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Petroleum emplacement inhibits quartz cementation and feldspar dissolution in a deeply buried sandstone

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ABSTRACT

Whether the emplacement of petroleum in sandstone reservoirs can preserve porosity during burial remains controversial. In the Kessog Field, UK Central North Sea, average porosities of the crestal sections of the fluvial-deltaic Pentland Formation reservoir can exceed 25 % despite burial to 4 km or more. The predicted porosity for the reservoir at this depth is only around 14 % based on regional data. Oil saturation data, thin-section point counts, grain-size and sorting measurements, reservoir pressure, and SEM images were combined to analyze the cause of the high reservoir porosity. Petroleum emplacement preventing cementation is the most likely mechanism for porosity preservation. Facies variation is not responsible, as the high-porosity sandstones from the crestal well are, in terms of average grain-size (fine-grained) and sorting coefficient (moderately well-sorted), nearly the same as the lower porosity sandstones from the flanks of the field (average porosity 13 - 15%). Other potential porosity-preservation mechanisms, such as overpressure, grain-coats and feldspar dissolution can be discounted. The sandstones with high oil saturations are characterized by: 1) most porosity being primary as opposed to secondary; 2) there being 2 – 5 % less quartz cement than in the water-saturated sandstones; 3) there being 2 – 3 % more K-feldspar and 2 – 6 % less kaolin than the water-saturated counterparts. This study demonstrates that petroleum emplacement can effectively inhibit quartz cementation and K-feldspar transformation to kaolin in sandstone reservoirs.

Keywords: quartz cementation, K-feldspar dissolution, reservoir quality, porosity preservation, sandstone porosity

INTRODUCTION

Petroleum emplacement in sandstone reservoirs can potentially preserve reservoir porosity by inhibiting quartz cementation and other diagenetic processes. This is one potential mechanism that may form deep, high-porosity oil and gas reservoirs (Bloch et al., 2002; Worden et al., 1998). However, this proposition is highly contentious. Some studies have recorded higher porosity and less quartz cement in the reservoirs where pore waters have been replaced by petroleum, thereby invoking petroleum emplacement as a mechanism of porosity preservation (e.g. Gluyas et al., 1993; Marchand et al., 2001; Worden et al., 2018; Lei et al., 2019). Nevertheless, at least an equal number of studies have reached the opposite conclusion; these studies observed on-going quartz cementation in oil-filled reservoirs and that the porosity of these reservoirs does not appear to be higher than the water-filled counterparts. Hence, they conclude that petroleum does not affect reservoir porosity (e.g. Giles et al., 1992; Barclay and Worden, 1998; Midtbø et al., 2000; Molenaar et al., 2008; Taylor et al., 2010).

Understanding the effect of petroleum on sandstone porosity has great scientific and commercial significance. Firstly, this can help to develop a more accurate predictive model for reservoir porosity. Second, if petroleum is capable of preserving porosity, it means the porosity of petroleum reservoirs can be maintained at great depths (e.g. >5000 m) once petroleum is emplaced. As a result, the lower depth limit of exploration targets can be extended to a deeper regime, and the number of high-quality deep reservoirs may be more significant than previous estimates. Moreover, this knowledge is also of great importance for oilfield production, as it provides the possibility of predicting the distribution pattern of porosity-permeability within an oilfield by modelling the history of petroleum filling, reducing the need to collect expensive core data (Worden et al., 1998).

However, assessing the effect of petroleum on sandstone porosity is often difficult. In addition to petroleum emplacement, there are other factors that may also help preserve porosity, such as reservoir overpressure and grain coats (Oye et al., 2018; Storvoll et al., 2002). For a high-porosity sandstone, it is usually difficult to discern and quantify the amount of porosity preserved by each of the factors (Aase and Walderhaug, 2005; Wilkinson and Haszeldine, 2011). However, if there is a case where the effect of other porosity-preservation mechanisms, except for petroleum emplacement, can be shown to be minimal, then demonstrating the porosity-preservation effect of petroleum emplacement might be possible. The reservoir sandstones of the Kessog Field in the North Sea (Figure 1) exhibit porosities up to 11% higher than the predicted porosity for the burial depth (Figure 2A), and most of these high-porosity sandstones are also characterized by high oil saturation (S_o > 40 %; Figure 2B), which indicates that high porosity and high oil saturation are possibly related. This paper aims to address two questions: are the high-porosity sandstones of the Kessog Field the result of high oil saturation? And what are the porosity and petrographic characteristics of the high-porosity sandstones potentially affected by petroleum emplacement? Petrographic data, conventional core data, well log data and reservoir structure data are utilized to test the hypothesis that the preservation of the high porosity in the Kessog Field is related to petroleum emplacement.

Figure 1. Location of the Kessog Field in the North Sea

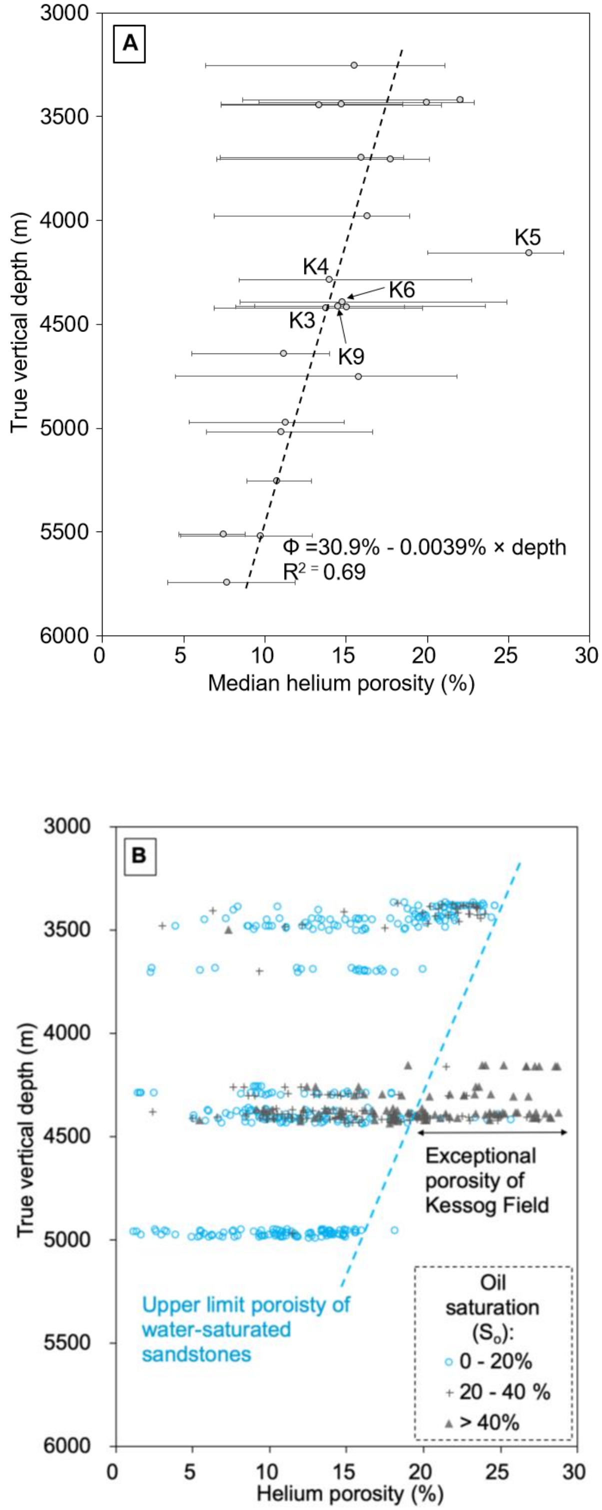


Figure 2. (A) Median porosity (P50) of different wells drilled the Pentland Sandstone (Error bar = P10 to P90 range of the porosity). The porosity data come from 22 Pentland wells with 2372

porosity measurements (summary in Supplementary Data). Wells K3, K4, K5, K6 and K9 are located in the Kessog Field. Median porosity of well K5, which is drilled at the crest of the field structure, is 11% higher than the empirical prediction. (B) High porosity of petroleum-saturated sandstones at the Kessog Field. The sandstones buried at 4.1-4.5 km are from wells K3, K4, K5 and K6. Sandstones at 3.3-3.7 km and 4.8-5.0 km are from other six Pentland wells where petroleum saturation data are available (Supplementary Data).

