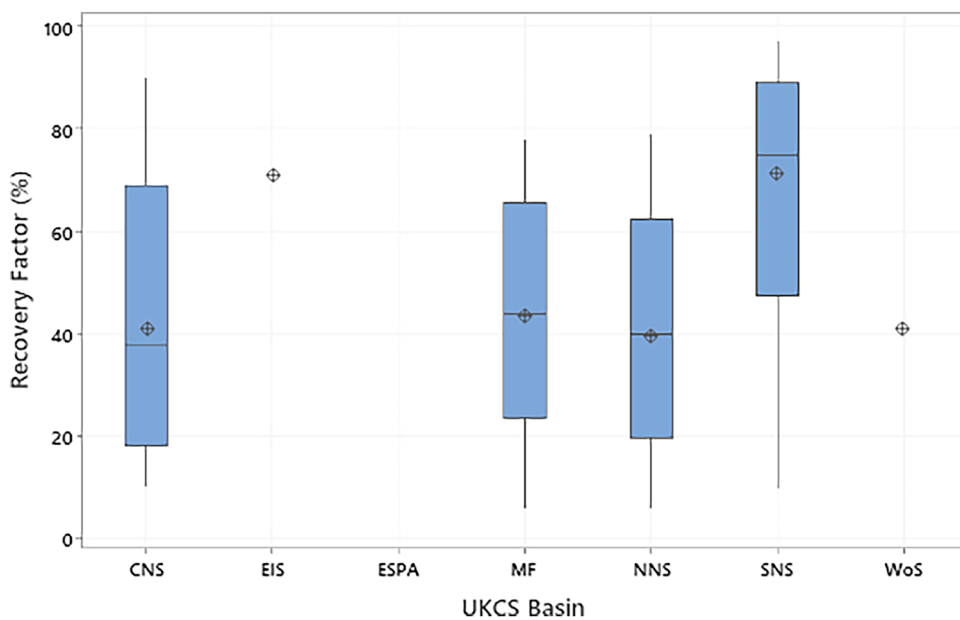
FIGURE 12 Distribution of recovery factors by basin for 238 fields recording the range, mean, 10th and 90th percentile for recovery.

emerging patterns for potential use in field performance prediction.

11 | SUMMARY OF THE DATA

The database can be used to summarize the spatial and temporal distribution of the various parameters. Spatial distribution refers to the geographic component of the analysis. For this purpose, the basin is subdivided into key areas (Figure 1). The temporal distribution refers to the age of the reservoir interval, which is presented at the system level. Gross depositional environment was also considered to be a key parameter of

interest, so majority of the plots have been coded for GDE as the additional parameter. It is clear that these systems are multidimensional with significant overlap between the key parameters. That is investigated further in a separate article.

12 | SPATIAL DISTRIBUTION OF CONTROLS AND PERFORMANCE METRICS IN THE UKCS

To examine the spatial differences, the UKCS was subdivided into seven key areas. These are based on the major sedimentary basins and are commonly accepted

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FIGURE 13 Distribution of recorded maximum field rate by basin for 410 fields recording the range, mean, 10th percentile and 90th percentile.
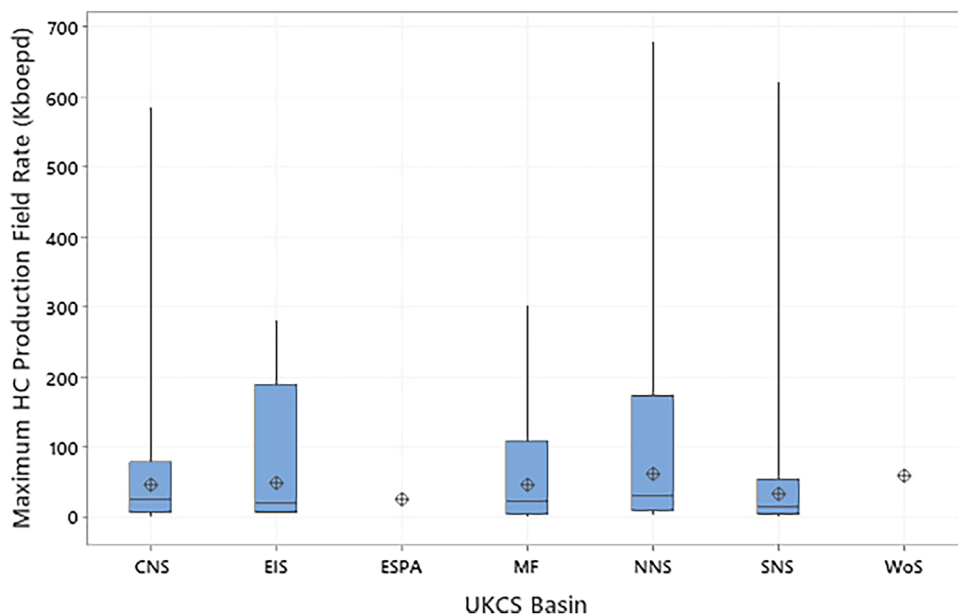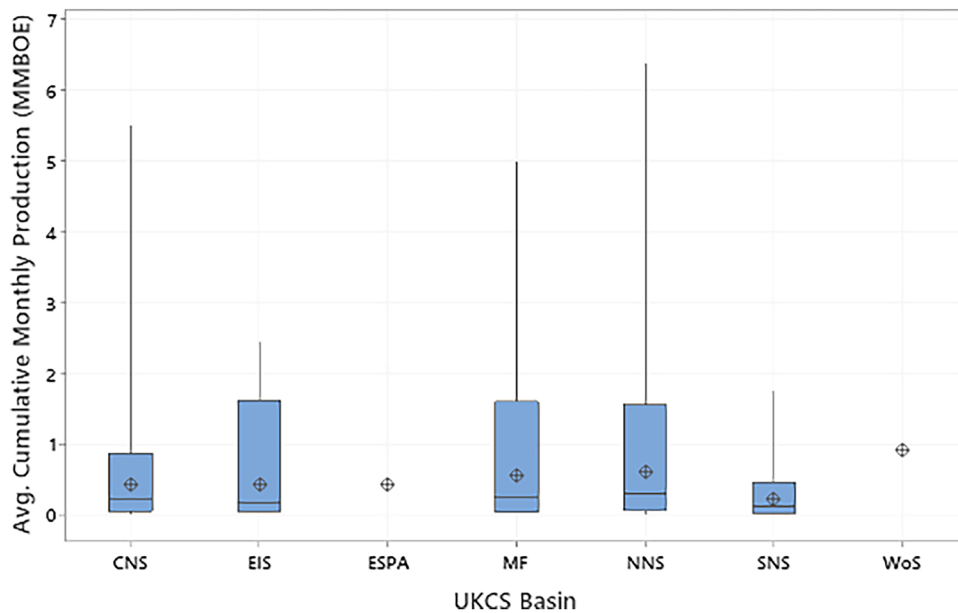

FIGURE 14 Distribution of calculated average field cumulative monthly production rate by basin for 409 fields recording the range, mean, 10th percentile and 90th percentile.

subdivisions of the shelf (ogauthority.co.uk) as summarized in Figure 1.

12.1 | Volumes by region

The distribution of production data for the 424 fields across the region as shown in Figures 9 and 10. The majority of total produced volume comes from the CNS and NNS in the form of oil and condensate with relatively negligible gas. The SNS is the main area for gas production with minor contribution from the EIS. With regards to discrete field units, the SNS is most prolific with about 140 unitized accumulations of mainly gas and a few condensate fields.

In-place reserve volumes by basin (Figure 11) show a similar relationship to production as most of the reserves have been produced.

