Anomalously high porosity and permeability in deeply buried sandstone reservoirs: Origin and predictability

Salman Bloch, Robert H. Lander, and Linda Bonnell

ABSTRACT

Porosity and permeability generally decrease with increasing depth (thermal exposure and effective pressure); however, a significant number of deep (>4 km [approximately 13,000 ft]) sandstone reservoirs worldwide are characterized by anomalously high porosity and permeability. Anomalous porosity and permeability can be defined as being statistically higher than the porosity and permeability values occurring in typical sandstone reservoirs of a given lithology (composition and texture), age, and burial/temperature history. In sandstones containing anomalously high porosities, such porosities exceed the maximum porosity of the typical sandstone subpopulation.

Major causes of anomalous porosity and permeability were identified decades ago; however, quantification of the effect of processes responsible for anomalous porosity and permeability and the assessment of the predictability of anomalous porosity and permeability occurrence in subsurface sandstones have rarely been addressed in published literature. The focus of this article is on quantification and predictability of three major causes of anomalously high porosity: (1) grain coats and grain rims, (2) early emplacement of hydrocarbons, and (3) shallow development of fluid overpressure.

Grain coats and grain rims retard quartz cementation and concomitant porosity and permeability reduction by inhibiting precipitation of quartz overgrowths on detrital-quartz grains. Currently, prediction of anomalous porosity associated with grain coats and grain rims is dependent on the availability of empirical data sets. In the absence of adequate empirical data, sedimentologic and diagenetic models can be helpful in assessing risk due to reservoir quality. Such models provide a means to evaluate the effect of geologic constraints on coating occurrence and coating completeness required to preserve economically viable porosity and permeability

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in a given play or prospect. These constraints include thermal history and sandstone grain size and composition.

The overall effect of hydrocarbon emplacement on reservoir quality is controversial. It appears that at least some cements (quartz and illite) may continue to precipitate following emplacement of hydrocarbons into the reservoir. Our work indicates that integration of basin modeling with reservoir quality modeling can be used to quantify, prior to drilling, the potential impact of hydrocarbon emplacement on porosity and permeability.

The best-case scenario for significant reservoir quality preservation due to fluid overpressure development is in rapidly deposited Tertiary or Quaternary sandstones. Our models suggest that significant porosity can be preserved in sandstones that have experienced continuous high fluid overpressures from shallow burial depths. The models also indicate that the potential for porosity preservation is greatest in ductile-grain–rich sandstones because compaction tends to be the dominant control on reservoir quality in such rocks. The case for significant porosity preservation associated with fluid overpressures in pre-Tertiary basins, however, is more problematic because of the complexities in the history of fluid overpressure and the greater significance of quartz cementation as a potential mechanism of porosity loss.

INTRODUCTION

General

Hydrocarbon accumulations can occur only if all essential elements (source rock, reservoir rock, seal rock, and overburden rock) and processes (generation-migration-accumulation of petroleum and trap formation) have operated adequately and in the proper time-space framework (Magoon and Dow, 1994). Absence or inadequacy of even one of the elements or processes eliminates any chance of economic success. Thus, sandstone reservoir parameters (reservoir size, porosity, and permeability) are among the geologic controls that have to be included in the consideration of risk factors for plays and prospects (e.g., Rose, 1992; White, 1993).

The importance of accurate predrill assessments, including reservoir quality, is growing as oil and natural gas companies are increasingly exploring deeper targets. A case in point is provided by a recent review of oil and gas production in the North Sea (Appert, 1998). The review performed by Institut Francais du Petrole indicates that only 10% of the reserves produced by 1998 were located deeper than 3500 m; however, one-third of all identified, but undeveloped, reserves occurred at depths below 3500 m (Appert, 1998). The proportion of undeveloped, deep reservoirs was even higher for gas fields. The trend toward greater producing depths has not been limited to the North Sea (Megill, 1988).

Anomalously high porosities and permeabilities in deeply buried sandstones can extend the economic basement and provide critical support for commercial production. Four known major causes of anomalously high porosity in sandstones are as follows: (1) grain coats and grain rims (effective only in detrital-quartz–rich sandstones), (2) early emplacement of hydrocarbons, (3) shallow development of fluid overpressure, and (4) secondary porosity. Although these phenomena are generally known to geologists, misconceptions exist regarding their occurrence and effectiveness. In this article, we discuss quantification and predictability of anomalous porosity as the result of the first three causes. The impact of secondary porosity on reservoir quality and its predictability are not addressed here as they have been discussed at length in previous publications (e.g., Bloch, 1994; Giles, 1997).

Mean Porosity, Maximum Porosity, and Anomalously High Porosity

Geologic methods used to predict, prior to drilling, porosity and permeability in potential reservoirs depend on the type of anticipated reservoir rock and the amount and quality of available information. Different approaches to reservoir quality prediction in frontier and mature areas have been discussed in several publications (e.g., Schmoker and Gauthier, 1988; Meshri and Ortoleva, 1990; Bloch, 1991; Byrnes and Wilson, 1991; M. D. Wilson, 1994a; Bloch and Helmold, 1995; Kupecz et al., 1998; Lander and Walderhaug, 1999). The main objective of most of these approaches is prediction of mean porosity and permeability. Monte Carlo analysis done in conjunction with the prediction provides one of the ways to more rigorously evaluate the porosity distribution for a prospective reservoir.

The methods referenced previously are applicable to prediction in normal sandstone reservoir targets. Such targets can be expected to have porosity distributions typical of reservoirs with a given lithology (composition and texture), age, and burial/temperature history. Empirical data indicate that in a majority of sandstone reservoirs, porosity values at a given depth (or over a relatively small depth range) display either an approximately normal distribution (Figure 1) or a lognormal distribution with a small variance (small skewness). If the porosity distribution is clearly skewed to the right (tailing off to the right), it may be due to a skewed distribution of the sample population or sampling problems. Common sampling problems include an insufficient number of samples or a large number of biased samples. In sandstone units not affected by sampling problems, skewness reflects primarily diagenetic

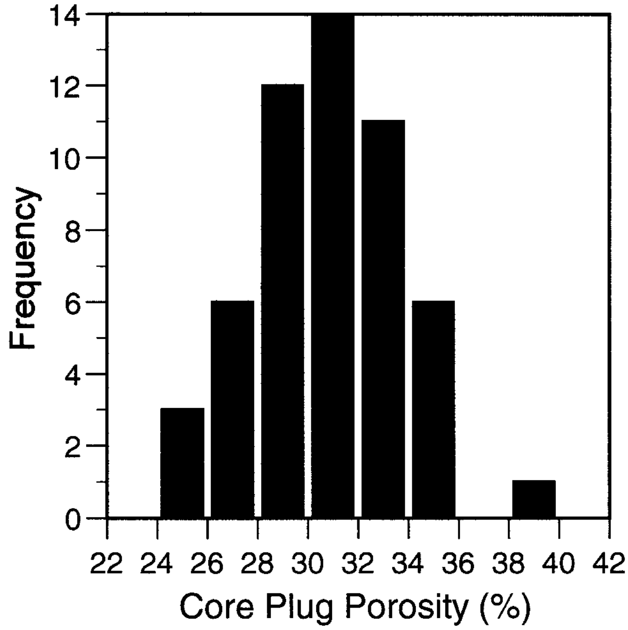


Figure 1. Approximately normal porosity distribution in a sampled interval of a Tertiary channel-fill sandstone, offshore west Africa.

effects. The heavier the diagenetic overprint affecting the sandstones, the more skewed the porosity population tends to be. Expectedly, extensive cementation and/or compaction shift the porosity distribution from approximately normal (Figure 1) toward lognormal (Figure 2).

In addition to mean porosity, the maximum porosity concept is useful in characterizing porosity distribution in a reservoir or a potential reservoir. Empirical maximum porosity values are determined by smoothing the line connecting the highest porosities on a porosity-depth plot (Maxwell, 1964). Maximum porosity of normal sandstones is different from anomalously high porosity. In sandstone units containing anomalously high porosities, such porosities exceed the maximum porosity of the normal sandstone subpopulation, although some overlap may exist with the high end of the normal subpopulation (Figure 3). The anomalous porosity subpopulation itself can also display approximately normal distribution (Figure 3).

Generally, a bimodal porosity distribution in clastic bodies indicates a distinct lithology change. By contrast, bimodal porosity distributions characterized by normal and anomalous subpopulations occur in lithologically similar sandstones. This definition of anomalous porosity is based on a statistical analysis of porosity distributions. The occurrence of such porosity,

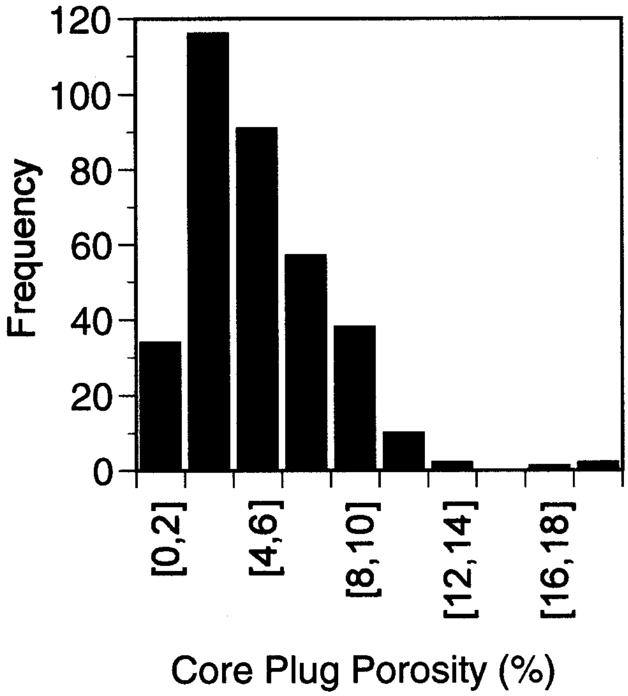


Figure 2. Lognormal porosity distribution in a deep, heavily silica-cemented sandstone unit. The highest porosities (>16%) occur in proximity to the contact with the overlying Ile Formation and reflect the presence of sporadic chlorite coats. Jurassic Ror Formation, North Sea. Well in Block 6406 of the Haltenbanken area, 4700.0–4800.75 m of measured depth (15,421–15,751 ft).

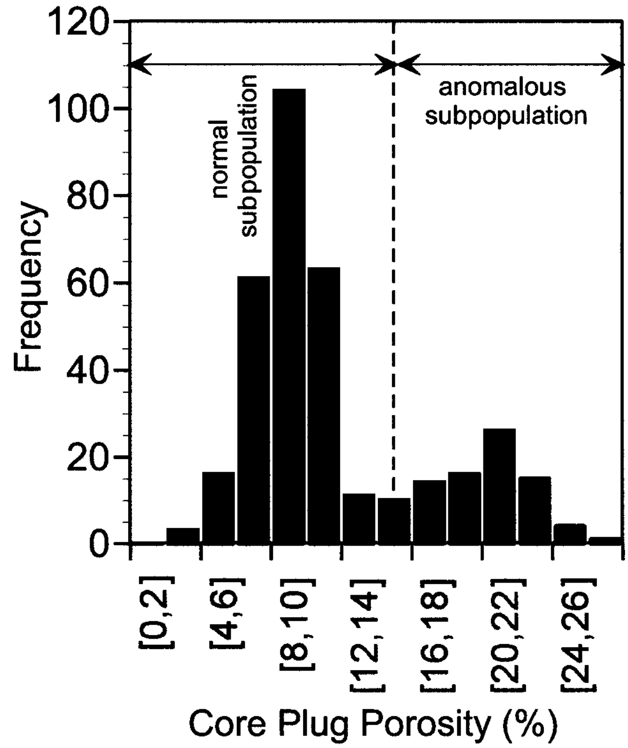


Figure 3. Bimodal porosity distribution in sandstones of the Middle Jurassic Ile Formation, North Sea. Well in Block 6406 of the Haltenbanken area; 4603.0–4699.75 m of measured depth (15,102–15,420 ft). The mean porosity for the whole population of 344 samples is 11.6% (standard deviation = 5.2%). The median porosity and the mode are 9.6% and 9%, respectively. The normal subpopulation (samples with porosity < 15%) of 263 samples represents sandstones with no or sporadic coat coverage of sand grains. The mean porosity is 8.9% (standard deviation = 2.0%). The median porosity and the mode are 8.9% and 9%, respectively. Although the porosity distribution of this subpopulation is different from that of the subjacent Ror Formation (Figure 2), the maximum porosities are very similar (approximately 15%). The anomalous subpopulation (samples with porosity > 15%) of 81 samples represents sandstones with nearly complete to complete coat coverage of sand grains. The mean porosity is 20.1% (standard deviation = 2.7%). The median porosity and the mode are 20.4% and 20%, respectively.

however, can be explained by known diagenetic phenomena as discussed in this article.

GRAIN COATS AND GRAIN RIMS

General

Grain coats are the result of authigenic processes and form subsequent to burial by growth outward from framework grain surfaces, except at points of grain-to-grain contact (M. D. Wilson and Pittman, 1977). Grain coats include clays and microcrystalline quartz. To avoid confusion, M. D. Wilson (1992, p. 209) proposed the term "inherited clay rims" to describe coats of detrital clay on framework grains "where the clays were present on the grains prior to their arrival at the site of deposition." Because clay rims can form at the site of deposition following transport (e.g., infiltrated clays), we use in our discussion the term "clay rims" rather than "inherited clay rims."

Grain coats and grain rims retard quartz cementation and concomitant porosity/permeability reduction by blocking potential nucleation sites for quartz overgrowths on detrital-quartz seed grains. Regardless of their origin, the effectiveness of grain coats or rims in preserving porosity is a function of their completeness, as well as their thermal history and grain size and the abundance of quartz grains (Walderhaug, 1996; Bonnell et al., 1998).

