GEOLOGIC NOTE

Sandstone vs. carbonate petroleum reservoirs: A global perspective on porosity-depth and porosity-permeability relationships

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ABSTRACT

Plots are presented comparing average porosity vs. depth for 30,122 siliciclastic petroleum reservoirs and 10,481 carbonate petroleum reservoirs covering all petroleum-producing countries except Canada. However, separate plots cover 5534 siliciclastic and 2830 carbonate reservoirs of the Alberta basin in Canada. Average permeability vs. average porosity is shown for the non-Canadian reservoirs. Key similarities and differences between sandstones and carbonates are noted, and implications are discussed regarding the dominant factors controlling reservoir quality in each lithology. Trends of steadily decreasing median and maximum porosity with increasing depth reflect burial diagenetic porosity loss in response to increasing thermal exposure with depth. These trends seem inconsistent with the suggestions that both sandstones and carbonates commonly increase in porosity by dissolution during deeper burial. Carbonate reservoirs have lower values of median and maximum porosity for a given burial depth, probably because of greater chemical reactivity of carbonate minerals relative to quartz and the resulting lower resistance to chemical compaction and associated cementation. Relative paucity of low-porosity (0–8%) siliciclastic reservoirs at all depths compared with carbonates may reflect the more common occurrence of fractures in carbonates and the effectiveness of these fractures for facilitating economic flow rates in low-porosity rock. Overall, carbonate reservoirs do not have lower permeability for a given porosity compared with sandstones but do have strikingly lower proportions of both high-porosity

Manuscript received June 22, 2004; provisional acceptance September 9, 2004; revised manuscript received November 8, 2004; final acceptance November 23, 2004.

DOI:10.1306/11230404071

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ACKNOWLEDGEMENTS

We thank K. Bjørlykke, J. H. Doveton, J. Garland, and A. Hurst for helpful suggestions to the manuscript. S. Vasshus and K. Ruud provided technical support for the Western Canada uplift and erosion corrections and reservoir locations.

and high-permeability values. The data presented can serve as a general guide for the distribution of reservoir quality that can reasonably be expected in exploration wells drilled to any given depth in the absence of detailed geologic information, such as burial and thermal history.

INTRODUCTION

The two fundamental differences between sandstone and carbonate reservoir rocks are (1) the site of sediment production (allochthonous for sandstones vs. autochthonous for carbonates) and (2) the greater chemical reactivity of carbonate minerals (Choquette and Pray, 1970; Moore, 2001). The latter difference has profound significance for diagenesis and reservoir quality, such that siliciclastic strata, for the most part, display only minor effects of eogenetic diagenesis other than carbonate concretions and soil development, whereas carbonates are characterized by extensive early lithification and porosity modification. Because of this contrast, large and systematic differences might be expected in the porosity-depth and porosity-permeability distributions of these two main lithological classes of petroleum reservoir rocks. Although the existence of such differences seems widely accepted and is commonly cited as a basis for separate treatment of carbonate reservoirs (Tucker and Wright, 1990; Lucia, 1999; Moore, 2001), the actual nature and magnitude of these differences are a topic that suffers from little or no quantitative documentation.

The purpose of this note is to address this void by showing a comparison between siliciclastic and carbonate reservoir parameters whose credibility is based on its extreme generality: a compilation of databases covering the petroleum reservoirs from essentially all producing provinces, a case study of planet Earth. From this purely empirical basis, we offer a series of hypotheses explaining the overall similarities and differences between siliciclastic and carbonate reservoir quality.

DATA

The data for this study were provided by IHS Energy (Energy Data Information Navigator Database), the University of Oklahoma, the U.S. Department of Energy (Total Oil Recovery Information System Database), the Department of Trade and Industry, United Kingdom, the Norwegian Petroleum Directorate, and the Alberta Energy and Utilities Board. Gulf of Mexico sandstone data are from Seni et al. (1997) and Hentz et al. (1997). The variables examined for the present study are top reservoir depth, maximum temperature, lithology, and average values of porosity and permeability for reservoir intervals in producing oil, condensate, and gas fields. Multiple reservoirs are listed for many individual fields. Porosity and permeability values are arithmetic average values supplied in the databases, presumably based on varying combinations of core analyses, wire-line-log readings, and production data in different fields. This data compilation also has great versatility for other types of analysis besides reservoir quality, including fluid pressure, seal integrity, migration, and biodegradation (Darke et al., 2004; Nadeau et al., in press). For the United States, offshore Gulf of Mexico, a total of 9312 sandstone reservoirs were condensed to include only the 662 reservoirs with recoverable reserves greater than 10 million bbl of oil equivalent to reduce bias. Lithology information was used to group the data into three categories: (1) siliciclastics, consisting mainly of sandstones, but also including siltstones and conglomerates; (2) carbonates (25% of the 41,450 cases where porosity and depth values are available); and (3) a subordinate number of other lithologies, mainly consisting of shale and igneous rocks (2% of the total). Heavy representation of reservoirs from North America (39% of reservoirs with porosity and depth listed) and the former Soviet Union (28%) reflects the purposes for which the data were originally compiled. The other regions represented are Europe (10%), Latin America and Mexico (8%), the Far East (7%), Africa (4%), the Middle East (2%), and Australasia (2%).