12.2 | Recovery factor by region

Referencing Figure 12, insufficient data were available from the EIS, ESPA and WoS to show a spread of recovery factors for the fields there. Examination of recovery factors across the other four regions show a wider range, higher mean and higher 10th percentile value for the SNS than other basins which is to be expected given that majority of fields in the basin are gas fields which
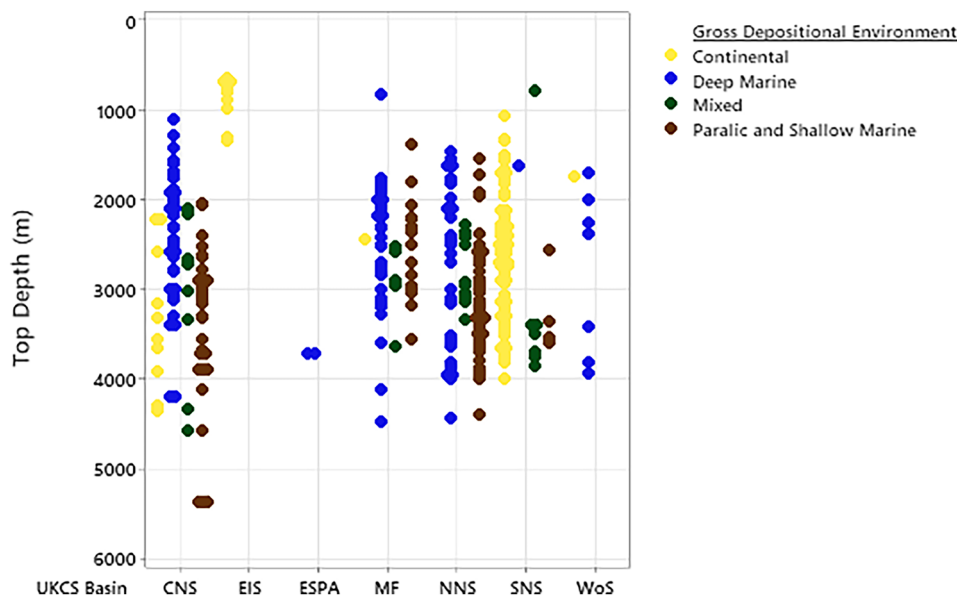
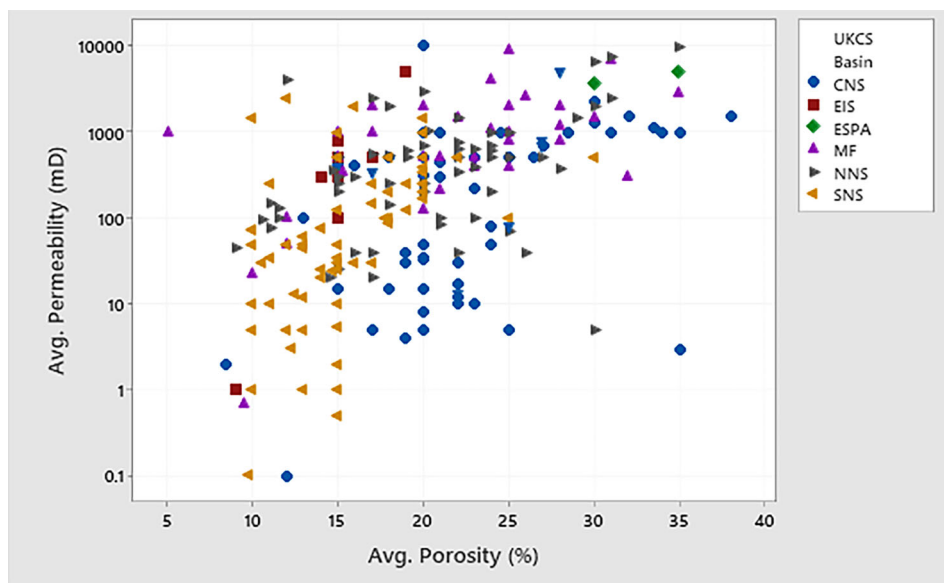**FIGURE 15** Top depth versus basin clustered and color coded by GDE.

FIGURE 16 Cross-plot of average porosity and average permeability values (shape and color coded by basin) for UKCS.

typically has a greater recovery efficiency. Values in the predominantly oil-producing basins reflect greater similarity in distribution of recovery factors.

12.3 | Field rates by region

The distribution of field production rates was examined with respect to the maximum field rates and average cumulative monthly production.

The maximum field rates (Figure 13) show the highest mean (and median) rates in the WoS and NNS and the lowest mean (and median) rates in the SNS and EIS. This probably reflects a correlation to the dominant fluid

phase in production in the different basins with oil being produced at a higher maximum rate.

Similar trends are observed in the average cumulative monthly production rates (Figure 14).

12.4 | Geological parameters by region

Figure 15 shows the regional distribution of top depth for each GDE. The greatest depths are recorded in the CNS in paralic and shallow marine deposits while the shallowest depths are recorded in the EIS Continental GDE. Based on the data, over 80% of reservoirs are found at depths of 2000–45,000 m, with a mean value of 2709 m.

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These depths fluctuate across the sub-basins reflecting the different tectonic histories.

Porosity-permeability (poro-perm) cross-plots for the UKCS grouped by basin (Figure 16) shows generally lower porosity in the gas basins of the SNS and EIS. This reflects the fluid dynamics for gas production which can tolerate lower porosity and permeability. Poro-perm in the oil prone basins is generally higher. This trend is also reflected when poro-perm is assessed by GDE (Figure 17) which is skewed by the large number of continental deposits that host gas fields in contrast to the shallow and deep marine systems which are oil prone and require better properties to produce.

Figures 18–21 highlight this distribution of porosity and permeability across the basins as well based on GDE.

13 | TEMPORAL DISTRIBUTION OF CONTROLS AND PERFORMANCE METRICS IN THE UKCS

13.1 | Volumes by age

Examining produced volumes based on reservoir age in Figures 22 and 23, the Jurassic hosts the majority of oil fields, a few condensate fields, and some gas fields. The majority (almost 70%) of hydrocarbons produced to date on the UKCS come from Jurassic, Paleocene, and Permian age reservoirs; with most of that coming from the Jurassic. The bulk of gas production has been from the Permian age reservoirs mainly hosted in the SNS.
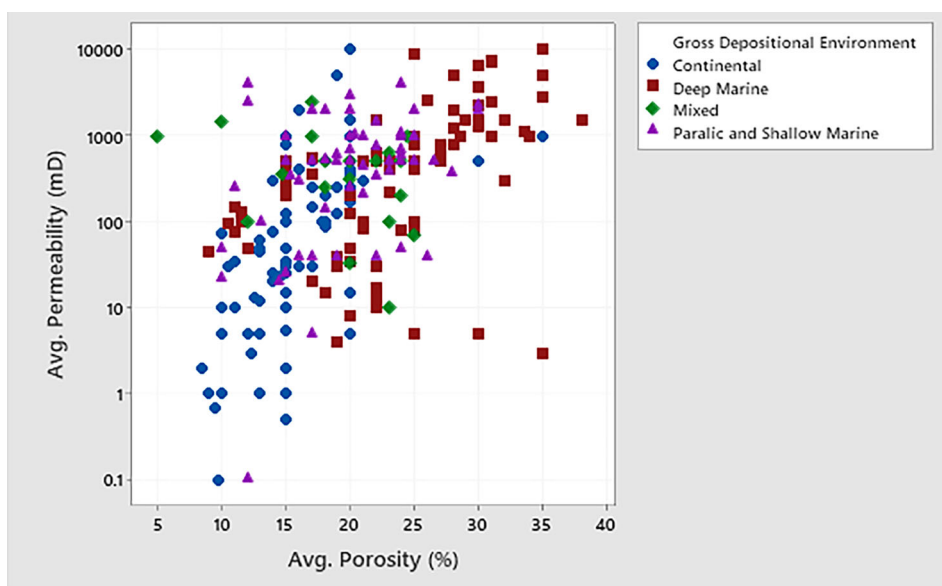

FIGURE 17 Cross-plot of average porosity and average permeability Values (shape and color coded by GDE) for UKCS.
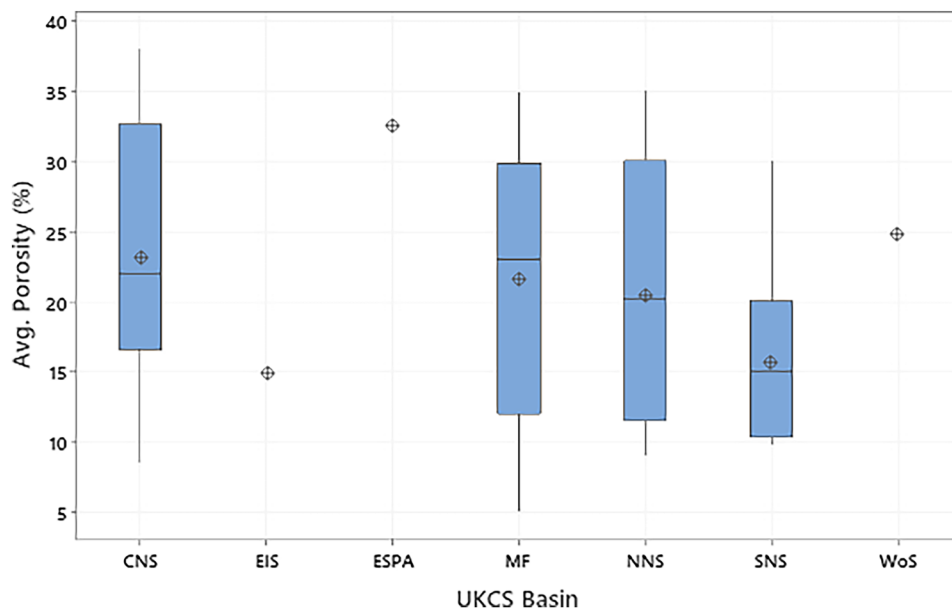