Grain coats and rims have no effect on the precipitation of cements other than quartz and therefore have no effect on porosity where the primary control on reservoir quality is the occurrence of cements such as carbonates, sulfates, or zeolites (Pittman et al., 1992). Grain coats and rims also have little impact on porosity preservation in mineralogically immature sandstones, because in these rocks quartz cement precipitation is typically negligible.

Authigenic chlorite and corrensite are the most commonly reported effective coats occurring in hydrocarbon reservoirs (Pittman et al., 1992, table 1). Microcrystalline-quartz coats are much less commonly reported, but this is at least partly due to the fact that they may be difficult to recognize upon cursory petrographic examination. In some instances, detrital-quartz grains coated by microcrystalline quartz have been erroneously interpreted as being leached. Finally, the importance of clay rims (inherited grain-rimming clays) in preserving sandstone porosity has not received much attention until fairly recently (M. D. Wilson, 1992).

Chlorite Coats

Origin of Chlorite Coats

Introduction

Authigenic chlorite coats are commonly iron rich (Pittman et al., 1992; Ehrenberg, 1993), but magnesium-rich chlorite coats also have been reported (Kugler and McHugh, 1990; Pittman et al., 1992). Although some occurrences are controlled by specific depositional environments (e.g., Ehrenberg, 1993), others are not (Pittman et al., 1992). The differences in composition and geologic occurrence imply multiple origins for authigenic chlorite coats. Despite the profusion of publications, there has been no attempt either to classify chlorite coats in sandstones or to establish criteria to distinguish their different origins.

In our opinion, there appear to be at least four different modes of formation of authigenic chlorite coats in sandstones:

1. Depositionally controlled iron-rich chlorite coats in shallow-marine sandstones (e.g., Lower–Middle Jurassic sandstones of the Norwegian continental shelf [Ehrenberg, 1993])
2. Depositionally controlled chlorite coats in turbidites (Houseknecht and Ross, 1992)
3. Provenance-controlled iron-rich chlorite coats (e.g., Upper Cretaceous Tuscaloosa sandstone of Louisiana [Pittman et al., 1992])
4. Magnesium-rich chlorite coats formed by interaction of precursor clay/iron oxide grain rims with magnesium-rich saline brines derived from underlying evaporites (Upper Jurassic Norphlet Sandstone in the Gulf Coast [Kugler and McHugh, 1990])

Depositionally Controlled Iron-Rich Chlorite Coats in Shallow-Marine Sandstones

Although specific depositional environments (Ehrenberg, 1993) are a prerequisite, they are not alone sufficient to form depositionally controlled chlorite coats on sand grains. Instead, several conditions have to operate adequately and in conjunction to ultimately generate a high-quality, deeply buried sandstone reservoir. These are an adequate source of ions (particularly iron), adequate grain size, high rigid grain content, and absence of a late carbonate killer cement.

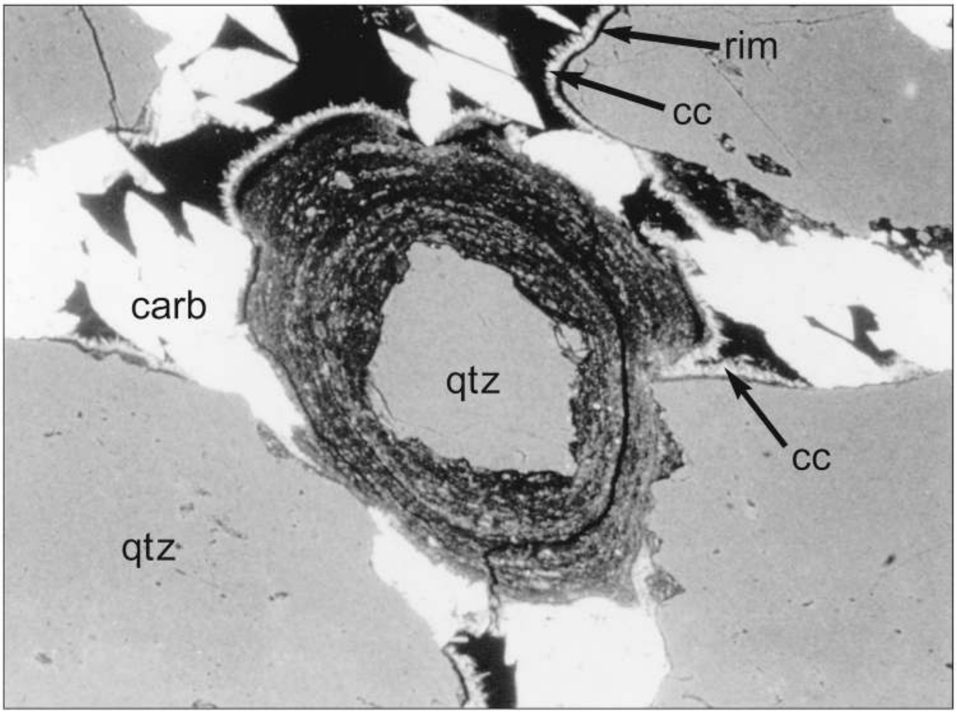
Depositional facies control on the occurrence of chlorite has been emphasized by Ehrenberg (1993). He concluded, based on sedimentologic and petrographic evidence, that chlorite-preserved porosity in Jurassic sandstones of the Norwegian continental shelf is confined to sandstones deposited in fluvially influenced, highest energy zones of nearshore marine environments. The results of a sedimentologic study of other offshore Norway sandstones containing chlorite-coated grains, by Gjelberg and Dreyer (Bloch et al., 1997), were in agreement with Ehrenberg's (1993) conclusions.

The high depositional energy is indicated by the presence of chloritic ooids and ooidal grain coatings in all chlorite-rich sandstones (Ehrenberg, 1993). The ooids are concentrically layered (Figure 4A) and most likely formed by mechanical accretion. In some samples, however, detrital grains are surrounded by a detrital-clay rim (consisting of chlorite plus illite) that does not exhibit internal layering (Figure 4B). The rims are coated by authigenic chlorite that grew on the detrital substrate (Figure 4B). In an experimental study, conducted under conditions approximating as much as possible the natural environment, Aagard et al. (2000) synthesized chlorite coats from clay rims occurring in sandstones from offshore Norway fields. Transmission electron microscopy analyses indicated that the precursor rims consisted of a berthierine-dominated mixed-layer clay.

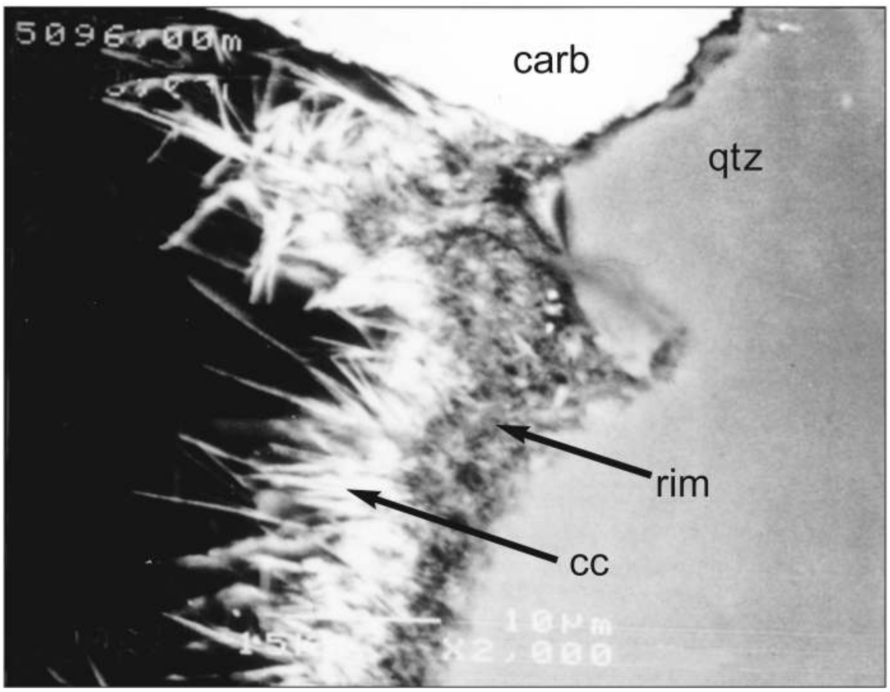
Source of iron. Concentration of iron in seawater is very low, and a fluvial source of this element for chlorite-rich sandstones in shallow-marine sandstones

Figure 4. (A) Ooid in the center of the photomicrograph made up of concentrically laminated clay accreted on a quartz grain. The concentrically laminated clay is coated by radial chlorite. qtz = detrital-quartz grain, carb = carbonate cement, cc = authigenic chlorite coat, rim = detrital-clay rim. Well in Block 6406 of the Haltenbanken area; sample depth is 5096 m (16,720 ft). Backscattered electron (BSE) image. (B) Quartz grain (qtz) is rimmed (rim) by clay (illite and chlorite), which, in turn, provides a substrate for growth of the radial chlorite coat (cc). Well in Block 6406 of the Haltenbanken area; sample depth is 5096 m (16,720 ft). BSE image.

A



B



is a logical hypothesis. Ehrenberg (1993) noted that chlorite-coated sandstones consistently occur in nearshore marine facies likely to be influenced by riverine water influx. He postulated that the riverine iron was most likely transported as amorphous iron hydroxides and then flocculated upon mixing with seawater. According to Ehrenberg (1993), in high-energy environments, detrital grains, rolled by water currents over the flocculated iron-rich clayey substrate, developed ooidal coatings (Figure 4A).

Additional evidence for Ehrenberg's hypothesis is provided by the presence of the berthierine precursor of chlorite coats (Aagard et al., 2000), and the frequent association of the coats with siderite, an Fe-rich carbonate. Formation of berthierine is limited to shallow-marine environments in tropical climates (Aagard et al., 2000). The association of chlorite and siderite cement, in turn, suggests a meteoric-water source of iron. The siderite formed at shallow depths as suggested by high minus-cement porosity and lack of any discernible compaction of easily deformable grains (chloritized pellets and chloritic ooids) in samples containing siderite cement. Precipitation of siderite in marine environments is favored by high iron activity (meteoric-water influx) and alternating anoxic and oxic pore fluids in sediment (e.g., nearshore sediments [Coleman, 1985]).

Grain size control. Although grain size is controlled, to a large extent, by the depositional environment, there is typically a significant grain-size range within each facies. This range is due to the variability of the factors that control grain size and sorting within any given environment, such as the average energy level, the maximum energy level, fluctuations in energy level, the rate of dissipation of high energy levels, the level of biogenic activity, provenance, and so forth.

An example of the control of grain size on the effectiveness of chlorite coating in preserving porosity is shown in Figure 5. Although the mean grain size does not display a significant statistical linear correlation with porosity in this example ($r = 0.66$), with a few exceptions, chlorite-coated samples with mean grain sizes greater than 0.45 mm have porosities in excess of 18% (Figure 5). A few coarse-grained sandstones have relatively low porosities because of carbonate cementation, poor sorting, or low grain-coat coverages, but the preceding relationship holds for moderately or better–sorted sandstones with a relatively low (<5%) carbonate-cement abundance.

Expectedly, grain size also affects permeability in chlorite-coated sandstones (Figure 6). With a few exceptions, chlorite-coated sandstones with a mean grain size greater than 0.45 mm have permeabilities greater than 10 md (10 md permeability corresponds to a porosity of roughly 18% in the studied sample suite). Simple statistical data illustrating the effect of grain size on porosity and permeability are given in Table 1.

The control of grain size on porosity and permeability is a function of the relationship between grain size and (1) surface area and (2) pore-throat size. In a given volume of sandstone, the larger the grain size, the smaller the surface area that must be coated to

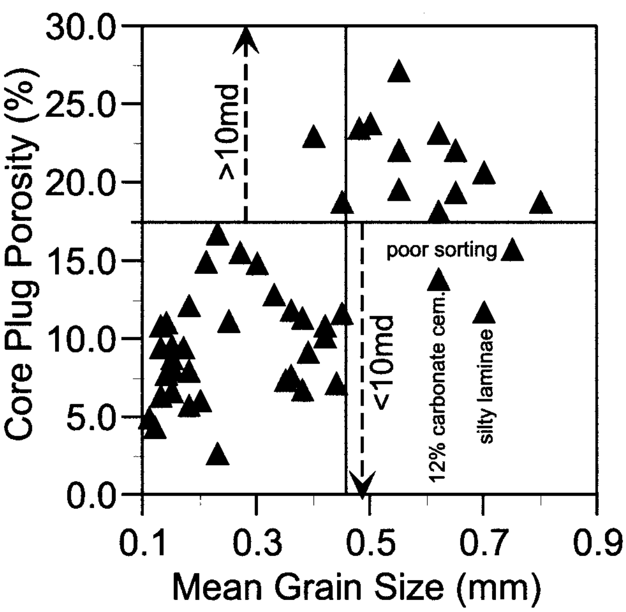


Figure 5. Chlorite-coated sandstones with a mean grain size greater than 0.45 mm have, with a few exceptions, better porosity than finer-grained chlorite-coated sandstones. Ile, Tofte, and Tilje formations, Jurassic, North Sea. Well in Block 6406 of the Haltenbanken area.

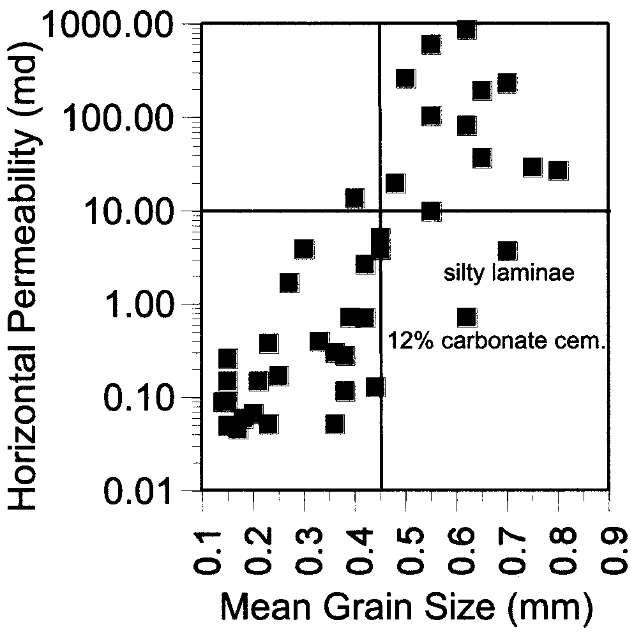


Figure 6. Chlorite-coated sandstones with a mean grain size greater than 0.45 mm have, with a few exceptions, higher permeability (>10 md) than finer grained chlorite-coated sandstones (<10 md). Ile, Tofte, and Tilje formations, Jurassic, North Sea. Well in Block 6406 of the Haltenbanken area.