GEOLOGICAL SETTING

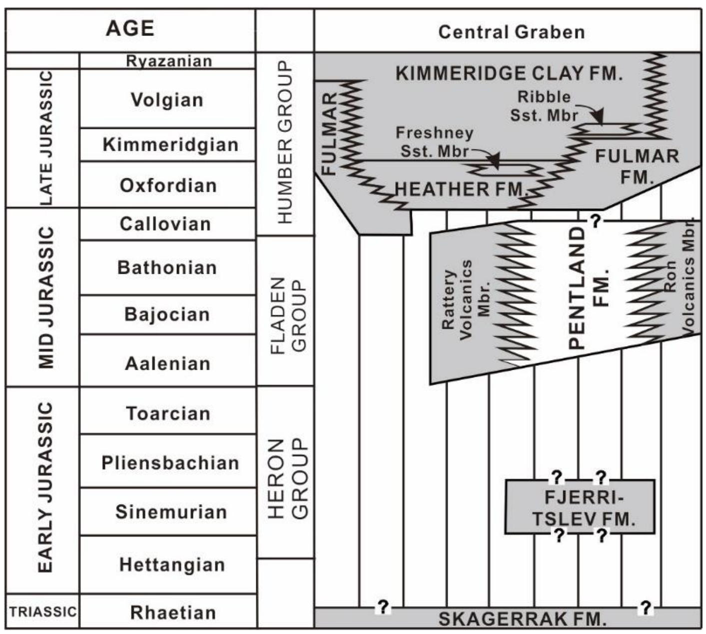


Figure 3. Stratigraphic position of the Pentland Formation within the Jurassic strata of the Central Graben (adapted from Richards et al., 1993). The Pentland Formation lies unconformably between the sediments of Upper Jurassic Humber Group and the Triassic Skagerrak Formation.

The term ‘Pentland Formation’ was initially introduced by Deegan and Scull (1977) to represent a heterolithic unit of sandstone, siltstone, shale and coal that lies between the Upper Jurassic marine sediments of the Humber Group and the Triassic non-marine sediments of the

Skagerrak Formation in the Central North Sea (Figure 3). Sediments of the Pentland Formation are predominantly sandstones with interbedded shales and coals deposited in a fluvial-deltaic or lagoonal environment on a coastal plain (Clark et al., 1993; Deegan and Scull, 1977). The formation is widespread in the Central North Sea, but for most oilfields, it is only a minor reservoir (Eriksen et al., 2003). Reserves in the reservoirs of the Pentland Formation are usually much smaller than in the Fulmar or Skagerrak Formation (Gluyas and Hichens, 2003). The Kessog Field, however, is an exception, for which the principal reservoir is the Pentland Formation.

The Kessog Field is a high-pressure, high-temperature gas condensate field discovered by BP in 1985. The reserves are equivalent to 100 million barrels of oil (Offshore Europe, 2001). Developing the field, however, is a great technical challenge due to a combination of extreme pressures and temperatures and a complex, compartmentalized reservoir.

The field is a tilted fault block bounded by a NW-SE trending fault on the NE side (Figure 4 and Figure 5). The western part of the field is sealed by shales, where the Pentland Formation is unconformably overlain by the Upper Jurassic Kimmeridge Clay Formation (Figure 5). In comparison, the eastern part is sealed by Cretaceous carbonate sediments, possibly because the Kimmeridgian shales have been eroded during the Late Jurassic or Early Cretaceous. The petroleum source for the field is most likely the Kimmeridge Clay Formation.

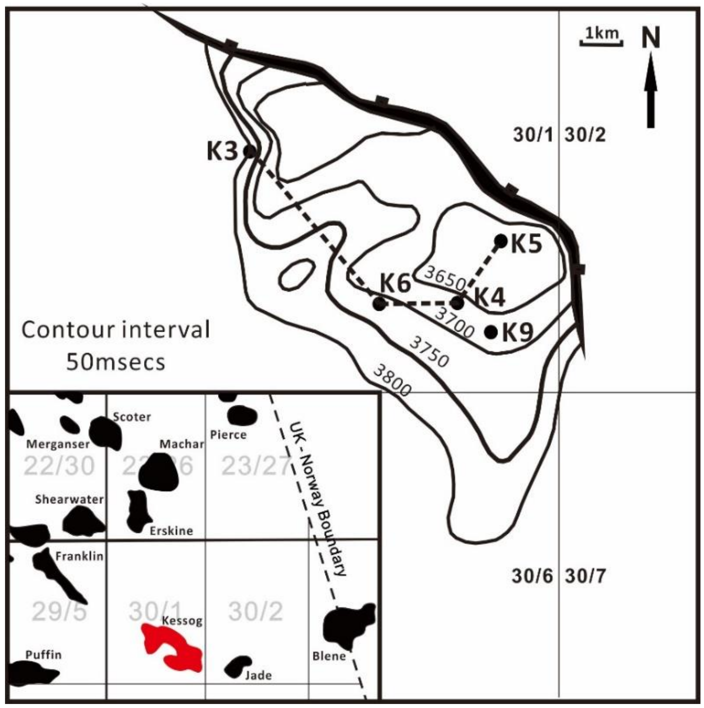


Figure 4. Structural map of the Kessog Field. The Kessog Field is a half-graben structure. The dashed line represents the cross-section in Figure 5.

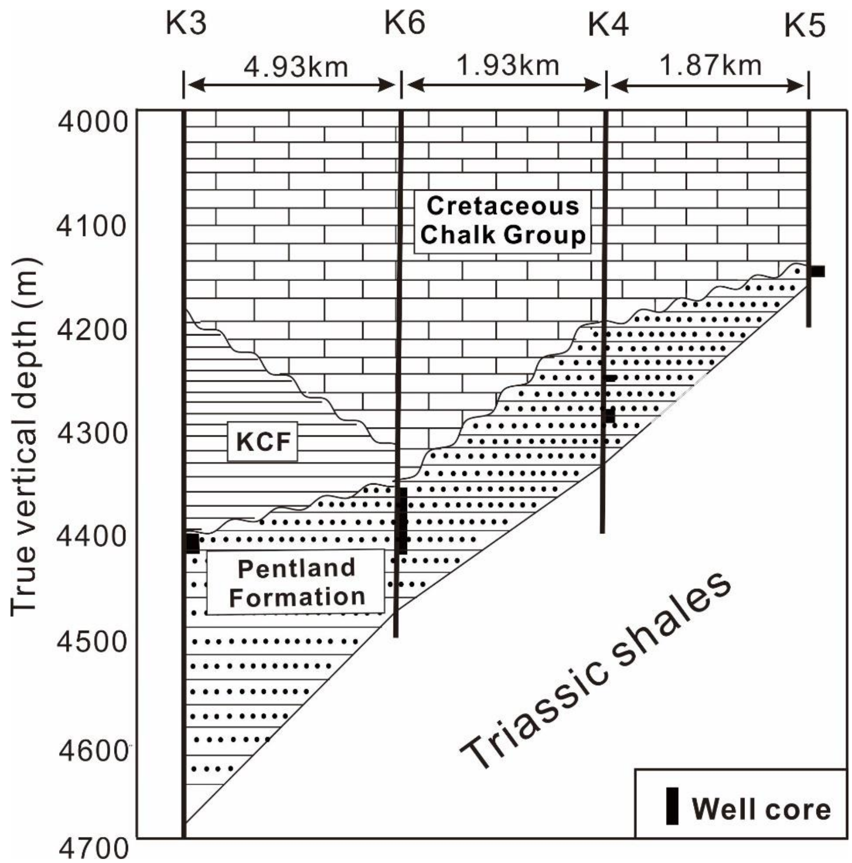


Figure 5. A cross-section across the Kessog Field based on the logs of wells K3, K4, K5 and K6. Note the distances between the wells are unequal. KCF = Kimmeridge Clay Formation

METHODS

There are five wells in the Kessog Field for study: wells 30/1c -3, -4, -5, -6 & -9, which are labelled as K3, K4, K5, K6 and K9 in this paper. Helium porosity, petroleum saturation, well log and formation test data of the wells penetrated the Pentland Formation are accessible in the UK Common Data Access (CDA) database. The sandstone porosity is measured using the Gas Expansion Method: a known volume of helium gas at a known pressure was expanded into a chamber containing a core plug sample in a Boyle's Law porosimeter, whereby the grain volume in the samples can be measured. Then, the bulk volume of the sample was calculated by mercury displacement using a hand-operated mercury displacement pump at atmospheric pressure. The porosity is determined by dividing the grain volume to the bulk volume of the sample. The oil saturation values were determined using the Retort Method. This method first injects mercury into the gas filled pore of a sample using a mercury pump, where the injected volume of mercury is equivalent to the volume of gas. Then, the method requires to heat the sample and measure the volumes of water and oil driven off. The oil saturation value is the ratio of the volume of oil to the total pore volume, which is the sum of the volumes of oil, gas and water. The reservoir temperature and pressure information were obtained from temperature log and repeated formation test results. These analyses were conducted by professional third-party core laboratories using established analytical methods, and the data are therefore considered to be reliable.

Thirty-nine sandstone samples from the borehole cores of the five wells of the Kessog Field (6-8 samples per well) were collected from the UK National Core Collection of British Geological Survey for study. The reservoir sandstones were evenly sampled across the reservoir sections consisting of sandstones, while the shale and coal sections were avoided. Samples were then impregnated with blue resin, made into thin-sections and point-counted (250 counts/slide) for mineralogical composition and porosity. Additionally, point-count data of 68 Kessog Field sandstone samples from Wilkinson et al. (2014) were also used.