FIGURE 18 Distribution of porosity by basin for 268 fields recording the range, mean, 10th and 90th percentile.
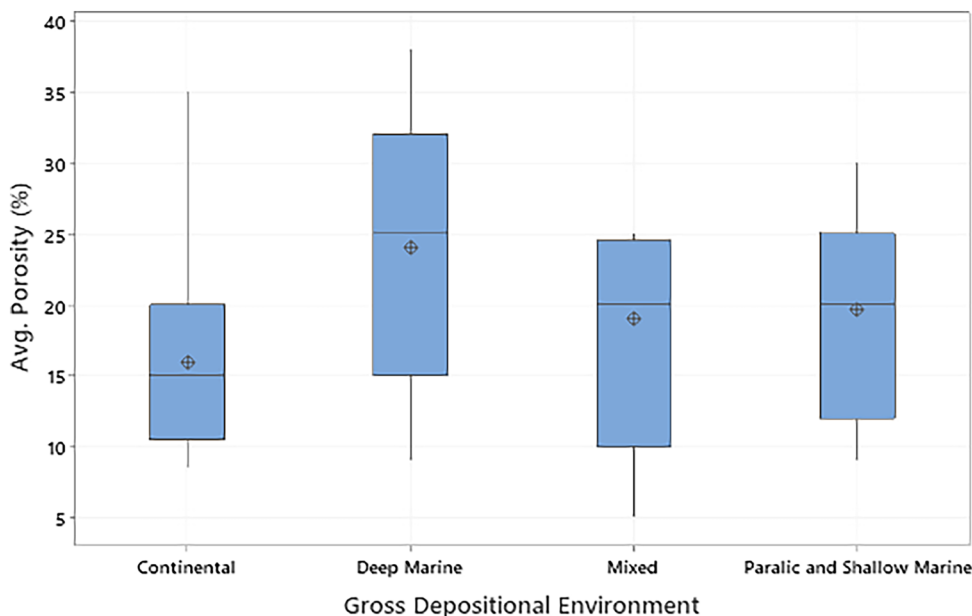
FIGURE 19 Distribution of porosity by GDE for 268 fields recording the range, mean, 10th and 90th percentile.
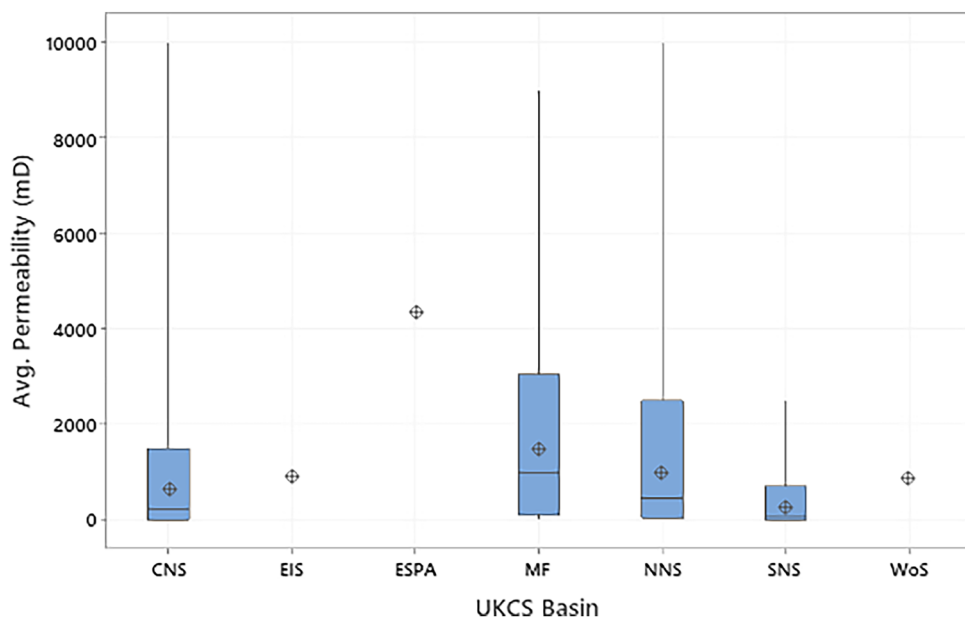

FIGURE 20 Distribution of permeability by basin for 261 fields recording the range, mean, 10th and 90th percentile.

Estimated in-place reserves are similar to the produced volumes as majority of re-serves have been produced already. Jurassic plays host the greatest amount of UKCS hydrocarbon reserves in the form of oil (close to 2000 mmboe) and the Permian hosts the largest gas reserves (under 10,000 mmboe) as seen in Figure 24.

13.2 | Recovery factor by reservoir age

Recovery Factors across the UKCS are wide ranging; from as low as 6% to as high as 97% with an average of 52%. Overall, this is of course dependent on a host of factors including fluid phase, reservoir quality and recovery techniques. Recovery factors by reservoir age (Figure 25) shows the highest values in the Permian, Carboniferous, and Triassic reservoirs evidently due to the nature of fluids produced (gas) from them.

13.3 | Field rates by reservoir age

The highest mean maximum field rates occur in the Jurassic and Paleocene (Figure 26). The Cretaceous fields also along with the Jurassic and Paleocene also have the highest mean average cumulative production (Figure 27). The older Permian and Carboniferous displaying the lowest rates.

FIGURE 21 Distribution of permeability by basin for 261 fields recording the range, mean, 10th and 90th percentile.
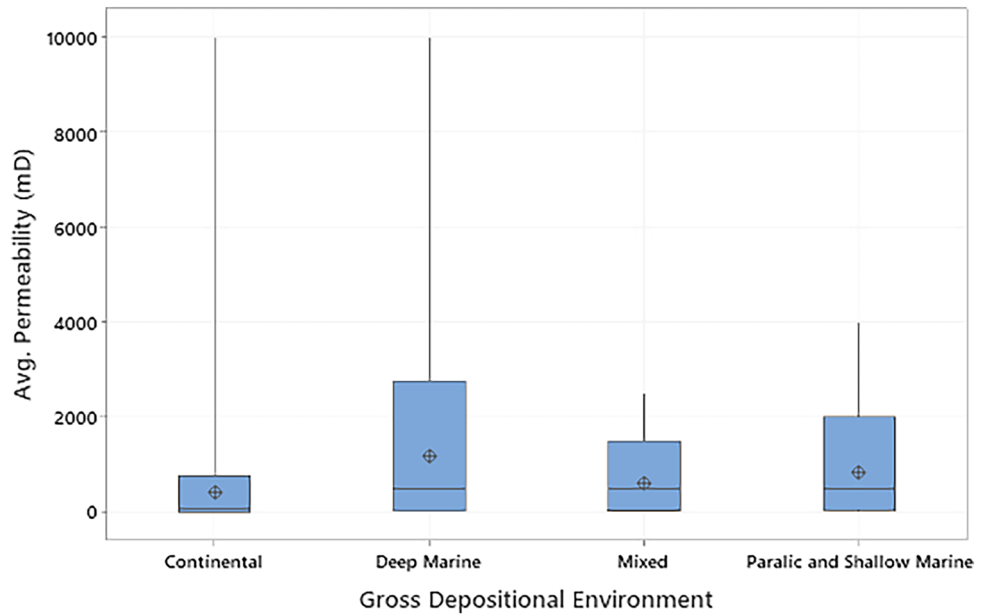

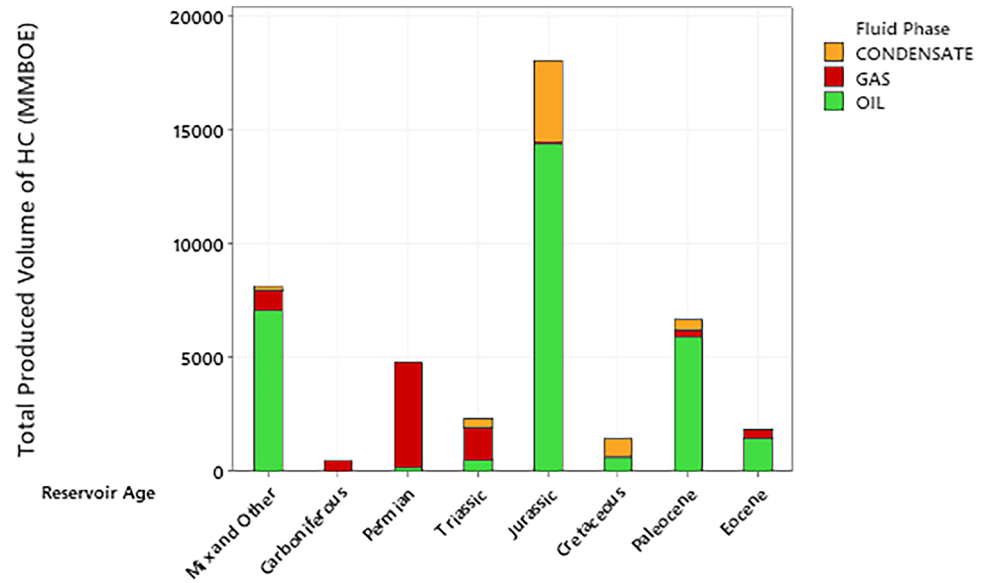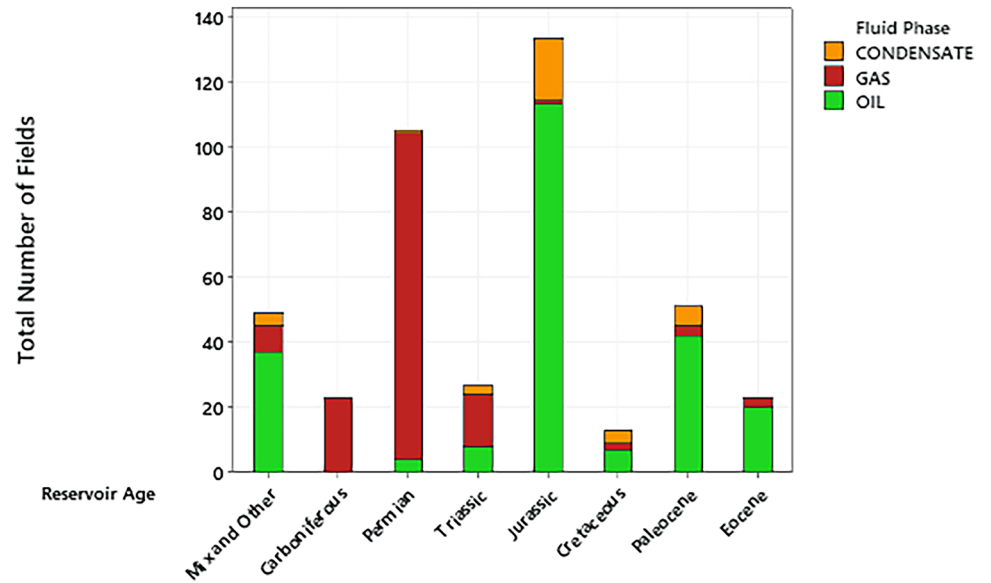**FIGURE 22** Total produced volumes versus reservoir age, stacked and color coded by fluid phase.