Table 1. Effect of Grain Size on Porosity and Permeability in Chlorite-Coated Sandstones

Lithology	Number of Samples	Grain Size (mm)		Ambient Porosity (%)		Horizontal Permeability (md)	
		Average	Median	Average (std. dev.)	Median	Average (std. dev.)	Median
Chlorite-coated sandstones with grain size $>$ 0.45 mm	16	0.60	0.60	19.4 (4.4)	19.5	157 (249)	34
Chlorite-coated sandstones with grain size $<$ 0.45 mm	39	0.25	0.20	9.9 (3.7)	9.5	0.9 (2.6)	0.1

significantly reduce quartz cementation. Therefore, it takes a smaller volume fraction of chlorite to achieve comparable coat completeness in coarse-grained sand than in otherwise identical fine-grained sand. Even where the completeness of grain coats is identical, the higher surface area associated with finer grain sizes results in more quartz cement and, therefore, lower porosity and permeability than in otherwise similar, coarser grained sandstones (provided that the sandstones have had sufficient thermal exposure). The contrast in surface area between fine- and coarse-grained sandstones is accentuated because coarser fractions of sand are consistently better rounded (smaller surface area) than the associated finer grained fraction.

The effect of the larger surface area in finer grained sandstones is intensified because an equal thickness of chlorite coating has a significantly higher deleterious impact on permeability in a fine-grained sandstone than in a coarse-grained sandstone. This is due to the fact that the constricting elements that control the movement of fluids through rocks are pore throats, not pore bodies (Ehrlich et al., 1991). In sandstones with a high rigid-grain content and limited amount of cement, pores and pore throats are wider in coarse-grained sandstones than in finer grained sandstones. A chlorite coat of a given thickness (coat thickness does not depend on grain size) is much more constricting in a narrow throat than in a wider one (Figure 7).

Compositional (rigid-grain content) control. The proportion of rigid grains (grains that do not undergo significant ductile deformation during burial) in a sandstone has a profound effect on reservoir quality. The

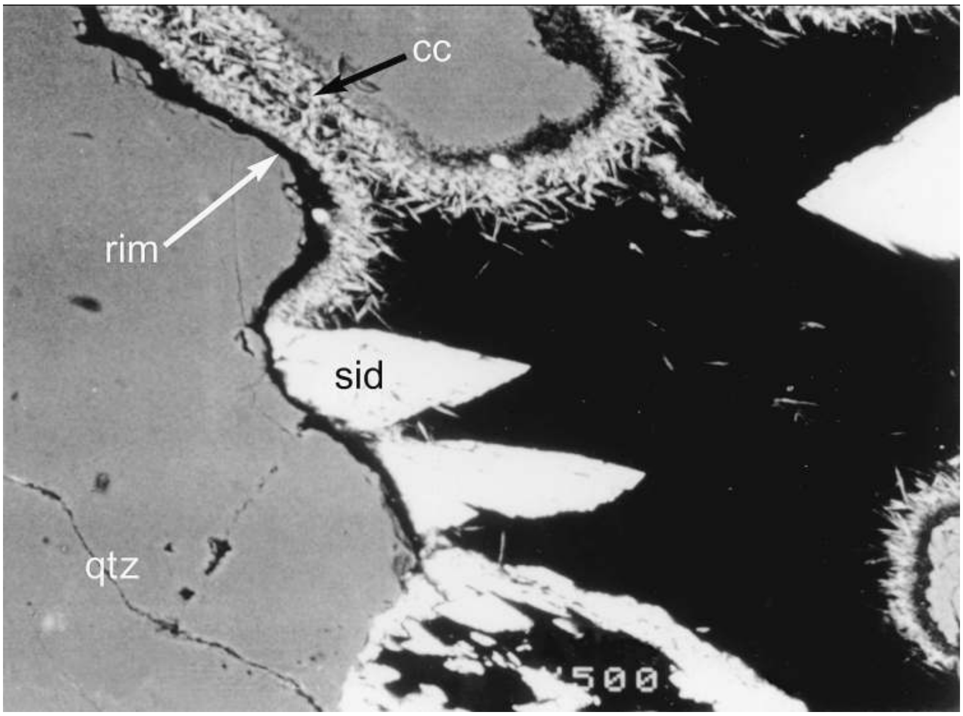


Figure 7. Chlorite coats (cc) constrict narrow pore throat (upper left-hand corner). This is one of the reasons why chlorite coats accentuate permeability differences between fine- and coarse-grained sandstones (see also Table 1). sid = siderite cement, qtz = detrital-quartz grain, rim = detrital-clay rim.

importance of a high rigid-grain content in preserving porosity in chlorite-coated sandstones is underscored by the fact that anomalously high porosity in chlorite-coated sandstones has been reported only in quartz-rich sandstones. Quartz cementation in quartz-grain–poor sandstones is limited because of the small amount of quartz seed grains that provide nucleating sites for silica cement. Furthermore, porosity cannot be preserved because of extensive ductile-grain deformation with increasing burial.

Carbonate cement postdating chlorite coats. In publications discussing chlorite coats as a factor in preserving porosity, there is little mention of carbonate cementation postdating chlorite coat formation. Although in Jurassic sandstones on the Norwegian shelf the amounts of late ankerite are generally small (2–3%), locally its impact on reservoir quality is significant. Occurrence of late ankerite indicates that even if all other conditions listed previously are met, there still is no guarantee that a sandstone body will have adequate reservoir quality in deep reservoirs.

Occurrence of late carbonate cements is a potential problem not only in chlorite-coated sandstones. A large number of reservoirs contain late ankerite or other iron-rich carbonate cements. Among such reservoirs are the lower Tertiary of the Gulf Coast (Loucks et al., 1979), the Oligocene Frio of south Texas (Lindquist, 1976), the Eocene Wilcox of central Texas (Stanton, 1977), the Pennsylvanian Strawn (Dutton, 1977), the Triassic Ivishak Sandstone in the Prudhoe Bay field (McGowen and Bloch, 1985), and the Eocene Wilcox of south and east Texas (S. G. Franks, 1982, unpublished Arco data). The most plausible interpretation of the origin of these cements in clastic reservoirs is elimination of excess CO_2, generated by thermal maturation of organic matter, by carbonate precipitation (Smith and Ehrenberg, 1989). This process occurs at 100–120°C (Smith and Ehrenberg, 1989). By contrast, chlorite coats precede quartz cementation, which is commonly initiated at temperatures above 75°C (Walderhaug, 1994b). The temperature constraints, indicating that precipitation of ankerite postdates chlorite coat formation, are thus in agreement with petrographic observations.

Depositionally Controlled Chlorite Coats in Turbidites

The occurrence of chlorite coats is not limited to shallow-marine sandstones. Abundance and distribution of clay coats and rims also can be depositionally controlled in turbidites.

In the Atoka Formation (Middle Pennsylvanian) of the Arkoma basin, sandstones with little clay (unconfined turbidite deposition on submarine-fan lobes) are extensively cemented by quartz overgrowths (Houseknecht and Ross, 1992). By contrast, in sandstones deposited by confined (channelized) sediment gravity-flow processes, much of the primary porosity is preserved. The preservation of porosity and inhibition of quartz cementation is due to clay rims emplaced during turbidite dewatering (Houseknecht and Ross, 1992). Although detrital-clay rims are the main porosity preserving agent, diagenetic clays are also present and “may represent recrystallization of the outer layer of an originally detrital clay, or may represent truly neoformed clays that nucleated on a favorable substrate provided by grain coatings of detrital clay” (Houseknecht and Ross, 1992, p. 236).

The possibility that some high-porosity, deep-water deposits may form by downslope transport of shallow-marine sandstones that contain detrital-chlorite rims and chlorite coats (Figure 4B) cannot be ruled out. Sullivan et al. (1999) suggested that chlorite-coated detrital grains in Paleocene reservoirs of the West of Shetland area might have originated in shallow-marine sands. Alternatively, chlorite coats in turbidites, rather than being redeposited, may have formed by recrystallization of redeposited chlorite-bearing rims. Such rims are less likely to be destroyed by grain collisions during downslope transport than the more fragile chlorite coats. Interpretation of the origin of chlorite coats in the Paleocene reservoirs of the West of Shetland area is further complicated by the presence of tuffaceous fragments deposited with the sandstones. Chlorite coats, rather than being recycled, may have formed by diagenetic alteration of the tuffaceous material (Sullivan et al., 1999).

From a practical point of view, there may not be a significant difference in the effectiveness of chlorite rims vs. chlorite coats in inhibiting quartz cementation. It appears that the mineralogy of clay rims/coats, and not their origin (detrital vs. authigenic), is critical in controlling the extent of porosity preservation. At conditions of deeper burial (temperature $>$ 100°C), illite (and mica) promotes dissolution of quartz, particularly at stylolite surfaces. The dissolved silica then diffuses to interstylolite areas and precipitates as quartz cement on uncoated surfaces of quartz grains that are in contact with pore fluids (e.g., Heald, 1955; Walderhaug, 1994a;

Bjørkum, 1996; Oelkers et al., 1996). By contrast, chlorite is not known to promote silica dissolution and, therefore, can be expected to be effective in preserving porosity regardless of whether it coats or rims detrital quartz grains.

Provenance-Controlled Chlorite Coats

In depositionally controlled occurrences of chlorite coats, discussed in the previous section, the formation of coats is limited to a relatively narrow range of depositional environments. By contrast, provenance-controlled coats are derived in situ by alteration of lithic (volcanic) rock fragments and occur in a wide range of depositional environments.

The Upper Cretaceous Tuscaloosa sandstone of the United States Gulf Coast is an example of a provenance-controlled coat origin. Where chlorite coats are well developed and the amount of quartz cement is limited, the sandstone contains partly dissolved volcanic rock fragments (VRFs) (Thomson, 1979). Partial dissolution of the VRFs is interpreted to be the in situ source of the ions required to precipitate chlorite (Thomson, 1979). In the absence of VRFs among the sandstone framework grains, chlorite coats did not develop or are present in negligible amounts, insufficient to prevent significant quartz precipitation and porosity loss. Experimental work (Pittman et al., 1992) provides support for the concept that in situ alteration of lithic rock fragments can lead to generation of authigenic-clay coats.

Because distribution of VRFs is not confined to specific depositional facies, chlorite coats in the Tuscaloosa occur in fluvial, deltaic, and nearshore marine sandstones (Pittman et al., 1992). Chlorite coats also have been reported in deep-water lithic sandstones, such as the Fanshawe sand in the Arkoma basin (e.g., Pittman and Wray, 1989).

As pointed out by Pittman et al. (1992), however, the presence of VRFs in a sandstone body does not alone ensure formation of chlorite coats and preservation of porosity. In litharenites with more than approximately 30% mafic VRFs, porosity is likely to be destroyed by ductile deformation at shallow burial depths. For chlorite coats to form and be effective at preserving porosity, the VRF content must be sufficient to provide an adequate source of ions to precipitate chlorite, but not high enough to cause porosity destruction by ductile deformation. The optimum mafic VRF content is about 10% in sandstones containing more than 65% detrital quartz (Pittman et al., 1992).

Magnesium-Rich Chlorite Coats Formed by Interaction of Precursor Clay/Iron Oxide Grain Rims with Magnesium-Rich Saline Brines

Magnesium-rich chlorite coats are much less common than the iron-rich coats discussed previously. Their reported occurrence is limited to the Norphlet Formation (Upper Jurassic) of the eastern Gulf Coast region—the eastern productive trend of offshore Alabama and offshore Florida (Kugler and McHugh, 1990; Thomson and Stancliffe, 1990). The coated sandstones are subarkoses and arkoses that were deposited in coastal eolian environments. Chlorite-coated sandstones have porosities exceeding 20% and negligible amounts of quartz cement, at depths of more than 6100 m (approximately 20,000 ft).

Thompson and Stancliffe (1990) suggested that VRFs were a contributor of magnesium necessary for the formation of chlorite. By contrast, Kugler and McHugh (1990) contended that the volume of VRFs in the Norphlet sandstones is not adequate to have generated the necessary magnesium. Kugler and McHugh (1990) pointed out that the presence of a complex diagenetic mineral assemblage within sandstones with a simple detrital composition strongly suggests import of several chemical elements (magnesium, sodium, and potassium). The most likely source for the allochthonous sandstone components is the underlying Louann Salt. The presence of magnesium-rich, rather than iron-rich, chlorite in Norphlet sandstones can be attributed to interaction of precursor clay and iron oxide rims on detrital grains with saline brines derived from the Louann Salt (Kugler and McHugh, 1990). This interpretation is supported by x-ray diffraction data indicating an increase of breunnerite (a variety of magnesite) in the Norphlet with decreasing distance from the Louann (Ginger et al., 1995).