The geographic distributions of sandstone and carbonate reservoir data are displayed in Figure 1. Despite low numbers of data relative to recoverable volumes for certain provinces, such as the Middle East, no significant gaps in geographic representation of petroleum provinces are apparent in Figure 1. We suggest that these figures thus provide qualitatively accurate snapshots of the spatial distribution patterns of the Earth's known resources of liquid petroleum for the two main classes of reservoir lithology.

A small number (71) of the carbonate reservoirs are exceptional in that they consist of chalk lithology, which typically has low permeability for very high porosity. These points are identified by plotting symbols in the figures but have not been included in the statistical values calculated (Table 1).

Results reported here should not be regarded as being representative of sandstone and carbonate rocks

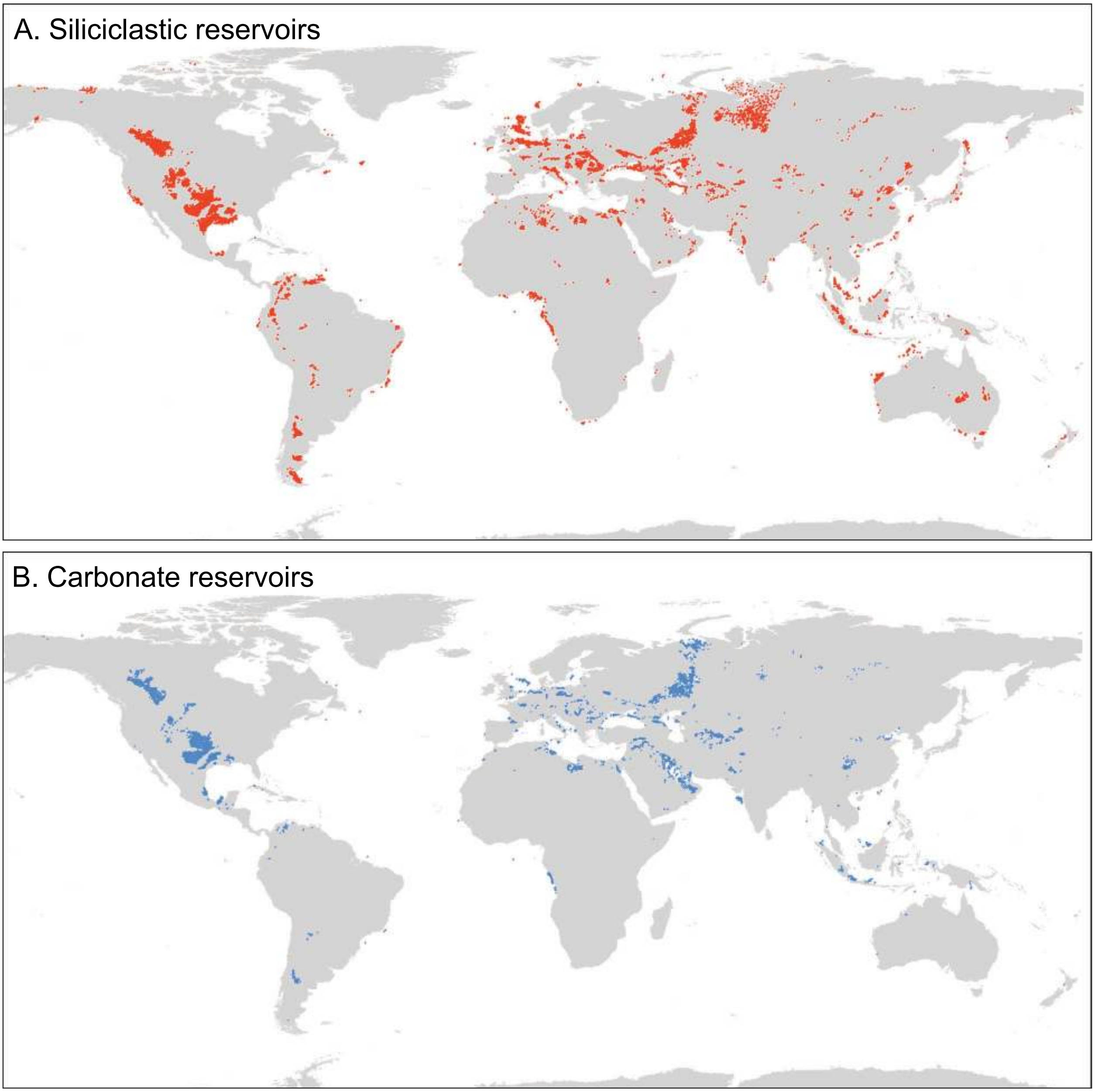


Figure 1. Geographic distribution of petroleum reservoirs, sorted by lithology.

in general, but rather of the producing zones of petroleum reservoirs. Reservoir quality in these zones may be higher than in similar lithologies elsewhere (Pray and Choquette, 1966; Feazel and Schatzinger, 1985), but this relationship is largely unknown.

Porosity-Depth

