

Porosity trends in the Skagerrak Formation, Central Graben, United Kingdom Continental Shelf: The role of compaction and pore pressure history

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ABSTRACT

This paper describes reservoir properties in the Triassic Skagerrak Formation in the Central North Sea. This prolific sandstone reservoir often possesses anomalously high porosity for its depth of burial. Simple statistical analysis of wire-line-log-derived porosity data is used to derive empirical trends as a function of both depth and vertical effective stress that show variations between neighboring hydrocarbon fields and between different parts of the basin. Porosity data from the Josephine (J) Ridge (Quadrant 30 of the United Kingdom Continental Shelf [UKCS]) show a marked degradation with depth, but the porosities are significantly higher than in similarly deeply buried areas such as the Puffin high to the west (Quadrant 29) or the Forties–Montrose high to the north (Quadrant 22). To understand the porosity patterns better the data have been analyzed by plotting against vertical effective stress. This allows a better comparison to be made between fields and wells within the high-pressure–high-temperature (HPHT) realm. High pressure here refers to fluid pressures above 10,000 psi (703 kg/cm), whereas high temperatures are above 300°F (149°C). Results show that porosity and fractional effective reservoir (the proportion of net sandstone with a porosity greater than a predetermined cutoff) decrease systematically with increasing vertical effective stress. Data from the different J Ridge fields fall on a common compaction trend even though they are derived from structures with marked variations in present-day depth of burial and static formation overpressure. Trends from the other areas of the Central Graben (the Puffin and Forties–Montrose

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highs) indicate more indurate reservoir states. The observed porosity trends are independent of fluid type within the reservoir and the absolute magnitude of overpressure. The main observed hydrocarbon effect is the result of buoyancy forces. The analysis supports the contention that, after accounting for facies-related grain-size variations, compaction controls average reservoir properties. Differences in compaction state between areas are postulated to relate primarily to structurally controlled timing of overpressure development relative to burial, and how these affect the resultant vertical effective stress history. Both the Puffin and Forties–Montrose highs are directly attached to the basin margins across stepped faults. These marginal terraces were open to lateral fluid flow for longer probably because across-fault seals were only established late in the burial history when higher temperatures promoted cementation and the destruction of permeability within fault cores. As a result, they developed overpressures in the last 5–10 m.y. or so and are largely normally compacted. The J Ridge horst block is hydrologically more isolated within the basin center by across-fault juxtaposition seals. Here, overpressure development appears to have started earlier, possibly between 50 and 60 Ma, retarding compaction and allowing preservation of higher porosities. Compaction continues to present day driven by the large static vertical effective stress gradients in these deeply buried reservoirs. The observed empirical trends offer a means of predicting average reservoir properties in deep untested exploration targets.

INTRODUCTION

The Triassic Skagerrak Formation is an important sandstone hydrocarbon play in the Central Graben, North Sea. It has proven to be a very prolific reservoir, but one that has also presented several challenges. One of the foremost challenges has been the prediction of reservoir properties as this is very variable within the basin. Traditionally reservoir quality is characterized through studying depositional patterns, subsidence history, and associated sandstone petrography and diagenesis utilizing core samples (e.g., Lippmann et al., 2005; Nguyen et al., 2013). These individual detailed studies help identify the key controls on porosity, but do not always allow more regional comparisons to be made or predictive models to be built. This paper aims to take a different approach and to analyze borehole-derived porosity–depth and porosity–effective stress trends from the Skagerrak Formation across the Central Graben, and to use these trends to build a predictive regional model. Statistical filtering is used to extract the average property trends, which are then interpreted in terms of the regional

structure and fluid overpressure history, rather than focusing on a more traditional and rigorous approach that attempts to marry basin modeling with detailed petrographic studies. It is hoped that this approach complements existing studies. In addition, it will be shown to offer a simple yet robust means of predicting average rock properties in exploration prospects.

The Skagerrak Formation has yielded some of the most significant discoveries in recent years in the North Sea. These include the Jade and Jasmine fields on the Josephine (J) Ridge (Quadrant 30 of the United Kingdom Continental Shelf [UKCS]), each of which has around 170 million barrels of oil equivalent (BOE) of reserves (Jones et al., 2005; Archer et al., 2010) and the Culzean field further to the north (In Quadrant 22), which has 220–250 million BOE resources (Figure 1). Generally, the Triassic reservoirs are deeply buried and are subject to high temperatures and variable, but often high, fluid overpressures. In drilling terms, the reservoir conditions are described by high-pressure–high-temperature (HPHT), referring to fluid pressures in excess of 10,000 psi (703 kg/cm), and temperatures in excess of 300°F (149°C). Many data sets are available to help assess the factors that influence porosity trends in this reservoir unit, comprising released exploration wells and proprietary data sets from producing fields.

The burial of sedimentary strata in a basin has long been known to cause porosity loss (Athy, 1930). This can result from both mechanical and chemical processes that operate together during the burial history (Lundegard, 1992). These processes include mechanical compaction (pressure-induced grain packing and distortion), chemical compaction (pressure solution), diagenetic reactions, and cementation (Allen and Allen, 2005). In mechanical compaction it is the weight of the overburden that physically compresses the grain framework causing small grain adjustments that result in permanent volumetric strain. These adjustments arise from grain slippage, ductile grain deformation, and by grain fracturing (Lander and Walderhaug, 1999). Together these mechanisms contribute to the exponential porosity-loss curves observed in many basins.

In the North Sea, the standard compaction curves used are those derived by Sclater and Christie (1980)

from analysis of well data. These authors used sonic log data from Paleocene and Jurassic reservoirs. They derived an exponential porosity-loss curve that was extended to shallow depths using surficial data from other published sources. Sonic log data from normally pressured shale and chalk sections were also used to compute compaction curves for these other key lithologies in the basin. The Sclater and Christie compaction curves use the Rubey and Hubbert (1959) porosity model:

$$\phi = \phi_o e^{-cZ} \quad (1)$$

in which both ϕ_o (surface porosity) and c (the porosity–depth coefficient) are functions of lithology, and Z is the depth below seabed. Parameter values for the North Sea are given in Table 1.

Other porosity-loss processes are largely temperature activated and generally have a greater influence as burial proceeds and within older reservoirs. Mechanical compaction typically ceases when a rigid grain framework is established. This occurs in sands that contain rigid grains when the intergrain volume (IGV) is around 25–30%, though the amount of compaction is grain size and sorting dependent. Grain crushing can accompany this early compaction, particularly in coarser grained sands (Chuhan et al., 2002). Early cementation facilitates the strengthening of the grain framework (Lander and Walderhaug, 1999; Bjorlykke, 2006). Sandstones that are poorly sorted and/or contain common ductile grains can compact to less than 20% IGV. Further porosity loss is then the result of pressure solution, mineral physicochemical changes, grain fracturing, and/or cement authigenesis. These processes may also show some dependence on the magnitude of vertical load.

This paper investigates the compaction state of the Skagerrak Formation by using simple statistical methods to study porosity changes as a function of depth and pore pressure. The approach taken relies largely on developing empirical trends. The aim is to extract from the well data the average trends in total porosity with depth (as calculated by petrophysical analysis) and to study these trends rather than look in detail at sandstone petrography and diagenesis, or to analyze core-based porosity and

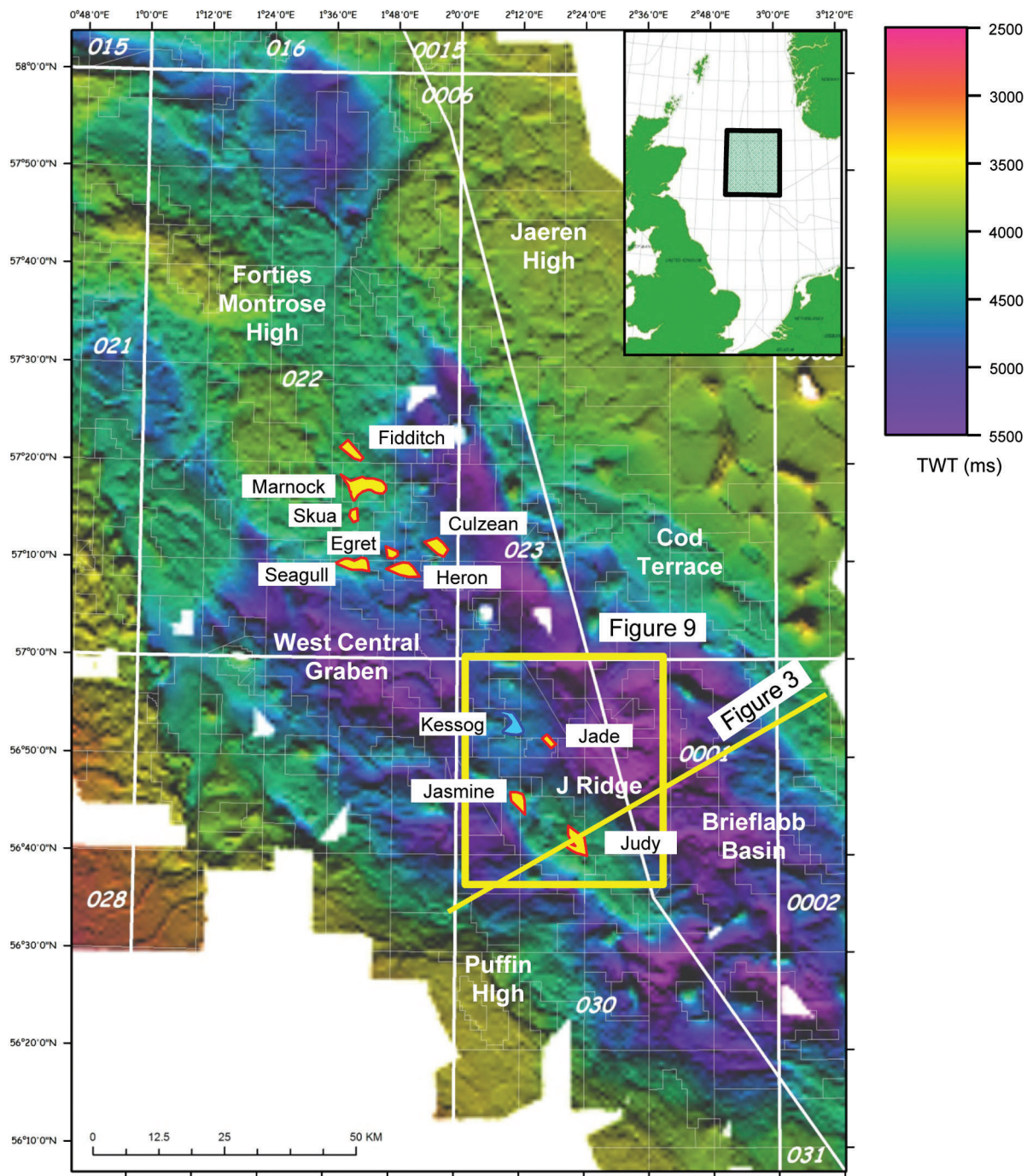


Figure 1. Regional base Cretaceous unconformity two-way time (TWT) map for the Central Graben highlighting the location of the main Skagerrak Formation fields. The fields are clustered on the southeastern flank of the Forties–Montrose high and on the J Ridge. The location of the Jurassic Kessog field is also shown as it is referred to later in the text.

permeability measurements. This is because core data rarely allow full characterization of reservoir units, particularly where they are very thick, and because not all wells are cored. Typically, core is only collected from the hydrocarbon-bearing upper and, therefore, higher porosity zones of the Skagerrak

Formation. Although understanding diagenetic processes is important for predicting reservoir quality, particularly at the microscale, other larger scale trends can be missed. These trends, and how they can be manipulated to derive empirical models for predicting bulk reservoir properties, form the focus of this paper.

Table 1. Parameter Values Derived by Sclater and Christie (1980) for Sediment Compaction in the North Sea

Lithology	Sclater and Christie Porosity Algorithm Exponents		
	Surface Porosity	Porosity-Depth Coefficient (ft ⁻¹)	Matrix Density (g/cc)
Sandstone	0.49	0.000082	2.65
Shale	0.63	0.00015544	2.75
Chalk	0.7	0.000216397	2.82
Water			1.04

A number of factors strongly influence porosity and act on a range of overlapping scales. These include depositional facies, grain size and sorting, petrography, allogenic clay content, and authigenic cements (Bloch et al., 2002). Their effects are to introduce a large amount of statistical variation to the measured porosity data. In this study, these factors are to some extent filtered using the computed volume of shale parameter (V_{shale}). Simple statistical averaging is then applied to the data to remove bed-scale facies variations and to extract what are the low-frequency background trends within net sands. As will be shown, this simple approach yields results that allow inferences to be made on the main controls on porosity preservation and destruction in the Skagerrak Formation reservoirs. They argue strongly for the predominance of compaction state and, by inference, pore pressure history (not just present-day pore pressure), as a key influence on porosity preservation in the Triassic sandstone reservoirs of the Central Graben. The results complement previous studies on reservoir compaction in the North Sea (e.g., Fisher et al., 1999), and add additional insights into the reasons for late compaction in deeply buried sandstones.

GEOLOGICAL SETTING

The Central Graben of the North Sea (Figure 1) is a prolific hydrocarbon province containing more than 20 billion barrels of discovered hydrocarbon resources. These are held in a host of different reservoirs and trap styles within the pre-, syn-, and post-rift sequences of the basin. The graben formed largely during a Late Jurassic east-northeast–west-south-west-directed rift episode (Roberts et al., 1990). This

was superimposed on an earlier and milder extension event that occurred in the Triassic (Errat et al., 1999). The extension was strongly partitioned in both rift episodes by the reactivation of a Caledonide metamorphic grain. This created an en echelon rift system that steps eastward via a number of accommodation zones. These zones are associated with east–west- and north–south-oriented faults and are responsible for the development of a number of large intrabasinal horst blocks. In the Central Graben the main horsts are called the Forties–Montrose high and the J Ridge, and separate the Central Graben into east and west Jurassic basins.

Subsequent post-rift thermal subsidence and sediment influx has deeply buried the main graben system and the medial horsts since the end of the Jurassic rift episode. Today they lie below a 3–4 km (1.86–2.49 mi) thick blanket of Cretaceous and Cenozoic strata. A significant increase in burial rate has occurred in the last 5–10 m.y. in the basin due to increased sediment flux from the United Kingdom and Scandinavian margins.

A summary stratigraphic chart for the Central Graben is shown in Figure 2. The sub-Cretaceous comprises Devonian–Carboniferous clastics, Permian Rotliegendes sandstone, Permian Zechstein salt, and a thick unit of Triassic redbeds that comprises the Smith Bank and overlying Skagerrak Formations. In the Jurassic, the prerift is represented by the Pentland Formation, a paralic sequence that locally contains coals. The Middle Jurassic Pentland Formation often sits on deeply eroded Triassic strata across the intrabasinal highs, the result of the mid-Cimmerian unconformity (Underhill and Partington, 1993), a regional surface related to Jurassic doming in the North Sea prior to regional extension. The Triassic strata and, to a lesser extent the Pentland Formation, were deposited in salt-controlled minibasins. The upper Jurassic syn-rift succession comprises the Oxfordian to Ryazanian Heather and Kimmeridge Formations of the Humber Group (Donovan et al., 1993; Rattey and Hayward, 1993). The post-rift succession comprises the lower Cretaceous Cromer Knoll Group, a largely deepwater shale-prone interval that locally contains limestone stringers and some thin turbidite sands. This is succeeded by the Upper Cretaceous Chalk Group. The overlying Cenozoic megasequence comprises