Impact of Chlorite Coats on Reservoir Quality

The occurrence of anomalously high porosity and permeability is clearly associated with chlorite-coated intervals, but the correlation is highly complex. The amount of quartz cement shows an overall inversely proportional relationship to coat completeness (Figure 8A), but the correlation is tenuous, largely because of the presence of two outliers. The outliers are characterized by a high abundance of quartz cement despite extensive coverage of quartz grains by chlorite coats. This contrary relationship most likely reflects the fact that the measurements of the extent of coat coverage and quartz cement abundance performed on two-dimensional thin sections are biased. Such measure-

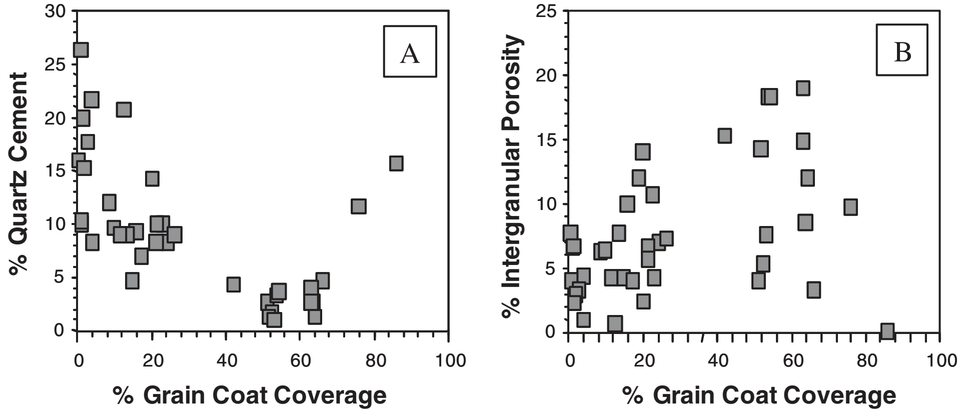


Figure 8. (A) Quartz cement abundance is generally inversely correlated with chlorite-coat coverage (see text for discussion of the two outliers). (B) Intergranular porosity shows a weak correlation with chlorite-coat completeness. Jurassic sandstones, Norwegian continental shelf.

ments cannot capture all breaks in coat continuity present on the surface of three-dimensional quartz grains. Significantly, even very minor breaks in coat continuity allow precipitation of quartz cement, given sufficient thermal exposure (Figure 9). The two-dimensional vs. three-dimensional sampling bias is also likely to be one of the causes of the tenuous correlation between coat completeness and intergranular porosity (Figure 8B). In addition to the impact of potential breaks in the coat completeness, the large scatter in Figure 8 reflects the differences in the critical geologic parameters that control the effectiveness of coating, such as burial history and sandstone composition and grain size. Byrnes and Wilson (1994) also observed large scatter in an overall negative correlation between the abundance of quartz overgrowths and clay-rim completeness.

Data from a well in Block 6406 of the Haltenbanken area (offshore mid-Norway) are ideally suited for a study of the impact of chlorite coats on reservoir quality. Almost the entire interval containing chlorite-coated sandstones, between 4603.0 and 5290.5 m (15,102.4 and 17,358.1 ft), was cored (Åre through Ile formations, Figure 10). Plugs from the cored intervals were taken every 25 cm (9.84 in.). Porosity and permeability were measured on 2039 plugs and 1353 plugs, respectively. In addition, 29 porosity and permeability measurements were performed on the cored interval between 4422.25 and 4429.75 m (14,509.4

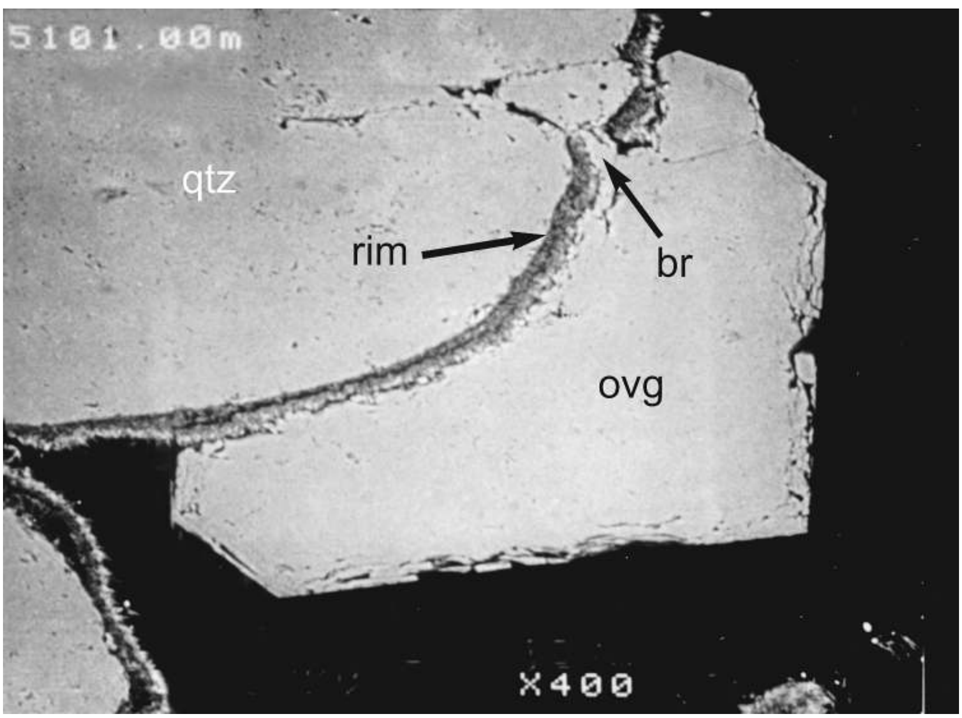


Figure 9. Quartz overgrowth (ovg) precipitated on a detrital-quartz grain (qtz) where there is a break (br) in the continuity of the clay rim (rim) and the thin chlorite coat. Well in Block 6406 of the Haltenbanken area, depth of sample 5101 m (16,736.4 ft). Backscattered electron image.

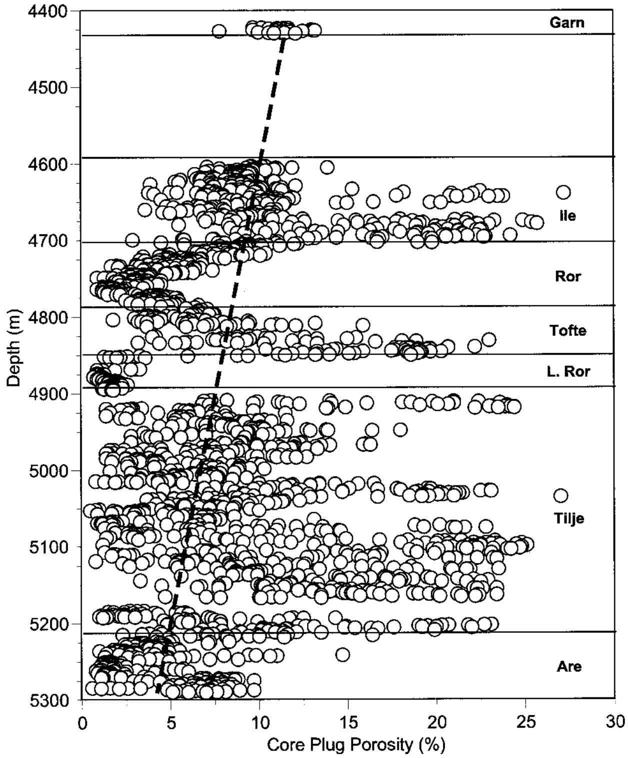


Figure 10. Many samples in the Ile, Tofte, and Tilje formations in a well from Block 6406 of the Haltenbanken area display anomalously high porosity relative to the average porosity/depth trend of Middle Jurassic sandstones of the Haltenbanken area. The average porosity/measured depth trend for the area is denoted by the dashed line (trend line from Ramm and Bjørlykke, 1994).

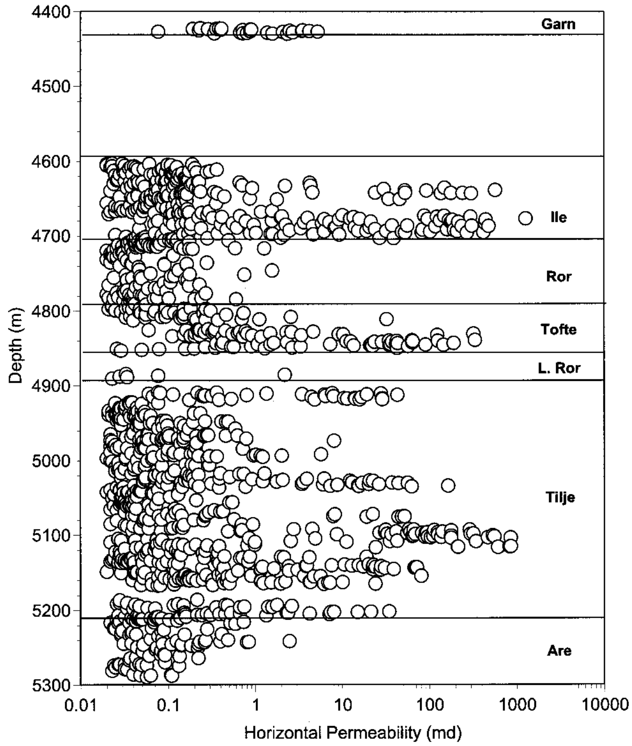


Figure 11. Many samples in the Ile, Tofte, and Tilje formations in a well from Block 6406 of the Haltenbanken area display anomalously high permeability values for the deep burial depth range.

and 14,534.0 ft) (Garn Formation, Figure 10). A sedimentologic study by J. Gjelberg and T. Dreyer (1995, unpublished data) determined that the presence of chlorite coats is confined to fluvially influenced, highest-energy zones of nearshore marine environments. Although the trends from this well cannot be uncritically extrapolated to other locations, the extensive and unbiased database provides useful information on the relative effect of chlorite coating on porosity and permeability in deeply buried sandstones.

Many of the samples in the cored interval display anomalously high porosity (Figure 10) and permeability (Figure 11). Porosity and permeability clearly do not correlate with depth. The best reservoir quality is invariably associated with well-developed chlorite coats in the Tilje, Tofte, and Ile formations. By contrast, in sandstones devoid of chlorite coats, average porosity either follows the general porosity-depth trend for the Haltenbanken area (Åre and Garn formations) or falls below this trend (Lower Ror and Ror formations).

The thickness of intervals with anomalously high porosity ranges from centimeters to approximately 30 m (100 ft). The thickest anomalous interval occurs between 4672.5 and 4703 m (15,330.5 and 15,430.5 ft) (thickness of 30.5 m [100 ft]) in the Ile Formation. These sandstones were deposited in a tidally influenced upper shoreface/delta-front environment (J. Gjelberg and T. Dreyer, 1995, unpublished data). A great majority of the samples in this interval have higher porosities and permeabilities than the average for Jurassic sandstones from the Haltenbanken area at identical depths (Figure 12).

Below approximately 5150 m most of the occurrences of anomalous sandstones are thin and have, on the average, lower permeabilities than the shallower anomalous zones. This may in part be due to sedimentologic controls (e.g., finer grain size), but it also is likely to reflect deterioration of reservoir quality with increasing thermal exposure as discussed in a following section.

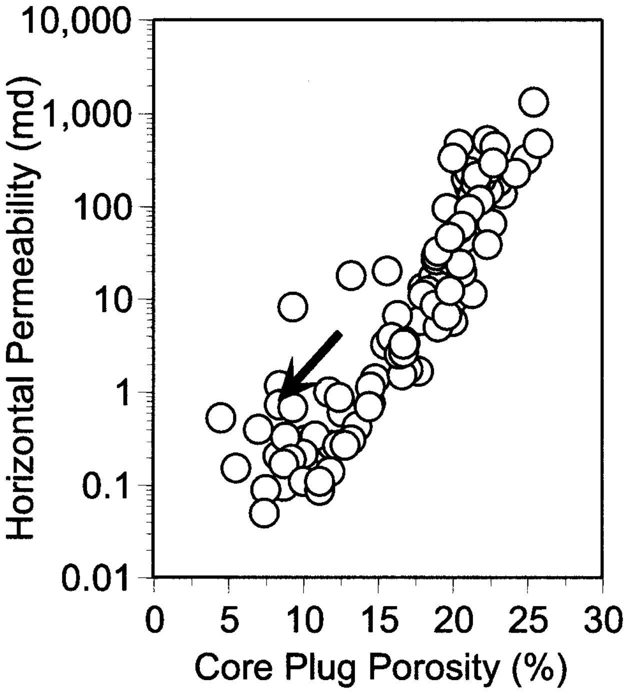


Figure 12. In the 30.5 m (100 ft) interval of the Ile Formation, most samples have higher porosity and permeability than the average for Jurassic sandstones from the Haltenbanken area at identical burial depth (denoted by the arrow). Average permeability and porosity value was taken from Ramm and Bjørlykke, 1994.

Predictability of Anomalous Porosity and Permeability in Chlorite-Coated Sandstones

Evaluation of the potential for occurrence of anomalous porosity and permeability due to chlorite coating is heavily dependent on empirical data. Therefore, geologic prediction of the occurrence of chlorite-coat–related anomalous porosity is not possible in frontier basins.

In more mature areas, chlorite-coat–prone sandstones can be identified, based on sedimentologic and petrographic criteria, from a limited number of samples. After initial well data indicate the presence of chlorite-rich anomalous zones, the three-dimensional distribution pattern of the coated sandstones can be evaluated. The distribution pattern is a function of the coat origin. As discussed before, chlorite coats fall into at least four genetic types. Regardless of the origin of the coats, however, there is no discernible correlation between the coat completeness and the volume of the grain-coating clay (Figure 13). Consequently, the extent of coat coverage of quartz grains, and therefore the impact of chlorite coats on porosity and permeability, cannot be predicted confidently prior to drilling; however, different scenarios of the potential impact of coats on porosity and permeability preservation at a given prospect can be assessed using diagenetic modeling, as discussed in the section "Assessment of the Potential Effect of Grain Coats and Grain Rims on Porosity and Permeability."

Microquartz Coats

Origin of Microquartz Coats

Microquartz coats, similar to chlorite coats, occur on surfaces of detrital-quartz grains and may inhibit precipitation of pore-filling quartz cement (overgrowths). In our opinion, occurrence of microquartz coats is underreported. These coats, which are not as obvious upon cursory petrographic examination as are chlorite coats, are sometimes overlooked or even misinterpreted as leaching of detrital-quartz grains.