FIGURE 23 Total number of fields versus reservoir age, stacked and color coded by fluid phase.
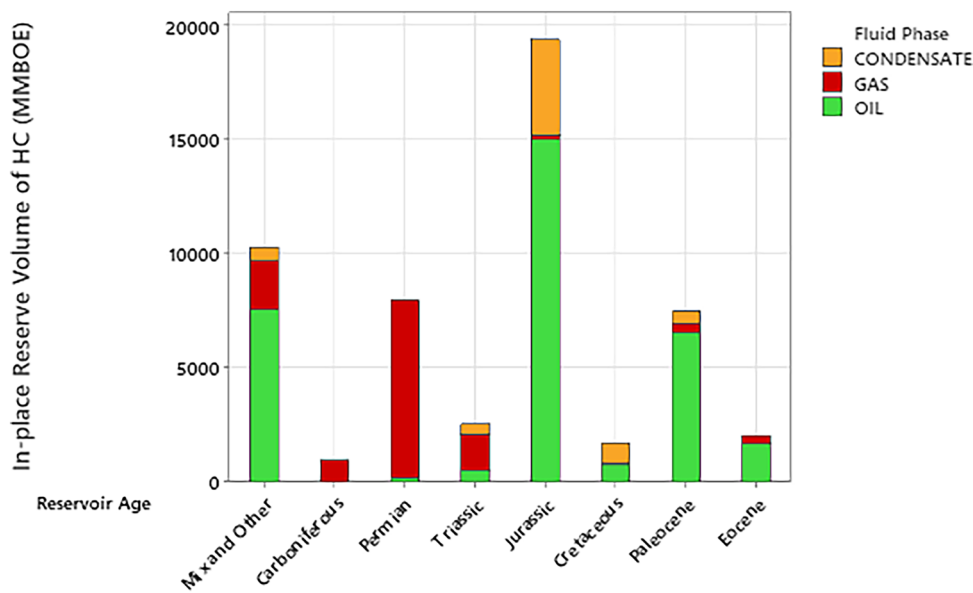
FIGURE 24 Total in-place reserve volumes (deduced using decline curve analysis) versus reservoir age, and color coded by fluid phase.
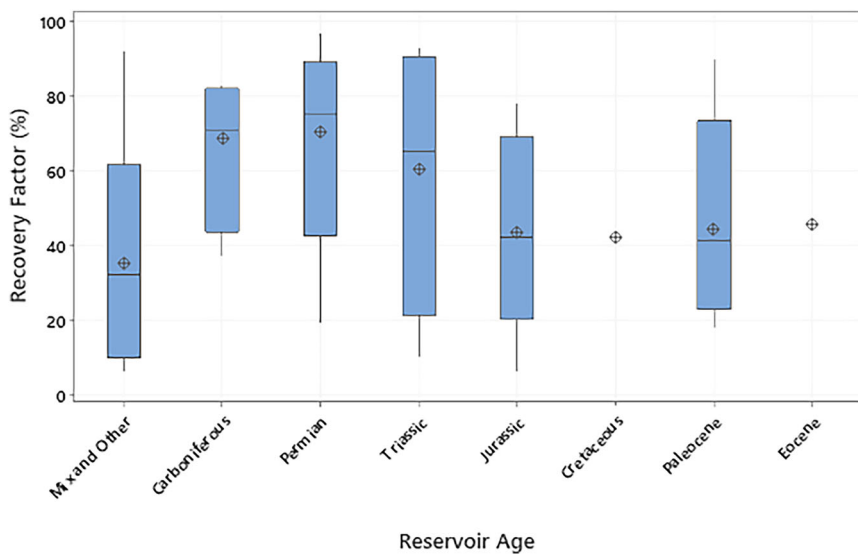

FIGURE 25 Distribution of recovery factors by reservoir age for 238 fields recording the range, mean, 10th and 90th percentile for recovery.
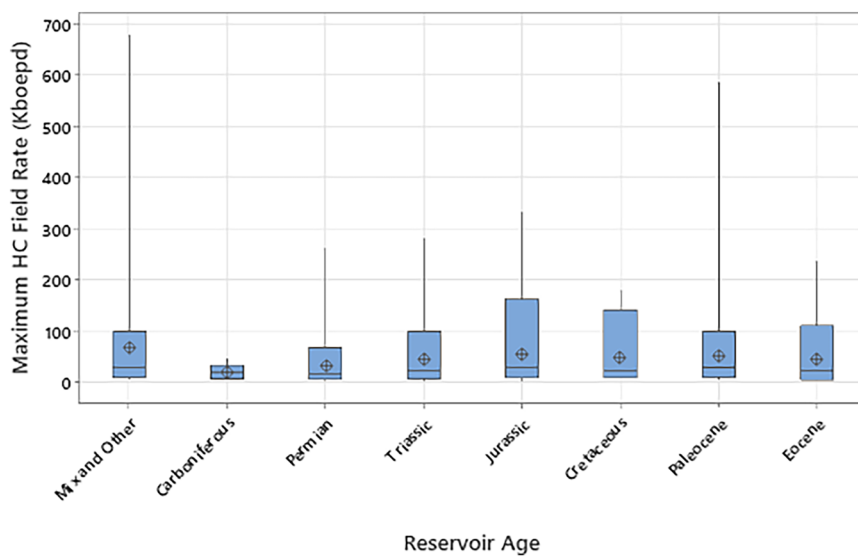

FIGURE 26 Distribution of maximum field rates by reservoir age for 410 fields recording the range, mean, 10th percentile and 90th percentile.

FIGURE 27 Average cumulative monthly production by reservoir age for 410 fields recording the range, mean, 10th percentile and 90th percentile.
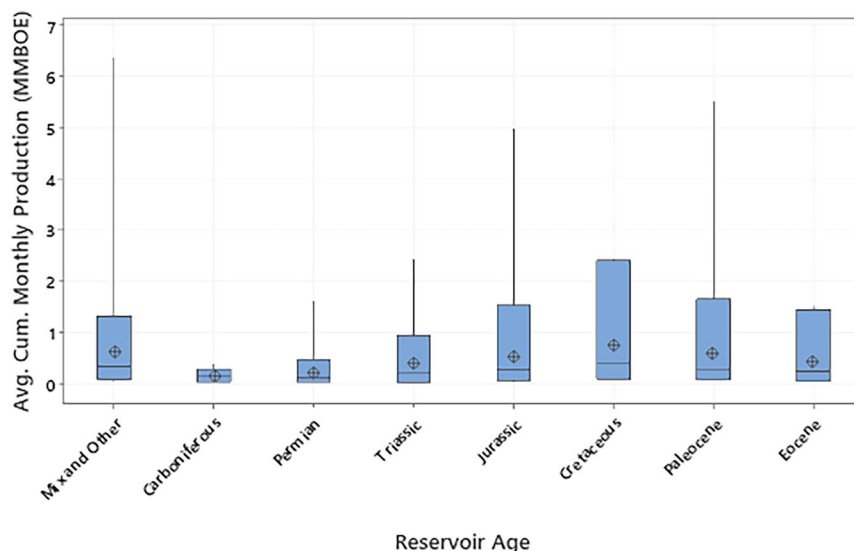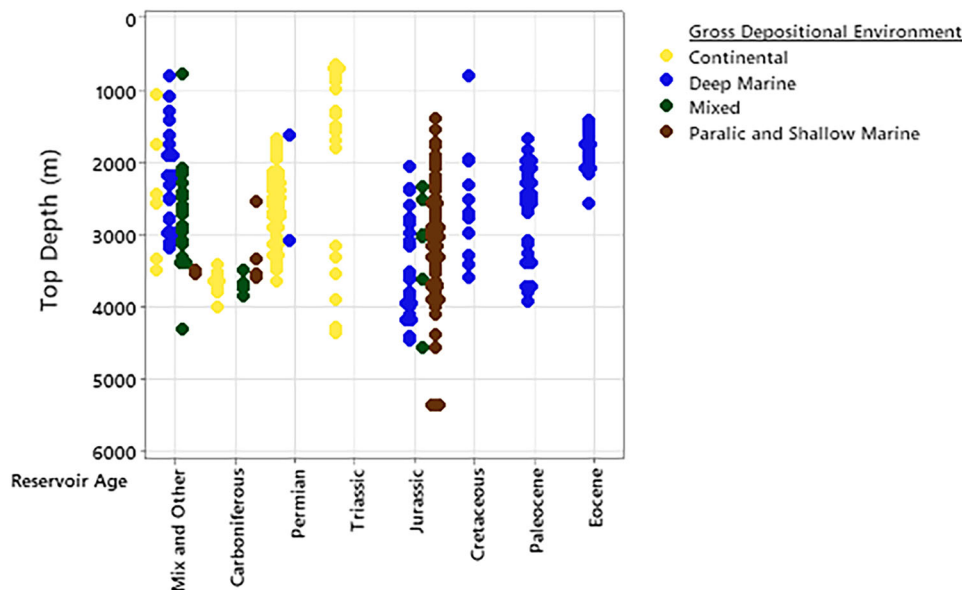
FIGURE 28 Top depth versus reservoir age clustered and color coded by GDE.