Grain size was determined by calculating the mean diameter of 100 quartz grains per sample on microphotographs. Since this mean grain size is measured on a 2D cross-section of quartz grains, the conversion into the actual 3D mean grain size is performed by multiplying the 2D grain size with a factor of 1.273 (Kong et al., 2005). Sorting was based on the grain size data: the data were converted from metric to the phi-scale, then the 5th, 16th, 84th and 95th percentiles of the phi-based grain size distribution were used to compute the sorting coefficient using Eq. (1) (McManus, 1988).

$$\text{Sorting coefficient} = (\Phi 84 - \Phi 16)/4 + (\Phi 95 - \Phi 5)/6.6 \qquad (1)$$

To observe the grain-coats and cement on grain surfaces, we selected two samples from each of the five wells in the Kessog Field, for secondary electron imaging under a Zeiss SIGMA scanning electron microscope (SEM) at an accelerating voltage of 20 kV. Samples with fresh fractures were coated with platinum and stub-mounted for examination in the SEM. All the experimental studies were completed in the laboratories of the School of Geosciences, University of Edinburgh.

RESULTS

Reservoir temperature and pressure

The Kessog Field reservoir is currently at a depth of 4.1 – 4.5 km. Between 170-70 Ma, the reservoir was buried to only shallow depths (<1000 m), and from 70 Ma to present, the reservoir experienced rapid burial to a depth below 4.1 km. The temperature in the reservoir is currently around 160-170^{o}C (

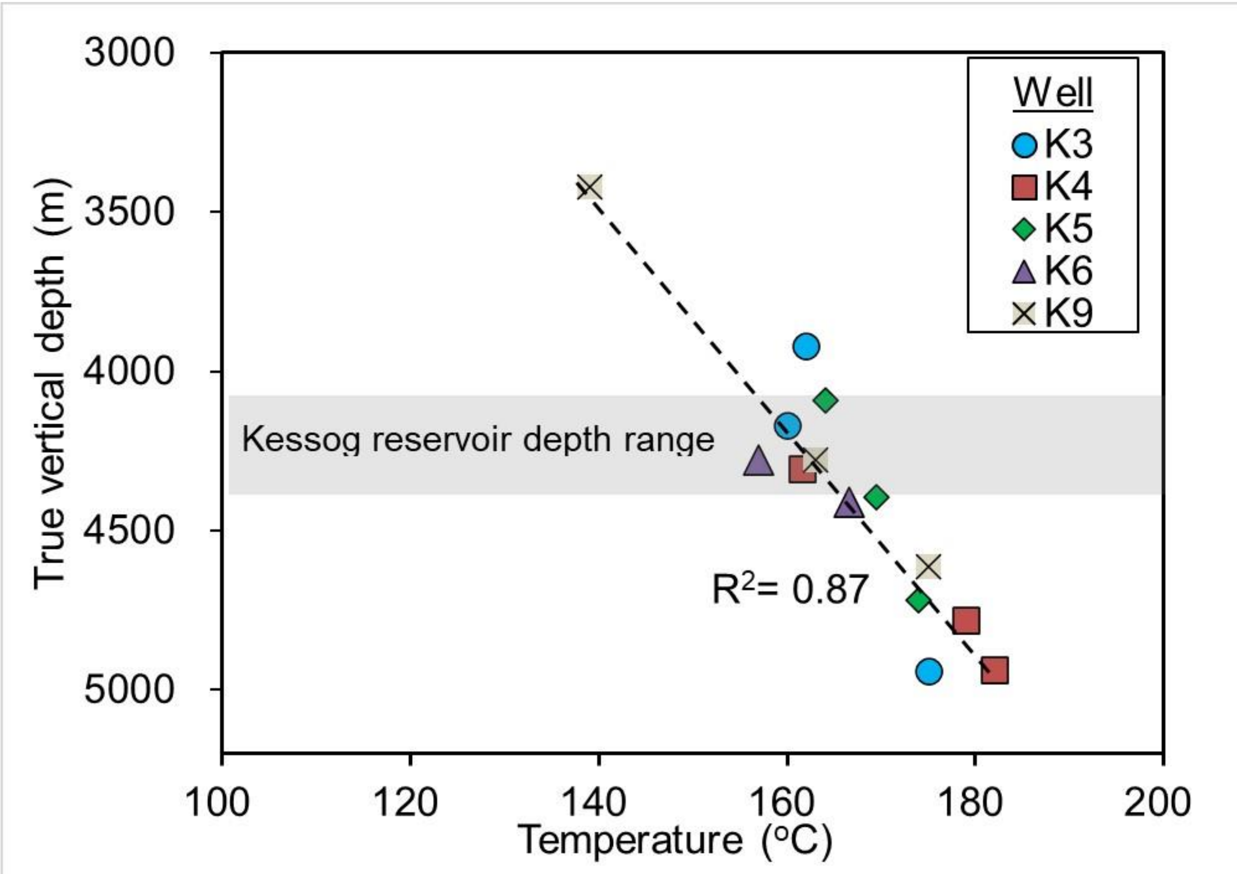


Figure 7). The Pentland Formation is highly overpressured below the depth of 4.1 km (Figure 8). The degree of overpressure in the Kessog Field is close to the other deep Pentland reservoirs, with reservoir pressure approaching the lithostatic pressure.

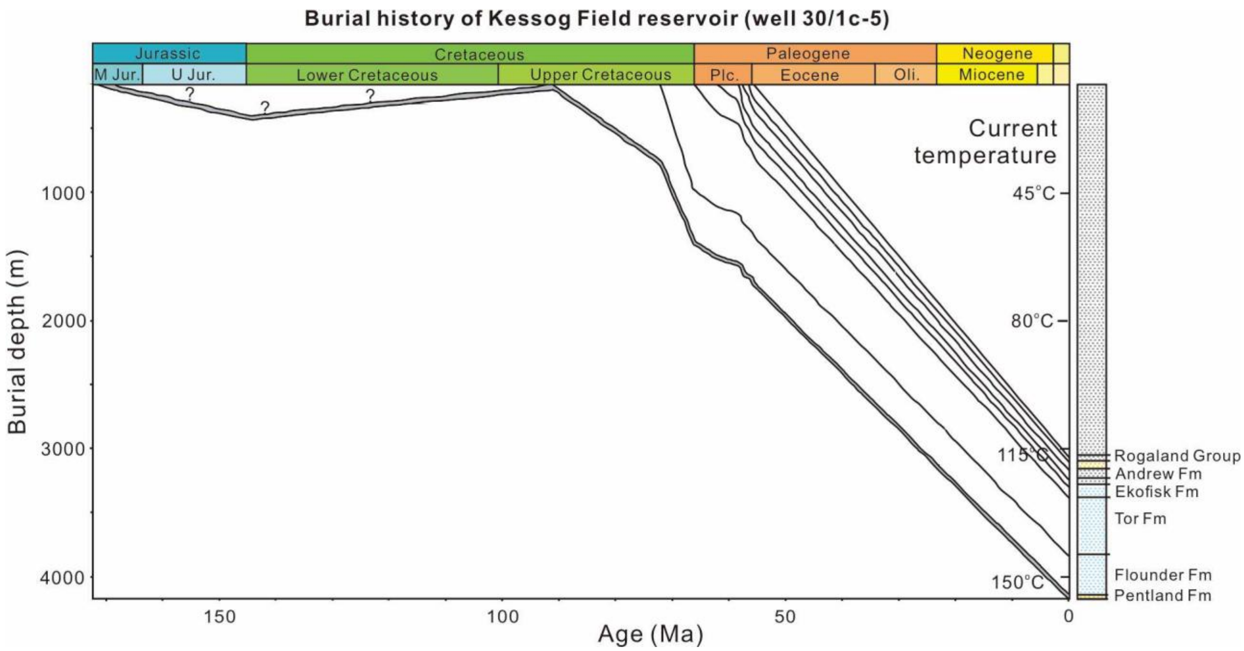


Figure 6. Burial curve for the Kessog Field from well K5. The burial process was modelled using PetroMod™ software. The thickness of the sediments eroded during the Early Cretaceous is uncertain. The Cenozoic sediments lack a clear stratigraphy, and hence burial has been assumed to be at a constant rate. The surface temperate and geothermal gradient are assumed to be 10^{o}C and 35^{o}C/km (see