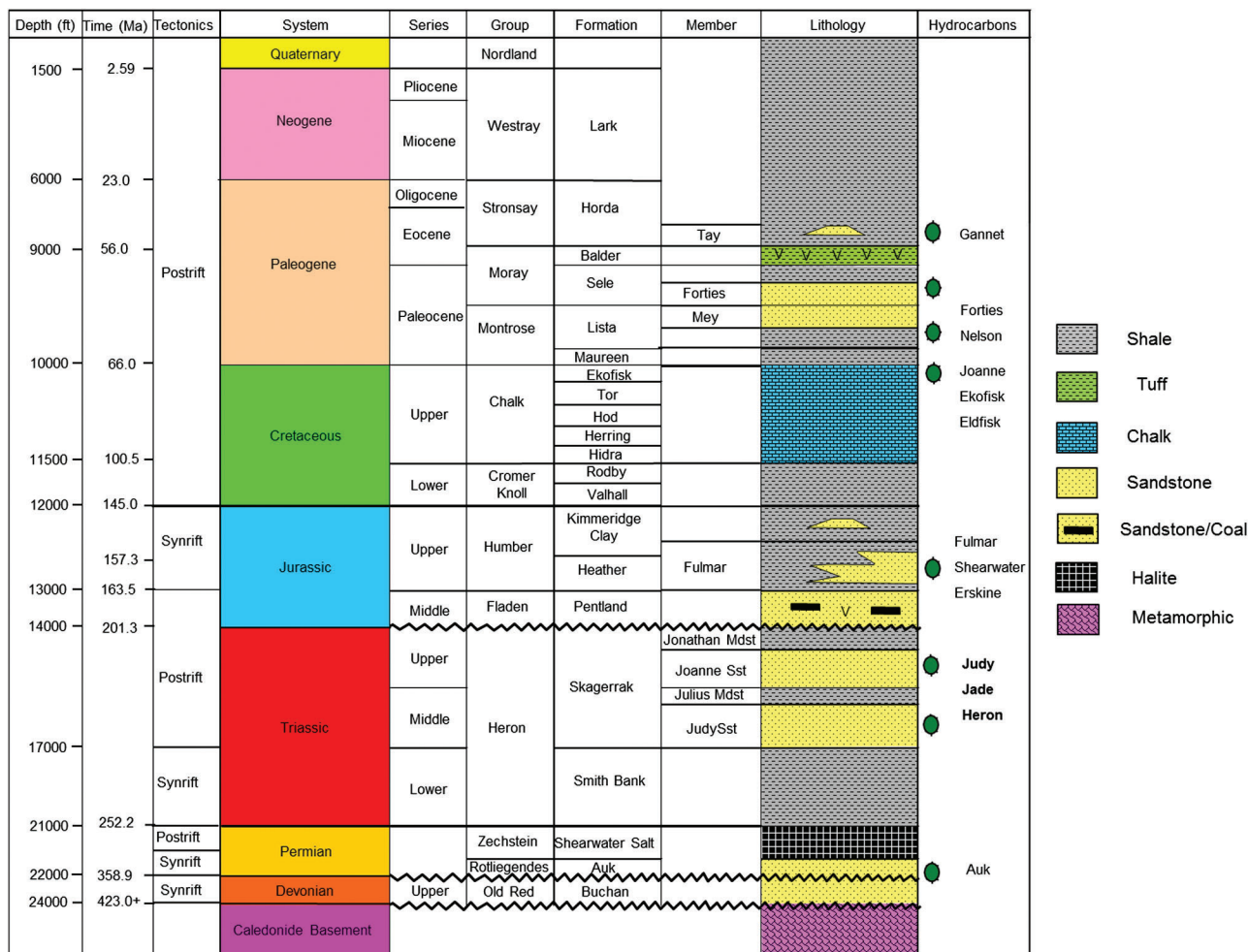


Figure 2. Regional stratigraphy of the Central Graben. Ages shown are from the International Commission on Stratigraphy chronostratigraphic chart by Cohen et al. (2013). North Sea stratigraphic nomenclature is from Knox and Cordey (1992).

deepwater clastics more than 3 km (1.86 mi) in thickness. The Montrose Group comprises a number of large deepwater turbidite fan systems that were shed from the Shetland platform during early Paleocene hinterland rejuvenation. After the North Atlantic Ocean opened, the Eocene and younger Hordaland Group was deposited and comprises predominantly siltstone and shale.

The Late Jurassic rift event was strongly influenced by the presence of a thick layer of Permian age salt (Smith et al., 1993; Errat et al., 1999). This mobile layer served to partially decouple the basement-related extensional fault movements from the overburden. Major rift-related fault displacement is often accommodated by salt movement with associated forced folding of the overlying Triassic and Jurassic strata. In addition, many of the salt stocks

and walls that existed prior to the onset of extension, collapsed during Late Jurassic rifting. This had two principal effects. It created local accommodation space for Jurassic synrift deposits and it produced a series of turtle-back anticlines in the intervening Triassic minibasins. The result is a suite of complex structural geometries that are now the locus of the main hydrocarbon accumulations in the Triassic and Jurassic strata across much of the Central Graben (Helgeson, 1999).

Figure 3 shows a depth section across the Central Graben, centered on the J Ridge. The J Ridge is an intrabasinal horst block separating two deep grabens: the Harrier Basin to the west and the East Central Graben (or Brieflab Basin) to the east. The line of section crosses the Judy field at the crest of the J Ridge. The known fluid pressure regimes within

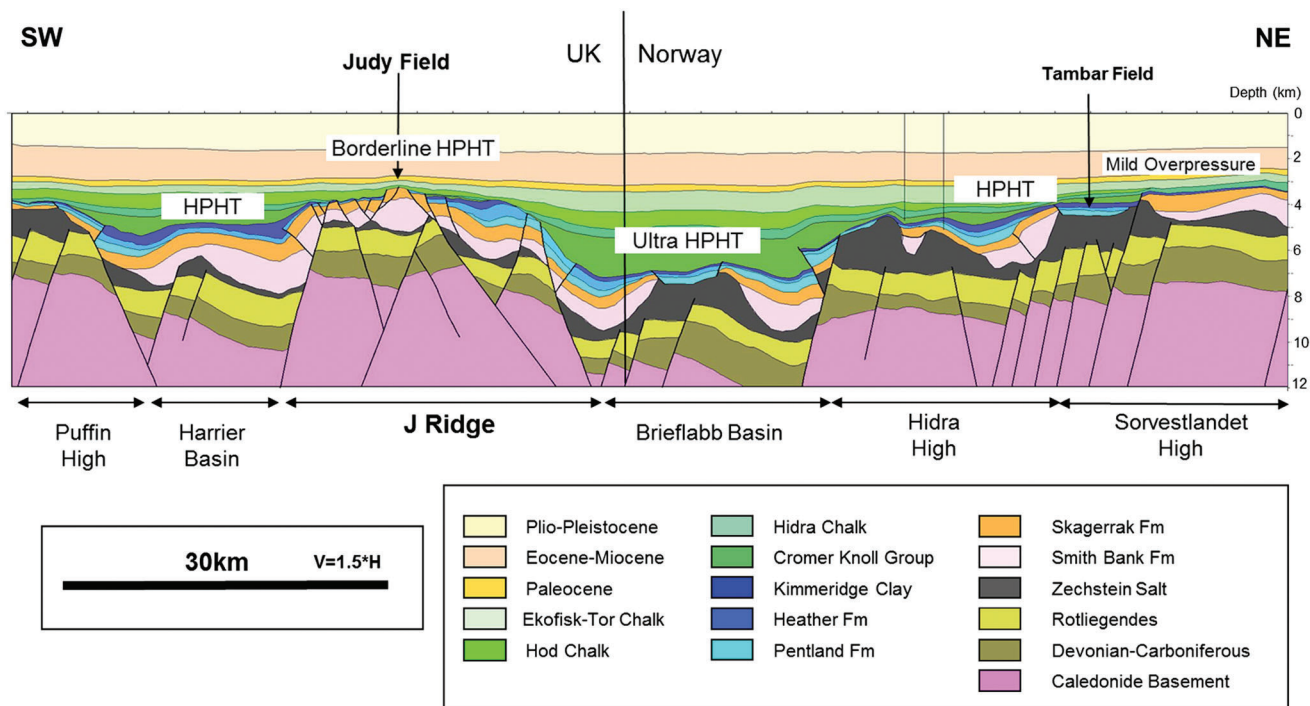


Figure 3. Regional southwest–northeast-oriented depth cross section across the Central Graben highlighting basin structure and pore pressure regimes. The location of the line of section is shown in Figure 1. HPHT = high-pressure-high-temperature.

the sub-Cretaceous are highlighted and vary from mild overpressure in the east on the Sorvestlandet high to what is referred to as ultra-HPHT in the deep grabens. Ultra-HPHT is loosely classified as a fluid pressure in excess of 15,000 psi (1055 kg/cm) and a temperature above 350°F (177°C). As shown in the section, the magnitude of overpressure is closely related to basin structure and depth of burial, decreasing from the deep grabens toward the gently dipping basin margins.

Representative burial plots for Triassic structures on the J Ridge are given in Figure 4. These are the product of a proprietary three-dimensional (3D) basin model. They serve to outline how ambient temperature has evolved during the last 220 m.y. of burial of the Skagerrak Formation, and how the rate of burial has accelerated in the last 50 m.y. This latter feature has been one of the main contributing factors to hydrocarbon generation and overpressure development in the basin. The main rift episode is not expressed in the

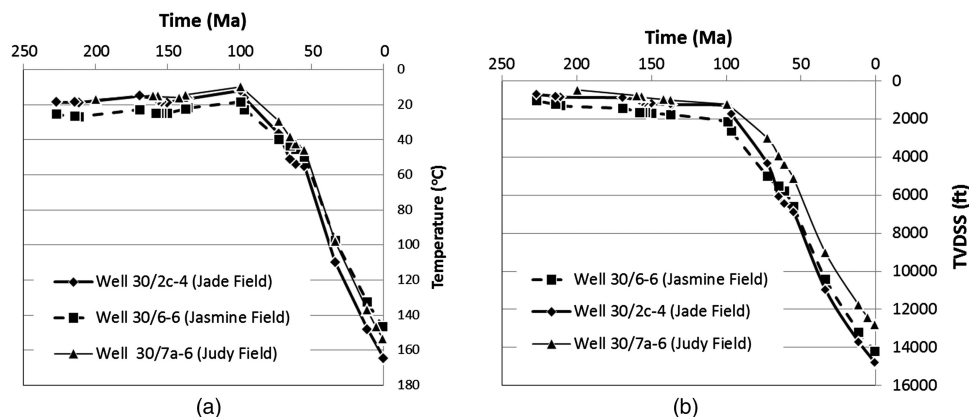


Figure 4. Burial and temperature history plots from three wells on the J Ridge. The data show how the burial has accelerated in the Cenozoic.

burial plots because the J Ridge remained an intrabasinal high during Late Jurassic rifting.

STRATIGRAPHY OF THE SKAGERRAK FORMATION

The Triassic Heron Group in the Central Graben is divided into two formations: the Smith Bank Formation and the overlying Skagerrak Formation. The Skagerrak Formation is itself divided into a number of members (Goldsmith et al., 1995, 2003). The two key reservoir units are the Joanne and Judy Sandstone members. These have similar facies and were deposited in a large terminal fluvial system in a dry-land setting (McKie and Audretsch, 2005). These units are sandstone rich and comprise a mosaic of stacked fluvial braid-plain facies including channel

fills, sheet floods, terminal alluvial fan deposits, calcic paleosols, and floodplain siltstones. Fluvial drainage was influenced by salt movement as the underlying Permian (Zechstein) halite was evacuated during deposition creating a series of minibasins (Smith et al., 1993). These minibasins now form turtle-back anticlines due to the later Jurassic salt collapse. These faulted anticlines form the main traps for the Skagerrak Formation fields.

Summary logs from two representative wells are shown in Figure 5. These wells offer type sections for the Joanne and Judy Sandstone members of the Skagerrak Formation. Both comprise thick sequences of interbedded sandstone and either shale or siltstone. The net-to-gross ratio for both units is more than 50% and, where fully preserved, these reservoirs exceed 1300 ft (396 m) thick. In both type wells, the porosity

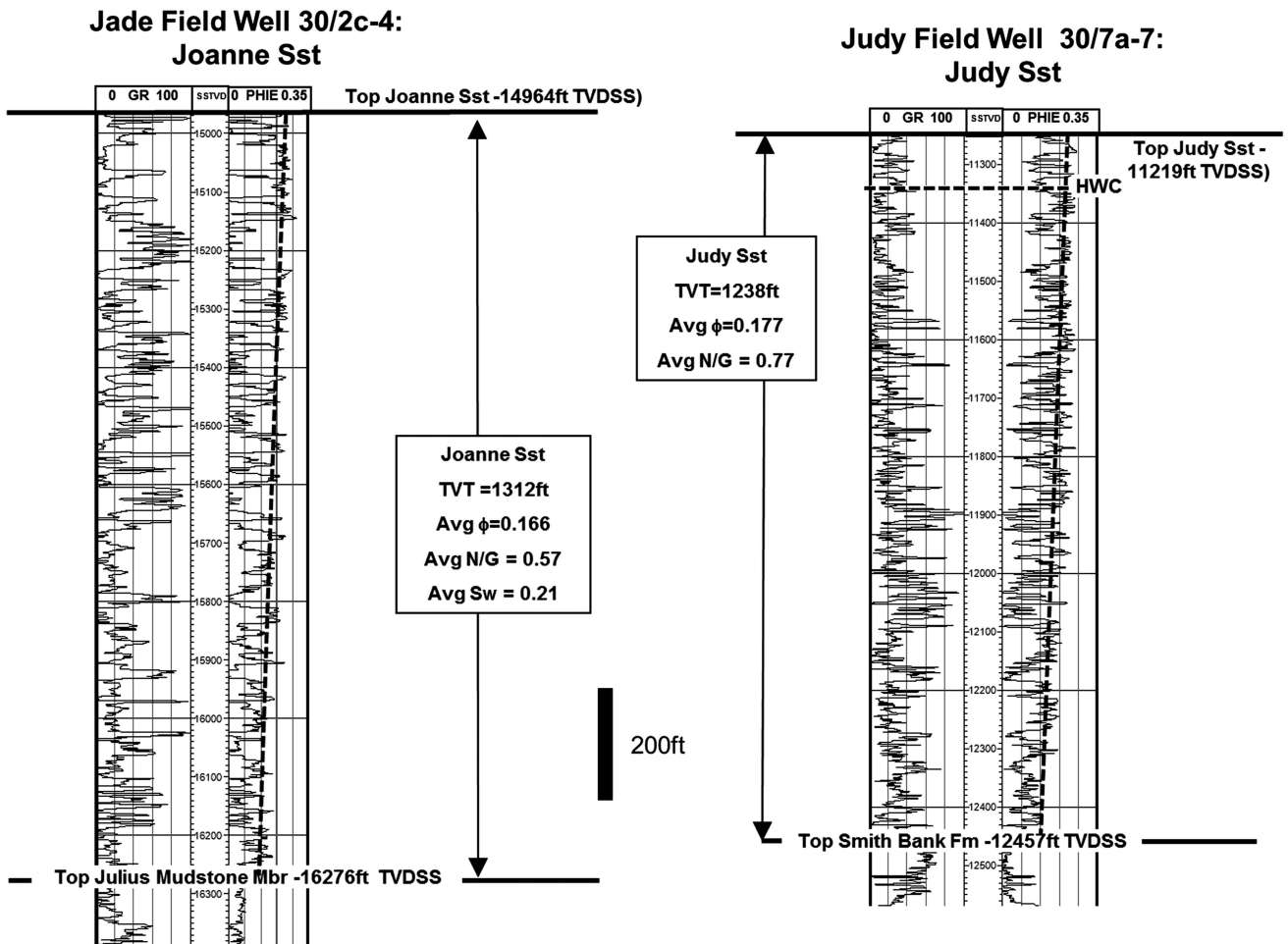


Figure 5. Type logs for the Joanne and Judy Sandstone members of the Skagerrak Formation from J block wells 30/2c-4 (Jade field) and 30/7a-7 (Judy field). The three well tracks are (from left to right) gamma ray, TVDSS, and porosity. TVDSS = true vertical depth subsea; Sst = Sandstone.

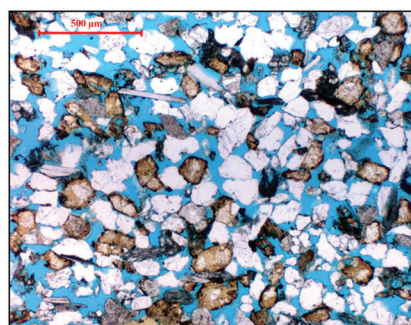
clearly degrades with depth (highlighted by bold dashed lines in Figure 5). The Joanne Sandstone in Jade well 30/2c-4 has an average net effective porosity of 16.6 pu (porosity units for which 1 pu = 1% fractional porosity) from a depth interval of 14,964–16,276 ft (4561–4961 m). In contrast, the Judy sandstone in the 30/7a-7 well has an average net effective porosity of 17.7 pu in the interval from 11,219 to 12,457 ft (3420 to 3797 m). As will be shown later, depth alone is not a good predictor of reservoir porosity when comparing these two wells. Porosity does decrease with depth both in terms of trends within individual wells and also for groups of wells drilled at different depths in the same field (see section titled Analysis Results). The aim of this paper is to analyze these trends and to understand the key controls on porosity preservation, and thus permit a robust and predictive model to be developed.