13.4 | Geological parameters by age

In Figure 28 the paralic and shallow marine reservoirs of Jurassic age are the deepest buried reservoirs and occur at depths of over 5000 m in the Franklin and Elgin fields. Eocene age reservoirs are the shallowest reservoirs, extending below 3000 m. There is a spread within each period and significantly the oldest reservoirs are not the most deeply buried. With the exception of the Triassic and Jurassic reservoirs of the Central graben, reservoir depth rarely exceeds 4000 m.

Plots for porosity and permeability (Figures 29–31) show a gradual and progressive decrease with age. Eocene reservoirs have the best properties while the lowest are in the Permian and Carboniferous. There are a few notable exceptions to this, Triassic reservoirs have especially high permeabilities and the Cretaceous deepwater deposits are typically better than their younger, Paleocene counterparts. The Cretaceous deepwater deposits are usually very good reservoirs.

14 | POROSITY, PERMEABILITY AND RECOVERY FACTOR BY GDE, BASIN AND AGE

Figures 32–34 show the relationship between average porosity and recovery factor by fluid phase. There are no
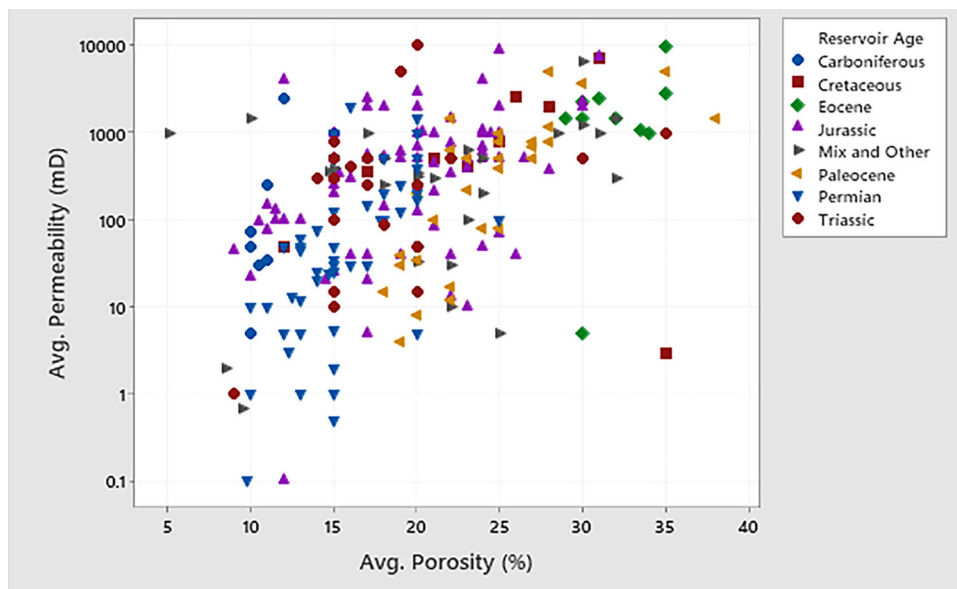
FIGURE 29 Cross-plot of average field porosity and permeability (shape and color coded by age) for UKCS.
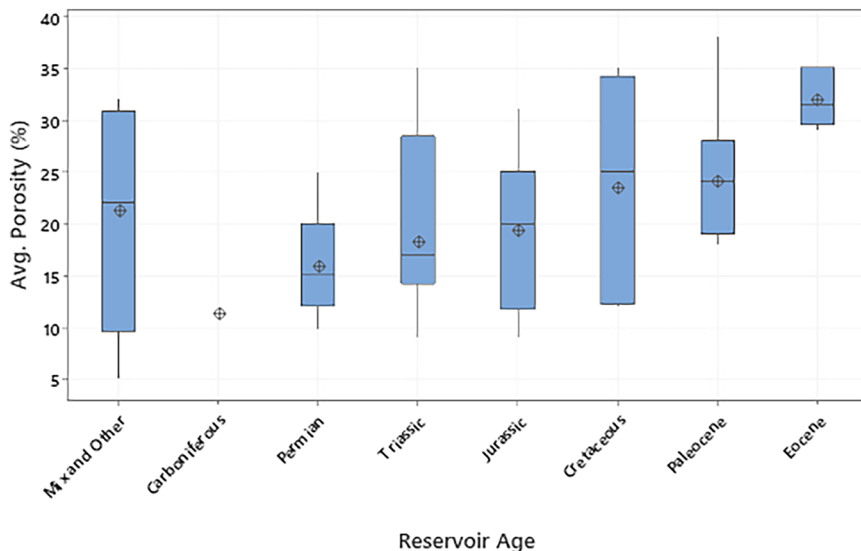

FIGURE 30 Distribution of average field porosity by age for 268 fields recording the range, mean, 10th and 90th percentile.

obvious trends in any of the graphs and very wide spreads of data, suggesting effect of porosity on recovery is not immediately evident.

A similar trend is also seen when similar plots are generated for permeability (Figures 35 and 36) although the plot for oil shows a clear clustering in the upper portion of the graph above a line that diagonally dissects the plot (Figure 37), suggesting that there is an upper limit of recovery that can be achieved for any given permeability.

Visualizing average depth, porosity, and permeability by basins on a map with accompanying data tables (Figures 38–40) we see reservoir quality and depth is on average lower and shallower in the southernmost basins of the SNS and EIS. Crossing the MNSH we see an increase in depth of reservoirs on average and an improvement in reservoir quality. Though with the

fewest amount of data points the West of Shetland seems to have on average deepest reservoirs and best reservoir quality. These trends might suggest improvement of reservoir quality with depth in the region.

15 | DISCUSSION

Exploration of trends in this data distribution across the UKCS region reflects a hydrocarbon province with a complex tectonic history, featuring a wide variety of depositional environments and reservoir fluids. Overall, production has also been very successful with a large proportion of in-place reserves having been recovered and several late-stage regional exploration activities still taking place.

FIGURE 31 Distribution of permeability by age for 261 fields recording the range, mean, 10th and 90th percentile.

FIGURE 32 Cross-plot of average porosity and recovery factors (shape and color coded by GDE) for 10 condensate fields.