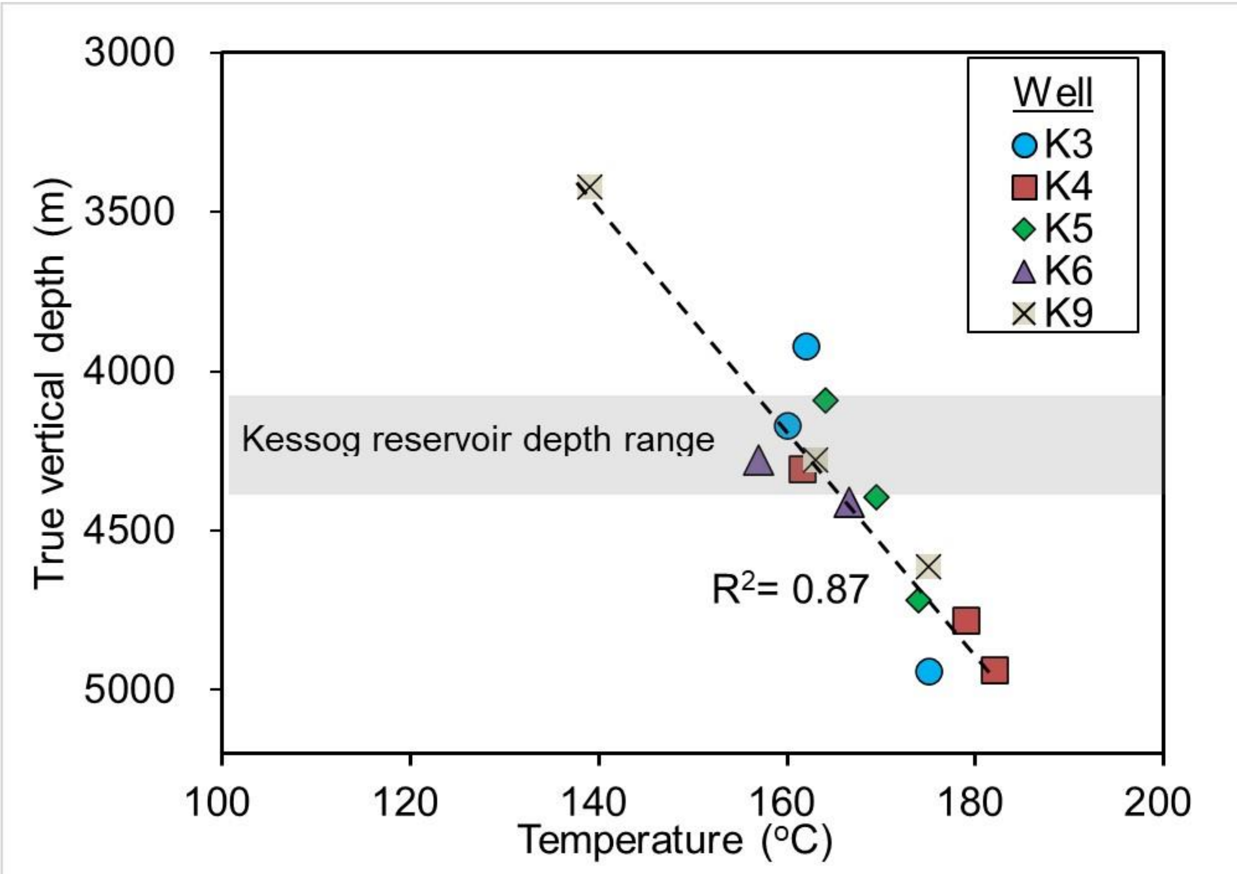

Well
K3
K4
K5
K6
K9
Kessog reservoir depth range
R^2= 0.87
True vertical depth (m)
Temperature (°C)
3000
3500
4000
4500
5000
100
120
140
160
180
200

Figure 7).

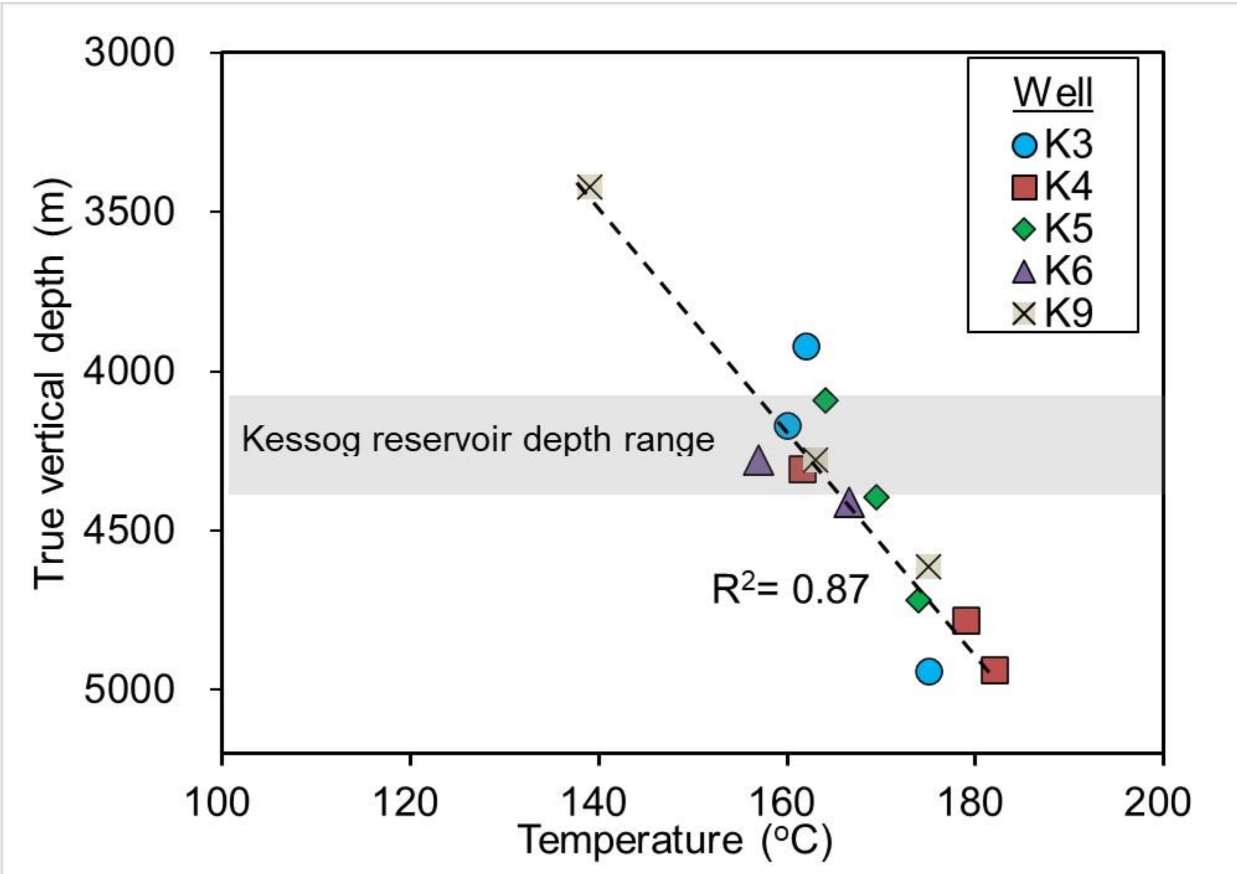


Figure 7. Subsurface temperature increase near the Kessog Field. The data are corrected log temperatures. The geothermal gradient is around 35°C/km.

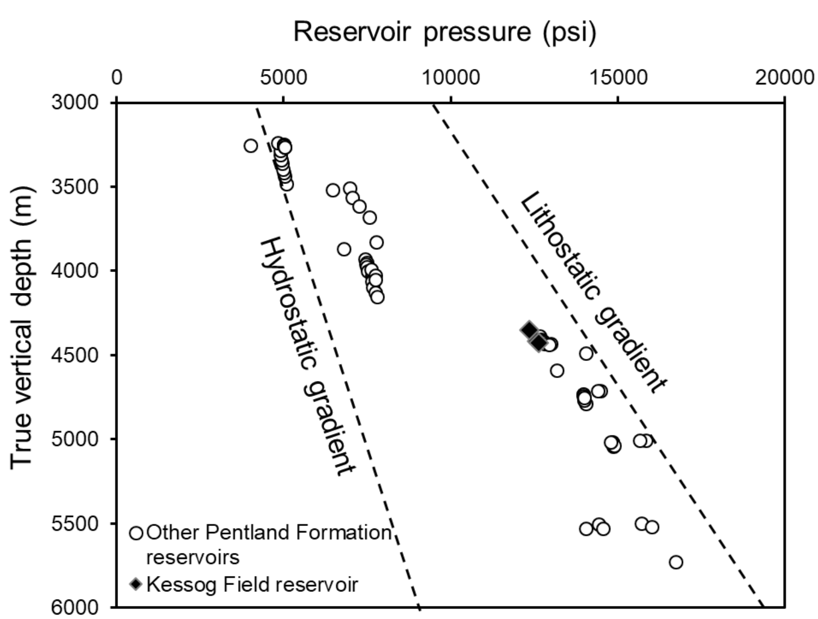


Figure 8. Reservoir pressure of the Pentland Formation versus depth. The Kessog Field is highly overpressured as with other deep Pentland reservoirs below 4.2 km. The hydrostatic and lithostatic gradients are from Moss et al. (2003). The pressure data are from 11 Pentland wells.