DIAGENESIS OF THE SKAGERRAK FORMATION

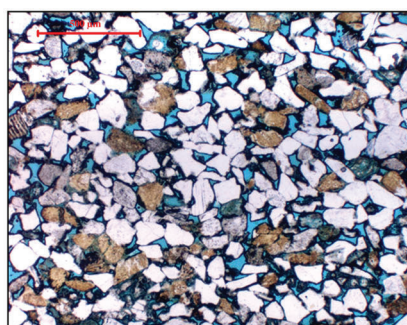
Although not strictly the subject of this paper, it is worth reviewing the diagenesis of the Triassic Skagerrak Formation as it ultimately influences reservoir quality trends. The diagenesis has been the subject of a number of research papers (Smith et al., 1993; Lippmann et al., 2005; Nguyen et al., 2013). These highlight a complex diagenetic history controlled by the grain size, sorting, and the facies of the sandstones. The main cement phases are quartz and locally carbonate and feldspar. Early salt cement

has recently been identified by Nguyen et al. (2013). This phase is interpreted to have been removed during fluid flushing associated with deeper burial and hydrocarbon migration, helping to increase (recover) primary porosity. Grain coatings such as illite and chlorite are common, and their presence is correlated with low quartz cement volumes. The presence of pore-lining chlorite rims occlude grain surfaces and therefore prevent significant quantities of framework stabilizing authigenic quartz from precipitating. Similar observations have been made by Osborne and Swarbrick (1999) in the overlying Jurassic Fulmar Formation where microquartz rims, high-pore-fluid salinity, and overpressures are considered to retard quartz precipitation and pressure solution (the development of stylolites).

As vertical load increases with depth of burial, the absence of pervasive cementation permits continued sediment compaction. Eventually, grains can start to get crushed when their yield strength is exceeded at point contacts (Milliken and Laubach, 2000; Makowitz et al., 2006) or dissolved by diffusive mass transfer at higher temperatures. These are more likely in deep normally pressured basins where vertical effective stresses are high. Grain fracturing at point contacts has not been described from the Skagerrak Formation, although it has been documented in the overlying Fulmar Formation (Fisher et al., 1999). Most of the diagenetic phases documented in the Skagerrak Formation formed before the late onset of both high overpressure and hydrocarbon charging (Lippmann et al., 2005).



Well 30/7a-8
Depth of burial = -11702 ft TVDSS
Porosity = 25 pu, kh = 1150 md
Vertical Effective Stress ~ 2000 psi
Q/F/R(%): 51/31/18
Cement = 15%



Well 22/19-1
Depth of burial = -11619 ft TVDSS
Porosity = 11 pu, kh = 0.56 md
Vertical Effective Stress ~ 2300 psi
Q/F/R(%): 61/21/18
Cement = 12%

Figure 6. Thin-section micrographs from two Skagerrak Formation fluvial reservoirs in the Central Graben. Data published with the permission of Neil Meadows, Redrock International. Q = quartz, F = feldspar, R = lithics. Cement = pore-filling blocky cement. Porosity is colored blue. Feldspar is stained. Bitumen grain coatings are black. Scale bar 500 microns. TVDSS = true vertical depth subsea.

Controls on reservoir quality are best addressed by detailed petrography. Thus, cement proportions can be evaluated and the relative timing of cement phases determined. This paragenesis can be equated to grain size and composition to derive a qualitative impression of how porosity is lost in a rock sample, that is, how much is lost to compaction versus cementation or grain deformation. Questions such as how dispersed clay affects permeability, and how grain dissolution enhances reservoir productivity, can be answered. These observations address the grain- and pore-scale processes. They are not necessarily best suited to deriving statistical trends in reservoirs that are thousands of feet thick. For this reason, this paper takes a different, but hopefully complimentary approach, using the statistical analysis of wire-line-log data.

To illustrate the problem of porosity prediction and modeling in the Skagerrak Formation of the Central Graben two thin section micrographs are presented in Figure 6. These show fluvial sandstone reservoirs from two different fields, one from the

Judy field on the J Ridge (well 30/7a-8), and the other from the Fiddich field on the Forties–Montrose high (well 22/19-1). Both are interpreted to show fluvial channel facies, and, from petrographic analysis, have similar grain size, similar compositions, and similar quantities of pore-filling cement. They presently possess similar static reservoir conditions (temperature and estimated vertical effective stress) based on near-identical burial depth and measured fluid pressures. Yet, one reservoir has 25% porosity and greater than a Darcy of permeability, the other only 11% porosity and a permeability of less than 1 mD. Clearly, one is visually more compact than the other, but why has this occurred? This is the key question that will be addressed here.

DERIVATION OF VERTICAL EFFECTIVE STRESS

The vertical effective stress (VES) is the weight of the overburden not supported by pore pressure and defines the vertical load imposed on the grain

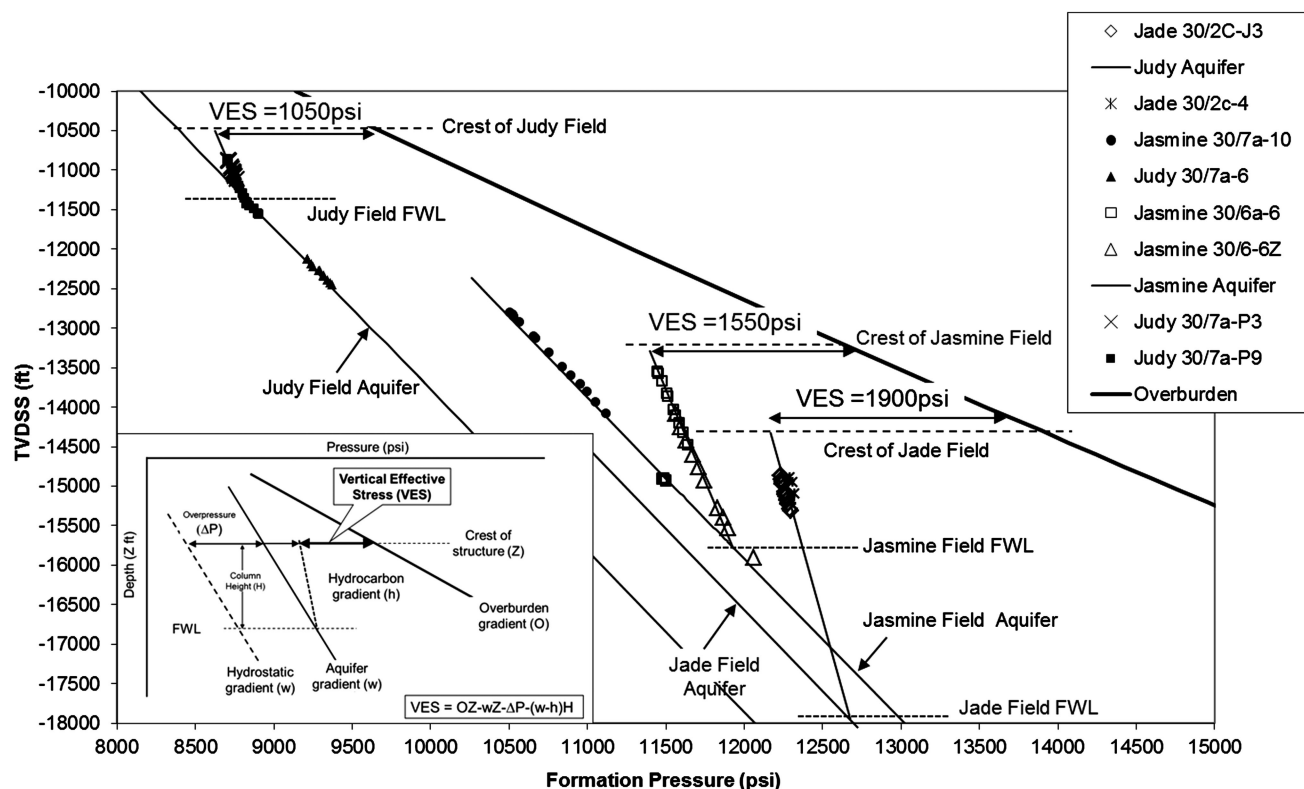
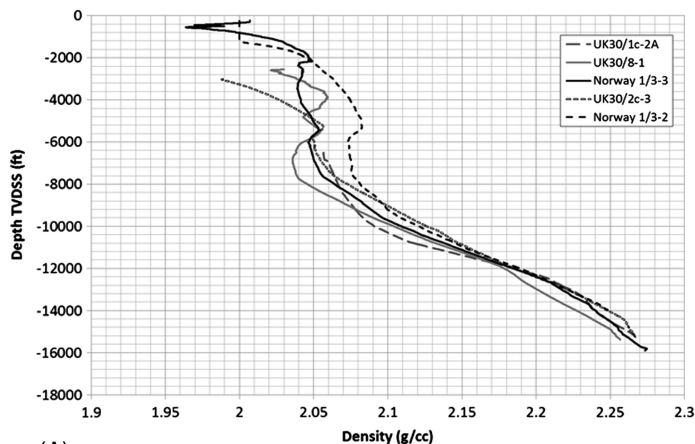
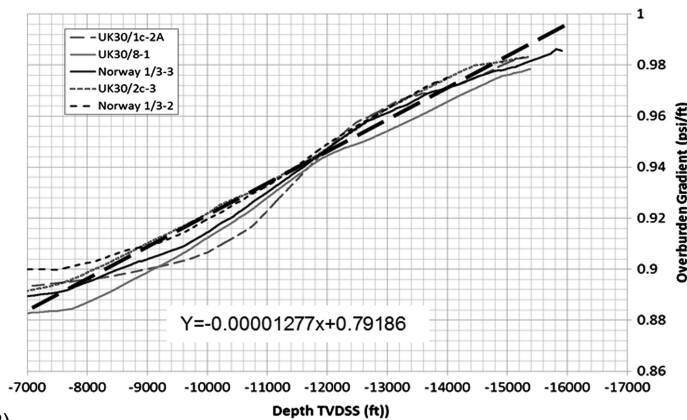


Figure 7. Measured pore pressure data (modular dynamic tester pressures) from the J Ridge Judy, Jasmine, and Jade fields. The vertical effective stress (VES) is highlighted for the crest of each field. FWL is the free water level based on intersection of fluid pressure gradients.



(A)



(B)

Figure 8. (A) Integrated density curves for five wells from the Central Graben. (B) The same data plotted in terms of overburden gradient (psi/ft). A linear regression offers a reasonable fit to the overburden gradient (heavy dashed line) and is used in the effective stress calculations. TVDSS = true vertical depth subsea.

framework. To determine VES requires up to five parameters: the weight of the overburden, the magnitude of pore pressure, the aquifer and hydrocarbon pressure gradients, and the depth of the hydrocarbon–water contact (or free water level [FWL]; see inset in Figure 7). The overburden gradient is derived from integrated density curves from wells (Figure 8). The magnitude of formation overpressure can be determined from direct measurement within permeable lithologies using repeat formation and modular dynamic testers (RFT and MDT) or from known (i.e., published) pressure cells (e.g., Gaarenstroom et al., 1993; Winefield et al., 2005). Example data from three J Ridge hydrocarbon fields are shown in Figure 7. The VES is highlighted in each field. It increases with depth, and more rapidly in the hydrocarbon column than in the underlying aquifer (see later). Integrated density curves from five wells in the Central Graben are shown in Figure 8. The curves are similar reflecting the mainly layer-cake

stratigraphy in the post-rift section. The integrated density curves have been generalized with a best-fit curve below 10,000 ft (3048 m) true vertical depth subsea (TVDSS) corresponding to the depth range of the Skagerrak Formation in the area of interest. A second order polynomial offers a reasonable fit to the density data and plots as linear depth trend for the overburden gradient (Figure 8B). The general layer-cake stratigraphy across the postrift sequences in the basin means that using a standard integrated density curve does not result in significant errors. The VES can be written simply as

$$\text{VES} = OZ - wZ - \Delta P - (w - h)H, \quad (2)$$

in which Z is the depth below seabed, O is the overburden pressure gradient derived from integrated density curves (Figure 8), w is the water pressure gradient; ΔP , the aquifer overpressure; h , the hydrocarbon gradient; and H , the hydrocarbon column

height above the free water level. In defining column height in equation 2, the following logic is used:

$$H = Z_{\text{fwl}} - Z \quad \text{for } Z < Z_{\text{fwl}}$$

$$H = 0 \quad \text{for } Z > Z_{\text{fwl}}$$

in which Z_{fwl} is the depth of the free water level (FWL). A water gradient (w) of 0.49 psi/ft (0.011 kg/cm/m) is employed for the Skagerrak Formation, reflecting the high salinity of the formation pore waters. All depths are measured from the datum of the seabed. The algorithm used to estimate the overburden means that the overburden gradient is not constant, but increases with depth.

Variations in overpressure result in changes in the magnitude of VES for a given depth of burial. Thus, different pressure cells have different vertical loads that may contribute to different magnitudes of

reservoir compaction. Conversely, if the compaction state can be shown to be similar between different pressure cells, then it means the overpressures developed late, after the compaction state was established, or that compaction is still active today and driven by the ambient stress conditions.

OVERPRESSURE CELLS WITHIN THE J RIDGE, CENTRAL GRABEN

The magnitude of overpressure in the J Ridge study area is variable, but generally shows a trend of overpressure decreasing from wells drilled in the deeper basins toward wells drilled in shallower flanking structures and structural highs. To the east of the main Central Graben, on the Norwegian Shelf (the Cod Terrace and Sorvestlandet high), the overpressure is

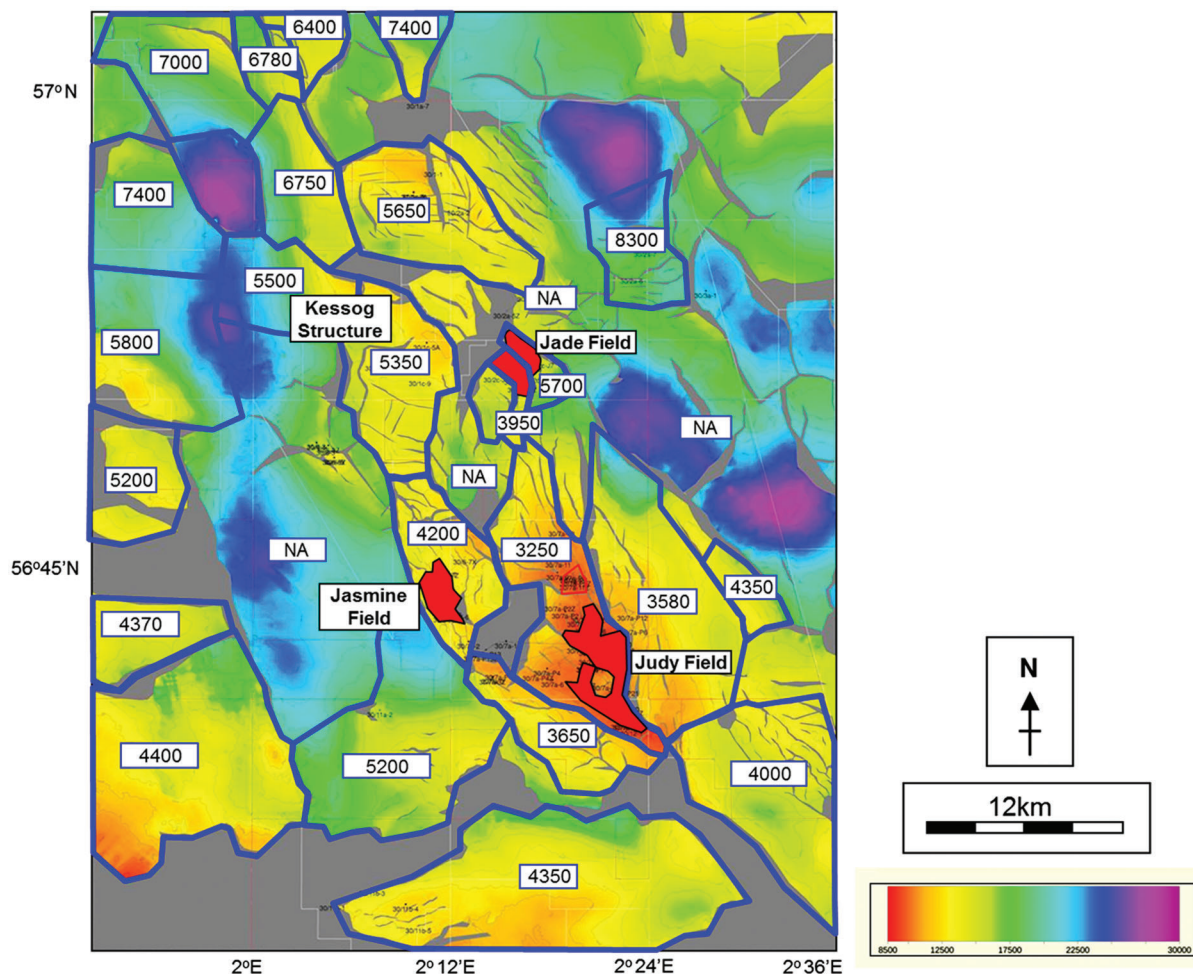


Figure 9. Top Triassic depth map for the J Ridge highlighting known pressure cells. Formation overpressures are quoted in psi from a datum of sea level using a 0.49 psi/ft (0.0105 kg/cm/m) hydrostatic gradient. Both faults and collapsed salt walls form pressure cell boundaries. The location of the map is shown on Figure 1. See text for discussion.

significantly lower in magnitude (Figure 3). High overpressures are also found to the west on the Puffin high. There is a strong spatial correlation between deeply buried Jurassic source kitchens in the main rift axis and the presence of very high overpressures. Structures that are directly plumbed into the deep grabens (via ramp margins, for example) have very high overpressures. Those that are separated from the grabens by large fault zones or fault terraces generally see a stair-step reduction in overpressure with distance from the graben center.