Formation of normal quartz overgrowths occurs by overlap and/or mergence of incipient overgrowths with the same crystallographic orientation as the underlying detrital grain (Pittman, 1972). By contrast, the random orientations of the small microquartz prisms coating surfaces of detrital-quartz grains interfere with the formation of normal quartz overgrowths (Heald and Larese, 1974). In addition to interfering with the growths of quartz cement, microquartz crystals may resist pressure solution by solidifying contacts between quartz grains (Osborne and Swarbrick, 1999). Experimental data (Heald and Renton, 1966) and the morphologies of microcrystalline quartz (Williams et al., 1985) suggest rapid crystallization of this phase from highly silica-saturated pore fluids. The silica is most likely derived by dissolution of sponge spicules and volcanic glass shards, as a result of increasing temperature during burial (Aase et al., 1996; Ramm et al., 1998).

Impact of Microquartz Coats on Reservoir Quality

The effectiveness of microquartz coating in preserving porosity is best documented by extensive data sets for Jurassic sandstones from the North Sea (Aase et al., 1996; Ramm et al., 1998). At 4200 m (13,770.5 ft) the porosity of uncoated Upper Jurassic sandstones from the Central Graben averages 11%. By contrast, the porosity-depth trend for microquartz-coated Upper Jurassic sandstones from the Central Graben (Ula and Gyda fields) is almost constant, at 20%, between 3500 and 4300 m (11,475.4 and 14,098.4 ft) (Aase et al., 1996; Ramm et al., 1998). Noteworthy is that

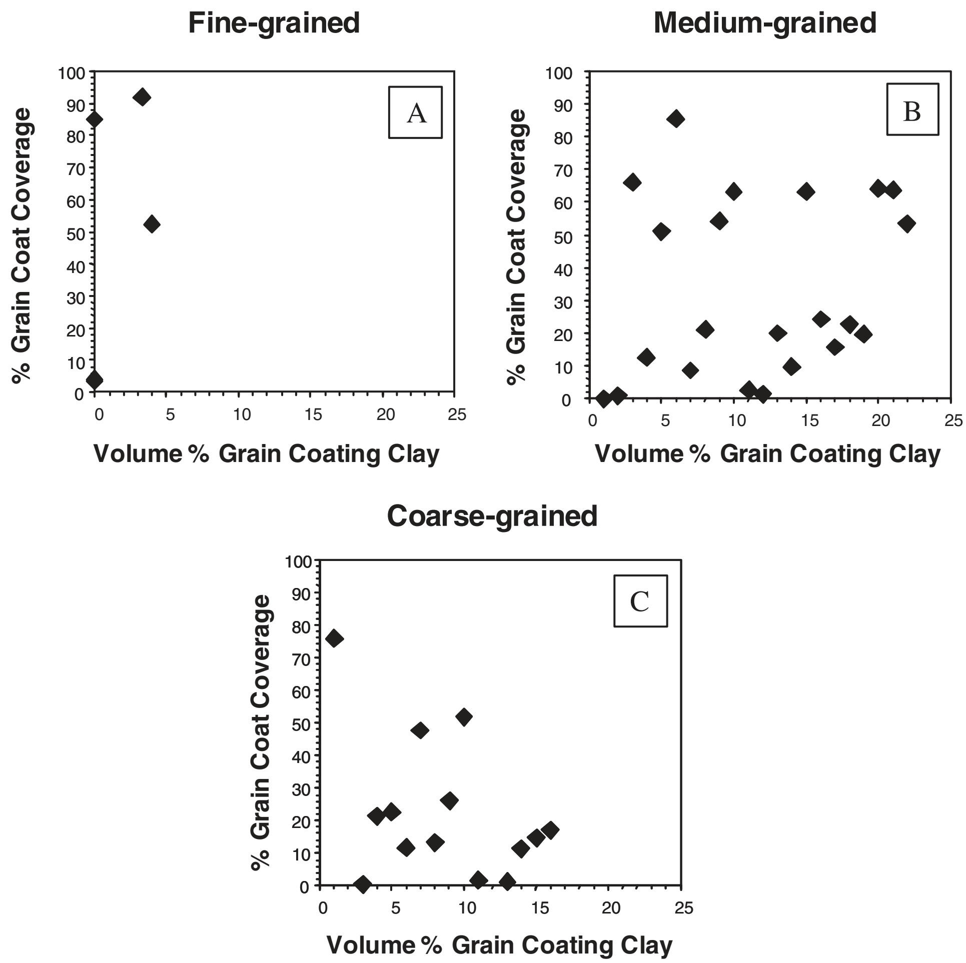


Figure 13. No discernible correlation exists between the extent of grain coverage by coats and the volume of the grain-coating clay in (A) fine-grained sandstones, (B) medium-grained sandstones, and (C) coarse-grained sandstones.

in two out of three wells with microcrystalline quartz coats investigated by Aase et al. (1996), porosity shows a distinctly bimodal distribution (similar to the chlorite coat effect shown in our Figure 3).

Predictability of Microquartz-Coat Occurrence in Sandstones

The content and distribution of sponge spicules, that source the growth of most reported occurrences of microquartz coats, are sedimentologically controlled. The key to understanding the distribution of the coats is mapping sponge-spicule–prone sedimentary facies and their reworking paths into sand-rich depositional systems (Aase et al., 1996; Ramm et al., 1998). Microquartz coats sourced by dissolution of volcanic glass obviously are related to periods of silicic volcanic activity. Volcanically sourced coats, therefore, occur within specific isochronous sandy intervals of the sedimentary column. As with chlorite-coated sandstones, modeling studies can be used to evaluate the coat completeness necessary to preserve economically viable reservoirs.

Clay Rims

Origin of Clay Rims

M. D. Wilson (1992) published the most comprehensive work to date on the origin of clay rims and their effect on reservoir quality. The following brief discussion is based on his work.

M. D. Wilson (1992) contended that the importance of inherited clay rims is underestimated because petrographers commonly overlook them. The lack of proper recognition of the occurrence and importance of clay rims is primarily attributable to the fact that these clays "generally occur as very thin coats and/or are covered and masked by iron oxides/hydroxides, matrix clays, or various authigenic clays" (M. D. Wilson, 1992, p. 209). He also suggested that inherited grain rims are common only in sandstones from eolian dune and marine-shelf environments. Clay rims, however, have also been reported from deep-water facies (Houseknecht and Ross, 1992) and soils (Brewer, 1976).

Impact of Clay Rims on Reservoir Quality

According to M. D. Wilson (1992), inherited clay rims are, in part, responsible for the high porosities of two shelf-sandstone reservoirs on the North Slope of Alaska. These reservoirs (Sag River sandstone in the Prudhoe Bay field and the Kuparuk A and Kuparuk C sandstones in the Kuparuk field) contain 4 to 5 billion bbl of oil and oil-equivalent gas in place (Barnes, 1987; Gaynor and Scheihing, 1988). Similarly, clay rims "are common in a large number of, if not most, eolian sandstones in North America and in eolian Rotliegendes sandstones in the North Sea" (M. D. Wilson, 1992, p. 209).

In the tight gas sandstones investigated by Wescott (1983) and Weimer and Sonnenberg (1994), sweet spots are confined to sandstones that have high clay-rim coverages but relatively low clay volumes. By contrast, interstratified clay-free and coarser grained nonreservoir sands are tightly cemented by quartz overgrowths.

An important phenomenon associated with the occurrence of clay coats and rims is their effect on water-saturation calculations. The difficulties in obtaining accurate water-saturation data in clay-coated and clay-rimmed sandstones complicate calculation of hydrocarbon reserves, recovery efficiency, and identification of productive intervals (Dolly and Mullarkey, 1996; Byrnes et al., 1998). A relatively minor amount of clay coats/rims (as little as 1–2% of the rock volume) can coat a relatively large surface area of sandstone grains. Irreducible water bound in these clays greatly decreases the resistivity as measured by logging tools. This, in turn, results in high log-calculated water saturations, using the standard Archie equation, in zones that are capable of producing hydrocarbons and only minor water.

The mechanism for preservation of porosity by clay rims in deeply buried quartzose sandstones is somewhat ambiguous because of the opposing effect of illitic clays in controlling porosity (Byrnes and Wilson, 1994). Inherited clay rims prevent nucleation of pore-filling quartz overgrowths on detrital-quartz grains, but illitic clay and micas at grain contacts act as a catalyst for chemical compaction and concomitant release of silica for quartz cementation (e.g., Heald, 1955, 1959; Thomson, 1959; Walderhaug, 1994a; Bjørkum, 1996; Oelkers et al., 1996). Sparse empirical data on the composition of clay coats suggest that nonillitic or illite-poor clay rims can be expected to be more effective in preserving porosity in deeply buried sandstones than are predominantly illitic rims.

In summary, a likely scenario in sandstones with quartz grains rimmed predominantly by illite is that silica released by quartz-grain dissolution is transported by diffusion to cleaner (rim-free) sandstones and precipitates there as quartz overgrowths. Eventually, the clayey sandstones end up retaining some porosity, whereas the clean sandstones may be extensively cemented by quartz overgrowths. By contrast, in sandstones in which quartz grains are rimmed predominantly by nonillitic clays, less silica is released because of stylolitization and grain-to-grain dissolution, and therefore, quartz cementation is relatively ineffective and significant porosity may be retained.

Predictability of Clay-Rim Occurrence in Sandstones

Similar to chlorite coats and microquartz coats, prediction of the proportion of quartz surface area that is covered by clay rims is not possible in frontier basins. Modeling studies are less useful in reservoir quality risk analysis for sandstones with detrital illitic rims than other coating types because current models do not adequately predict the effects of chemical compaction on porosity loss.

Although the beneficial effect of clay rims appears to be most pronounced in sandstones from eolian dune and marine-shelf environments, not all such sands contain effective clay rims. Furthermore, other depositional environments cannot be excluded from consideration, as illustrated by the occurrence of clay rims in turbidites (Houseknecht and Ross, 1992). Even in units where the occurrence of clay rims has been documented, the poorly understood effect of clay composition on porosity preservation has to be considered. In summary, our limited understanding of the effect of clay rims on reservoir quality in quartzose sandstones can only help us focus on relatively favorable sandstone units. Clay rims, where complete, can preserve up to 10% porosity relative to uncoated sandstones by preventing quartz overgrowth cementation (Byrnes and Wilson, 1994).

Other Inhibitors of Quartz Cementation

Heald and Larese (1974) published a comprehensive list of different types of coats on detrital-quartz grains. In addition to coats discussed previously (chlorite and microquartz), they also described occurrences of iron oxide coats and carbonate specks rimming quartz grains. Iron oxide coats are relatively ineffective in preventing quartz cementation. Carbonate specks on detrital-quartz grains force quartz overgrowths to form isolated crystals that enlarge at a much slower rate than a continuous overgrowth envelope (Heald and Larese, 1974).

Warren et al. (1997) interpreted anomalously high porosity in deeply buried (> 4300 m [> 14,000 ft]) sandstone intervals of the Late Cretaceous Guadelupe Group in the Cusiana field as being caused by phosphate poisoning. Their interpretation was based on the observation that in lithic sandstones composed of quartz and a variety of phosphate grains, porosity was as high as 20%. By contrast, interbedded clean quartz arenites were heavily cemented by quartz.

Ajdukiewicz et al. (1991, p. 533) proposed that the anomalously high porosity and negligible quartz cementation in deeply buried Norphlet sandstones were caused by the unit's "isolation from a basinward source of silica-bearing fluids." Presumably, the isolation is caused by the presence of underlying evaporites. This hypothesis, however, does not explain the occurrence of quartz cement in other isolated sandstones of the Gulf of Mexico.

Assessment of the Potential Effect of Grain Coats and Grain Rims on Porosity and Permeability

As previously indicated, prediction of anomalous porosity preserved by grain coats and grain rims is heavily dependent on empirical data. Empirical data in some cases can provide a guide to identifying grain-coat– and grain-rim–prone intervals. Although it is not possible to accurately predict, prior to drilling, coat or rim coverages, their potential to preserve anomalous porosity can be assessed by diagenetic models. The assessment involves testing different coating scenarios, given sandstone lithology and burial history models of the intervals of interest.