Figure 2 shows top reservoir depth vs. average porosity for siliciclastics and carbonates separately and compares trends of these lithologies. A certain degree of disparity is involved for these axes because the top reservoir depth is the minimum depth of the interval represented by the average porosity value. Porosity values of P90 (90% of reservoirs have porosity greater than this value), P50 (median), and P10 were calculated for each 0.5-km (0.3-mi) depth interval, and a maximum-porosity line (only scattered outliers greater than this trend) was qualitatively estimated for each plot (Table 1). Although we believe that temperature is more important than depth for controlling average reservoir porosity (Schmoker, 1984; Bjørkum et al., 1998), depth is displayed in Figures 2 and 3 because

Table 1. Values of Statistical Trends Shown in Figures 2 and 4 for Siliciclastic (SI) and Carbonate (CB) Reservoirs

Average Reservoir Porosity (%) vs. Depth (Figure 2)

	P90		P50		P10	
Depth (km)	SI	CB	SI	CB	SI	CB
0–0.25	13.0	6.0	24.0	18.0	31.0	28.0
0.25–0.75	14.0	6.0	22.0	16.0	30.5	28.0
0.75–1.25	14.0	10.0	20.0	12.2	30.0	20.0
1.25–1.75	12.6	8.0	20.0	12.0	28.0	19.0
1.75–2.25	12.0	5.1	20.0	10.1	27.0	19.5
2.25–2.75	11.0	4.5	18.0	10.0	27.0	19.0
2.75–3.25	10.5	4.9	16.0	8.7	23.9	16.0
3.25–3.75	10.0	4.9	15.0	7.8	24.5	14.2
3.75–4.25	8.5	3.0	13.9	8.0	24.0	14.0
4.25–4.75	8.3	2.6	12.9	8.0	22.0	15.0
4.75–5.25	6.8	1.2	11.0	7.3	18.0	12.5
5.25–5.75	6.8	0.9	10.3	6.2	20.0	10.8

Arithmetic-Average Reservoir Permeability (md) vs. Average Porosity (Figure 4)