Figure 9 shows a top of Triassic depth map for the J Ridge study area highlighting the known aquifer pressure cells defined by RFT and MDT data from wells. The cells are areas of constant aquifer overpressure within the Skagerrak Formation (values given in psi). Pressure cell boundaries occur in association with salt walls and major basin-bounding faults. The more structures that are drilled, the more fragmented the known pressure cells have become, suggesting that hydraulic seals are commonly associated with many of the faults possessing throws in excess of 500 ft (152 m), particularly below depths of around -13,000 ft (3962 m), even when reservoir units are juxtaposed. The observed overpressure magnitudes systematically reduce toward the crest of the J Ridge from the deep graben to the northeast. This reduction in overpressure follows the direction of inferred hydrocarbon charge into the Judy field (Lines and Auld, 2004). The main mechanisms for overpressure generation are inferred to be late Cenozoic burial disequilibrium compaction and hydrocarbon generation (particularly late-stage gas cracking in deep source kitchens in the last 1–5 m.y.; Osborne and Swarbrick, 1997; Isaksen, 2004; Swarbrick et al., 2005; di Primio and Neumann, 2008). The development of the pressure cells observed today is therefore a late phenomenon in the burial history of the Central Graben. A key question to ponder is how has this affected reservoir properties in the Skagerrak Formation?

DATA SOURCES AND ANALYSIS METHODS

The primary data set used in this study contains digital curves of total porosity from a combination of exploration and development wells, the latter from

producing fields. Table 2 lists the fields and wells used in the study together with the formation overpressures employed, the typical depth range of the available data, and average reservoir properties such as porosity and net to gross. These are derived by petrophysical analysis using a suite of electric logs. The key logs used are the density (DEN) and neutron porosity (NEUT) logs. In addition, the sonic travel-time log (DT) is used if the density and neutron logs are absent. Shale-affected and hydrocarbon-affected porosity are calculated using a density–neutron cross-plotting technique that identifies the matrix composition (sandstone or limestone). The methodology identifies the density (D) and neutron (N) porosity for the matrix minerals (quartz and carbonate) and calculates the porosity using the standard mixing model published, for example, by Schlumberger (1972):

$$\phi = (\phi D_1 + \phi N_1 - \phi D_1) / (1 - (\phi N_1 - \phi N_2) / (\phi D_1 - \phi D_2)), \quad (3)$$

in which 1 refers to sandstone and 2 to limestone. A correction to ϕN_1 and ϕD_1 is made iteratively to account for other matrix minerals, such as feldspar. Where the DT curve is employed, the Wyllie time-averaged equation is used to perform the total porosity estimate. The result of these calculations is an estimate of total porosity (corrected for shale micro porosity). All calculations were performed in the Fugro petrophysical program PowerLog™.

Well data is typically sampled at 0.5 ft (0.15 m) intervals as is customary for most log data. The porosity data is then filtered using the calculated volume of shale curve (Vshale) to screen for nonreservoir facies. Vshale is calculated again using the density and neutron curves using a cross-plotting technique that compares the log values to those for a pure shale.

In the Skagerrak Formation nonreservoir facies include siltstone, shale, and caliche horizons. A 40% Vshale cutoff is used to differentiate reservoir from nonreservoir. This net reservoir is then filtered by porosity. A cutoff of 8 pu is used (which equates to a permeability to air at ambient conditions of approximately 0.1 md) to differentiate effective from non-effective reservoir (Figure 10). This is considered the minimum permeability likely to flow moveable

Table 2. Exploration Well Data Used in This Study. Proprietary Wells are not Shown*

Field/Area	Exploration Well	Top Reservoir (TVDSS ft)	Interval (ft)	HWC (ft)	HC gradient (psi/ft)	Overpressure (psi)	Avg Porosity (frac)	Net/Gross (frac)
Jade	30/2c-3	−14477	1162.5	−17850	0.17	3950	0.192	0.685
	30/2c-4	−14964	1312	−17850	0.17	3950	0.166	0.57
Judy	Proprietary	J3, J4Z, J5, J6, J8, J11						
	30/7a-8	−11529	921	−11717	0.24	3250	0.216	0.648
	30/7a-9	−12125	1216	−11750	0.24	3250	0.185	0.644
	30/7a-11Z	−11235	1056	−11750	0.21	3250	0.226	0.58
	30/7a-12	−12164	1036	−12430	0.2	3250	0.196	0.508
	30/7a-7	−11219	1238	−11325	0.2	3250	0.178	0.767
Jasmine	Proprietary	P1, P3, P7, P9, P16, P16Z, P17, P18, P20						
	30/7a-10	−12853	1487			4200	0.181	0.546
	30/6-6	−13478	1034	−15600	0.21	4200	0.195	0.523
	30/6-6Z	−13960	2026	−15600	0.21	4200	0.149	0.449
	30/6-7Z	−14784	547	−15300	0.21	4200	0.189	0.482
	30/6-7Y	−14396	1401	−15600	0.21	4200	0.168	0.357
Kessog	Proprietary	S1, S2, S3, S4						
	30/1c-5	−15208	970			5350	0.175	0.767
	30/1c-4	−14231	1049			5350	0.223	0.486
Heron	22/29-5RE	−14293.5	324	−15275	0.21	5700	0.199	0.461
	22/30-2	−14606	1199	−15275	0.21	5700	0.177	0.46
	22/30a-6	−15584	1027	−15275	0.21	5700	0.159	0.36
Puffin	29/3b-4	−14865	675			5650	0.135	0.625
	29/3a-5	−15397	247			5500	0.126	0.386
	29/4a-2	−15143	671			5750	0.151	0.388
	29/5a-7	−14426	570			5800	0.141	0.476
	29/8a-3	−12854	1419			4450	0.142	0.583
	29/9b-2	−13995	668			4400	0.124	0.451
	29/9c-4	−14421	678			4450	0.135	0.6
	22/24a-1	−11508	2002.5	−11790	0.24	3400	0.171	0.766
Marnock	22/24a-2	−11369	883	−11820	0.24	3400	0.18	0.483
	22/24a-3Z	−11239	970	−11843	0.24	3350	0.177	0.435
	22/24b-5ST1	−11391.5	1816	−11638	0.24	3400	0.176	0.825
	22/24a-6	−12214	1093	−12434	0.24	3450	0.176	0.352
	22/24b-7	−11666	1536	−12073	0.24	3500	0.173	0.755
	22/24b-9	−11784	1502	−12140	0.24	3500	0.154	0.623
Cod Terrace	7/11-8 Judy	−14457	1038			2030	0.102	0.438
	7/8-3	−12999	808			3180	0.113	0.096
	7/11-8 Joanne	−12138	2086			2030	0.112	0.4
	7/12-6	−11467	584			2010	0.158	0.453

*HWC = hydrocarbon-water contact; HC = hydrocarbons.

hydrocarbons and offer pressure support during reservoir depletion. The term “porosity” as used in this paper refers to the total measured porosity of those reservoir units that are classified as net effective.

To further extract the trends in porosity, the data have also been filtered using a 100 ft (30 m) sample

window. This simplifies plotting and smoothes out variations observed at the bed scale. This method represents all net reservoir or net effective reservoir within the 100 ft (30 m) window by one averaged measurement. No account is made for facies beyond that offered by the Vshale discriminator. This

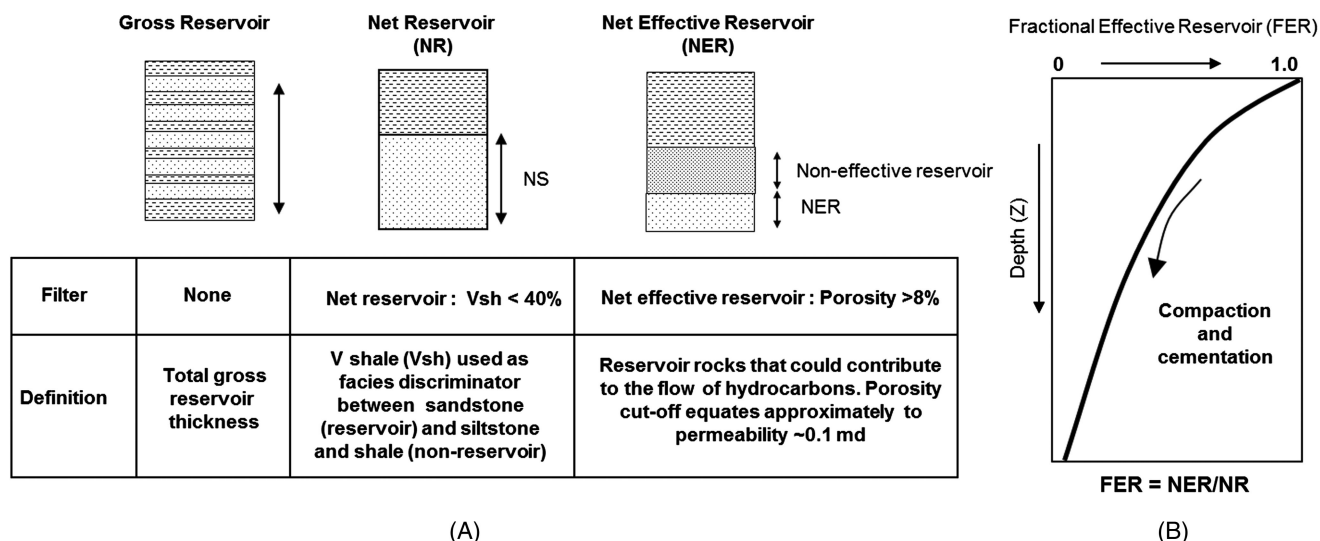


Figure 10. (A) Definitions of net reservoir and net effective reservoir as used in this study. (B) The parameter called fractional effective reservoir (FER) is employed as a measure of porosity decline within a reservoir. It is defined as the ratio of net effective reservoir to net reservoir. The graph schematically shows how FER declines with depth related to compaction and cementation.

operation has been made after all the well data from a particular field or area have been grouped together and sorted by either depth or vertical effective stress. It has not been done on a well-by-well basis.

ANALYSIS RESULTS

Porosity Depth Trends from J Ridge Wells and Other Areas

The porosity in the Skagerrak Formation declines with depth in each of the J Ridge fields (Figure 11). The Jade, Jasmine, and Judy fields each

have their own porosity depth trend. The plot only considers net sand, defined as having (V_{shale}) of less than 40%. The broad scatter in the porosity–depth data from each field reflects natural variations related to facies, grain size, and diagenesis. The best-fit linear trends for each field are near parallel, however, and define average porosity gradients of approximately -5 porosity units (pu) per 1000 ft (305 m). This means that for a field like Jade, which has a hydrocarbon column in excess of 3000 ft (914 m) (Jones et al., 2005), the average porosity in the Skagerrak Formation declines by almost 15 pu from the top to the base of the structure. Because

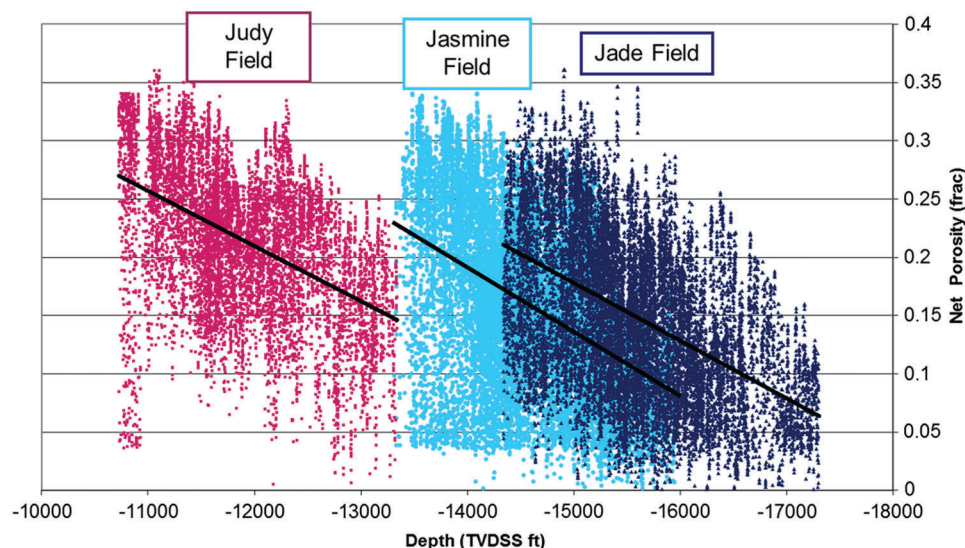


Figure 11. Porosity versus depth plot showing all computed porosity data from the Joanne Sandstone reservoir of the Jade, Jasmine, and Judy fields. A V_{shale} discriminator of 40% is used to differentiate between reservoir and nonreservoir. Each field has its own porosity–depth trend. The average gradients in porosity are nearly parallel to each other and record porosity decline within the fields of approximately 5 pu per 1000 ft (m). TVDSS = true vertical depth subsea.

Figure 12. Porosity versus depth plot showing all porosity data from the Marnock–Skua, Puffin, and Heron fields. A Vshale discriminator of 40% is used to differentiate between reservoir and nonreservoir. Each field has its own porosity–depth trend. The average gradients in porosity are quite variable and lower than those observed in the J Ridge.

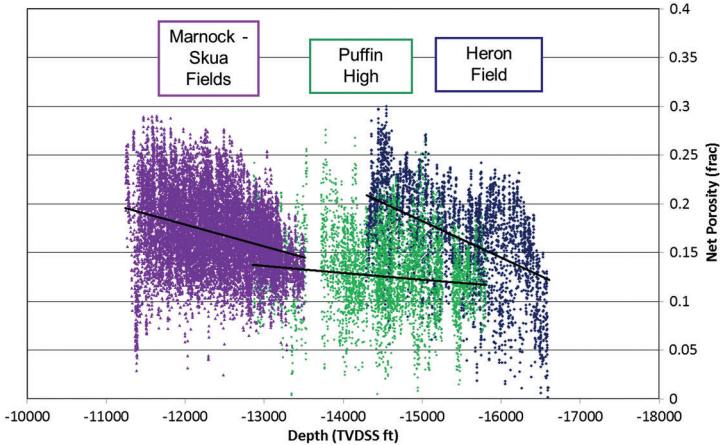
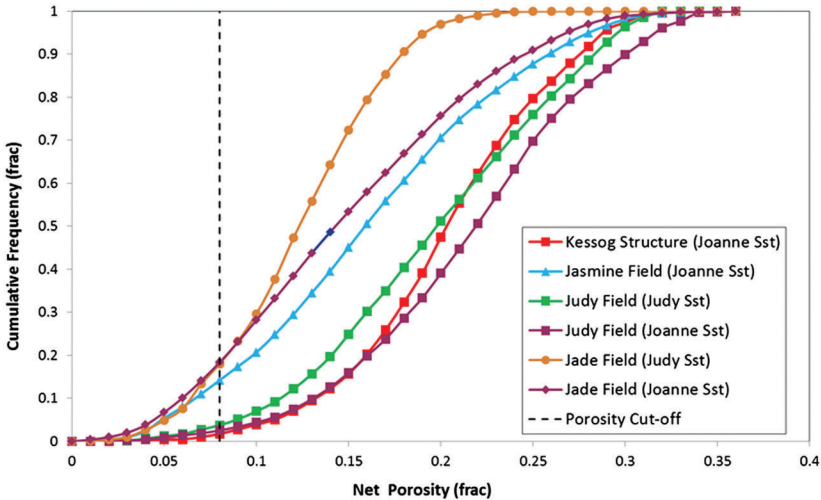
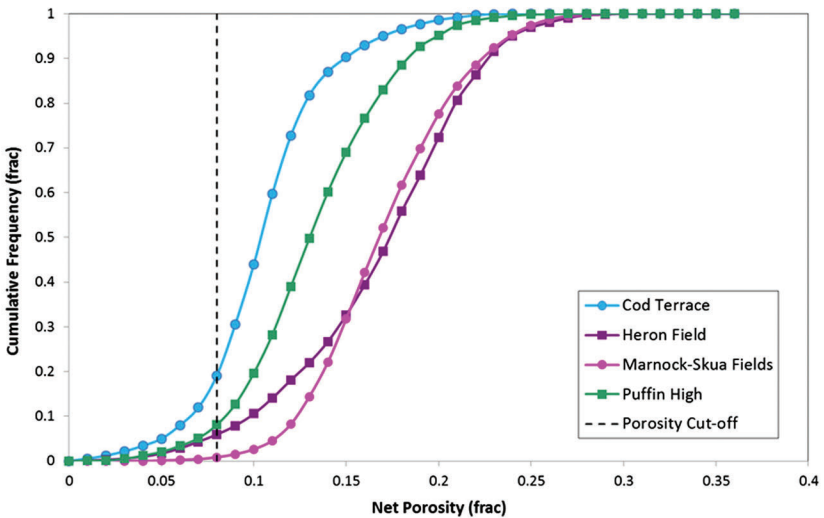


Figure 13. (A) Cumulative frequency curves for porosity data from the J Ridge fields. (B) Cumulative frequency curves for porosity data from the Cod terrace in Norway Quadrant 7, Puffin high and the Marnock–Skua area to the east, west, and north of the - J Ridge, respectively. These data sets show narrower statistical ranges of porosity values than those of the J Ridge reservoirs. Sst = Sandstone.