The effectiveness of grain coats in inhibiting quartz cementation as a function of grain size, temperature history, and completeness of the chlorite coats was modeled by Bonnell et al. (1998) using the Exemplar diagenetic model (Lander and Walderhaug, 1999). We used this model to determine the grain-coat coverage necessary to preserve 15% intergranular porosity in samples from two representative reservoir intervals in wells from the Gulf of Mexico and the Norwegian shelf. These areas have greatly different temperature histories although the maximum temperatures are similar (Figure 14A). In addition to temperature histories, other key input data to the model consisted of identical sample compositions (73% monocrystalline quartz, 0.3% matrix, and 0.3% nonquartz cement) and

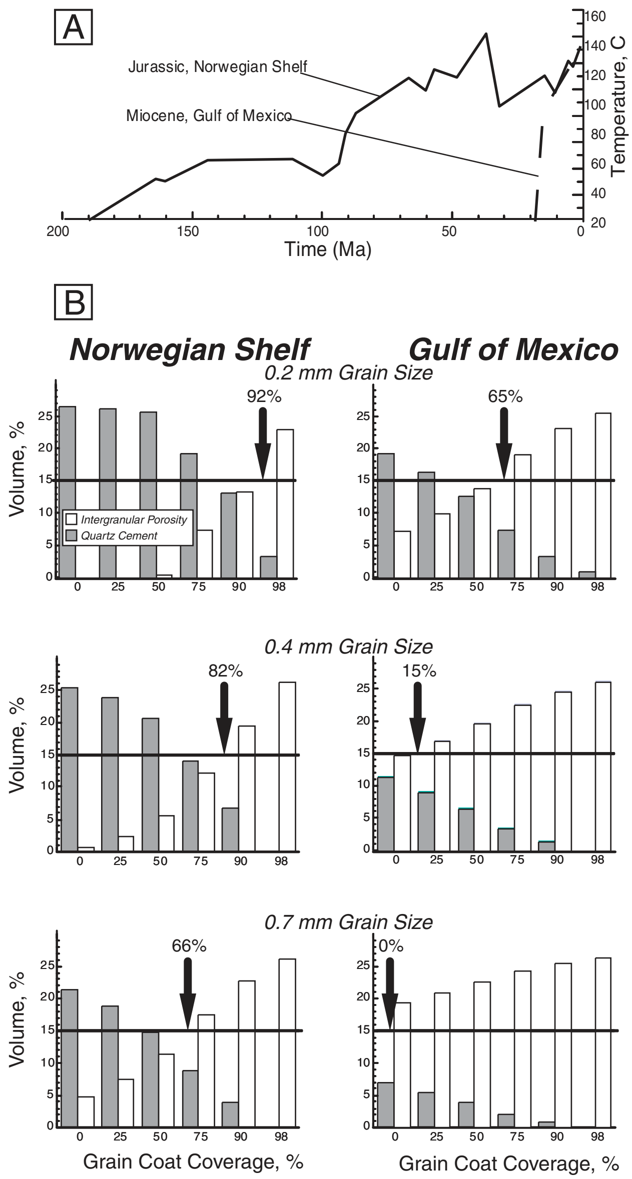


Figure 14. (A) Temperature history for Jurassic sandstones from the Norwegian shelf and for Tertiary sandstones from the Gulf of Mexico. (B) Grain-coat coverage needed to preserve 15% of thin section porosity in sandstones from the Norwegian shelf and the Gulf of Mexico. In fine-grained sandstones (mean grain size of 0.2 mm), 92% grain coverage and 65% grain coverage are needed to preserve 15% porosity in Jurassic and Tertiary sandstones, respectively. In medium-grained sandstones (mean grain size of 0.4 mm), 82% grain coverage and 15% grain coverage are needed to preserve 15% porosity in Jurassic and Tertiary sandstones, respectively. In coarse-grained sandstones (mean grain size of 0.7 mm), 66% grain coverage and no grain coverage are needed to preserve 15% porosity in Jurassic and Tertiary sandstones, respectively.

grain sizes of 0.2, 0.4, and 0.7 mm. Expectedly, fine-grained samples required greater grain-coat coverage to preserve porosity than did coarser grained samples with identical burial histories and composition (Figure 14B). Similarly, sandstones that were exposed to high temperatures for a longer time (Norwegian shelf) required greater grain-coat coverage than samples with a lower time-temperature exposure (Gulf of Mexico) and identical composition and grain size (Figure 14B).

HYDROCARBON EMPLACEMENT

Introduction

The first publication known to us to suggest a correlation between reservoir filling by hydrocarbons and anomalously high porosity was written by Johnson (1920, p. 33), who stated that "the importance of this invasion [by hydrocarbons] is that water is displaced from the reservoir and thereby cementation arrested." This statement, however, was not supported by any data. The idea that early filling by hydrocarbons halts, or at least significantly retards, reduction of sandstone pore spaces by authigenic cements had been generally (and commonly uncritically) accepted until recently. In the last few years, several authors have questioned the significance of hydrocarbon filling in porosity/permeability preservation, at least in some geologic settings (e.g., Midtbø et al., 2000).

The voluminous literature on the relationship between hydrocarbon filling and sandstone porosity preservation with burial can be divided into the following categories:

1. Effect of hydrocarbon filling on specific cements
   a. Quartz (e.g., Lowry, 1956; Hawkins, 1978; Giles et al., 1992; Saigal et al., 1992; Emery and Robinson, 1993; Nedkvitne et al., 1993; Walderhaug, 1994b; Worden and Oxtoby, 1995; Ramm et al., 1998; Worden et al., 1998; Midtbø et al., 2000)
   b. Illite (e.g., Hancock and Taylor, 1978; Sommer, 1978; Lee et al., 1985; Kantorowicz, 1990; Macci et al., 1990; Giles et al., 1992; Ehrenberg and Boassen, 1993; Midtbø et al., 2000)
   c. Kaolin (e.g., Seneeflock, 1978)
   d. Carbonates (e.g., Burley et al., 1989; Neilson et al., 1998)
2. Contrast in diagenetic alteration of minerals in the oil zone vs. alteration in the water zone (e.g., Prozorovich, 1970; Yurkova, 1970)
3. Effect of hydrocarbon entrapment on physical diagenesis (e.g., O'Brien and Lerche, 1986)
4. Origin and effect of diagenetic traps (e.g., Levandovski et al., 1973; H. H. Wilson, 1977; Lee and Bethke, 1994)

The purpose of the following discussion is to reconcile the apparent inconsistencies between the contrasting views on the hydrocarbon effect and to propose a simple approach to evaluate, prior to drilling, the potential impact of hydrocarbon emplacement on sandstone porosity and permeability.

Effect of Hydrocarbon Emplacement on Cementation

Retardation, or even cessation, of porosity-reducing diagenetic processes in sandstones is seemingly a logical consequence of the fact that relative permeability of water in hydrocarbon-saturated sandstones is very low (Honarpour et al., 1986). The difficulty in empirically establishing the effect of the presence of hydrocarbons on cementation appears to be due to the following factors: (1) lack of control on the hydrocarbon filling and leakage histories, (2) lack of consideration of the differences in texture, composition, and thermal exposures of samples from water legs compared with overlying hydrocarbon saturated intervals, (3) lack of data on variations in the hydrocarbon type and saturations among samples, and (4) lack of knowledge of the variations in wettability among samples.

The difficulty in obtaining meaningful data is the consequence of the approach commonly used to study the effect of hydrocarbon emplacement on cementation. The approach is based on a comparison between samples from the oil (gas) leg and samples from the water leg of the same well. To obtain conclusive results, however, comparisons must be made between samples representing virtually identical lithologies, ages, and pressure-temperature conditions of burial (M. D. Wilson, 1994b). Such samples are difficult, if not impossible, to obtain. This sampling limitation also makes it difficult to determine quantitatively the relative impact of oil vs. gas emplacement on cementation. Most importantly, it is likely that cementation is a function of wettability. Although quartz grains are generally considered to be water-wet (Anderson, 1986; Robin et al., 1995), the potential effect of wettability on cementation following hydrocarbon emplacement is rarely addressed.

Heald (1955) suggested that quartz cementation was the end result of a three-step silica redistribution process. His conclusion is supported by recent work based on both empirical data and computer modeling (e.g., Oelkers et al., 1992, 1996; Bjørkum, 1996; Walderhaug, 1996). The silica redistribution process involves (1) release of aqueous silica from quartz dissolution at stylolites or reactions involving other silicate phases such as smectite, (2) transport of silica by diffusion, and (3) precipitation of silica as cement by surface-controlled reactions. In principle, quartz cementation may continue, after hydrocarbon emplacement, by silica released by dissolution at stylolites diffusing along continuous water films surrounding quartz grains. Thus, as pointed out by Walderhaug (1994a, p. 331), "quartz cementation may stop in a reservoir containing an oil that easily wetted quartz while quartz cementation continued in another reservoir filled by an oil that did not wet quartz surfaces." The scenario proposed by Walderhaug (1994a) is entirely possible in view of the fact that wettability, and thus susceptibility to cementation, depends not only on the mineralogy of the solid phases but on several factors, many of which are poorly understood.

Other factors affecting wettability include grain size and porosity (Worden et al., 1998), presence of heavy metals that can alter the surface properties of minerals, and the composition of organic compounds present in crude oils (Cuiec, 1987; Robin et al., 1995; Hoeiland et al., 2001). Two studies (Cuiec, 1987; Robin et al., 1995) indicated that in addition to quartz, feldspar, illite, and dense clusters of fine kaolinite ($\approx$1 μm) were preferentially water-wet. Coarser kaolinite booklets ($\approx$10 μm) were found to be oil-wet (Robin et al., 1995). This implies that quartz, illite, and fine kaolinite cementation can continue, in at least some hydrocarbon reservoirs, by diffusional transport if an adequate source of the required ions is available.

The potential impact of hydrocarbon emplacement on porosity in sandstones is, in our opinion, well elucidated in a recent article by Worden et al. (1998). They concluded that available empirical data do not provide an unequivocal answer to the hydrocarbon effect controversy. Instead, Worden et al. (1998) constructed theoretical models to determine the role of oil emplacement on porosity preservation. The models consist of three end-member quartz-cementation scenarios: silica provided externally by advection (open system, water-wet), silica supplied internally in a sandstone that is water-wet (closed system, water-wet), and silica supplied internally in a sandstone that is oil-wet.

In the open system, water-wet scenario, oil emplacement stops quartz cementation because the large decrease in relative permeability to water significantly reduces the supply of silica caused by diminished fluid fluxes. In the closed system, water-wet scenario, quartz cementation is retarded, but not halted, because of the reduction in the diffusion rate, which becomes the rate-controlling process. The extent of retardation depends on the sandstone fabric and oil saturation (Worden et al., 1998). Noteworthy is that Morrow (1990, p. 1476) concluded, based on an evaluation of numerous tests, that "most reservoirs are at wettability conditions other than very strongly water wet." This observation suggests that the effect of retardation may be significant even in systems considered to be closed, water wet. In the oil-wet scenario, quartz cementation is effectively halted because the silica-bearing water is not in contact with the surfaces of quartz grains.

Although the models considered exclusively quartz cementation, the conclusions reached should apply to other types of cements (Worden et al., 1998). Further progress in understanding the effect of hydrocarbon emplacement and the relative impact of gas vs. oil on cementation should come from experimental studies being conducted under well-constrained conditions (R. Larese and D. Hall, 2000, personal communication).

Implications of Hydrocarbon Filling for Porosity Prediction

At this point, it is difficult to confidently quantify the effect of hydrocarbon emplacement on cementation and porosity evolution in sandstones. It appears that at least some cements (e.g., quartz, illite) may continue to precipitate following emplacement of hydrocarbons into the reservoir. Of the three scenarios of Worden et al. (1998) discussed previously, however, two result in a halt of cementation, and the third one leads to a wide range of retardation of cementation. Thus, it appears that early emplacement of hydrocarbons is more likely than not to halt or significantly impede cementation. Empirical data provide evidence that at least in some reservoirs (including quartzose sandstones) there is preservation of porosity due to early hydrocarbon filling. For example, available data from the Brewster-1 well (northwestern shelf of Australia) suggest not only that emplacement of hydrocarbons into a quartzose reservoir can preserve porosity but also that the extent of porosity preservation in such reservoirs can be estimated prior to drilling.

The Brewster gas accumulation (>1 tcf) occurs in a Late Jurassic–Early Cretaceous quartz arenite to sublitharenite reservoir. Samples of the reservoir sandstone average 9% thin-section porosity (J. G. McPherson, 1992, personal communication), whereas the

Exemplar diagenetic model (Lander and Walderhaug, 1999) calculated a present-day thin-section porosity of 0.5% (Figure 15). The reason for this discrepancy was most likely retardation of quartz cementation by hydrocarbon emplacement, as there was no evidence for other mechanisms (grain coats/rims, overpressure, secondary porosity) of porosity preservation or enhancement.

Deighton (1996), in his analysis of the geologic history of the well, concluded that expulsion of hydrocarbons now filling the Brewster reservoir occurred in the middle Tertiary (approximately 30 Ma). According to the diagenetic model calculations, the reservoir interval in the Brewster-1 well had a thin-section porosity of 9% about 25 Ma, that is, shortly after the hydrocarbon expulsion and emplacement. The 5 m.y. difference is within the uncertainty limits of both calculations. This example indicates that integration of basin modeling with reservoir quality modeling can be used to predict, prior to drilling, the potential impact of hydrocarbon emplacement on porosity/permeability. The evaluation requires a calibration data set consisting of lithological and burial/thermal history data.

OVERPRESSURE

Introduction

Fluid overpressure is defined as the amount of fluid pressure that is greater than the hydrostatic gradient

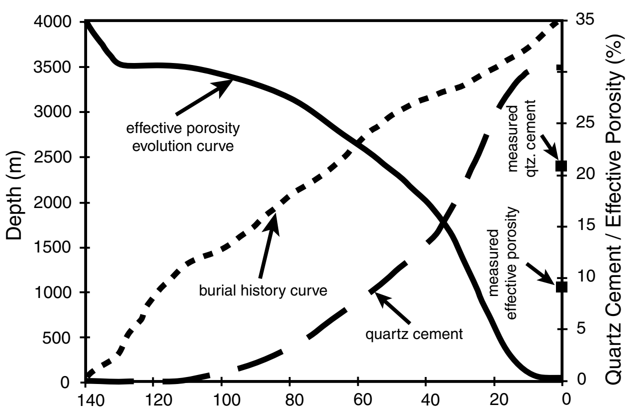


Figure 15. Diagenetic modeling indicates lower effective porosity (0.5%) and higher quartz cement abundance (30.5%) than the actual values of effective porosity and quartz cement (9% and 21%, respectively). The most likely reason for the discrepancy between modeled and actual porosity and quartz cement values is emplacement of hydrocarbons about 25 Ma.

for the fluid from the top of the water column (Dickinson, 1953) (Figure 16A). An important aspect of fluid overpressures is that by bearing some of the mass of the overlying sediment column, the fluid reduces the pressure on the solid part of the rock, the effective stress (Figure 16B). Effective stress is a major control on sandstone compaction, and as a result fluid overpressures can in some cases help preserve porosity. For example, the fluid overpressure at 5000 m (16,405 ft) depth shown in Figure 16B reduces the effective stress on the solid part of the rock to a value equivalent to that at 750 m (2460 ft) under hydrostatically pressured conditions. The ability of fluid overpressures to preserve porosity is highly dependent on the timing of fluid overpressure development, as well as on the mechanical properties of the reservoir sandstones. The timing of fluid overpressure development, in turn, is a function of the causal mechanisms involved. A critical aspect of overpressure analysis is the limit of economic production potential of approximately 19.6 kPa/m (0.85 psi/ft) (Law and Spencer, 1998).