Porosity and petrography

The average helium porosity of well K5 is abnormally high at 25% (Table 1 and Supplementary Data), whereas for the depth of the Kessog Field, only 14 % would be predicted from regional Pentland Formation data (Figure 2A). In contrast, the average porosities of wells K3, K4, K6 and K9 are significantly lower (Table 1), but are consistent with the regional mean porosity (Figure 2A). However, it is notable that a few sandstones of wells K3, K4 and K6 are also of high porosity, comparable to well K5, and the majority of these are characterized by high oil saturation (S*o* > 40 %, Figure 2B).

Table 1. Average porosity and oil saturation (S*o*) of Kessog Field wells (in order of increasing depth)

Well	Avg. TVD (m)	Avg. helium porosity (%)	Avg. oil saturation (%)	Reservoir thickness (m)
K5	4155	24.7±1.1	57±6	23.5
K4	4288	14.1±0.7	27±2	138
K6	4392	15.8±0.5	35±1	117.5
K9	4412	15.2±0.7	n.a	203
K3	4423	13.7±0.5	14±1	280

Note: mean values of helium porosity and oil saturation are expressed as ± 1 standard error of the mean.

Photomicrographs of typical reservoir sandstones from well K5, K4, K3 and K9 are illustrated in Figure 9, showing that the porosity of these sandstones generally decreases with depth. The petrographic data suggest that the average sandstone grain size (corrected to 3D) of different wells are nearly uniform, lying within the range of 0.14 - 0.17 mm (Table 2). The sandstones also exhibit similar degrees of sorting, with sorting coefficients within the range of 0.54-0.63 (moderately well-sorted sand, Table 2); the sandstones of well K4 are slightly less well sorted (sorting coefficient: 0.77), so are moderately sorted sands. Grain contacts in the high-porosity sandstones are typically long contacts (Figure 10), whereas in the less porous and more quartz-cemented sandstones, concave-convex (CC) contacts are common, indicating a higher degree of chemical compaction in the latter.

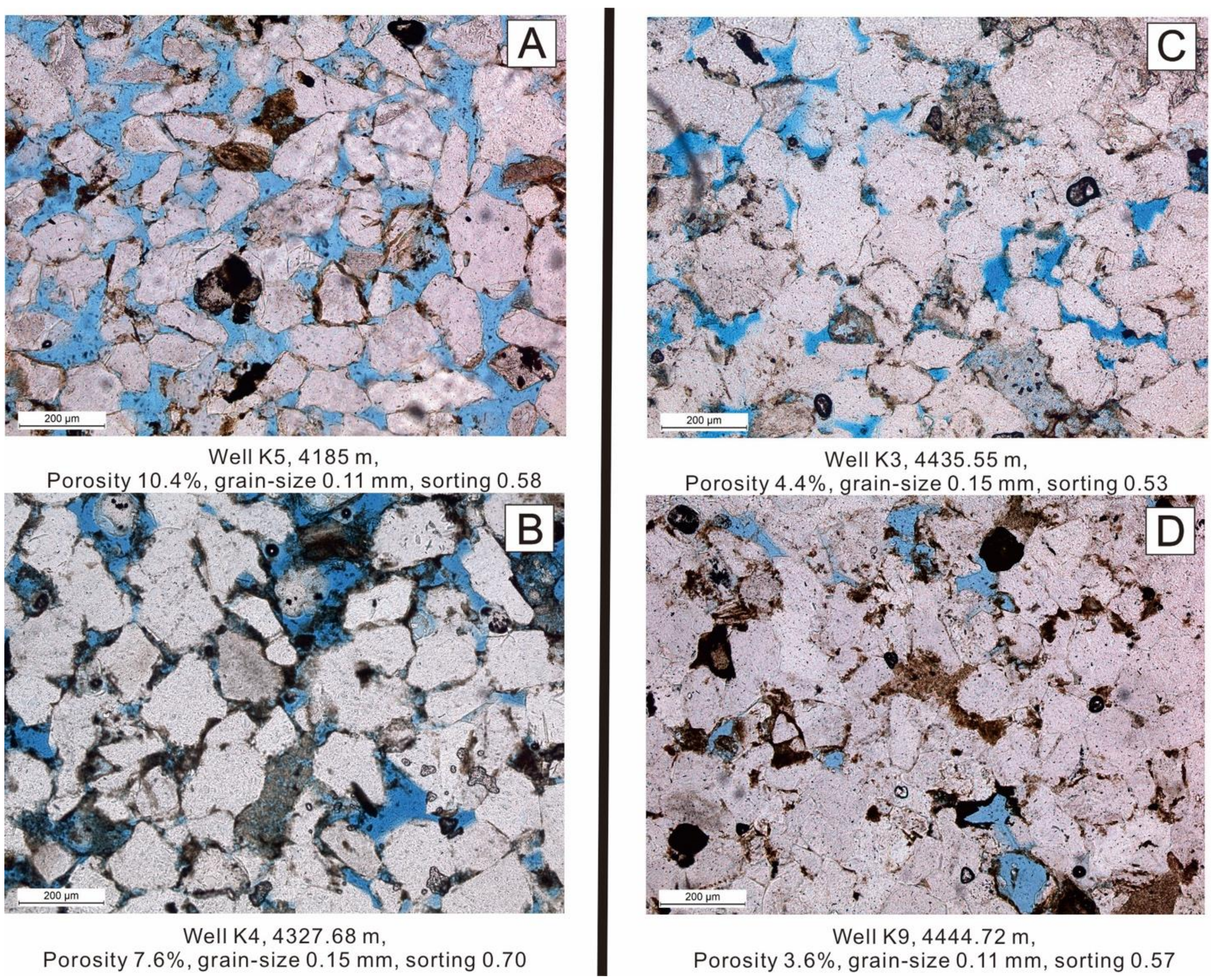


Figure 9. Microphotographs showing sandstones in different Kessog wells (increasing depth from A to D). The sandstones are very fine to fine-grained with similar degrees of sorting, and all the photos are on the same scale. In the shallowest well K5, the sandstones are porous; whereas in the deepest well K9, the sandstones are highly cemented.

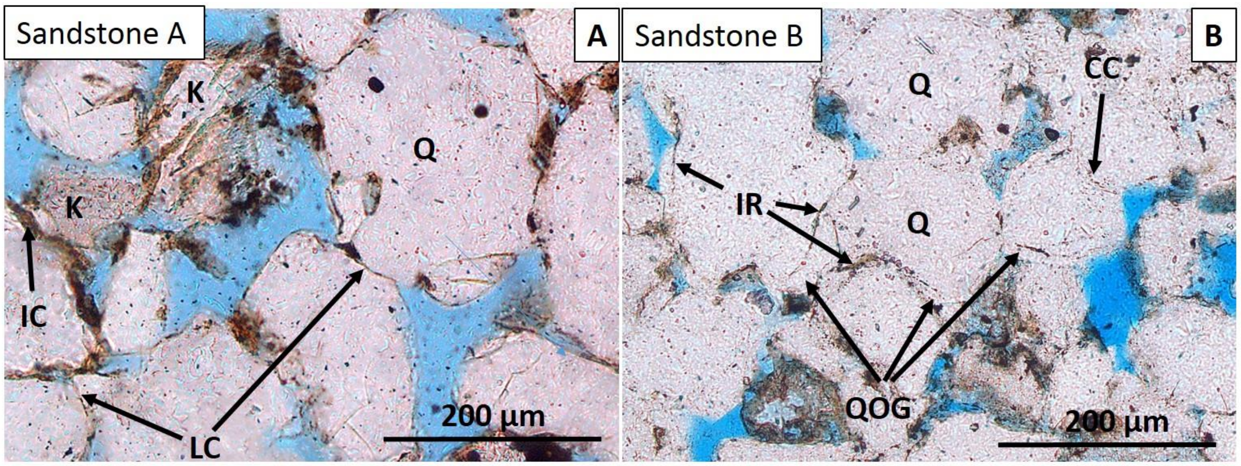


Figure 10. (A) Microphotograph of a high-porosity sandstone from the well K5 (TVD 4159 m, point-counted porosity 10.4%, avg. grain size 0.11 mm, sorting 0.58). (B) a sandstone from well K3 with similar grain size and sorting as in (A) (TVD 4410.55 m, point-counted porosity 4.4%, avg. grain size 0.15 mm, sorting 0.53). The most common grain contact type in sandstone A is long contact (LC), whereas in sandstone B, concave-convex (CC) contact is common, indicating a higher degree of chemical compaction. Thick illite coats (IC) only appear on the surface of a small number of quartz grains. Illite rims (IR), as shown in (B), commonly fail to prevent quartz overgrowth. Q = detrital quartz grains; QOG = quartz overgrowth; K = K-feldspar.