(A)



(B)

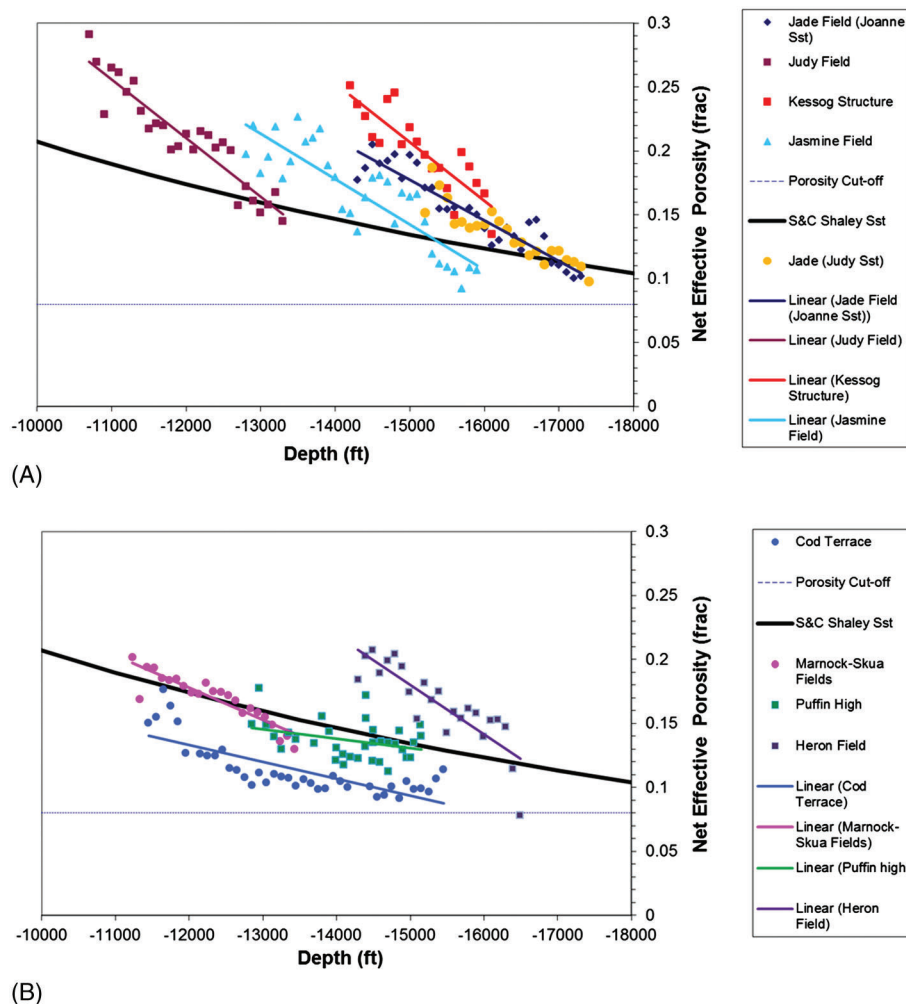


Figure 14. Plots showing filtered net effective porosity versus depth for (A) the J Ridge fields (Jade, Jasmine, Judy, and Kessog) and (B) data from the Puffin high, Norway Quad 7, and Marnock-Skua areas. The well data have been filtered using $V_{\text{shale}} < 40\%$. Each data point is the average of a 100 ft (m) depth interval. All the fields and areas define separate porosity–depth trends. The standard compaction curve for the North Sea, the Sclater and Christie (1980; S and C) curve, is shown for reference. This has been plotted for a shaley sandstone with $V_{\text{shale}} = 20\%$ as it is midpoint of the 0–40% V_{shale} range. The Puffin high is the only data set that falls on the Sclater and Christie (1980) curve. See text for further discussion. Sst = Sandstone.

different fields have their own porosity–depth trends, the depth domain is not ideally suited to making predictions. For example, an average porosity of 20 pu may occur in the Judy field at a depth of 12,000 ft (3658 m) TVDSS, whereas in the Jasmine field at 13,500 ft (4115 m) and in the Jade field at 14,500 ft (4420 m).

Figure 12 shows the porosity–depth data for other study areas: the Puffin high to the west of the J Ridge, the Marnock-Skua area (on the flanks of the Forties-Montrose high) to the north, and from the nearby Heron field (Figure 1). These areas show similar broad porosity data clouds, but the average trends tend to have lower porosity–depth gradients than the J Ridge fields. Again, no common relationship exists between porosity and depth in this cluster of fields.

Cumulative frequency curves of porosity from the study areas are shown in Figure 13. The data have been separated into those derived from the J Ridge

reservoirs (Figure 13A) and those from the other study areas (Figure 13B). The distributions for the J Ridge are significantly broader than those from the Puffin high, Norway Quad 7, and Marnock-Skua fields. Although average porosities are higher in the J Ridge, they are also statistically more variable, that is, more heterogeneity is associated. The low ends of the porosity distributions are also lower for the J Ridge reservoirs than for the more uniform distributions present in the other areas. Possible reasons for these differences will be discussed later. Note that the Heron Field, which lies between the J Ridge and Forties-Montrose high, has a broad porosity distribution more in common with the J Ridge fields than the nearby Marnock-Skua fields on the Forties-Montrose high.

The results of statistical filtering using a 100 ft (30 m) sample gate are shown in Figure 14A, B. In the depth domain, the data for the J block fields show

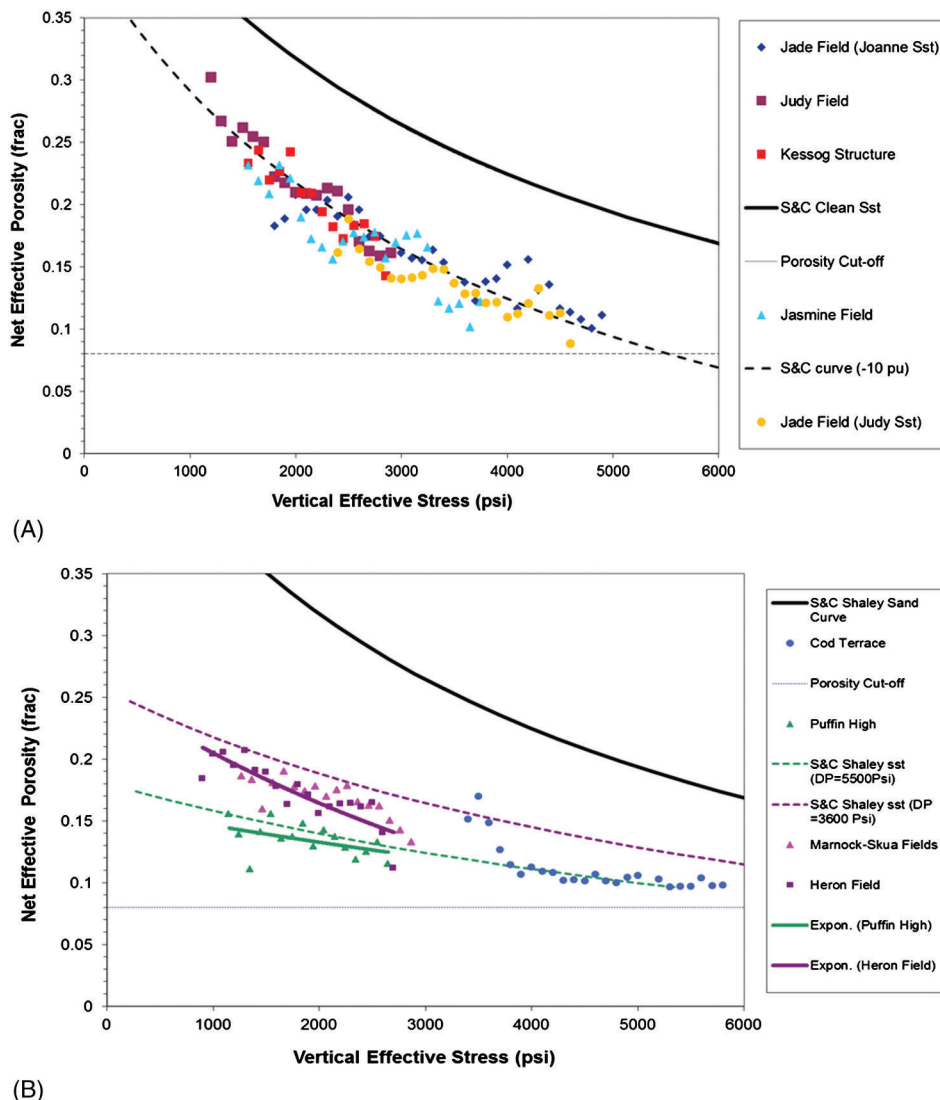
a set of near-parallel decline curves similar to those shown in Figure 11. Also included in Figure 14A are data from the water-saturated Kessog structure to the west of the Jade field. Figure 14B shows data from the three other study areas of the Central Graben. Each of these areas has its own distinct porosity decline trend. Only the Puffin high data fall on the published North Sea normal compaction curve from Sclater and Christie (1980), calculated here for sandstone with a shale volume of 20%. The Marnock–Skua data lie just above this trend, but on a similar porosity decline gradient. The J Ridge data all lie well above this normal compaction curve. At the crests of individual J Ridge fields, the data are significantly higher than the average basin trend (up to 10 pu). At the base of the available J Ridge data sets, the porosities fall close to the normal compaction curve.

The J Ridge fields clearly possess anomalously high porosities for their depth of burial. The Norwegian Quadrant 7 (from the Cod Terrace) data on the other hand appears more compacted. The trend of the Norwegian data is near parallel to the Sclater and Christie (1980) shaley sandstone normal compaction curve, but about 3 pu lower for any given depth. With all this variability, depth alone is clearly not a good predictor of absolute porosity, even though, in general, porosity declines with depth in all the areas studied.

Porosity versus Vertical Effective Stress Trends

One of the primary objectives of this paper is to utilize VES to normalize porosity–depth data in the Skagerrak Formation. This is not a new concept, but

Figure 15. The same data as Figure 14 plotted in the vertical effective stress (VES) domain. Each data point is the average of a 100 psi VES increment. (A) All the J Ridge data fall onto one trend that parallels the Sclater and Christie (1980) normal compaction curve, but which is 10 pu lower. (B) Data from the Puffin high and Marnock–Skua area fall on normal compaction curves displaced by overpressures (DP) of 5500 and 3600 psi, respectively. The Heron Field, although more overpressured, falls on a trend similar to that of Marnock–Skua. See text for further discussion.



its utility is sometimes overlooked. Vertical effective stress is related to the magnitude of pore pressure, and because pore pressure varies dramatically between pressure cells in the Central Graben (Figure 9), it is logical to use this parameter to assess porosity trends, particularly as the depth domain has been shown to be ineffective for predicting porosity. Figure 15 shows the same data in Figure 14 plotted in the VES domain. The J block data (including the Kessog structure) all collapse onto one porosity-decline curve that is almost perfectly parallel to the Sclater and Christie (1980) normal compaction curve for a shaley (20% V_{shale}). Thus, the structures and fields that occur at variable depths on the J Ridge, each having different magnitudes of fluid overpressure, all lie on a single, that is, unified, porosity-decline curve. For the J Ridge, average porosity is a function of VES, regardless of whether the reservoirs are hydrocarbon bearing (like the Jade field) or not (like the Kessog structure). For any given VES, the J Ridge data are about 10 pu lower than the normal compaction curve and thus are over-compacted for their present-day VES state.

The trends for the other areas remain distinct from the J Ridge in the VES domain (Figure 15B). These trends have markedly reduced porosity-effective stress gradients compared with the J Ridge data. Both the Puffin high and Marnock–Skua data sets can however also be described by normal compaction curves, but ones that are displaced to the left by 5500 and 3600 psi (387 and 253 kg/cm) overpressure, respectively. These magnitudes of overpressure

are very close to those measured from each structure (5600 and 3400 psi (394 and 239 kg/cm), respectively). The implication is that both the Puffin and Marnock areas are essentially normally compacted, but each has received a late stage of marked overpressure inflation that has reduced VES. The J Ridge structures are different and clearly not described by such a simple geohistory. Compaction in the J Ridge was presumably retarded earlier, thus preserving higher porosities. Reasons for this are discussed later.

Trends in Reservoir Quality and the Use of the Fractional Effective Reservoir Parameter

In the porosity-averaging exercise used previously, a porosity cutoff was employed to discriminate between effective and noneffective reservoir. As porosity declines with depth of burial, it is possible to use the fractional decline in the net effective reservoir to help evaluate the rock quality trends. To do this a parameter referred to as fractional effective reservoir (FER) has been employed (Figure 10). This is defined as the net effective reservoir count (porosity > 8 pu) within the 100 ft (30 m) or 100 psi (7 kg/cm) filter window divided by net reservoir count (rock with $V_{\text{shale}} < 40\%$) within the same window. Qualitatively, a decline in average porosity should be expected to be accompanied by a decline in FER once the reservoir starts to have a proportion of its porosity below the 8 pu threshold cutoff used.

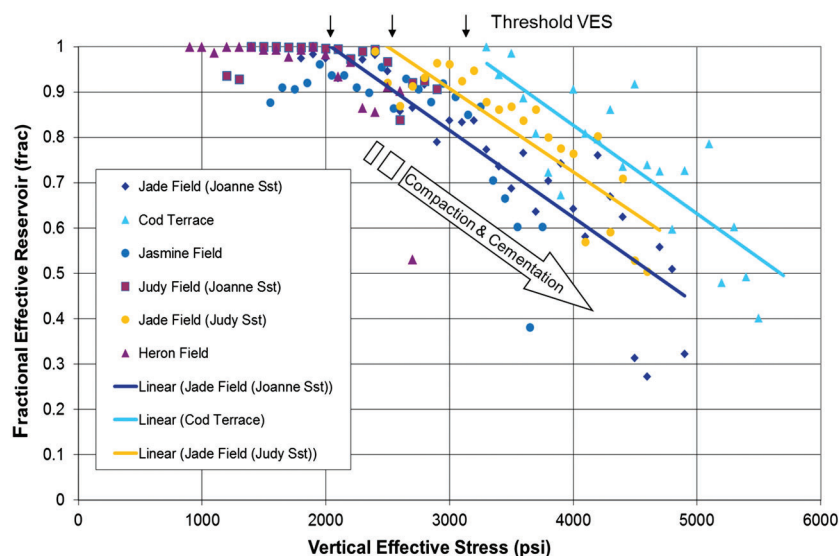


Figure 16. Fractional effective reservoir (FER) plot versus effective stress for all the regions studied. The plot emphasizes differences in the compaction state between the different areas. The lowest porosity region (Cod Terrace) shows the highest threshold vertical effective stress (VES) for onset of FER decline. See text for discussion. Sst = Sandstone.

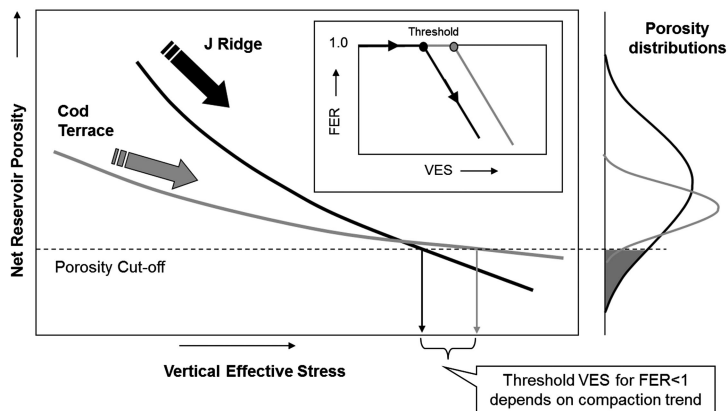
Trends in FER are shown in Figure 16. The data sets show that FER decreases linearly above a threshold VES of between 2000 and 3000 psi (141 and 211 kg/cm). The trends are all approximately parallel. The Cod Terrace data fall to the right of Jade field data. The Judy Sandstone FER data from the Jade field fall between the Jade field Joanne Sandstone and Cod Terrace trends. The Jasmine field Joanne Sandstone data are statistically similar to the Jade field Joanne Sandstone data. This means that for a given VES the Cod Terrace data have a higher proportion of net effective sandstone than in either the Jade or Jasmine fields, even though the Norwegian data is characterized by wells having the lowest average porosity and the lowest overpressure in the region studied. Data from the Puffin high and Marnock-Skua area (not plotted) have FER = 1.0 even though porosities in these structures are lower than in the Jade or Jasmine fields.