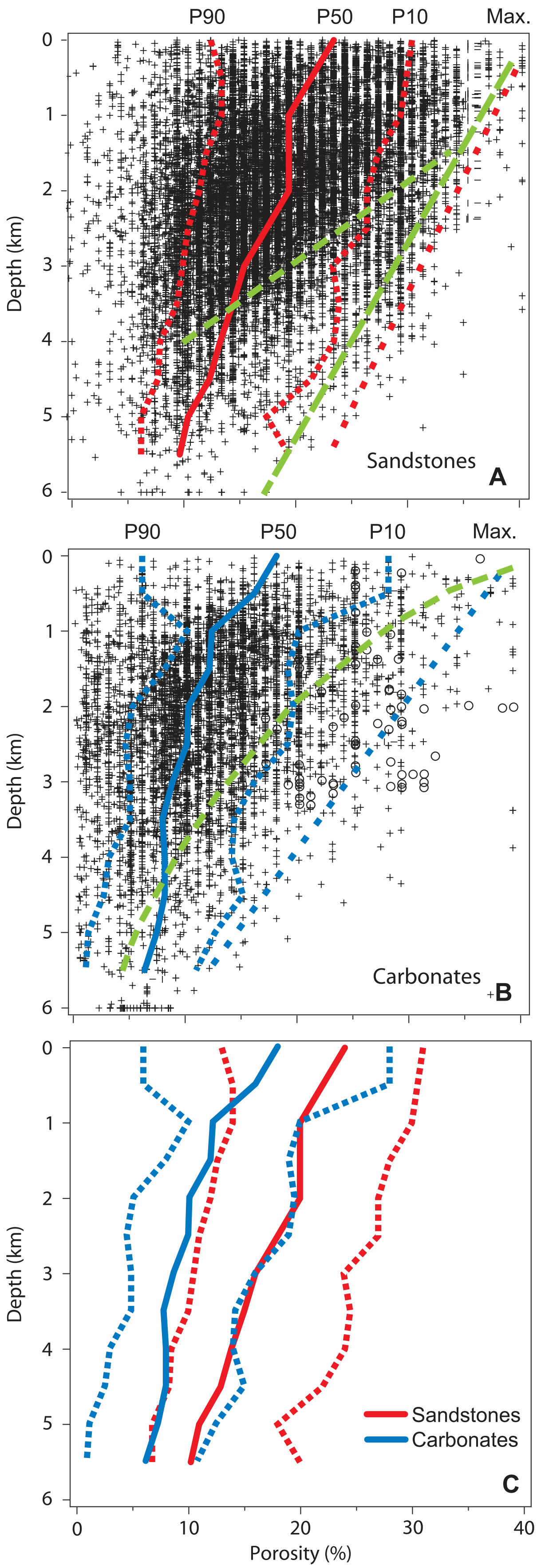
	P90		P50		P10	
Porosity (%)	SI	CB	SI	CB	SI	CB
2.5–7.5	0.30	1.1	10	17	92	100
7.5–12.5	2.0	4.6	29	42	190	177
12.5–17.5	5.0	6.0	40	46	200	250
17.5–22.5	18	7.0	95	58	468	525
22.5–27.5	48	10	243	100	1000	700
27.5–32.5	73	19	570	260	1660	2201
32.5–37.5	120	–	1000	–	2972	–

there are far more data points for porosity-depth and because porosity-temperature plots show similar relationships. The following key similarities and differences between the siliciclastic and carbonate plots are noted:

- Both lithologies display wide porosity variation at shallow to intermediate depths.
- Both lithologies show apparently linear decrease in both P50 and maximum porosity with increasing depth.
- Sandstones have higher P50 and maximum porosity for a given depth. In fact, the carbonate P50 trend is almost identical to the sandstone P90 trend.
- Sandstones have much lower relative proportions of low-porosity values (0–8%) at all depths.

A separate database provided by the Alberta Energy and Utility Board was used to examine porosity, depth, and lithology for reservoirs in the Alberta basin, Canada (Figure 3). With 8364 porosity-depth pairs (34% carbonates) from a 400,000-km^2 (154,440-mi^2) area, this western Canada database is much more densely populated than any area represented in the global database. Carbonates of the Alberta basin are mainly Devonian, whereas the sandstones are mostly Cretaceous. Because of their different stratigraphic concentrations, the carbonates have a deeper depth range than the sandstones. The Alberta basin was asymmetrically uplifted, resulting in 0–2.8 km (0–1.7 mi) of erosion in the early Tertiary, and depths in Figure 3 were corrected to preuplift values (Issler et al., 1999). Thus corrected, the Alberta data display several features similar to the global distributions, including

- trends of decreasing maximum porosity with depth in both sandstones and carbonates
- lower average and maximum porosity for a given depth in carbonates relative to sandstones



- occurrence of abundant low-porosity reservoirs (<8%) in carbonates but not sandstones

These similarities support the generality of the key similarities and differences noted for Figure 2, whereas the following differences between Figures 2 and 3 are attributed to special circumstances pertaining to the Alberta basin:

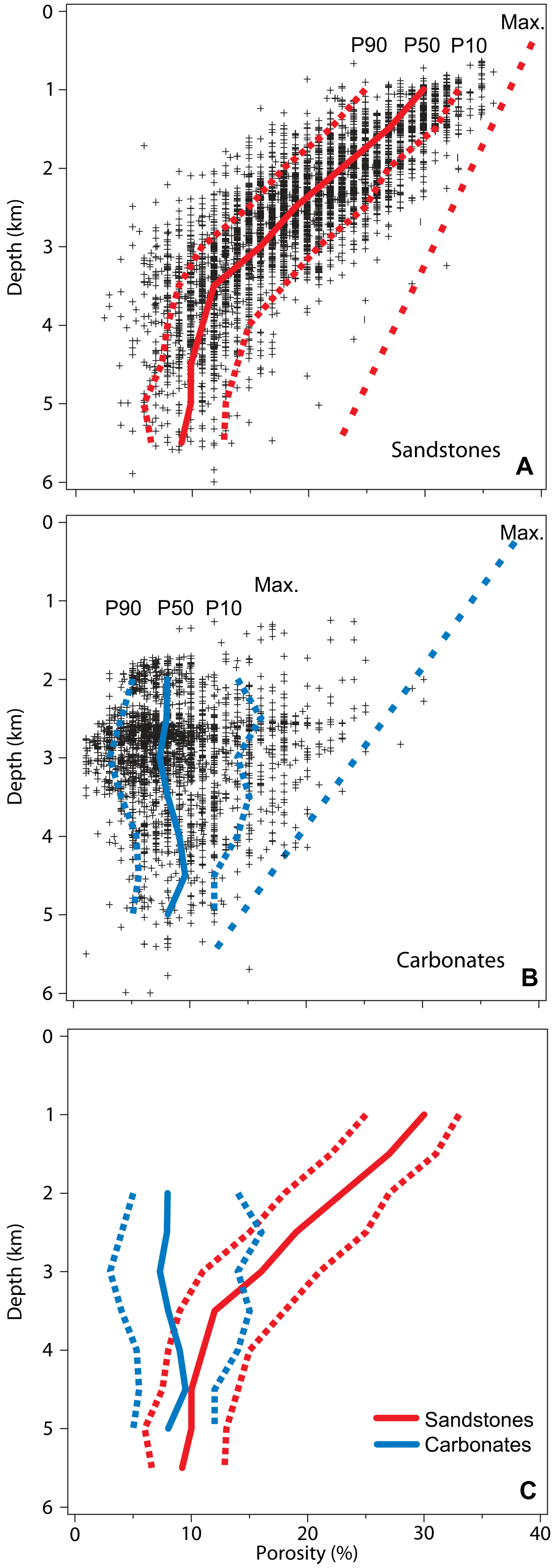
- steeper trends of P50 and maximum porosity vs. depth in the Alberta sandstones (compared with Figure 2A), with few porosities below 20% at shallower depths
- no decrease of P50 with depth in the Alberta carbonates, combined with heavy clustering of the data in a field around 2.5–3.5-km (1.5–2.1-mi) pre-uplift depth and 3–10% porosity

Porosity-Permeability

Sandstone and carbonate reservoirs are compared in terms of arithmetic-average permeability vs. average porosity in Figure 4 (29,275 reservoirs total, 27% of which are carbonate). Unfortunately, permeability data are not available for the Alberta basin data set. Trends of P90, P50, and P10 were calculated for prediction of permeability in each interval of 5% porosity. The following key similarities and differences between the siliciclastic and carbonate plots are noted:

- Both lithologies have similar trends of P50 permeability from 5 to 20% porosity, although sandstones have higher P50 permeability at 25–30% porosity.

Figure 2. Average porosity vs. top depth for global petroleum reservoirs composed of sandstone (A) and carbonate (B). A few points with values outside the plot axes have been plotted at the limiting values. Statistical trends are compared in (C), including P90 (90% of reservoirs have porosity greater than this value), P50 (median), and P10. Chalk reservoirs (open circles in B) were not included for calculation of these trends. Long-dashed green line in (A) is the porosity-depth trend for Tertiary sands of south Louisiana (Atwater and Miller, 1965; from data plotted in Blatt et al., 1980, p. 419), an example of quartzose sandstones buried with low geothermal gradient (18°C/km). Short-dashed green line in (A) is the porosity-depth trend for the Middle Jurassic Garn Formation, offshore mid-Norway (Ehrenberg, 1990), an example of quartzose sandstones buried with moderate geothermal gradient (35°C/km). Dashed green line in (B) is the porosity-depth trend for Tertiary and Cretaceous carbonates of south Florida, an example of shallow-water carbonate platform lithologies buried with low geothermal gradient (18°C/km) (Schmoker and Halley, 1982).



- Siliciclastic reservoirs have markedly higher proportions of both high porosity values (>20%) and high permeability values (>100 md). Forty percent of all points in Figure 4A has porosity greater than 20%, vs. 6% of points in Figure 4B, whereas 47% of all points in Figure 3A has permeability greater than 100 md vs. 28% of points in Figure 4B.
- Carbonate reservoirs have a greater relative proportion of high permeabilities at low porosities. Four percent of all points in Figure 4A have both permeability greater than 100 md and porosity less than 15%, vs. 20% of points in Figure 4B.
- Both lithologies include a subordinate group of reservoirs with multidarcy permeabilities at porosities below 15%, which we suspect to reflect fracture instead of matrix values.

INTERPRETATION

The similarities and differences noted above have implications regarding the underlying processes controlling reservoir quality. Our reasoning is necessarily hypothetical, however, because we have had little opportunity for critically examining the individual reservoirs comprising this global database. Furthermore, this preliminary treatment does not consider various factors that may introduce scatter into the porosity-depth relationships, such as uplift and erosion following maximum burial and variations in stratigraphic age and geothermal gradient.