The framework grains of the Pentland Sandstone in the Kessog Field are dominated by detrital quartz (Table 2 and Supplementary Data). Optically-identifiable feldspar in most cases is present in only small amounts (<4%), and lithic fragments are nearly absent, hence the sandstones are quartz arenites (Folk, 1974), in line with the regional norm (Wilkinson et al., 2014). The principal clay minerals are kaolin (0.7 - 5.5%) and illite (8 – 17%; Table 2). The kaolin in the sandstones occurs in the form of dense blocky and vermicular aggregates, which fill oversized pores left presumably by the dissolution of feldspar grains. The morphology of illite is more diverse: it can be compacted clasts, grain rims or coats, matrix in-filling primary porosity or very occasionally a replacement of kaolin. The majority of illite occurs as compacted clasts, which are considered to be detrital in origin. The volume of K-feldspar shows a decreasing trend with depth: from 3.8±0.4% from well K5 to 1.3±0.3% in K3 and 0.6±0.3% in K9 (Table 2). Meanwhile, kaolin increases from 0.7±0.2% (well K5) to 5.5±1.0% (well K3) and 6.3±1.7 (well K9).

Quartz overgrowth (QOG) is the dominant cement in the sandstone reservoirs of the Kessog Field. The average volume of quartz overgrowth determined by point-counting is least in the crestal well K5 (2.8 ± 0.4 %, Table 2); in deeper wells the average volume increases to 6.4 ± 1.0% in well K3 and 7.8 ± 2.2 % in well K9 (Table 2, Figure 11). Under SEM, some quartz cement in the high-porosity sandstones is present as an unusual, anhedral form (Figure 12A), in contrast to the euhedral, smooth crystal faces of standard quartz cement (Figure 12B). The SEM analysis was performed on two sandstone samples per well. The irregular outlines of the cement are common in the sandstones of well K5, and occasionally observed in well K3. In the sandstones of other wells, however, quartz cement appears as standard, euhedral crystals.

The sandstones of the crestal well (K5) contain mostly primary porosity (10.3 ± 0.9 %, **Error! Reference source not found.**), and secondary porosity is of lesser importance (3.9 ± 0.5 %). In the other wells, primary porosity typically varies between 1 and 5 %, and secondary porosity between 2 and 5 % (Table 2). From the relics of dissolved minerals, it can be inferred that the secondary porosity was created mostly by the dissolution of feldspar grains. Primary porosity hence appears to be important for the reservoir quality of the Kessog Sandstone. Figure 13A shows that primary porosity has a positive correlation with the point-counted total porosity. In the sandstones of high porosity, the porosity is predominantly primary porosity (Figure 13A). In contrast, the percentage of secondary porosity is widely scattered in high-porosity sandstones, with no correlation with the amount of point-counted total porosity (Figure 13B).

Table 2. Average composition, grain-size and sorting of the sandstones

Well	n*	Quartz (%)	K-feldspar (%)	QOG† (%)	Illite** (%)	Kaolin (%)	Primary porosity (%)	Secondary porosity (%)	Grain-size (mm)	Sorting
K5	28	62±1	3.8±0.4	2.8±0.4	9.2±1.2	0.7±0.2	10.3±0.9	3.9±0.5	0.14±0.01	0.58±0.02
K4	13	60±1	1.8±0.3	4.0±0.9	17.0±3.0	2.9±0.6	3.7±1.1	5.0±0.8	0.17±0.01	0.71±0.04
K6	50	54±1	0.6±0.1	6.4±0.6	14.7±1.9	4.8±0.5	5.5±0.7	3.1±0.3	0.15±0.01	0.57±0.02
K9	8	65±1	0.6±0.3	7.8±2.2	11.8±2.6	6.3±1.7	1.3±0.6	3.2±1.3	0.15±0.02	0.63±0.05
K3	8	68±2	1.3±0.3	6.4±1.0	8.2±1.9	5.5±1.0	2.0± 0.7	2.1±0.5	0.15±0.01	0.54±0.04
Avg. PF§	245	60.6	1.4	6.9	11.4	4.0	4.1	3.3	n.a	n.a

Note: mean values are expressed as ± 1 standard error of the mean. See Supplementary Data.

*n = number of samples;

** The illites are compacted clasts that are interpreted to be detrital in origin. Grain-coating illite or the illite replacing kaolin occur very occasionally in the reservoir and their volumes are below the resolution of the point-count method.

†QOG = quartz overgrowth;

§Avg. PF = average composition of the Pentland Sandstone buried at 3000-6000 m, data from Wilkinson et al. (2014).

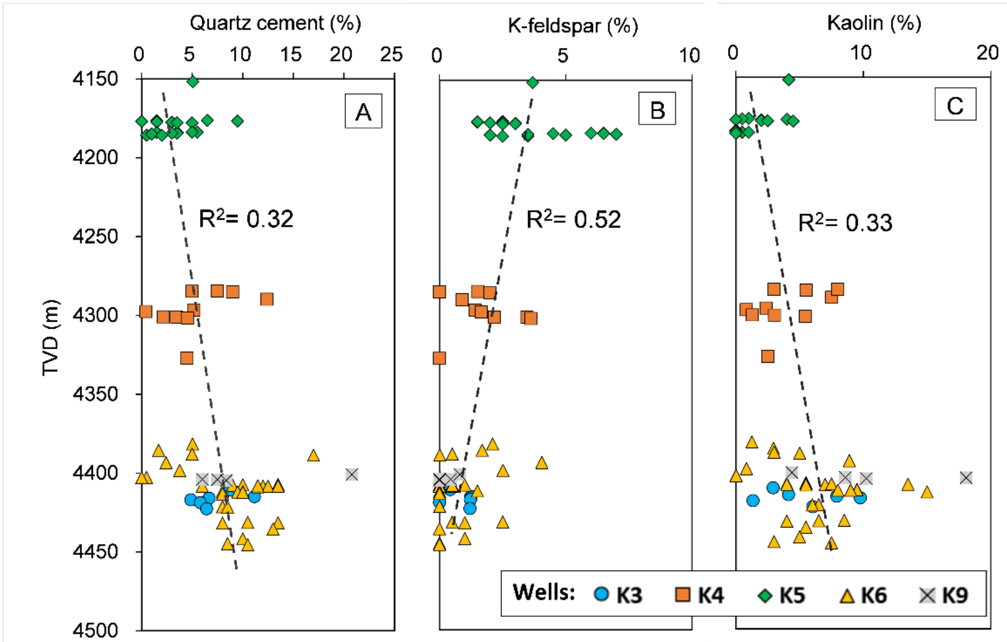
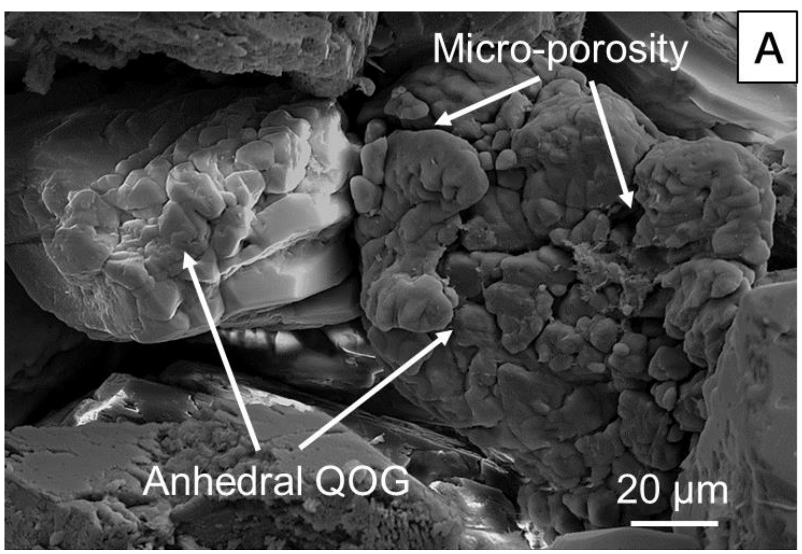


Figure 11. Variation of point-counted (A) quartz cement, (B) K-feldspar and (C) Kaolin with depth in the main sandstone facies (fine-grained) of Kessog Field reservoir. Siltstone, very fine-grained and medium-grained sandstone samples were excluded in these figures. The amount of quartz cement and kaolin increase, with depth while K-feldspar shows a decreasing trend.



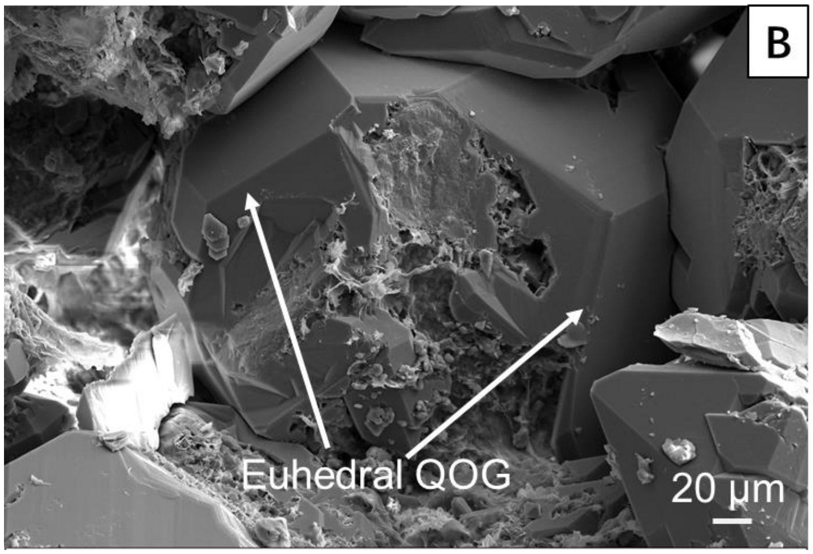


Figure 12. SEM micrograph of anhedral quartz cement (A) with irregular form in a sandstone from the crestal well K5 (TVD 4158 m, point-counted porosity 11.6%), and for comparison, euhedral quartz cement (B) from well K9 (TVD 4404m, point-counted porosity 14%). Microporosity can be seen between individual anhedral quartz cement crystals. The space is likely filled by petroleum that stops the quartz cement from forming euhedral crystal faces. This irregular quartz morphology could be a diagnostic feature for petroleum emplacement inhibiting quartz cementation.