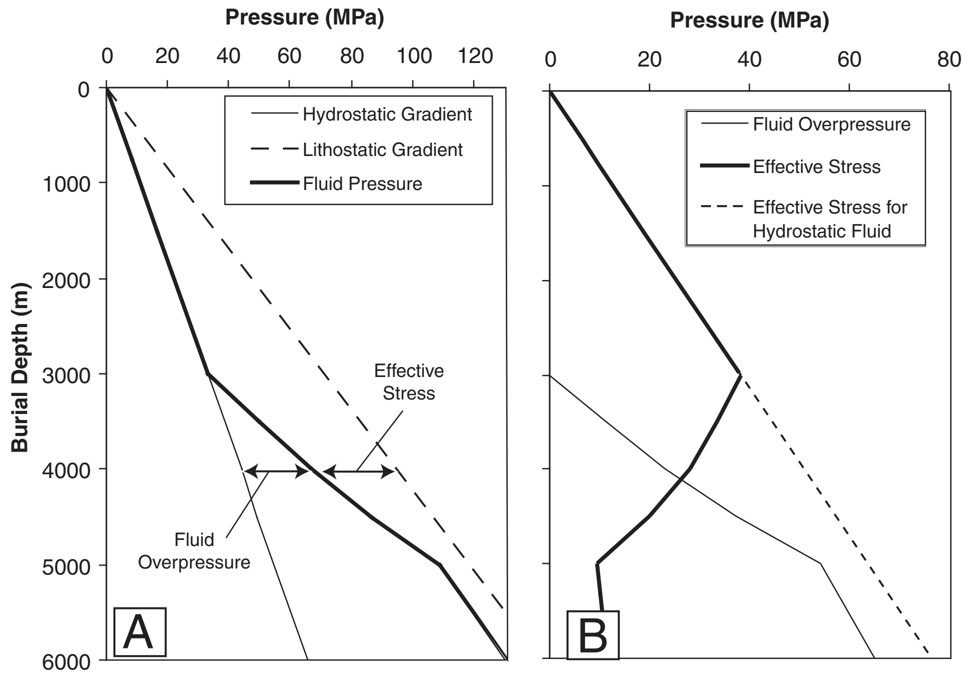
Causes of Fluid Overpressure

Fluid overpressures can form (1) where the rate of pore volume reduction is fast relative to the rate of fluid release, (2) where the rate of pore fluid expansion is fast relative to the rate of fluid release, and (3) in response to large-scale fluid movement (Osborne and Swarbrick, 1997). The first two mechanisms represent transient flow conditions and are responsible for the geopressures found in basins such as the Gulf of Mexico and the North Sea. The latter mechanism is typically associated with basins that exhibit near–steady-state flow conditions in response to topographic driving forces, such as artesian basins.

The transient mechanisms of fluid overpressure generation have the greatest potential to affect sandstone diagenesis. Therefore, the focus of the following discussion is on the processes that cause rapid losses in pore volume or rapid increases in fluid volume. A common characteristic of both pathways toward geopressure development is the occurrence of low-permeability zones that impede the free movement of fluid away from regions with rapid pore volume reduction or fluid expansion. A critical additional control on the occurrence of fluid overpressures, therefore, is the three-dimensional distribution of permeability through geologic time.

Three mechanisms have been cited as driving forces for rapid pore volume reduction: (1) disequilibrium

Figure 16. (A) Hypothetical fluid pressure transect with depth shown together with the gradients in hydrostatic and lithostatic pressures. Fluid overpressure is defined as the amount of fluid pressure in excess of hydrostatic pressure, and effective stress is defined as the difference between lithostatic pressure and fluid overpressure. (B) Variations in the effective stress and fluid overpressure with depth for the transect shown in A.



compaction, where pore volume loss occurs in response to mechanical compaction, (2) coupled chemical and physical diagenesis, where the chemical redistribution of materials leads to a net loss in pore volume, and (3) several mechanisms having the potential to cause rapid increases in pore fluid volume that could create fluid overpressures. Rapid increases in pore fluid volume may be caused by (1) aquathermal expansion, (2) smectite illitization, (3) kerogen maturation, and (4) oil-to-gas cracking. A thorough overview of the mechanisms generating fluid overpressure was provided recently by Osborne and Swarbrick (1997).

Porosity preservation as a result of inhibition of mechanical compaction due to reduced effective stress is most pronounced where fluid overpressure develops at shallow depths and persists throughout the burial history of the sandstone. Empirical data indicate that fluid overpressures associated with disequilibrium compaction can occur at relatively shallow depths, where the rate of porosity loss with effective stress is greatest. This mechanism has been recognized as a critical control on fluid overpressure development in basins that have undergone rapid burial and that contain a high proportion of relatively low permeability sequences (e.g., Bethke, 1986). By contrast, most of the remaining driving forces that cause fluid overpressure occur at higher temperatures and depths. Fluid overpressures generated at greater depths have much less potential to preserve porosity because much of the porosity loss due to mechanical compaction occurs within the upper 2000 m of burial, where fluid pressures are at or near hydrostatic.

Fluid Overpressure Detection and Prediction

Well-established techniques exist for detecting (e.g., Stein, 1992; Kan and Sicking, 1994) and modeling (e.g., Mann and Mackenzie, 1990) the occurrence of fluid overpressures that occur in response to disequilibrium compaction. Detection methods, such as analysis of reflection seismic data, are effective primarily because disequilibrium compaction causes undercompaction. Interval velocity deviations from normal trends can, therefore, in some areas (Tertiary section of the Gulf of Mexico or offshore west Africa) be related to abnormally high pore pressures. Such techniques are not effective for rocks that developed fluid overpressures late in their burial history and were therefore normally compacted prior to overpressure buildup.

Approaches toward predictive modeling of fluid overpressure development are available for disequilibrium compaction and aquathermal expansion. These approaches are incorporated in most commercially available basin modeling systems. Models are as yet in immature stages of development for fluid overpressure that occurs in response to smectite illitization, hydrocarbon generation, and oil-to-gas cracking.

Effect of Fluid Overpressure on Porosity Preservation

The effect of pore fluid overpressures on porosity preservation has been evaluated in several studies (e.g., Scherer, 1987; Ramm and Bjørlykke, 1994; M. D. Wilson, 1994c; Gluyas and Cade, 1998). The algorithms developed by these authors were based on empirical relationships between present-day porosity and present-day pore fluid overpressures. The effects of the timing of fluid overpressure development and the composition of sandstones on porosity preservation were not considered. These effects, however, can be critical, and their quantification can significantly improve predrill modeling and prediction of reservoir quality in overpressured sandstones.

Lander and Walderhaug (1999) have attempted to consider these factors in the Exemplar model of sandstone compaction and quartz cementation. In the model, compaction is defined as a reduction of bulk rock volume and is expressed in terms of intergranular volume (IGV). Defined as the sum of intergranular porosity, matrix, and cements, IGV is a good index of the compaction state of the sandstone and provides an indication of the maximum porosity that can be expected. Maximum porosity is equal to IGV in sands devoid of cements and matrix.

Lander and Walderhaug (1999) simulated compaction through time as a function of the effective stress history and the mechanical strength of the rock. The mechanical strength of the rock is largely a function of the composition and texture of the sandstone framework grains. We use the Lander and Walderhaug (1999) model to illustrate how the timing of fluid overpressure development and the composition of sandstones affect porosity preservation using synthetic scenarios. In each of the following examples, sandstones are linearly buried to a depth of 4000 m (13,124 ft) at constant thermal gradient of 30°C/km (1.64°F/100 ft). We consider the effect of the timing on fluid overpressure development by comparing three fluid pressure scenarios (Figure 17): (1) hydrostatic pressure for the entire geologic history, (2) shallow development of fluid overpressure, where the overpressure gradient is fully developed by 800 m (2625 ft) of burial, and (3) deep development of fluid overpressure, where fluid overpressure developed from 2400 to 4000 m (7874 to 13,124 ft) of burial. The two fluid overpressure scenarios assume that the present-day fluid pressure is 85% of the lithostatic pressure (i.e., near the fracture gradient of the sandstone). The pressure history is uncomplicated, that is, maximum fluid overpressure, once reached, persists to the present day.

We also consider the effect of geologic time by comparing model results using linear Miocene and Cretaceous burial histories, and the effect of composition by comparing a synthetic sandstone rich in rigid grains ($Q_{84}F_8L_8$) with a synthetic ductile-grain–rich ($Q_{50}F_0L_{50}$) sandstone. The compaction and quartz cementation model parameters used in this simulation

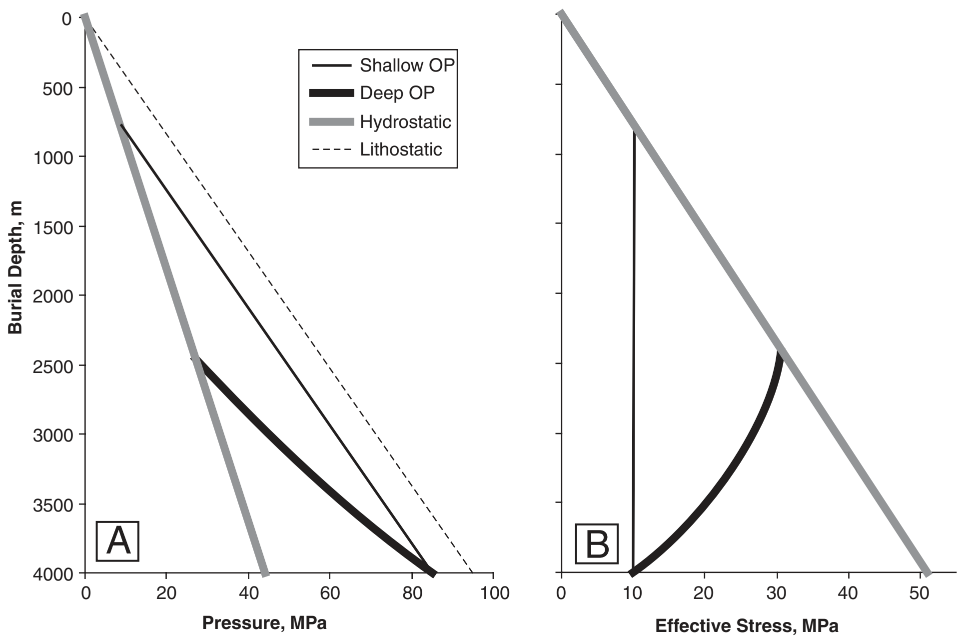


Figure 17. (A) Fluid pressures shown as a function of depth for the hydrostatic, shallow, and deep fluid overpressure scenarios used in the synthetic models. (B) Effective stresses as a function of depth for the three fluid pressure scenarios. OP = overpressure.

correspond to those reported in Lander and Walderhaug (1999).

To gauge the effect of the different fluid pressure scenarios on mechanical compaction, we can view model predictions for IGV through time. The IGV results are highly sensitive to both the fluid-pressure history and the composition of the sandstone, but not to geologic time (compare Figure 18A with Figure 19A for ductile-grain–rich sandstones, and Figure 18B with Figure 19B for rigid-grain–rich sandstones). In our synthetic ductile-grain–rich example, predicted IGV is significantly higher (about 16%) using the shallow fluid overpressure scenario than using the hydrostatic scenario (Figures 18A, 19A). The predicted IGV of the ductile-grain sandstone subjected to the deep fluid overpressure scenario, however, is only slightly higher than for the hydrostatic case (Figures 18A, 19A).

Rigid-grain–rich sandstones compact much less than do ductile-grain–rich equivalents at a given effective stress. As a result, the potential of fluid overpressure to preserve porosity in rigid-grain–rich sandstones through reduced compaction is more limited. This is illustrated in Figures 18B and 19B, where the predicted IGV is only about 6% greater for the shallow fluid overpressure scenario than that predicted for the hydrostatic case. The predicted IGVs for the deep fluid overpressure scenario and the hydrostatic case are nearly identical, with the deep fluid overpressure scenario re-