Porosity Controls

The wide spread of porosity at shallow and intermediate depths in Figure 2A and B contrasts with numerous case histories showing porosity-depth trends showing relatively little scatter in given depth ranges and especially at shallower depths (Schmoker and Halley, 1982; Schmoker and Gautier, 1988; Ehrenberg, 1990; Ramm and Bjørlykke, 1994; Brown, 1997). However, these previous data sets involve particular stratigraphic

Figure 3. Petroleum reservoirs in the Alberta basin, western Canada (not included in Figure 2). Average porosity vs. top depth for petroleum reservoirs composed of sandstone (A) and carbonate (B). Statistical trends are compared in (C). Depth values have been corrected for up to several kilometers of asymmetrically uplift of the basin. Maximum-porosity trends are copied from Figure 2A and B.

units that presumably had limited ranges of high porosity before being buried to varying depths. In contrast, the large scatter of porosity at shallow to intermediate depths in Figure 2A and B reflects the great variability of the rocks comprising petroleum reservoirs worldwide. Thus, increasing burial and thermal exposure tend to reduce porosity in all reservoirs, but different reservoir lithologies begin their burial histories from diverse starting points. Key aspects of this variability include (1) original porosity, by which we mean the porosity present at the time of sediment deposition, dependent on grain sorting (Beard and Weyl, 1973) and clay content in sandstones and on mud content and grain type in carbonates (Dunham, 1962; Enos and Sawatsky, 1981); (2) early diagenetic porosity modification (especially important in carbonates); and (3) the differing porosity response of different facies and lithologies to burial diagenesis (Pittman and Larese, 1991; Brown, 1997). Another factor contributing to the wide scatter of porosity at shallower depths in Figure 2 is the possibility that some reservoirs have been partially exhumed from earlier conditions of maximum burial.

Despite the above variability, however, both P50 and maximum porosity show clear trends of decrease with increasing depth, probably reflecting the combined and interrelated effects of chemical compaction and cementation and the dependence of both processes on thermal exposure (Schmoker, 1984; Walderhaug, 1996). Although specific data are lacking for the individual points in Figure 2, we suspect that the reservoirs nearest to the maximum porosity limit at any given depth represent the best combinations of favorable factors that include (1) lithologies with high potential for preserving original or early-formed porosity (clean quartzose sandstones; mud-lean limestones low in early-cement-prone echinoderm fragments; and sucrosic to vuggy dolostones); (2) stratigraphic circumstances sheltered from near-surface porosity loss; and (3) circumstances facilitating near-surface porosity creation. However, because sandstones tend to show little evidence of eogenetic porosity modification (Bjørlykke, 1984; Bjørkum et al., 1990), we submit that