FIGURE 33 Cross-plot of average porosity and recovery factors (shape and color coded by GDE) for 79 gas fields.
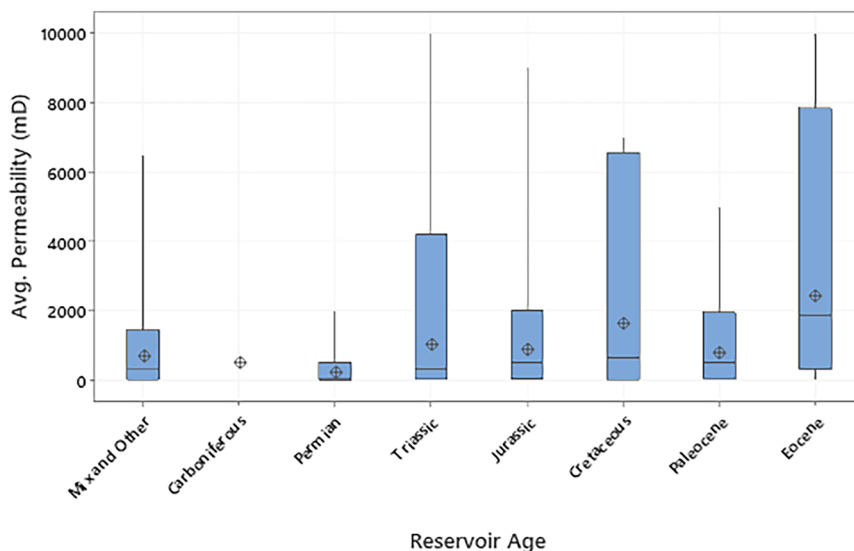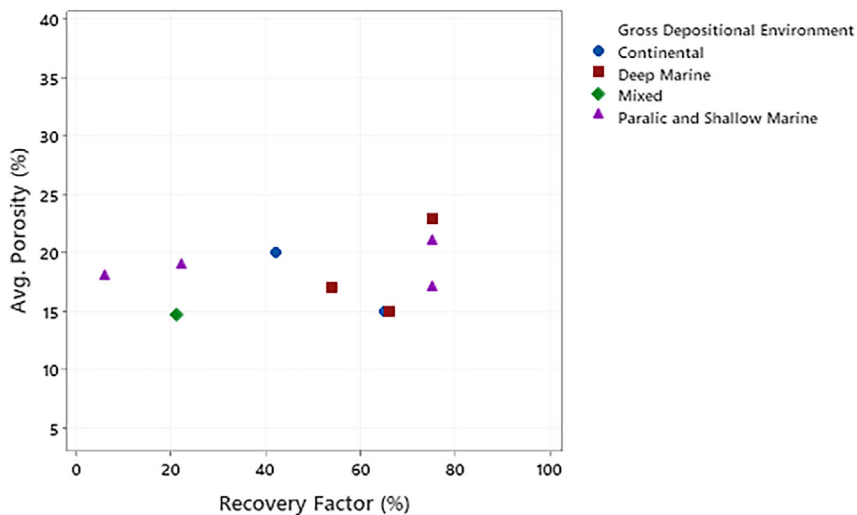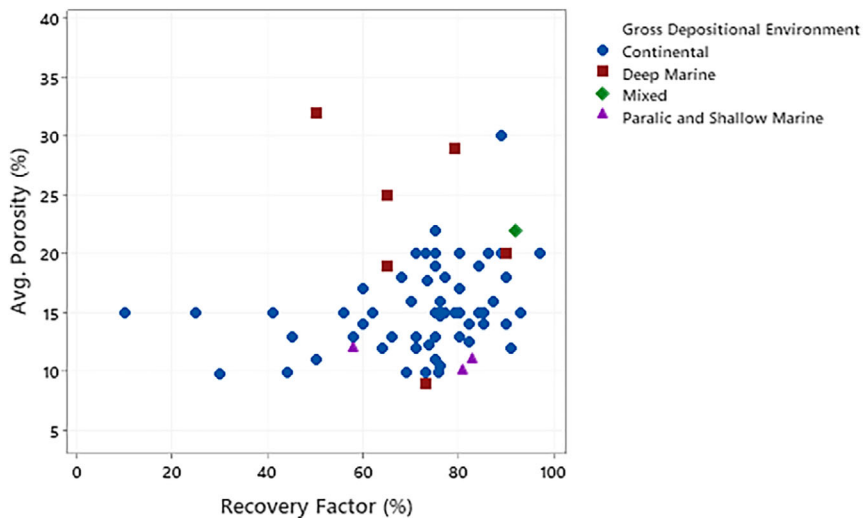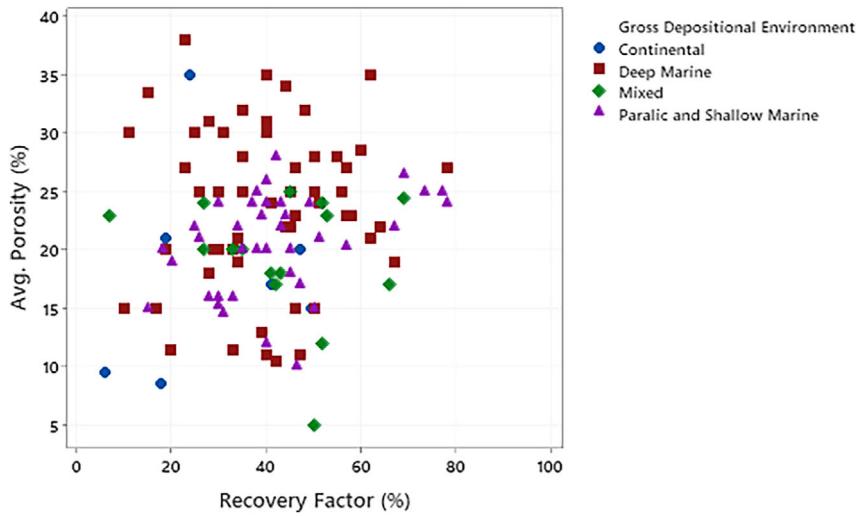
FIGURE 34 Cross-plot of average porosity and recovery factors (shape and color coded by GDE) for 120 Oil Fields.
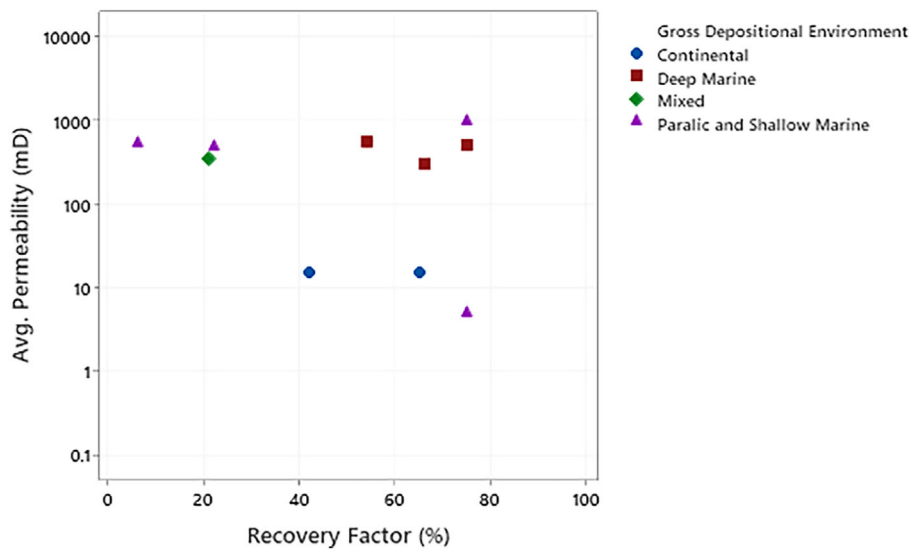
FIGURE 35 Cross-plot of average permeability and recovery factor values (shape and color coded by GDE) for 10 condensate fields.
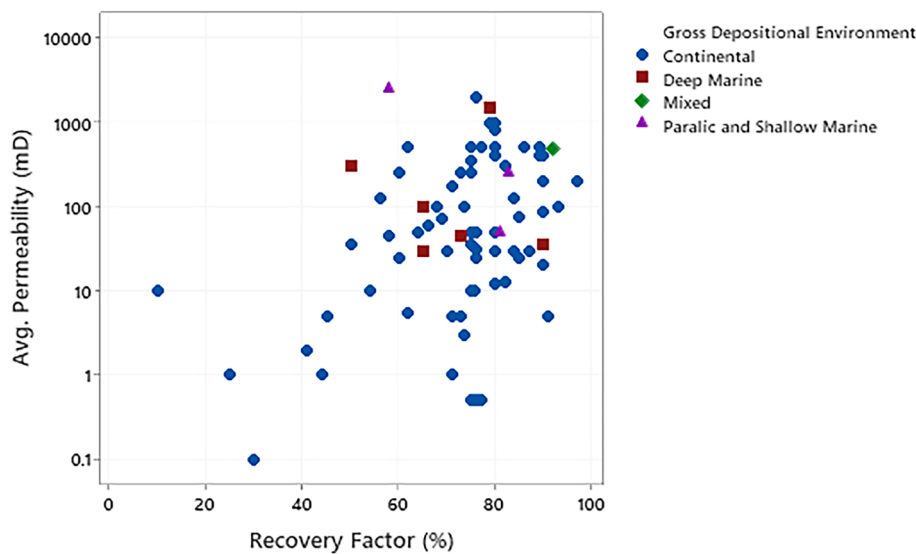
FIGURE 36 Cross-plot of average permeability and recovery factor values (shape and color coded by GDE) for 80 gas fields.

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FIGURE 37 Cross-plot of average permeability and recovery factor values (shape and color coded by GDE) for 117 oil fields.

FIGURE 38 Illustration of average top depth for basins on the UKCS using color ramp; with tabulated statistics showing number of observations, mean, standard error of mean, standard deviation, and quartile measures.

Variable	UKCS Basin	No. of Observations	Mean	SE Mean	St Dev	Minimum	Q1	Median	Q3	Maximum
Top Depth (m)	SNS	136.0	2691.0	55.6	648.7	792.5	2350.7	2610.5	3253.5	4000.0
	EIS	14.0	885.4	67.8	253.6	652.3	701.0	777.2	1068.3	1355.0
	CNS	107.0	2879.3	86.6	895.9	1100.0	2192.1	2774.0	3397.0	5364.0
	MF	59.0	2489.6	88.0	675.9	823.0	2063.0	2430.0	2957.0	4480.0
	WoS	9.0	2587.0	296.0	889.0	1700.0	1875.0	2270.0	3618.0	3936.0
	NNS	97.0	2933.9	75.7	746.0	1475.0	2468.0	3000.0	3539.0	4430.0
	ESPA	2.0	3725.0	0.0	0.0	3725.0	*	3725.0	*	3725.0

Variable	UKCS Basin	No. of Observations	Mean	SE Mean	St Dev	Minimum	Q1	Median	Q3	Maximum
Avg. Porosity (%)	SNS	76.0	15.6	0.4	3.9	9.8	13.0	15.0	18.0	30.0
	EIS	9.0	14.9	0.9	2.7	9.0	14.5	15.0	16.0	19.0
	CNS	65.0	23.2	0.8	6.2	8.5	20.0	22.0	27.8	38.0
	MF	40.0	21.6	1.1	6.6	5.0	17.0	23.0	25.0	35.0
	WoS	8.0	24.8	1.3	3.7	17.0	22.8	26.0	27.0	28.0
	NNS	68.0	20.4	0.7	5.9	9.0	16.0	20.2	24.0	35.0
	ESPA	2.0	32.5	2.5	3.5	30.0	*	32.5	*	35.0