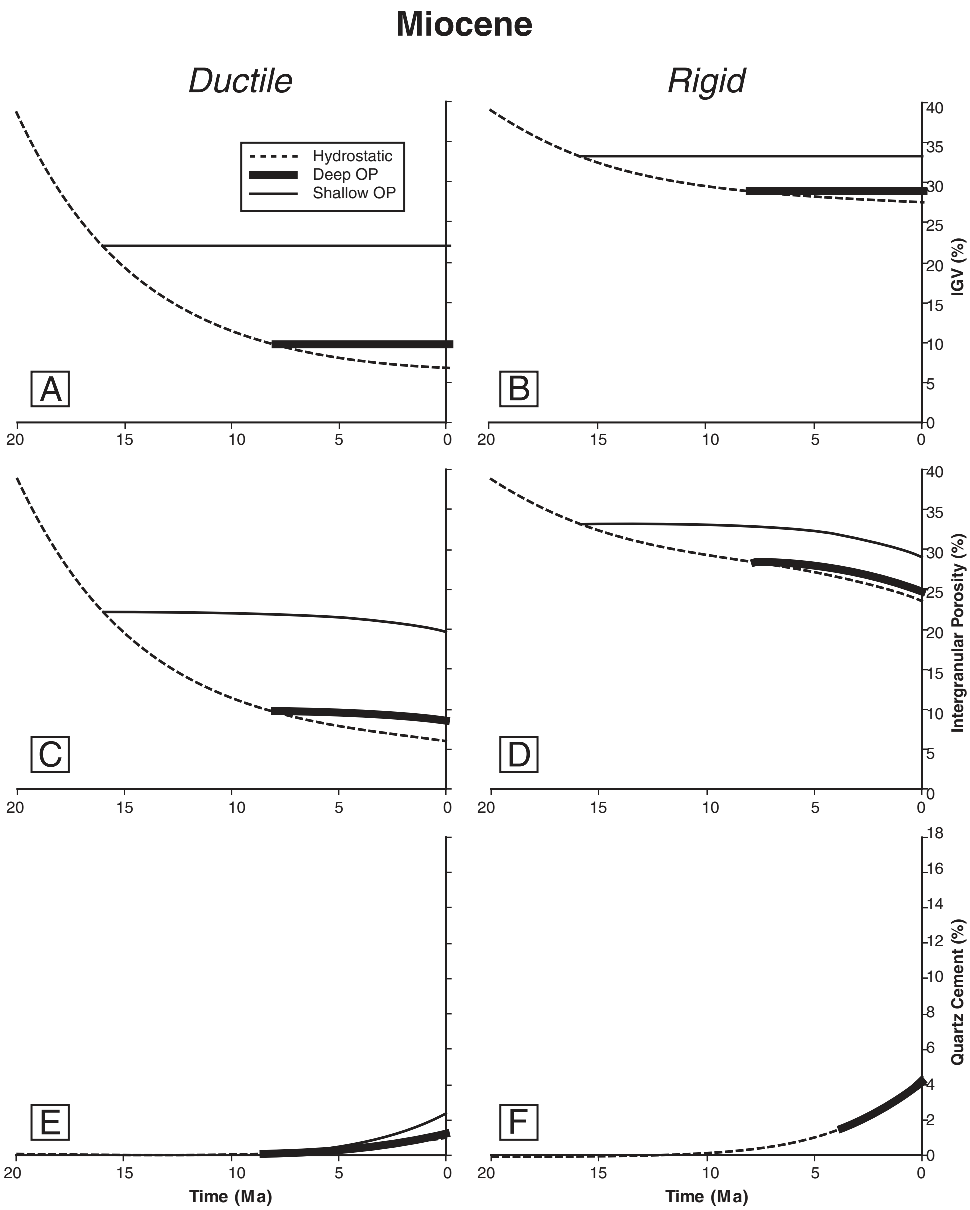


Figure 18. Diagenetic model results illustrating controls on porosity preservation for a synthetic Miocene sandstone. (A, B) Modeled intergranular volume (IGV) with time for a ductile-grain–rich sandstone and a rigid-grain–rich sandstone, respectively. (C, D) Modeled intergranular porosity with time for a ductile-grain–rich sandstone and a rigid-grain–rich sandstone, respectively. (E, F) Modeled quartz cement abundance with time for a ductile-grain–rich sandstone and a rigid-grain–rich sandstone, respectively. Our synthetic sandstone is assumed to be medium grained and well sorted. All framework grains in the rigid-grain–rich sandstone are assumed to be nonductile; 74% of these are quartz. The framework grains in the synthetic ductile-grain–rich sandstone consist of equal proportions of shale rock fragments and quartz grains.

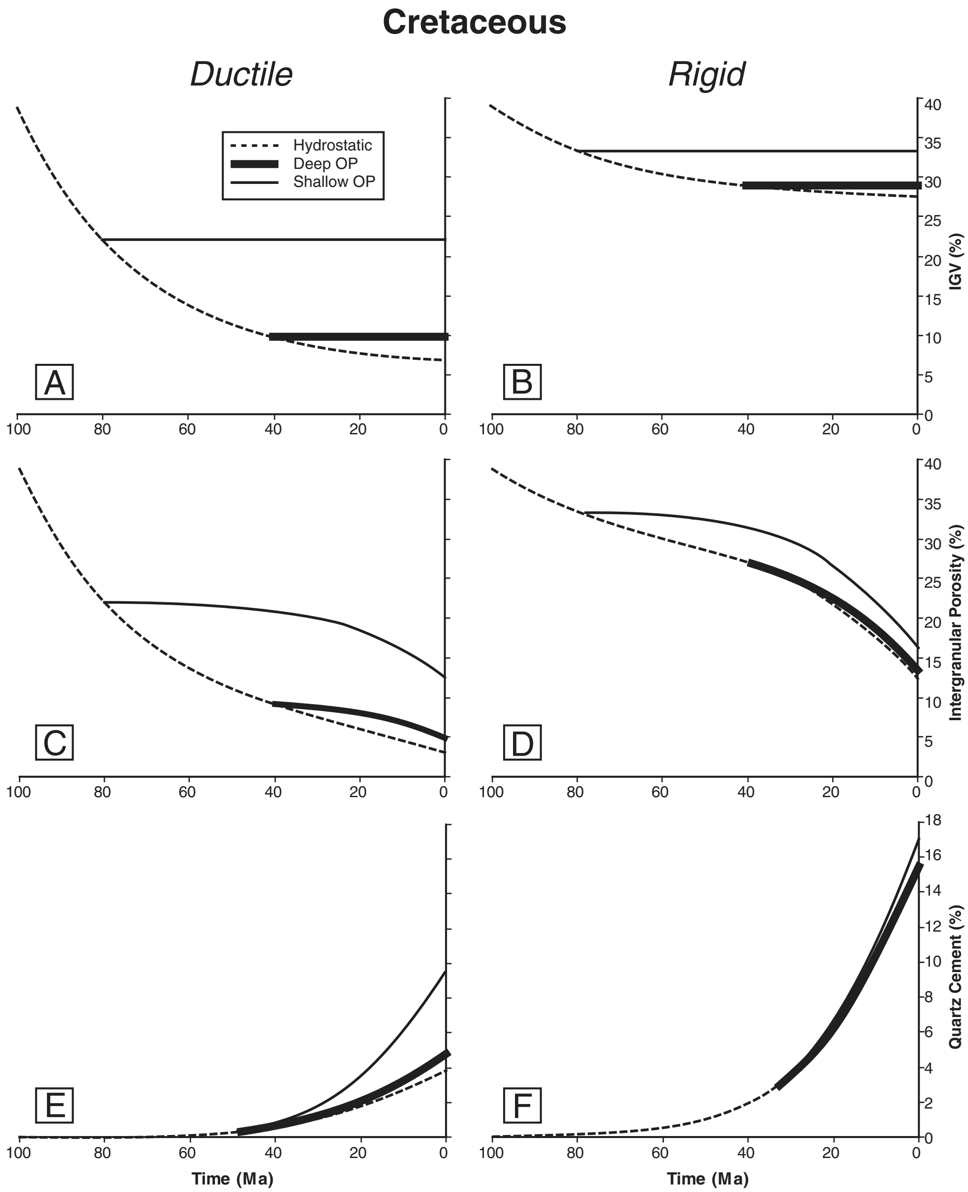


Figure 19. Diagenetic model results illustrating controls on porosity preservation for a synthetic Cretaceous sandstone. (A, B) Modeled intergranular volume (IGV) with time for a ductile-grain–rich sandstone and a rigid-grain–rich sandstone, respectively. (C, D) Modeled intergranular porosity with time for a ductile-grain–rich sandstone and a rigid-grain–rich sandstone, respectively. (E, F) Modeled quartz cement abundance with time for a ductile-grain–rich sandstone and a rigid-grain–rich sandstone, respectively. The texture and composition of the synthetic samples used in these simulations are identical with those described in Figure 18. OP = overpressure.

ducing compaction by only 1% IGV (Figures 18B, 19B).

Although elapsed geologic time does not appear to be a primary control on the compaction state of sandstones (Lander and Walderhaug, 1999), it is an important factor governing the extent of quartz cementation (Walderhaug, 1996). The rate of quartz cementation is also sensitive to the surface area available for nucleation of overgrowths, which in turn is a function of the compaction state of the sandstone (Scherer, 1987; Lander and Walderhaug, 1999). As a result, higher rates of quartz cementation can, given sufficient time, partially offset porosity preserved in overpressured sandstones if quartz cementation occurs in the presence of fluid overpressure.

The occurrence and rates of quartz cementation under overpressured conditions are controversial, and little has been published that directly addresses this issue. Presence of quartz cement in overpressured Tertiary sandstones from the United States Gulf Coast (Land et al., 1987; Freeman, 1990) suggests (but does not prove) that quartz cementation occurs in highly overpressured sandstones where fluid overpressure has been likely to have formed prior to the onset of quartz cementation. By contrast, the development of quartz cement is retarded by overpressure in clastic reservoirs in the Upper Jurassic of the United Kingdom Central North Sea (Osborne and Swarbrick, 1999) and the Middle Jurassic of the Viking Graben (M. D. Wilson, 1994c). Osborne and Swarbrick (1999) attribute the retardation to the inhibition of chemical compaction (pressure solution) by early overpressure.

In our synthetic examples, we allow quartz cementation to continue after fluid overpressure development to illustrate the potential impact that cementation might have on porosity preservation. The model predicts that ductile-grain–rich sandstones subjected to the shallow fluid overpressure scenario will be significantly (16% in our synthetic example) less compacted compared with the hydrostatic case (Figures 18A, 19A), but the overall intergranular porosity preservation is decreased to 14% for the Miocene sandstone (Figure 18C), and 9% for the Cretaceous sandstone (Figure 19C) as a result of cementation. The extent of predicted quartz cementation in the synthetic Miocene and Cretaceous ductile-grain–rich sandstones is illustrated in Figures 18E and 19E.

The predicted intergranular porosity preservation resulting from the shallow and deep fluid overpressure scenarios for rigid-grain–rich rocks is less than that for ductile-grain–rich rocks, with porosity preservation of 5% and 4% for the synthetic Miocene and Cretaceous rigid-grain–rich examples, respectively (Figures 18D, 19D). Expectedly, quartz cementation in the detrital-quartz–rich example is greater than that in the ductile-grain–rich example (compare Figures 18F and 19F; Figures 18E and 19E). Note that in both ductile-grain–rich and detrital-quartz–rich sandstones, quartz cementation is a function of geologic time, with Cretaceous sandstones predicted to contain more quartz cement than the younger Miocene sandstones.

Assessing Reservoir Quality of Overpressured Sandstones

The best-case scenario for significant reservoir quality preservation due to fluid overpressure development is in rapidly deposited Tertiary or Quaternary sandstones that are encased in low-permeability lithologies such as shales. In such cases, the extent of porosity preservation due to reduced compaction is maximized because fluid overpressures develop at shallow depths in response to disequilibrium compaction. Moreover, the potential loss of porosity due to quartz cementation is minimized because of the limited time available and because of the lower thermal gradients that are normally associated with the rapid burial. In our synthetic example, a rigid-grain–rich sandstone can show preservation of as much as 6% porosity in such cases, and even larger extents of porosity preservation can be expected for ductile-grain–rich sandstones.

The case for significant porosity preservation associated with fluid overpressures in pre-Tertiary basins is more problematic. Disequilibrium compaction in pre-Tertiary rocks can lead to fluid overpressure generation shortly after burial, but it is difficult to maintain high fluid overpressures to the present day using reasonable shale permeabilities (Harrison and Summa, 1991). Likely, high fluid overpressures in some pre-Tertiary basins are influenced by deep overpressure generating mechanisms such as those associated with hydrocarbon reactions or quartz cementation. If a significant proportion of the fluid overpressure developed at depth, it is unlikely that significant porosity preservation due to reduced compaction will result.

CONCLUSIONS

The rate of porosity and permeability decline with increasing burial depth can be significantly reduced by (1) grain coats and grain rims (in detrital-quartz–rich sandstones), (2) early hydrocarbon emplacement, and (3) shallow development of fluid overpressure in quartz-rich and quartz-poor lithologies.

Grain coats and grain rims impede porosity and permeability reduction by inhibiting quartz overgrowth precipitation on host detrital-quartz grains. Although the general principle of porosity and permeability preservation by coats is the same for rims, there are major differences in the origin and effectiveness among different grain coats and grain rims.

At this time, accurate prediction, prior to drilling, of the extent of the development of coats or rims (and, therefore, their effectiveness) within the grain-coat– and grain-rim–prone intervals is not possible, but the potential impact of these features on preservation of anomalous porosity and permeability can be assessed by diagenetic models. The assessment involves testing different coating scenarios, given sandstone lithology and burial history models of the intervals of interest. The results of such studies used in conjunction with an evaluation of the likelihood of occurrence of coated intervals can be used to enhance risk assessment due to reservoir quality.

Retardation, or even cessation, of porosity-reducing diagenetic processes in sandstones by emplacement of hydrocarbons is seemingly a logical consequence of (1) reduction in the supply of dissolved ions and (2) reduction in nucleation surfaces for cements on oil-wet surfaces. In practice, however, the extent of the inhibition process and its effect on reservoir quality are controversial. Empirical data suggest that at least some cements (e.g., quartz, illite) may continue to precipitate following emplacement of hydrocarbons into the reservoir; but in some reservoirs (including quartzose sandstones) there is compelling evidence for preservation of porosity due to early hydrocarbon filling. Our work indicates that if a calibration data set, including limited lithological and burial/thermal history data, is available, integration of basin modeling with reservoir quality modeling can be used to quantify, prior to drilling, the effect of hydrocarbon emplacement on porosity and permeability.

Fluid overpressure most effectively preserves porosity and permeability in rapidly deposited Tertiary or Quaternary sandstones. The extent of porosity preservation due to reduced compaction is maximized in such sandstones because fluid overpressures develop at shallow depths in response to disequilibrium compaction. Furthermore, if quartz cementation occurs in the presence of fluid overpressure, the loss of porosity due to quartz overgrowths is minimized because of the limited time available for cementation and because of the lower thermal gradients that are normally associated with the rapid burial.

Significant porosity preservation associated with fluid overpressures in pre-Tertiary basins is more problematic than in younger sands. Disequilibrium compaction in pre-Tertiary rocks can lead to fluid overpressure generation shortly after burial, but the likelihood that high fluid overpressure was maintained throughout the burial history is low. High fluid overpressures in many pre-Tertiary basins are likely influenced by deep generating mechanisms associated with organic and inorganic reactions. If fluid overpressure developed at depth, porosity will not be preserved to a significant extent given that most mechanical compaction occurs at depths less than 2500 m under hydrostatic conditions.

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