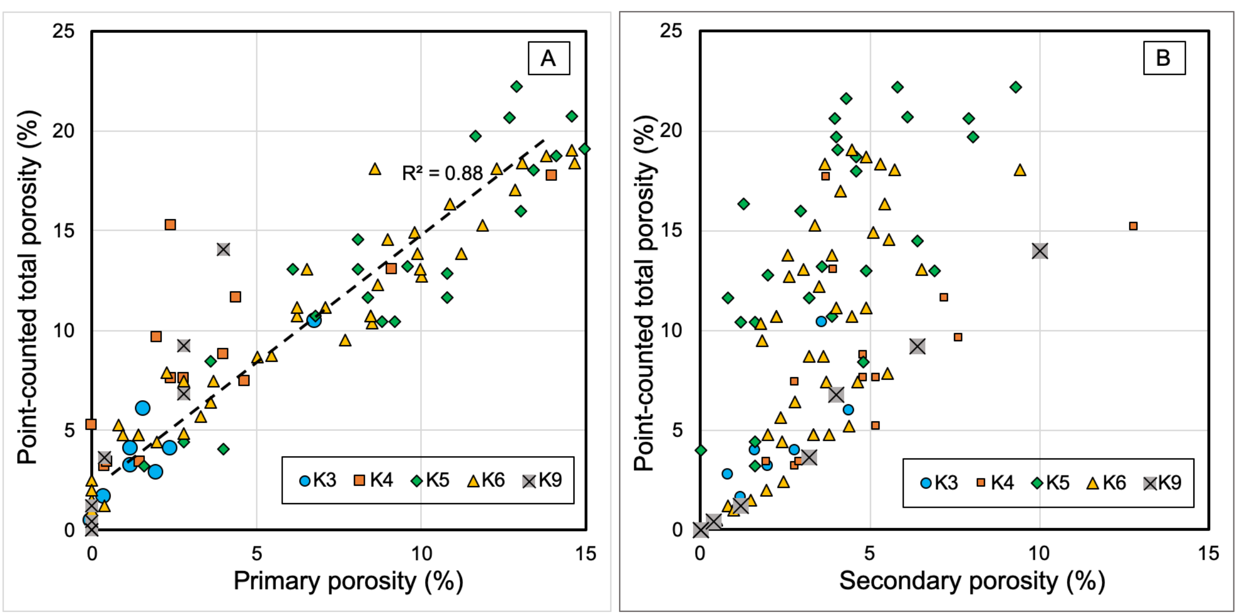


Figure 13. Plots of primary porosity (A) and secondary porosity (B) versus total porosity (point-counted) in the Kessog Sandstone. The porosity in the high-porosity sandstones is pre-dominantly primary in origin.

DISCUSSION

Possible cause of high porosity

How does a sandstone retain high porosity during deep burial? Or what kind of sandstone retains porosity at depth? One of the most critical factors in deciding the porosity of a sandstone during burial is its depositional composition and texture (Bjørlykke and Jahren, 2015). For example, clean, fine-grained and well-sorted sandstones are more likely to become high-porosity reservoirs at depth since the rocks can develop a robust texture to resist mechanical compaction (Chuhan et al., 2003). Besides this, there are five other commonly invoked mechanisms to explain the occurrence of high-porosity sandstone reservoirs: grain-coating microquartz (Aase et al., 1996; Aase and Walderhaug, 2005; Jahren and Ramm, 2000) and chlorite (Ajdukiewicz and Larese, 2012; Dowey et al., 2012; Ehrenberg, 1993); porefluid overpressure (Osborne and Swarbrick, 1999; Stricker and Jones, 2016); mineral dissolution (i.e. secondary porosity; Day-Stirrat et al., 2010; Wilkinson et al., 2003) and early petroleum emplacement. In addition, bitumen coats on quartz grains (Maast et al., 2011), phosphate poisoning of mineral surfaces (Warren and Pulham, 2001) and thermal anomalies near salt (Taylor et al., 2010), which are relatively less common, are also potential mechanisms. This section assesses which of the mechanisms is responsible for high porosity in the Kessog Field.

Grain-size, sorting and mineralogy: petrographic data show little difference in grain size and sorting between different wells of the Kessog Field (Table 2). The high-porosity sandstones of well K5 do not show any depositional texture that could account for the high porosity. In addition, sandstones with a similar texture as the high-porosity sandstones are generally more quartz-cemented in the other wells, e.g. in Figure 9. This suggests that a similar depositional texture can equally form a high- or low-porosity sandstone in different parts of the same oilfield reservoir (**Error! Reference source not found.**Figure 9).

The high-porosity sandstones of well K5 also show similar mineralogical composition as the other sandstones (Table 2). The only noteworthy difference is the volume of illite. Illite is a key mineral that can affect compaction and therefore the porosity of a sandstone, as a high content of detrital illite present as clasts may significantly enhance sandstone compaction (Chuhan et al., 2003). Point-count results show that sandstones of well K5 contain less illite than the sandstones of wells K4, K6 and K9 (Table 2), indicating that the lesser volume illite may contribute to the porosity preservation in well K5. However, this scenario can be refuted by the mineralogy and porosity data from well K3, which contains even less illite than well K5 but the porosity is comparable to the regional norm (Figure 2). Hence, there is no evidence to support that variation in any mineralogical component as the cause of high-porosity in the Kessog Field.

Grain coats: grain-coating micro-quartz that is capable of preserving sandstone porosity by inhibiting quartz cementation occurs in sandstones of marine origin (Aase and Walderhaug, 2005). This is because the micro-quartz is precipitated from the dissolution of detrital siliceous sponge spicules (Aase et al., 1996; Worden et al., 2012). Nonetheless, there have been few exceptional cases in which micro-quartz grows in fluvial-deltaic sandstones: the examples include the fluvial Skagerrak Formation in the North Sea (Nguyen et al., 2013), and the Safaniya Sandstone in Saudi Arabia (Çağatay et al., 1996). The micro-quartz cement in these sandstones was interpreted as being precipitated from silica-saturated fluvial waters and occurs only in trace amount that is insufficient to reduce quartz cementation. The Pentland Formation was deposited in a fluvial-deltaic setting; as such, micro-quartz cement is not expected to occur. In practice, micro-quartz cement has not been observed in any sandstone samples from the Pentland Formation under the optical microscope or SEM.

As for chlorite coats, previous studies on the petrology and mineralogy of the Pentland Formation have not reported any chloritic clays or grain-coats in the sandstones (Coward, 2003; Wilkinson et al., 2014). In the Kessog Field in particular, optical and scanning electron microscopy in this study has not observed any chlorite grain coats in the reservoir sandstones, which eliminates the possibility that chlorite coats are preserving sandstone porosity.

Grain-rimming or coating illite, however, is common in the sandstones. But the effectiveness of illite coats inhibiting quartz cementation is uncertain: on the one hand, only a few studies (e.g. Heald and Larese, 1974; Storvoll et al., 2002) have asserted that sandstones with illite coats have low quartz cement and high porosity; on the other hand, many more studies have indicated that illite coats have enhanced pressure solution between quartz grains, causing more porosity loss (e.g. Bjørkum, 1996; Oelkers et al., 1996; Thomson and Stancliffe, 1990; Walderhaug, 1994). In the case of the Kessog Field, quartz cement is not observed on the surface of quartz grains that are covered by thick illite coats (>10 μm, e.g. in Figure 10A), suggesting the coats may have inhibited quartz cementation. However, thin grain coats (<10 μm), such as the illite rims in Figure 10B, are commonly overgrown by quartz cement and do not appear to inhibit quartz cementation. Thick illite coats in the Kessog sandstones are only present on a limited number of quartz grains (Figure 10A) and therefore, their effectiveness in inhibiting quartz cementation for the whole reservoir is considered to be negligible. Also, the high-porosity sandstones of well K5 were observed to contain no more illite coats than the other sandstones, which disproves the hypothesis of illite coats preserving porosity in the sandstones.

Overpressure: all the Pentland Formation reservoirs are overpressured to similar degrees below a depth of 4.2 km (Figure 8), hence the effect of overpressure on the compaction of sandstone is expected to be similar for all these reservoirs. Overpressure therefore cannot account for the observed porosity difference between different Pentland wells or oilfields.