As shown in Figure 13, the normally compacted fields (Puffin and Marnock-Skua) have more uniform porosity distributions than the J Ridge structures and consequently possess fewer measured porosities less than the imposed 8 pu threshold (hence, the higher FER measurements). The Cod Terrace data also are characterized by a similarly narrow porosity distribution, combined with an even lower average porosity. The more uniform distributions indicate that compaction and diagenesis have combined to reduce porosity variations between the different reservoir facies. The Cod Terrace data have the most advanced diagenetic overprint, possibly because many of the wells are drilled above or close to salt walls where increased fluid flow may have promoted cementation.

A relative lack of accommodation space during deposition across the buried salt walls may also have favored preferential development of finer grained sheet floods and overbank siltstones as opposed to channel facies at these locations. The J Ridge structures possess higher overall porosities, and have a much broader porosity range as well. This greater preserved heterogeneity in porosity values reflects improved facies, a less compacted reservoir state, and a less aggressive diagenetic overprint.

The Judy Sandstone from the Jade field has a more uniform distribution than the overlying Joanne Sandstone in the same field (Figure 13A). It also has a lower average porosity because it is buried on average more deeply. Thus, it can be considered slightly more compacted. It does, however, share almost identical porosity-depth and porosity-VES trends with the overlying Joanne Sandstone. The Cod Terrace data are similarly more compacted with a significantly more uniform porosity distribution. The reason for a higher FER threshold observed in these more compacted data sets appears related to this lower degree of statistical variability. Thus, compaction state and, by inference, pore pressure history is reflected in the FER vertical effective stress threshold value. It is clear from the data that a more compacted reservoir has a lower porosity-depth decline gradient coupled to a narrower porosity distribution. A less-compacted reservoir has a steeper porosity-depth decline curve and broader porosity distribution. These features combine in the less compacted reservoir to yield an earlier intersection of the porosity cutoff with increasing VES. Thus, the less compacted reservoir loses more porosity by compaction with increasing depth (vertical load)

Figure 17. Simple model to explain how different compaction trends can result in different fractional effective reservoir (FER) threshold stresses. VES = vertical effective stress.



and its VES threshold is reached before the stronger, more compacted reservoir.

A schematic model that attempts to explain this reservoir behavior is shown in Figure 17. Two porosity–depth decline curves are shown, one for the J Ridge and one for a more compacted reservoir such as the Cod Terrace. The porosity distributions for each area are also shown. Both are normally distributed, but the J Ridge data have a larger range, and also a greater proportion of porosity below the effective reservoir cutoff. In terms of VES, the J Ridge data reaches a threshold earlier than the Cod Terrace data for FER decline. What emerges from reviewing the FER trends is a complex regional porosity pattern that links the magnitude of overpressure and its relative timing to the observed rock property trends in terms of both porosity distributions and rates of porosity decline.

The Role of Facies Variations

Reservoir grain size and facies have a key role in compaction because finer grained lithologies can compact more quickly, especially if they have a large proportion of ductile matrix or rock fragments. This can be illustrated for the Skagerrak Formation by employing the Vshale discriminator. In the braided fluvial deposits of the Skagerrak Formation, channel sands are often clean and well sorted, and consequently have a relatively low calculated Vshale. Sheet flood and crevasse splay sands are typically less well sorted and are often micaceous. Generally, these have a higher calculated Vshale. Thus, Vshale

can be used to crudely differentiate between the different sandstone facies recognizing that these Vshale petrofacies have only a loose correlation to the sedimentological facies models. For the purpose of this study, channel sands are considered to equate to sands that have Vshale less than 15%, with sheet flood sands having Vshale between 15% and 40%. More argillaceous and finer grained units (for example, terminal splay silts) are classified as having Vshale between 40% and 60%. When the reservoir property trends for these three facies groups are plotted for the J Ridge data set versus effective stress, they define separate, but converging, trends (Figure 18). The clean channel sands have the greatest measured porosity-loss gradient. These sands, therefore, currently compact at a greater rate with increasing VES than the other less well sorted and finer grained facies. This occurs because the channel facies with its slightly coarser grain size and better sorting started from a higher porosity state when the present-day effective stress conditions became established. The lowest present-day porosity-loss gradient occurs in the argillaceous petrofacies. These fine-grained sediments compacted earlier during burial and do not see porosity preservation due to pore pressure effects or secondary porosity creation. The magnitude and the timing of compaction vary as a function of facies.

Porosity loss clearly occurs for all facies as VES increases, but the rate of loss is strongly facies, that is, grain-size dependent. That they all converge indicates that net effective porosity loss is complete for the various facies when the VES reaches around

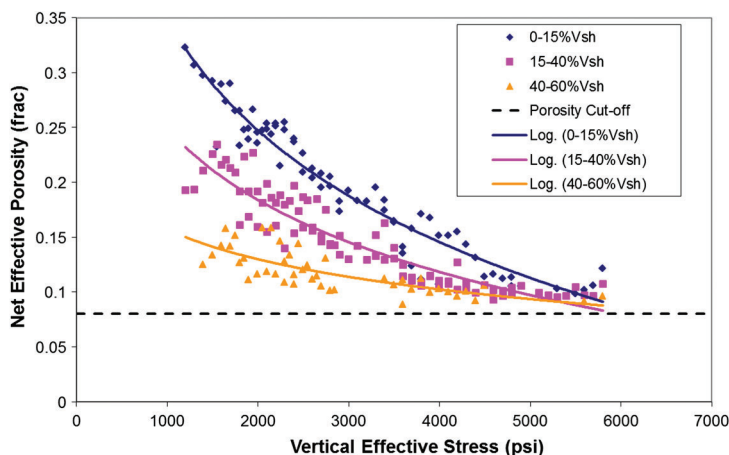


Figure 18. Porosity versus effective stress trends for different Vshale (Vsh) classes within the Skagerrak Formation. The data from all the J Ridge fields has been grouped together and the porosity trends evaluated using three separate Vshale ranges. The results show a strong dependence between Vshale and porosity decline. The lowest Vshale class (equated with channel sands) shows the greatest range of porosity decline as vertical effective stress increases implying these sands compact the most. The data sets converge at around 9 pu porosity, inferred to be the porosity floor for compaction in the Skagerrak Formation reservoirs.

5500 psi (387 kg/m). This is interpreted to represent the VES floor for effective reservoir in the Skagerrak Formation. Porosity loss does not stop, but continues by cementation or by viscous processes such as pressure solution below the effective reservoir porosity cutoff.

DISCUSSION

Implications for Compaction and Porosity Loss in the Skagerrak Formation

The development of a strong relationship between porosity and VES strongly points to compaction as a key process in controlling the average porosity trends in the Skagerrak Formation of the Central Graben. Here, compaction is considered stress-sensitive porosity loss. This may be the result of mechanical (grain movement) or chemical (pressure solution) processes, or because cement precipitation is also stress dependent. The precise processes responsible for the anomalously high porosities observed in the Skagerrak Formation and for their destruction with increasing VES are beyond the scope of this paper. The trends themselves are particularly useful, however, and allow a means of predicting reservoir properties in undrilled exploration prospects. Two related questions can also be addressed. (1) Why do the J Ridge data sets show such a steep porosity-versus-depth decline relative to those of the other areas studied? (2) Why are the porosity–VES trends in the different areas different from each other?

To investigate the J Ridge porosity-decline gradient, it is instructive to consider the porosity trends in the different J Block fields in terms of VES. The change in VES within a hydrocarbon column as a

function of depth is (from equation 2):

$$\delta(\text{VES})/\delta Z = O + Z(\delta O/\delta Z) - h. \tag{4}$$

In a water-saturated reservoir it is

$$\delta(\text{VES})/\delta Z = O + Z(\delta O/\delta Z) - w. \tag{5}$$

Using the overburden gradient equation from Figure 8 together with observed hydrocarbon fluid pressure gradients (Table 1), the effective stress gradient in the Jade field at a depth of –14,400 ft (4389 m) TVDSS is 0.990 psi/ft (0.02 kg/cm/m), whereas for the Judy field at –11,000 ft (3353 m) TVDSS it is 0.832 psi/ft (0.018 kg/cm/m; Table 3). In the Jasmine field at –13,500 ft (4115 m) it is 0.927 psi/ft (0.02 kg/cm/m). Appendix 1 shows how these values are derived. Normal compaction at the same VES range as observed in the J block fields (1000–5000 psi [70–352 kg/cm]) occurs at relatively shallow burial depth range (2500–11,000 ft [762–3353 m]) where the sediments are less compacted and overburden bulk densities lower. As a result, effective stress gradients are significantly lower (around 0.440–0.470 psi/ft [0.009–0.01 kg/cm/m]) in the absence of trapped hydrocarbons. The effective stress gradients in the deeply buried J Ridge fields are therefore more than double those characteristic of shallow burial normal compaction. These large gradients on first sight may appear physically unrealistic, but they reflect the development of long-buoyant hydrocarbon columns combined with the weight of the deeply buried and compacted overburden rocks. The steep porosity decline gradients observed in the depth domain record the influence of the present-day low effective stresses and high effective stress gradients in the reservoirs. This means that the porosity depth

Table 3. Parameters Used to Calculate Vertical Effective Stress (VES) Gradients in Skagerrak Formation Hydrocarbon Fields

Field	Fluid Gradients (psi/ft)		FWL (depth ft)	Crest Depth (ft)	VES Gradient (psi/ft)	
	Aquifer (w)	Hydrocarbon (h)			Aquifer	Hydrocarbon
Jade	0.49	0.17	–17800	–14400	0.670	0.990
Judy	0.49	0.24	–11450	–10500	0.570	0.820
Jasmine	0.49	0.21	–15600	–13300	0.642	0.922
Heron	0.49	0.21	–15200	–13500	0.647	0.927
Marnock	0.49	0.24	–11800	–11200	0.588	0.838

gradients of between 4 and 6 pu per 1000 ft (m) as clearly observed in the J block fields (Figure 11) are compaction trends. In the depth domain, they may look anomalously large, but in the VES domain, they are parallel to the normal compaction curve (Figures 14, 15). The sands continue to compact under the present-day large static effective stress gradients to attain a more stable consolidation state. This also implies that the porosity decline is directly affected by hydrocarbon charge via a feedback through VES.

The different geographical areas studies have distinct porosity–depth and porosity–effective stress

trends. The J Ridge fields have higher porosities than the other areas even though they are at similar burial depths and are similarly over-pressured. Clearly, the absolute magnitude of overpressure is not the main control on porosity preservation. This suggests that the timing of overpressure development is of greater importance. The Puffin high and Marnock–Skua area appear to be more normally compacted, even though both overpressures and effective stress gradients are high. In these areas, the development of high overpressure is a recent phenomenon. Using the same inference, the higher porosity J Ridge fields must

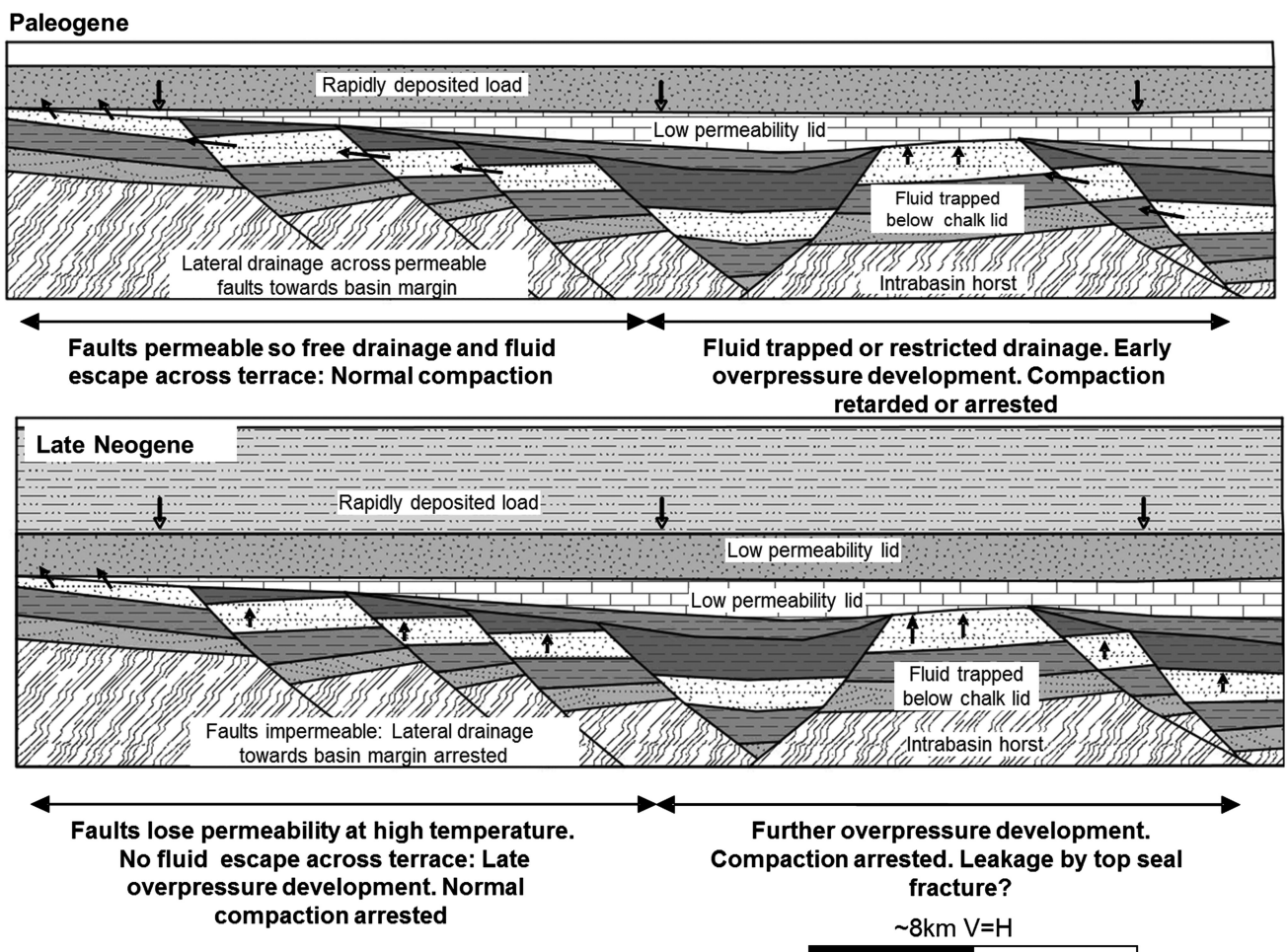


Figure 19. Schematic model to explain why different compaction (and by inference) overpressure histories develop in different parts of the Central Graben. The central J Ridge horst block is sealed early by a low permeability Chalk lid coupled with juxtaposition seal across bounding faults. Fluids moving into this structure cannot escape and so early overpressure development arrests compaction. The basin margin terraces behave differently. The low permeability chalk lid is absent from the basin margin. Fluid movement can occur across permeable faults due to aquifer juxtaposition and leak to the surface. No overpressure develops and the terraces normally compact. Later in the basin history, increased burial and temperatures promote cementation and permeability destruction in fault zones preventing the terraced areas from draining laterally. They then experience late fluid pressure inflation due to fluid expansion and movement from the deep hydrocarbon kitchen areas.

have developed their overpressure earlier. So why is there a difference in timing?