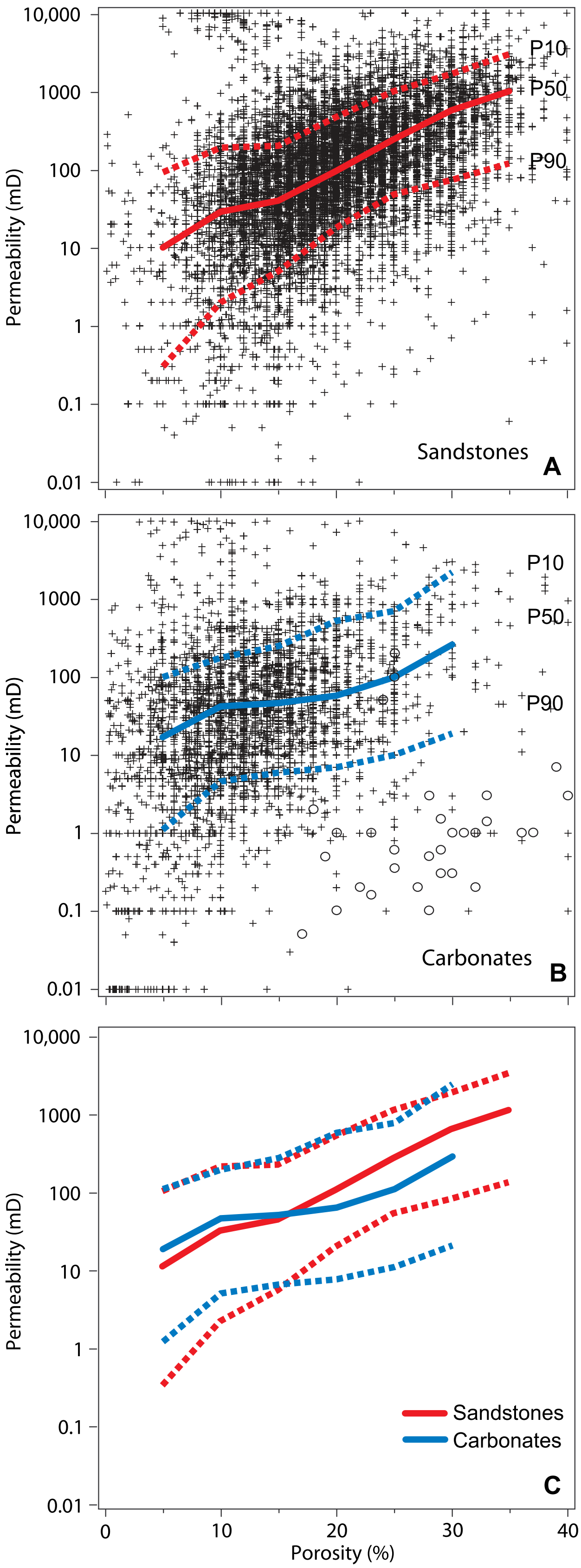


Figure 4. Arithmetic-average permeability vs. average porosity for global petroleum reservoirs composed of sandstone (A) and carbonate (B). A few points with values outside the plot axes have been plotted at the limiting values. Statistical trends are compared in (C). Chalk reservoirs (open circles in B) were not included in the calculated trends.

the latter two factors are mainly important for carbonate lithologies.

Figure 2 also shows the comparison of the global porosity-depth distributions with three individual data sets having wide variations in burial depth, simple burial histories not involving uplift, and restricted lithologic variation in depositional facies prone toward preservation of good reservoir quality. The Garn and offshore Louisiana data sets consist of quartzose sandstone, whereas the south Florida data set consists of shallow-water, tropical carbonates. The Garn and south Florida data sets both show steeper trends of porosity decrease than the global maximum porosity vs. depth trends. This difference highlights the exceptional nature of the reservoirs defining the global maximum-porosity trends. For sandstones, the maximum-porosity trends may either represent conditions of exceptionally low geothermal gradient, such as offshore Louisiana, or exceptional lithologic factors, such as chlorite-coated sand grains (Ehrenberg, 1993). For carbonates, the south Florida example shows that low geothermal gradient alone is not sufficient to produce maximum porosity values at great depth; further study of the deeper carbonate reservoirs' maximum porosities is needed to determine the critical factors involved.

A steady decrease of both sandstone and carbonate P50 and maximum porosity trends with depth (Figure 2) seems inconsistent with the view that both lithologies commonly undergo major increases in porosity during deeper burial because of dissolution by aggressive fluids (Schmidt et al., 1977; Scholle and Halley, 1985; Choquette and James, 1987; Surdam et al., 1989; Hutcheon et al., 1992; Mazzullo and Harris, 1992; Moore, 2001; Esteban and Taberner, 2003). The many case histories invoking burial (mesogenetic) porosity enhancement almost universally suffer from weak quantitative documentation, where conclusions about porosity timing and amounts depend fundamentally on qualitative petrographic opinions. The responsible fluids are most commonly attributed to maturation of kerogen in source rocks, but aggressive behavior has also been explained by water of low ionic strength expelled from clay minerals (Burst, 1969) changing saturation state because of vertical flow (changing temperature and pressure; Wood, 1986), illitization of smectite or kaolin with burial (Bjørlykke 1984), hydrocarbon-sulfate reaction (Hill, 1995), mixing waters of differing composition (Hill, 1995; Morse et al., 1997), and biodegradation of oil (Ehrenberg and Jakobsen, 2001; Heubeck et al., 2004). A major component of porosity creation during burial should produce noncorrelation between porosity and depth, but the general compilation in Figure 2 is more compatible with the viewpoint that mesogenetic dissolution results principally in porosity rearrangement instead of creation (Giles and de Boer, 1990), and that the main burial-diagenetic process affecting both sandstone and carbonate porosity is gradual porosity occlusion.

Such conservatism is also supported by available case studies of particular stratigraphic units having both a restricted range of preburial porosity and a wide range of present burial depth (for example, Loucks et al., 1984; Schmoker and Gautier, 1988; Ehrenberg, 1990; Giles et al., 1992, in sandstones and Schmoker and Halley, 1982; Brown, 1997, in carbonates), as well as by general theoretical arguments involving quantitative mass-balance calculations (Bjørlykke, 1994). Noncorrelation between porosity and depth in the Alberta basin carbonates (Figure 3B) could partly reflect burial leaching of residual calcite associated with dolomitization at paleodepths of 0.6–1.2 km (0.37–0.74 mi), as proposed for many of these reservoirs by Amthor et al. (1994) and Mountjoy and Marquez (1997). However, even the Alberta carbonates show distinct decrease of maximum porosity with depth, and P50 values are not notably different from the global carbonates in Figure 2B.