Secondary porosity: in the high-porosity sandstones of well K5, the point-count results show that the type of porosity is dominated by primary porosity (Table 2). In comparison, the amount of secondary porosity in the high-porosity sandstones of well K5 is not significantly higher than in the sandstones of wells K3, K4, K6 and K9 (Table 2, Figure 13). This suggests that the high porosity was formed through the preservation of primary porosity, rather than the creation of porosity by grain dissolution.

Other potential mechanisms: Maast et al. (2011) noticed a highly porous section of sandstones between the oil-leg and water-leg of the reservoir of the Miller Field, UK Central North Sea (well 16/3b-5). This section of sandstones is about 15m thick, containing porosity that is approximately 10% higher than both the oil- and water-legs of the reservoir. Through observations under the microscope, Maast et al. (2011) concluded that this high porosity is preserved by grain-coating bitumens on quartz grains. The high porosity sandstones in the Kessog Field, however, mostly occur in the top of the reservoir where it is petroleum saturated. This is not where bitumen would be expected to form. Two other mechanisms — phosphate poisoning of grain surfaces (Warren and Pulham, 2001) and thermal anomalies near salt (Taylor et al., 2010) are unlikely to happen in the Kessog Field as it is not close to any known phosphate or salt beds.

Influence of petroleum on the sandstone porosity

If the porosity of a reservoir is preserved by petroleum emplacement, what porosity distribution pattern is expected? Since petroleum is less dense than water, it would first accumulate in the top of a reservoir and then gradually fill toward the bottom. Therefore, if petroleum is capable of preserving sandstone porosity, porosity preservation is expected to be the greatest at the reservoir top, and to decreases downwards, as the time of petroleum emplacement becomes later (Wilkinson and Haszeldine, 2011). This is consistent with the pattern of porosity variation within the Kessog Field, where the highest porosity occurs in the shallowest well K5 (Table 1); the reservoir porosity in the well is 9 – 11 % higher than the porosity of the other wells (Table 1). Also, quartz cement in well K5 is significantly less abundant (2 – 5 % less) than in the other wells (Figure 11, Table 2). Hence, the variations of porosity and quartz cement within the reservoir of the Kessog Field can be well explained by the process of petroleum emplacement.

The grain contacts in the high-porosity sandstones of well K5 are typically long-contacts (Figure 10A); combined with the small volume of quartz cement (2-3%), it can be inferred that the petrography of the high-porosity sandstones is similar to a sandstone that is buried to only 2-3 km (80 – 115^{o}C) in the North Sea Basin. This is supported by experimental sandstone compaction curves and empirical oilfield data (Gluyas and Cade, 1997), which suggest that the porosity of well K5's sandstone (25%) normally occurs in sandstones buried at approximately 2.5 km in the North Sea, giving an estimate of the depth of petroleum emplacement. The small volume (2-3%) of quartz cement in the sandstone can effectively retard or prevent significant porosity loss by compaction (McBride, 1989), but further growth of quartz cement has been inhibited by petroleum emplacement. This would result in a sandstone reservoir whose porosity can be preserved to greater depth, and one petrographic feature of these sandstones influenced by early petroleum emplacement is that primary porosity dominates over secondary porosity, as is observed in the sandstones of well K5 (Table 2).

Petroleum emplacement retarding K-feldspar dissolution

Another feature of the high-porosity sandstones in well K5 is the significantly higher amount of K-feldspar than the other sandstones (Figure 11, Table 2); meanwhile, kaolin, which is a product of K-feldspar dissolution (Bjørlykke and Jahren, 2015; Yuan et al., 2019), is scarce (0.7 ± 0.2 %). There are three possible mechanisms that can potentially cause the variation of K-feldspar and kaolin within the Kessog Field.

Firstly, K-feldspar and kaolin could be controlled by variations in the original sandstone composition. However, as previously discussed, the petrographic data show otherwise uniform sandstone composition and texture across the field. And if the K5 sandstones were richer in K-feldspar upon deposition, then the lack of diagenetic kaolin becomes problematic. Therefore, variation in detrital composition is not a reasonable explanation for the high content of K-feldspar but less abundant kaolin in well K5.

The second possible explanation is that the pattern of K-feldspar and kaolin was controlled by meteoric water flushing when the sandstones were close to the paleo-ground surface. The presence of the unconformity surface at the top of the Kessog Reservoir indicates the sandstones had been subjected to sub-aerial erosion in the past (Figure 5). The K5 sandstones are much thinner (23.5 m) than the sandstones of the other wells, which are all greater than 100 m thick (Table 1). This suggests that the well K5 has been subjected to more erosion, and correspondingly more meteoric water flux, than the latter, so that greater transformation of K-feldspar to kaolin might be expected here. As this is the opposite of the observed pattern, this refutes the hypothesis that the preservation of K-feldspar in well K5 is because of less meteoric water leaching near the surface.

The third possible scenario is that K-feldspar dissolution in well K5 was inhibited by petroleum emplacement in a manner analogous to petroleum restricting silica mobility (Worden et al., 1998). The emplacement of petroleum limits the transport of the ions released by K-feldspar dissolution, thereby impeding K-feldspar dissolution and the growth of kaolin. Overall, petroleum emplacement inhibiting K-feldspar dissolution is the most reasonable explanation for the preservation of K-feldspar in the K5 sandstones.

Implication for petroleum reservoir quality prediction

This study delivers a clear answer to the controversial question of whether petroleum emplacement can preserve sandstone porosity in diagenesis. The quartz arenite reservoir of the Kessog Field with high oil saturations is shown to contain up to 11% higher porosity than the otherwise similar water-saturated sandstones (Figure 2). Petroleum emplacement inhibiting quartz cementation is concluded to be the primary cause of the high porosity. This effect of porosity preservation by petroleum emplacement is important for exploration ventures targeted on deep oil and gas reservoirs, which may be previously deemed uneconomic due to predicted low porosity and permeability. Conventional reservoir quality prediction models forecast significant reservoir quality risk with these targets as they are under elevated temperature and pressure conditions and possibly subjected to extensive quartz cementation and a high degree of compaction (Lander et al., 2008; Walderhaug, 2000). However, if these reservoirs had been charged with petroleum in the early stages of diagenesis, prior to the onset of quartz cementation, primary porosity in these reservoirs might be significantly preserved during deep burial. Basin modelling identifying reservoirs with early petroleum emplacement can be a useful tool for screening and designating the potential deep reservoirs of high porosity. Also, reservoir models aiming at predicting quartz cement and reservoir quality in sandstones should take into account the timing and rate of petroleum emplacement to produce a more accurate modelling result.

This work also suggests that petroleum emplacement in the Kessog Field has hindered the process of K-feldspar dissolution to precipitate kaolin in the sandstone reservoir. Since all diagenetic chemical reactions take place through an aqueous phase, it is reasonable to speculate that petroleum emplacement can also affect many other diagenetic reactions due to the disruption of chemical ions' transport pathways between reactants and precipitation sites after petroleum emplacement. Processes such as illitization of smectite and carbonate cementation, which have profound influence on sandstone reservoir quality (Giles and de Boer, 1990; Morad, 1998), may also be influenced by petroleum emplacement process. There is, however, only limited published work concerning the effect of petroleum emplacement on clay mineral diagenesis (e.g. Midtbø et al., 2000; Worden and Barclay, 2003) or carbonate cementation (e.g. Lei et al., 2019). Particularly, the relationship between petroleum emplacement and various diagenetic reactions in sandstones needs to be further considered and explored in future studies. Progress can be made with examining reservoirs with limited facies variation, in conjunction with high-quality petrographic data and fluid saturation analysis.

CONCLUSION

1. Sandstones of the Kessog Field have higher porosity than expected from regional trends. The average porosity of crestal well K5 is 25%, which is 11% higher than the porosity (14%) predicted for the Pentland Sandstone at the corresponding depth; the porosity of a few

sandstones in wells K3, K4, K6 and K9 are also exceptional, ranging between 15% and 30%. The majority of these high-porosity sandstones are saturated with oil (>40%).

2. Grain-size, sorting and mineralogy of the high-porosity sandstones are similar to the medium- to low porosity sandstones, suggesting the original sandstone composition and texture do not account for the occurrence of high porosity. The impact of grain-coats (microquartz, chlorite and illite), reservoir overpressure and mineral dissolution on the porosity of the Kessog reservoir can be shown to be insignificant. Petroleum emplacement inhibiting quartz cementation is the only possible mechanism that can explain the occurrence of high-porosity in the Kessog Field.
3. The high-porosity sandstones under the influence of petroleum emplacement exhibit four characteristics: (1) they occur at the crest of the reservoir; (2) primary porosity is the main type of porosity; (3) there is 2 - 5% less quartz cement than the water-saturated sandstones; (4) there are 2 - 3% more K-feldspar and 2 - 6% less kaolin than the water-saturated sandstone, indicating that petroleum emplacement has also inhibited K-feldspar dissolution.

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