The explanation (or hypothesis) favored here is that the medial horst of the J Ridge has behaved as a more closed hydrologic system through time. Fluid entering this high during basin dewatering could only escape vertically through the top seals because large down-throwing faults bound the structure. Lateral drainage was thus prevented both by synrift juxtaposition seals and the structural configuration of the ridge as a migration focus in the basin. The result would have been relatively early onset of overpressure and the arrestment of reservoir compaction

below the low permeability lid of the overlying Cretaceous chalk. The other areas studied are attached to larger platforms (the Puffin high to the Fulmar terrace and basin margin) and the Marnock–Skua area to the large Forties–Montrose high. The Cod Terrace is on the eastern margin of the Central Graben. These areas all appear to have remained open to lateral drainage preventing early overpressure development and allowing the Skagerrak Formation to normally compact. Only with recent deep burial and increased temperatures, have these areas become isolated from the basin margin, presumably because fault zones have become

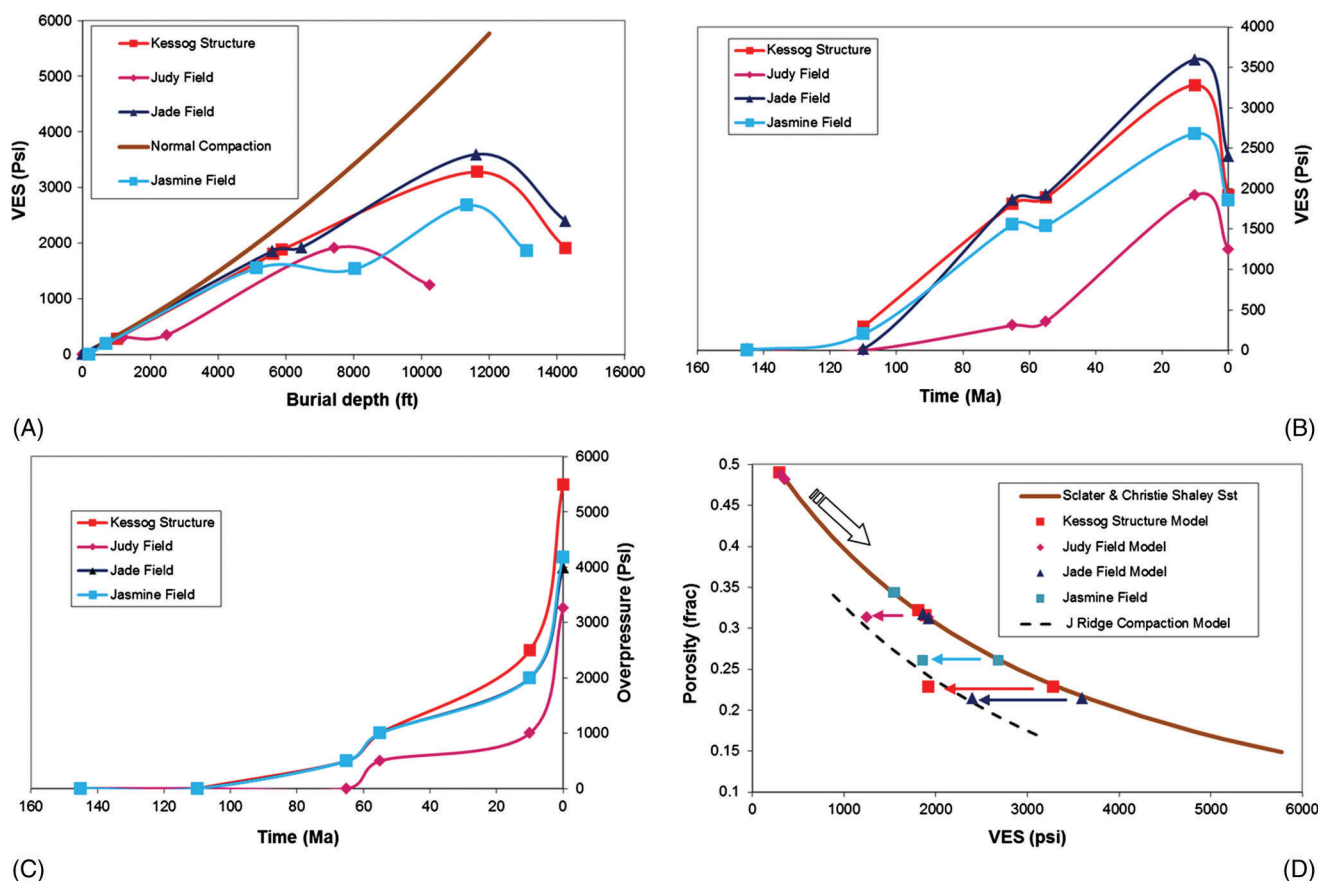


Figure 20. Simple one-dimensional decompaction model applied to the Skagerrak Formation at the crests of the Judy, Jade, and Jasmine fields, and to the Kessog structure, and used to model porosity as a function of pore pressure history. (A) Modeled burial versus vertical effective stress (VES) for the three fields. (B) Estimated VES in each of the fields as a function of time. VES increases during burial until a maximum is reached around 10 Ma. The maximum is conditioned assuming average porosity is controlled by compaction. (C) Inferred fluid overpressure history. In the J Ridge fields, early overpressures develop (with magnitude of between 500 and 1000 psi) during the Paleocene and help to retard compaction. (D) Porosity versus VES. Each field slides down the normal compaction curve during progressive burial (arrow) until rapid overpressure inflation in the last 10 m.y. arrests compaction and reduces VES. They align on a compaction curve (the unified J Ridge trend) parallel to the Sclater and Christie (1980) curve for a shaley sandstone. Sst = Sandstone.

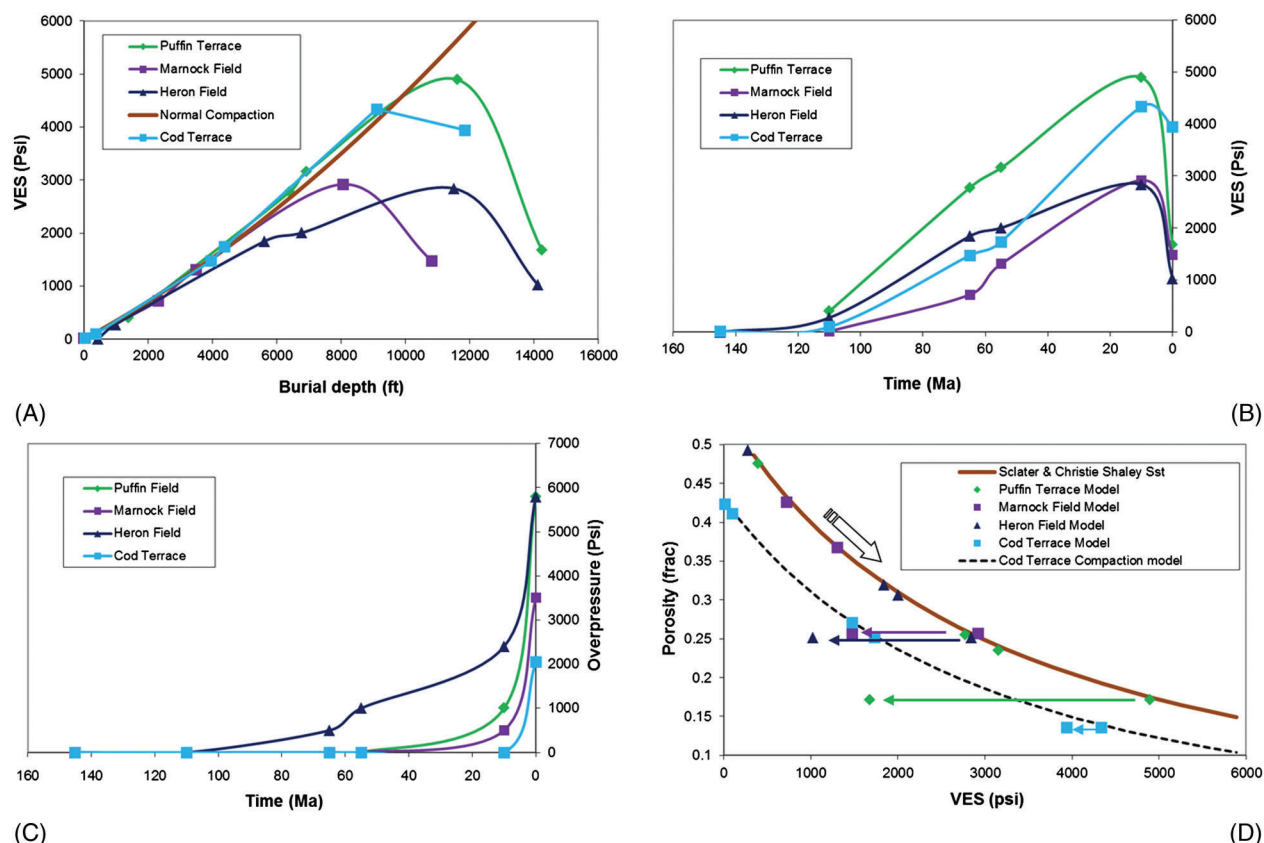


Figure 21. Simple one-dimensional decompaction model applied to the Skagerrak Formation at the crests of the Marnock, Heron, and Puffin fields and applied to a generic well in the Cod Terrace. (A) Modeled burial versus vertical effective stress (VES) for the four areas. (B) Estimated VES in each of the fields as a function of time. VES increases during burial until a maximum is reached around 10 Ma after which it decreases rapidly. The maximum VES is conditioned assuming average porosity is controlled by compaction. (C) Inferred fluid overpressure history. The Heron Field is assumed to develop early overpressure (with magnitude of around 1000 psi) during the Paleocene, helping to retard compaction. The other areas show no significant overpressure development until the last 5–10 m.y. (D) Porosity versus VES. Each field or structure slides down the normal compaction curve during burial until rapid overpressure inflation in the last 10 m.y. arrests compaction and reduces VES. This moves each field to the left on the plot by an amount that is a function of the magnitude of present-day overpressure. A second compaction curve is shown for the Cod Terrace reflecting a finer grain size present in this area. This curve is required to explain the low porosity data shown in Figure 14B. Sst = Sandstone.

progressively less permeable to fluid movement through time. This fault zone behavior is generally thought to reflect increased quartz cementation within cataclasites as burial temperatures exceed 100°C (212°F) (Fisher et al., 2003). Figure 19 schematically summarizes the structurally controlled drainage history model.

To show how this model works in practice, it is instructive to perform simple one-dimensional back stripping of pseudowells from the J Ridge, Cod Terrace, Marnock, Puffin, and Heron areas. Results of this exercise are shown in Figures 20, 21. Table 4 outlines the back-stripping parameters, whereas Table 5 shows the depths of formation

tops for the structures and fields modeled. By assuming average porosity is given by the Sclater and Christie (1980) compaction curve, it is possible to use the observed present-day porosity to constrain the magnitude of maximum VES and, knowing the lithostatic load as a function of time, to infer the aquifer overpressure of the Skagerrak Formation as layers are back-stripped. Thus, a simple, if schematic, overpressure history can be developed that is consistent with the observed compaction state. Back-stripping is done in the stages defined by the well stratigraphy listed in Table 4. The results suggest the J Ridge and Heron fields developed their inferred early

Table 4. Summary Parameters Used in the Simple One-dimensional Back-Stripping Exercise to Model the Burial, the Pore Pressure Evolution, the Vertical Effective Stress and the Porosity History for the Study Areas in the Central Graben

Present Day Top	Facies Proportions (frac)			Porosity (frac)	Porosity-Depth Coefficient (ft ⁻¹)	Matrix Density (g/cc)
	Sst	Shale	Chalk			
Seabed	0.30	0.70	0.00	0.588	0.00013350	2.720
Mid Miocene	0.20	0.80	0.00	0.602	0.00014081	2.730
Paleocene	0.50	0.50	0.00	0.560	0.00011887	2.700
Chalk	0.00	0.00	1.00	0.700	0.00021640	2.820
Valhall	0.00	1.00	0.00	0.630	0.00015544	2.750
BCU	0.20	0.80	0.00	0.602	0.00014081	2.730
Skagerrak	0.60	0.40	0.00	0.546	0.00011155	2.690
SmithBank	0.10	0.90	0.00	0.616	0.00014813	2.740
Permian–Carboniferous	0.50	0.50	0.00	0.560	0.00011887	2.700
Basement	Solid					

overpressure (magnitude of 500–1000 psi [35–70 kg/cm] above hydrostatic) by the Paleocene (50–60 Ma), whereas the Marnock and Puffin fields remained normally pressured until the last 5–10 m.y. The inferred overpressure history for the J Ridge is very similar in form to Scenario 2 of di Primio and Neumann (2008), who used a range of calibration data to build a 3D basin model of the Jade and Judy fields with significant pressure contribution from gas generation and lateral fluid movement.

At the structural crest of the Jade, Judy, and Jasmine fields, porosities within the cleaner channel

sandstones are typically around 30 pu. Some of this porosity is possibly recovered from grain and cement dissolution (di Primio and Neumann, 2008; Nguyen et al., 2013). No core data are dominant, but it is probably quartz and carbonate. This is an avenue for further research, but the data presented here suggest that whatever mechanisms are reducing porosity in the cleaner reservoir sands of the Skagerrak Formation, they appear to be stress sensitive today. It is clearly important and desirable to link the observed porosity and FER trends observed in the Skagerrak Formation to reservoir petrographic studies. This would allow the processes involved to

Table 5. Formation Tops Used in the One-dimensional Back-Stripping Model

Field/Area	Present Day Formation Tops						
	Puffin high	Marnock	Heron	Cod Terrace	Judy	Jade	Kessog
Horizon	Depth (ft)						
Seabed	250	275	275	275	250	250	250
Mid Miocene	4500	4500	4500	4524	4500	4500	4500
Paleocene	9650	8890	9590	9429	9000	10000	10000
Chalk	10328	9980	10900	9888	10000	11000	11000
Valhall	13850	ABS	13950	11978	ABS	ABS	ABS
BCU	14300	ABS	14200	12120	ABS	ABS	14000
Skagerrak	14500	11100	14400	12139	10500	14500	14500
SmithBank	17000	14500	17000	15500	16000	18000	18000
Permian–Carboniferous	20000	18000	20000	19000	19000	21500	21500
Basement	22500	21000	22500	21500	21000	24000	24000

be better understood. This is currently a separate and ongoing research focus area (e.g., Nguyen et al., 2013), but it is still not properly understood.

Compaction appears to play an important and ongoing role in the Triassic Skagerrak Formation of the Central Graben, even though the ambient reservoir conditions are predominantly in the HPHT realm where temperature-controlled quartz cementation might be expected to be very active and establish strong grain frameworks. It is understood from previous studies (e.g., di Primio and Neumann, 2008) that a combination of chlorite grain coatings and the feldspathic composition of the sands help retard later quartz cementation in the Skagerrak Formation. In the absence of ductile grains, mechanical compaction of clean fine-grained sands should cease around 20–25 pu. Porosity decline below this must then occur by cementation and/pressure solution. That the present-day state of effective stress is in part a product of hydrocarbon charge suggests the process of compaction is ongoing due to the high temperatures and high-effective-stress gradients in the reservoirs. Similar observations have been made based on petrographic studies by Fisher et al. (1999). They conclude that late, deep-burial mechanical compaction occurs within the Jurassic Fulmar formation of the Central Graben resulting from the collapse of high porosity sands preserved by early microcrystalline quartz cements, and promoted by later framework grain dissolution.

The development of overpressure in the Skagerrak Formation reservoirs is key to understanding the compaction process. In combination with the buoyancy effect of long hydrocarbon columns, the overpressures result in low vertical effective stresses. These help retard compaction and thus allow the Skagerrak Formation sands to preserve relatively high porosities for their depth of burial. However, compaction is still very much active and the low VES and large effective stress gradients associated with the hydrocarbon columns promote porosity decline with depth. Thus, the low vertical effective stresses on one hand preserve porosities, but on the other, the resultant large effective stress gradients cause rapid porosity loss with depth at deeper levels within traps. This has implication for reservoir performance where large hydrocarbon columns are present.