FIGURE 39 Illustration of average porosity for basins on the UKCS using color ramp; with tabulated statistics showing number of observations, mean, standard error of mean, standard deviation, and quartile measures.
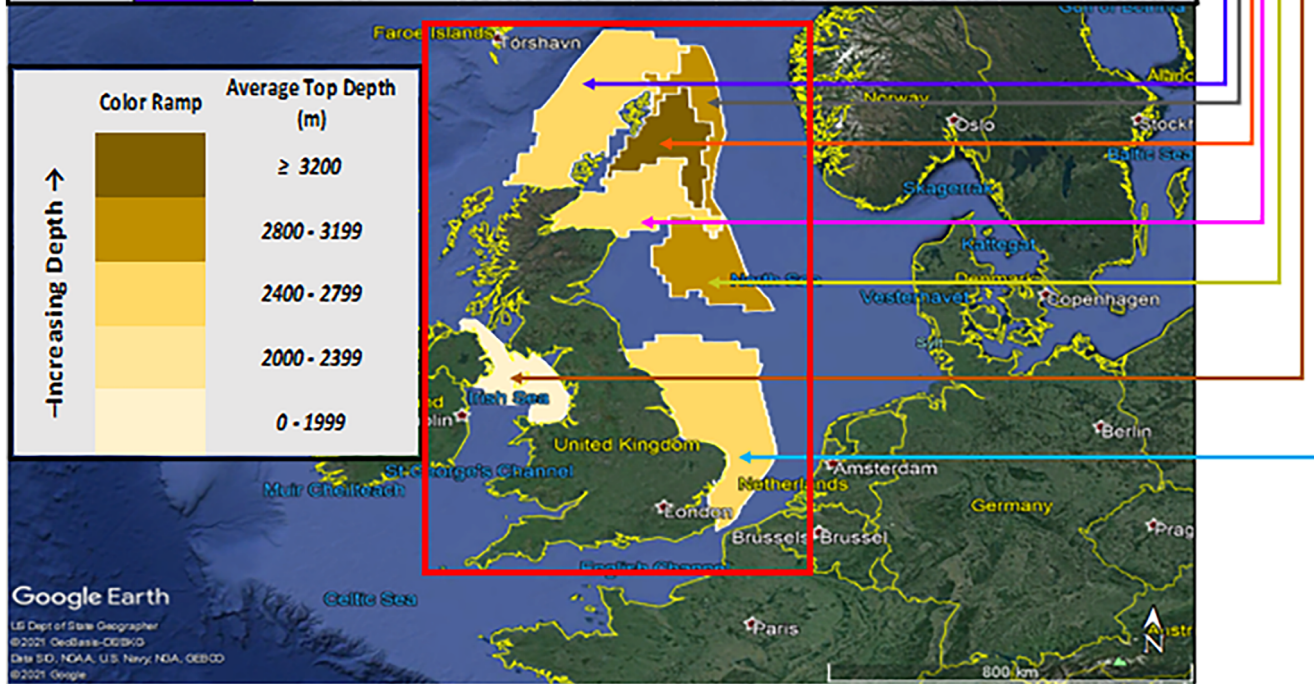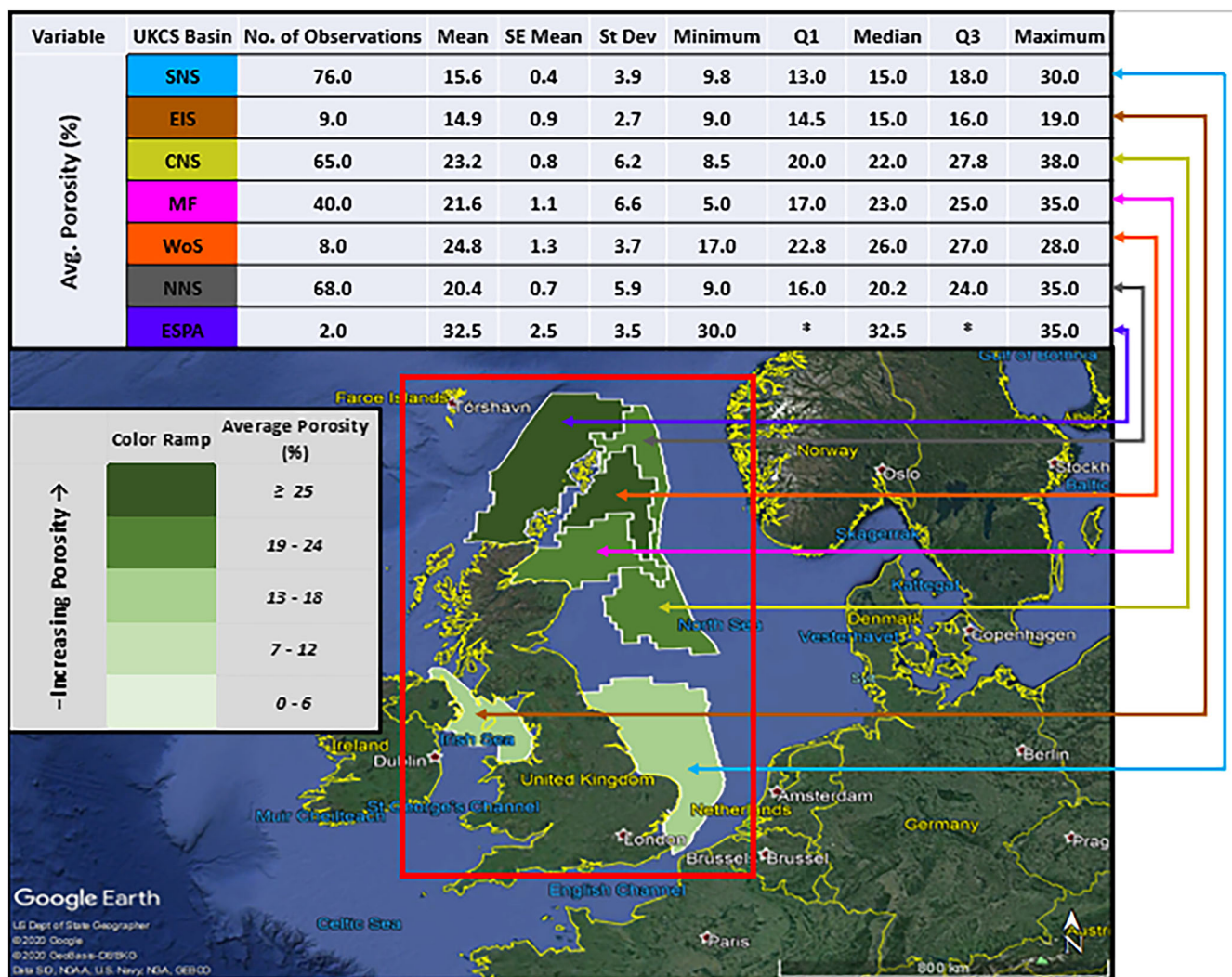
Summarizing the data in a tectonic spatio-temporal context beginning from the post-Caledonian orogeny in the SNS, highlights the majority of Carboniferous reservoirs (approx. 70%) are of continental GDE, being deposited in delta top fluvial systems (Kombrink et al., 2010; Monaghan et al., 2017; Underhill, 2003). They now lie at depths between 2000 m to 4000 m but have had complex burial histories with at least two major phases of uplift (Booth et al., 2020; Pearce et al., 2005). Reservoir quality in the Carboniferous of the SNS appears to be quite variable, commensurate with the high degree of reservoir heterogeneity typically associated with fluvial systems (Issautier et al., 2014; Mode et al., 2017; Ravenne et al., 1989). Given that the bulk of these Carboniferous reservoirs are gas prone, the pressures are high, and the deposits are coarse grained with good permeabilities, and recovery factors are generally good. Rates of depletion in the form of maximum field rate and average cumulative monthly production are relatively low. This is because rates of depletion are deliberately slowed and managed in line with predetermined maximum efficient rates of depletion to avoid lower ultimate recovery at the end of field life (Bruce, 1976; Posner, 1972; Raza et al., 2019; Sukubo & Obi, 2018).