The idea that early petroleum charge should inhibit later porosity loss by cementation has been much discussed for both sandstones and carbonates (Feazel and Schatzinger, 1985; Worden et al., 1998). For sandtones, compilations of core measurements from at least one major petroleum province (North Sea) give little support to the practical significance of porosity preservation by petroleum (Giles et al., 1992; Bjørkum and Nadeau, 1998), although local relationships have been interpreted otherwise (Gluyas et al., 1993). For carbonates, however, evidence for significantly higher porosity in oil-filled reservoir volumes appears strong (Dunnington, 1967; Scholle, 1977; Schmoker and Halley, 1982; Koepnick, 1985; Oswald et al., 1996; Neilson et al., 1998). This question cannot be examined in the present data set because all the porosity values refer to petroleum-filled strata. All that can be said is that neither petroleum nor other mechanisms for inhibiting diagenesis (including grain coatings and overpressuring; Bloch et al., 2002) appear to prevent the inexorable trend of porosity decrease with depth as seen from a global perspective.

The major lithologic differences shown in Figure 2 are that carbonate reservoirs have lower values of both P50 and maximum porosity for a given burial depth than siliciclastics. These differences are ascribed to the greater chemical reactivity of carbonate relative to siliciclastic minerals, probably reflecting lesser resistance of carbonate minerals to chemical compaction and associated cementation.

The striking paucity of siliciclastic reservoirs with low porosity (0–8%) at all depths compared with carbonates has two possible interpretations. One is that low-porosity sandstones may be relatively sparse at depths less than 6 km (3.7 mi) in the Earth's crust because of retention of microporosity and secondary macropores. In our experience, however, this is unlikely. An alternative explanation is that low-porosity reservoirs are simply more economically viable in carbonates than in siliciclastic lithologies because of the more common occurrence of fractures in carbonates and the effectiveness of these fractures for facilitating economic flow rates.

Permeability Controls

Interpretation of permeability data is particularly uncertain in the absence of corresponding information on rock fabric (Bryant et al., 1993; Lucia, 1999). Nevertheless, it seems reasonable to assume that most sandstone reservoirs are characterized by the dominance of intergranular porosity, whereas a large proportion of carbonate reservoirs can be expected to have abundant vugs. Such a difference might be expected to result in lower permeability for a given porosity in the carbonates, but this does not appear to be supported by the observed distributions (Figure 4). If anything, the data show the opposite trend of higher proportions of high permeability values at low porosity in carbonates. This characteristic may reflect greater incidence of fracture permeability in the carbonate reservoirs, instead of more favorable fabrics composing the rock matrix. The observation that carbonates are characterized overall by both lower porosity and lower permeability may result from the greater susceptibility of carbonates to diagenetic porosity occlusion because of the higher chemical reactivity of carbonate minerals, as postulated above. Lower permeability corresponding to lower porosity, however, is simply a fundamental characteristic of porous media (Nelson, 1994) and does not necessarily imply different pore geometry.

CONCLUSIONS

The wide spread of average porosity at shallow to intermediate depths in both sandstones and carbonates reflects the wide variations in depositional characteristics (composition and texture), early diagenesis, and burial and thermal histories encompassed by producing petroleum reservoirs. Trends of steadily decreasing median and maximum porosity with increasing depth suggest that porosity creation by dissolution is far less significant than porosity occlusion during burial diagenesis of both sandstone and carbonate reservoirs. We do not say that burial dissolution does not occur at all; only that this phenomenon is not evident from available porosity-depth distributions, seems generally poorly documented, and may therefore be of minor importance in the majority of deeply buried reservoirs. Lower median and maximum porosity for a given burial depth in carbonate than in sandstone reservoirs probably reflects the greater chemical reactivity of carbonate minerals relative to quartz and resulting lower resistance of carbonate rocks to chemical compaction and associated cementation. The relative paucity of low-porosity (0–8%) siliciclastic reservoirs at all depths compared with carbonates may reflect the more common occurrence of fractures in carbonates and the effectiveness of these fractures for facilitating economic flow rates in low-porosity rock. Overall, carbonate reservoirs do not appear to have lower permeability for a given porosity compared with sandstones. The data presented can serve as a general exploration guide for the probability of encountering the desired porosity and permeability at a specified depth in a frontier area.

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