Using Average Porosity Trends for Reservoir Quality Prediction

The observed porosity trends can be implemented in geomodels to improve porosity modeling within structures with large hydrocarbon columns. The recognition that compaction plays the dominant role in determining porosity-decline trends in the Skagerrak Formation also allows a simple model to be constructed that can help predict how rock quality changes with increasing depth of burial. This is useful because a number of, as yet, untested Skagerrak Formation structures exist in the deep Central Graben beyond the current depth range of well data. A key uncertainty in these exploration prospects is reservoir quality. To model the rock quality in these structures requires the pore pressure be known or at least a range estimated and the weight of the overburden. The numerous published pressure cell maps for the Central Graben (e.g., Gaarenstroom et al., 1993; Darby et al., 1996; Winefield et al., 2005) can help in this process. Integrated density curves from well data enable the weight of the overburden to be estimated as a function of depth (e.g., Figure 7). Armed with a prediction of VES it is then possible to use the empirically derived compaction trends for the Skagerrak Formation to estimate average reservoir properties (both porosity and net to gross). Net

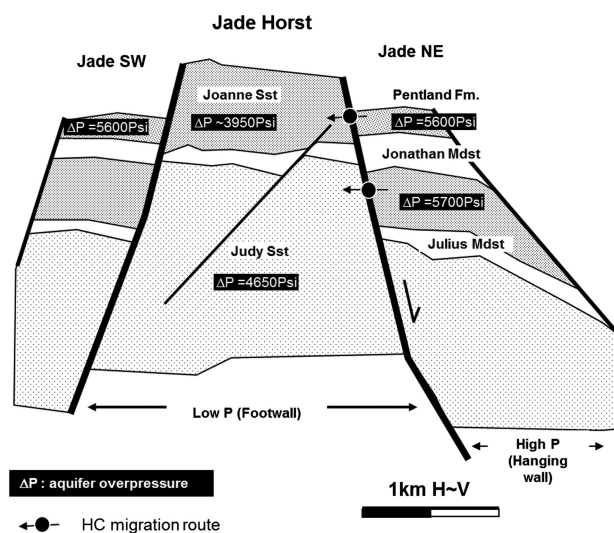
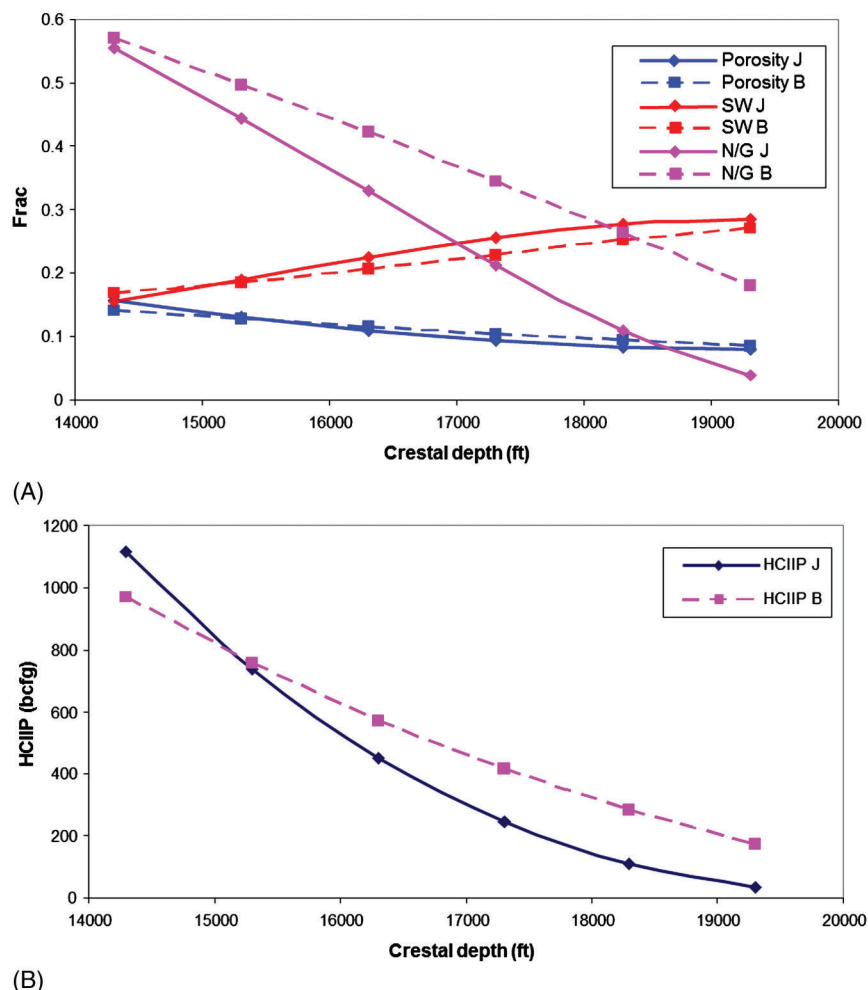


Figure 22. Schematic east-west cross section across the Jade field highlighting compartment overpressures and inferred hydrocarbon migration routes. See text for discussion.

Figure 23. Model results for the successive burial of the Jade Horst (Joanne Sandstone) under constant aquifer overpressure of 4000 psi. The structure depth increases by 1000 ft (-m) increments. The model uses the J Ridge unified compaction trend to describe porosity decline with increasing depth of burial and compares this with a trend defined for a basin structure that has experienced normal compaction with very late overpressure inflation. J = J Ridge model. B = Basin model. (A) Change of bulk average reservoir properties as progressive burial occurs. (B) Calculated HCIP (hydrocarbons initially in place in billion cubic feet of gas [bcfg]) for the structure). See text for discussion.



effective sandstone is simply net sandstone multiplied by FER. Net sandstone can be estimated from play maps and nearby well data and for the Skagerrak Formation is usually in the range 40%–70%.

Volume weighting of petrophysical properties is employed to calculate the bulk-average properties needed for probabilistic modeling of a trap. This technique is required because the structural geometry itself can have a significant impact on the average rock properties, particularly if gross rock volume increases rapidly with depth in a trap.

To illustrate how the model works, the central horst of the Jade field has been used to show the effects that increasing burial and higher overpressures could have on the calculated hydrocarbons initially in place (HCIP). Two different compaction models are used: the J Ridge compaction model (denoted by the letter J) shown in Figure 14A and a basinal model (reflecting normal compaction with late overpressure inflation, denoted by the letter B) shown in

Figure 14B. Currently, the upper hydrocarbon leg in the central horst block of the Jade field contains around 1.1 Tcf of gas plus associated condensate trapped within the Joanne Sandstone member of the Skagerrak Formation (Jones et al., 2005). The crest of the field is at 14,300 ft (4359 m) TVDSS and the aquifer overpressure is estimated to be around 3950 psi (278 kg/cm; using an aquifer gradient of 0.49 psi/ft [0.0105 kg/cm/m] from a datum of sea level; Figure 22). The compaction model allows the field to be taken to greater burial depths and pressures to assess the effects this has on rock quality and hydrocarbons in place.

Burial of the Jade horst at constant overpressure results in a progressive increase of VES and consequently produces a rapid porosity decline (Figure 23A). Net to gross also declines rapidly whereas average water saturation increases. The effect on potential HCIP is shown in Figure 23B. The decline in HCIP is rapid and shows that the

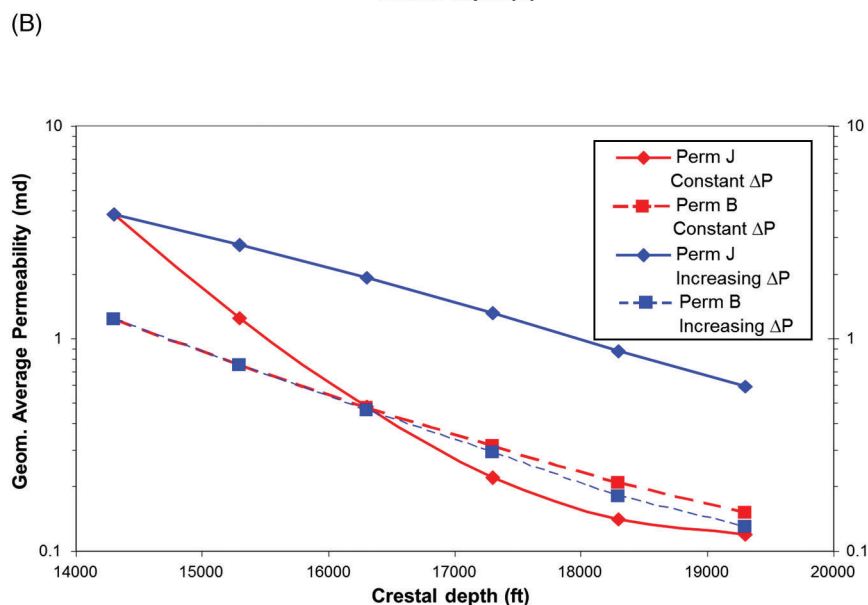
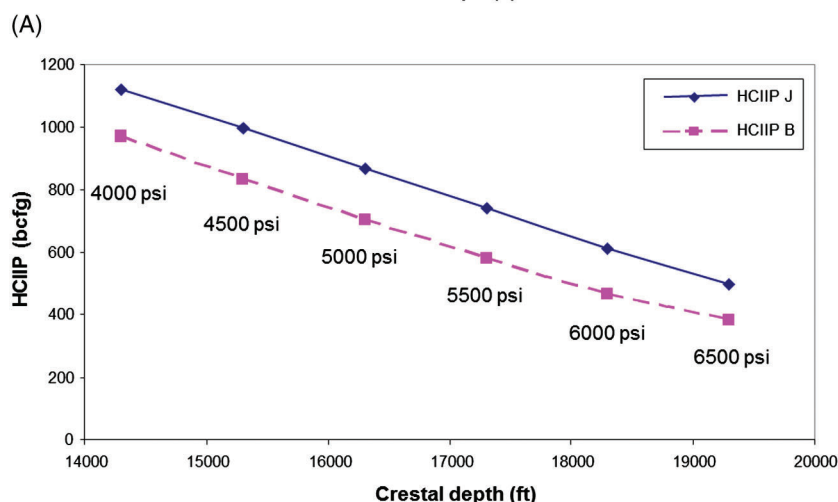
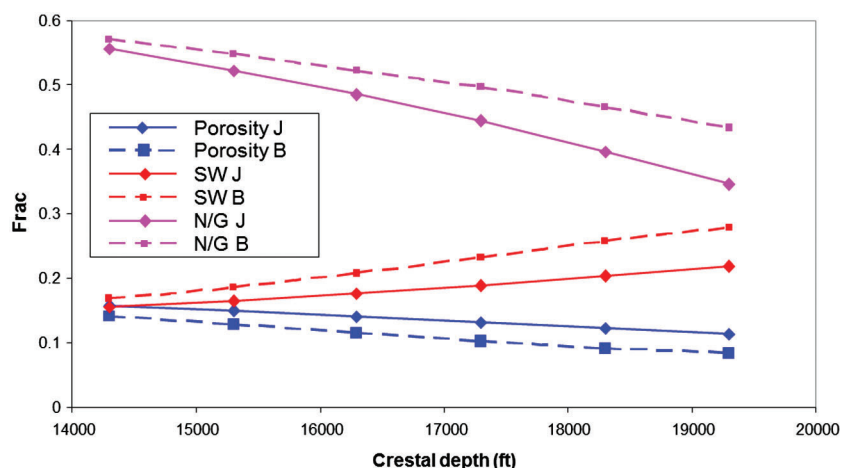


Figure 24. Model results for progressive burial of the Jade Horst (Joanne Sandstone) under increasing aquifer overpressure of 500 psi for every 1000 ft (m) of depth increase. The different compaction models (J and B) both predict that reservoir properties are less affected by burial and the structure would remain potentially economic even at depths of 18500 ft (m) TVDSS due to reduced VES. (A) Bulk average reservoir properties of the horst block at different burial depths. (B) Calculated HCIP within the Jade Horst for both models. The magnitude of overpressure in the model steps is shown. TVDSS = true vertical depth subsea; VES = vertical effective stress; HCIP = hydrocarbons initially in place.

Figure 25. Calculated bulk geometric average permeability for the different Jade horst compaction models and overpressure histories. ΔP in the legend refers to overpressure. Only the J Ridge compaction model (J) coupled to increasing overpressure with depth preserves permeability capable of offering a reservoir that will likely yield commercial flow rates at depths below 16000 ft (m) TVDSS. The normally compacted basin model (B) shows no enhanced permeability preservation with increasing overpressure, because compaction is not influenced by the pore pressure history. See text for further discussion. TVDSS = true vertical depth subsurface.

structure would quickly cease to be a viable exploration target. To be independently economic, a deep HPHT exploration prospect in the UK sector of the

North Sea realistically requires around 50 million BOE of resources. This roughly equates to 400 bcf of gas in place. In the case of the Jade prospect, the

structure would be unattractive if its crest was below 16,500 ft (5029 m) true vertical depth in an aquifer overpressure cell of 4000 psi (281 kg/cm). The decline in rock properties and HCIP is greater for the J model than for the B model due to the greater compaction gradients used in the former.

If the overpressures increase concomitant with deeper burial (as is the general basin trend in the North Sea), then the effects of increased burial are significantly ameliorated. Providing overpressures are high, then a deep Jade prospect could host significant resources even if buried to depths in excess of 18,000 ft (5486 m; Figure 24A, B). The maintenance of low effective stresses to significant depths prevents porosity decline by compaction. Figure 24B shows that the Jade structure could contain around 600 billion cubic feet (gas; bcfg) at a depth of 19,000 ft (5791 m) if the overpressure has a magnitude of 6500 psi (457 kg/cm). The implication is that deeply buried Skagerrak Formation exploration prospects within the Central Graben may yet offer economic resources providing they have been compartmentalized (hydraulically isolated) from the basin margins early during Cenozoic burial and have high overpressures. Even if the structures are normally compacted (model B), they can still preserve sizeable quantities of hydrocarbons in place.

High overpressures can clearly retard compaction, but exactly when the overpressures develop during the burial history is clearly important. Later aquifer pressure inflation indirectly results in significant overcompaction of a reservoir relative to the empirical trends built for the J Ridge. This appears to have been the case for example for the Puffin high. It is therefore important to be aware not only of the absolute magnitude of overpressure, but also to assess the timing of its development and factor this into the compaction model. Deep structures attached to the basin margin across fault zones or terraces may have been better hydraulically connected (better drained) for longer and so be normally compacted. The Jade field example shows that a normally compacted structure can still preserve sizeable quantities of hydrocarbons in place at great depths. In such a case, however, poor exploration results will still ensue due to marginal rock quality. This is highlighted in Figure 25, in which

geometric average permeability has been calculated for the Jade horst compaction model for both the J and B trends. The results highlight that only the J compaction model preserves economically viable permeability during progressive burial. This is because the basin model trend is normally compacted and is associated with a more uniform and statistically lower porosity distribution (Figure 13B). The absence of a high-end-porosity population robs the normally compacted reservoir of high permeability channel flow units, even in the absence of additional diagenetic overprint. These are preserved by the early overpressure developed in the J model and can thus continue to contribute to economic well performance even at great depths of burial.

CONCLUSIONS

An analysis of porosity in the Skagerrak Formation using basic statistical techniques has shown compaction to be the dominant process influencing rock property trends in the J Ridge area of the Central Graben. All the J Ridge structures (across a 7000 ft [2134 m] depth range) share similar internal porosity trends controlled by vertical effective stress (VES). In comparison, porosity–depth trends vary between the fields as do porosity–depth gradients. The porosity–effective stress relationships are similar for J Ridge fields and the Sclater and Christie (1980) normal compaction curve for clean sands in the North Sea (but offset to lower porosity due to pore pressure inflation). Further comparison shows that the steep porosity–depth gradients are the direct product of large static effective stress gradients in the reservoir and therefore owe their origin to compaction. Different trends in porosity–effective stress space between different parts of the Central Graben probably reflect timing of final overpressure attainment relative to burial depth and compaction state. Late overpressure inflation may result in poorer reservoir properties for a given effective stress as shown here for the Puffin terrace to the west of the J Ridge and for the Marnock area on the Forties–Montrose high to the north. These areas display separate trends more aligned with normal compaction. That these areas

are also highly overpressured suggests overpressure development happened later in the burial history than for the J Ridge, the structural location for which, as an intrabasinal horst flanked by two major grabens, appears to have contributed to its hydrologic isolation.

A simple measure of rock quality, fractional effective reservoir (FER), when plotted against effective stress may help to discriminate between timing of compaction and final overpressure accrual. The observed compaction trends allow both porosity and FER to be modeled. This has the potential to be used as an exploration tool to predict average rock properties in exploration prospects, providing an estimate of overpressure is available. Early overpressure development and its maintenance are required to provide deep reservoir targets with the ability to preserve high-permeability channel flow units.

From a very simple empirical analysis of porosity-versus-depth trends, it has been possible to make inferences on the pore pressure evolution and outline the key controls on average porosity preservation in the Skagerrak Formation across the Central Graben of the North Sea. The results shed additional light on the complex controls on reservoir quality and emphasize the importance of compaction processes in addition to facies distributions, chemical diagenesis and temperature-controlled cementation reactions during progressive burial. Compaction remains active until present day in the deep Skagerrak Formation reservoirs on the J Ridge, augmented by the development of long-buoyant hydrocarbon columns.

APPENDIX: DERIVATION OF THE VERTICAL EFFECTIVE STRESS GRADIENTS FOR THE J RIDGE FIELDS

From equation 2, the vertical effective stress is defined as

$$\text{VES} = OZ - wZ - \Delta P - (w - h)H. \quad (6)$$

The overburden gradient O (psi/ft) is given in Figure 8B as a linear regression of the well data, and is a function of Z :

$$O = aZ + b, \quad (7)$$

in which $a = 0.00001277$ and $b = 0.79186$. This linear equation can be substituted into equation 6, remembering that H , the

hydrocarbon column height, is given by $H = Z_{\text{fwi}} - Z$:

$$\text{VES} = aZ^2 + bZ - wZ - \Delta P - (w - h)(Z_{\text{fwi}} - Z). \quad (8)$$

The effective stress gradient at any depth is simply the derivative of equation 8:

$$\delta(\text{VES})/\delta Z = 2aZ + b - h \quad (\text{for } Z < Z_{\text{fwi}}) \quad \text{and} \quad (9)$$

$$\delta(\text{VES})/\delta Z = 2aZ + b - w \quad (\text{for } Z > Z_{\text{fwi}}). \quad (10)$$

Table 3 summarizes the results of applying these equations to the Central Graben Skagerrak Formation fields analyzed in this paper.

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