Continental reservoirs dominate the Permian of the SNS, although these are more arid, (eolian and fluvial) and typically finer grained. Similar to the Carboniferous reservoirs, these are also mostly encountered between 2000 to 4000 m with a few shallower occurrences and have also undergone a complex burial history. The reservoir quality in these fluvial and eolian settings are highly variable, reflecting a complex diagenetic history (Leveille et al., 1997; McNeil et al., 1995; Purvis, 1992; Verdier, 1996). There are a limited number of gas-bearing reservoirs, north of the Mid North Sea High but the
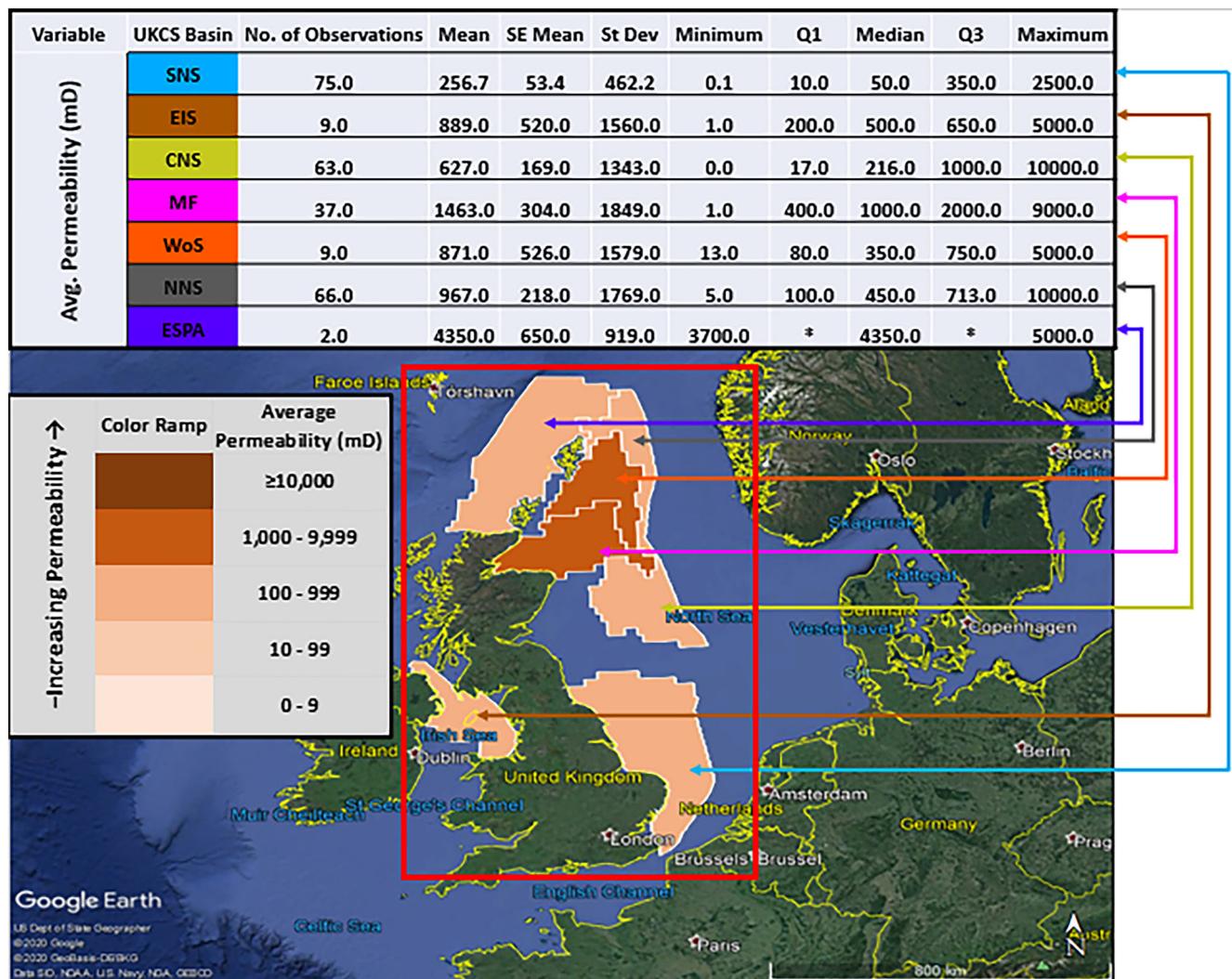
Variable	UKCS Basin	No. of Observations	Mean	SE Mean	St Dev	Minimum	Q1	Median	Q3	Maximum
Avg. Permeability (mD)	SNS	75.0	256.7	53.4	462.2	0.1	10.0	50.0	350.0	2500.0
	EIS	9.0	889.0	520.0	1560.0	1.0	200.0	500.0	650.0	5000.0
	CNS	63.0	627.0	169.0	1343.0	0.0	17.0	216.0	1000.0	10000.0
	MF	37.0	1463.0	304.0	1849.0	1.0	400.0	1000.0	2000.0	9000.0
	WoS	9.0	871.0	526.0	1579.0	13.0	80.0	350.0	750.0	5000.0
	NNS	66.0	967.0	218.0	1769.0	5.0	100.0	450.0	713.0	10000.0
	ESPA	2.0	4350.0	650.0	919.0	3700.0	*	4350.0	*	5000.0

FIGURE 40 Illustration of average permeability for basins on the UKCS using color ramp; with tabulated statistics showing number of observations, mean, standard error of mean, standard deviation, and quartile measures.

majority to the south are gas and consequentially the recovery factors are very high.

In the Triassic, majority of reservoirs are fluvial, deposited in incipient rift basins and salt withdrawal synclines. These Continental deposits extend through the EIS, SNS, CNS and up to the NNS. These reservoirs are a mix of gas, condensate, and oil reservoirs; sometimes occurring at depths as shallow as 700 m in the EIS and SNS and down to depths over 4000 m in the NNS. Again, we observe a high degree of variability in the sample population's reservoir quality. With the range of fluids produced and the range of poro-perm measurements, recovery factors are equally and expectedly diverse. Production rates also play to type, dependent on fluid phase.

With the paucity of lower Jurassic deposits as discussed in Section 4, we observe mainly middle Jurassic paralic and shallow marine deposits accompanied by upper Jurassic deep marine deposits traversing the CNS and MF through the NNS and up to the WoS. These reservoirs are overwhelmingly oil reservoirs with a few condensate reservoirs, typically at depth. Top reservoir depths extend to over 5000 m. Once again, with extensive deltaic deposits, reservoir performance is highly variable. Production rates are generally on the higher side. Data shows that majority of in-place reserves on the UKCS are found in these shallow marine Jurassic reservoirs in the form of oil.

Following the termination of Jurassic rifting in the early Cretaceous, deep marine conditions resulted in turbidite deposits overlain by chalk. The Cretaceous reservoirs are mainly present in the outer MF and into the CNS where they pass upward to the Paleocene reservoirs. Top depths occur to about 3600 m. Both porosity and permeability in sampled fields were mostly >20% and >100 mD) respectively. With turbidite reservoirs there is some measure of complexity regarding empirical

inferences on reservoir quality (Munawar et al., 2018) and so without examining diagenetic histories and architectural elements on most of these, that would be avoided. There is little data available on recovery factors, but the few data points show moderate to low recovery (<60%). Production rates are among the highest in the study area.

The Palaeogene deposits also host turbidite reservoirs as referenced in Section 4. These Eocene and Paleocene reservoirs have top depths in the range of 2000–4500 m. Reservoir quality is mainly good, especially with regards to porosity (15%–20% on the lowest average measures). Permeability only seems to be poor in a few reservoirs but is mostly >100 mD. Palaeogene reservoirs extend throughout all basins north of the Mid North Sea High (MF, CNS, NNS, ESPA, and WoS) as mostly oil reservoirs with a few gas and condensate fields. Recovery factors for Paleogene reservoirs are mostly ≤60% and production rates are on the high side.

Examining the information through the lens of gross depositional environment we see that depth ranges and mean values for reservoir occurrences in deep marine and continental reservoirs are most similar (~700–4400 m and 2500 m respectively). Paralic and shallow marine reservoir top depths show deeper minimum (~1400 m) and maximum (~5400 m) values and a higher mean value (~3100 m). As seen in Figure 2, 19 deep marine as well as paralic and shallow marine reservoirs are shown to be of consistently higher reservoir quality than continental reservoirs. Some of the reasons for these differences in reservoir quality as well as production behavior across the depositional environments are discussed in Shepherd (2009a, 2009b). Regardless of these differences in reservoir quality and due to the influence of other factors including fluid phase of hydrocarbons produced, trends in recovery are variant across depositional environments.

At the formation/group level Continental deposits of the Permian Leman sandstones independently host the largest amount of in-place reserve volumes in the form of gas, followed by Brent group paralic and shallow marine GDE reservoirs in the form of oil and then the forties deep marine GDE reservoirs hosting oil.

16 | CONCLUSION

This article documents the compilation of a database which captures the range of geological, PVT and engineering parameters that may influence hydrocarbon production. Data were compiled from a total of 424 fields and surface-level analysis was undertaken. This has revealed some broad trends in the data but there is also significant variability, which suggests that the relationships are more complex. As such, this first stage of the analysis serves primarily to document the distribution, both stratigraphically and geographically of the major units. Offshoots of this work will focus on more detailed multivariant statistical analysis of the data in order to investigate the relative importance of the various factors and shed further light on their interactions. The data presented in this article are taken from a wide variety of publicly available information which is not universally distributed across all of the fields. This analysis has produced a database which can be sub-sampled to focus on the fields with the best coverage of data for subsequent analysis.

CONFLICT OF INTEREST STATEMENT
The authors have no conflict off interest to declare.

DATA AVAILABILITY STATEMENT
Data for this research were acquired from a variety of public sources. The curated database along with a complete list of references is available from the University of Aberdeen Library Cataloguing Service (cataloguing@abdn.ac.uk).

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