

Petroleum geology of South Australia

Vol. 2: Eromanga Basin



CHAPTER 11 Reservoirs and seals

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EROMANGA BASIN	2
Introduction	2
Petrophysical data	2
Reservoirs and seals	3
Poolowanna facies.....	3
Algebuckina Sandstone	4
Hutton Sandstone	4
Birkhead Formation	4
Namur Sandstone.....	4
Murta Formation and McKinlay Member	5
Wyandra Sandstone Member of the Cadna-owie Formation	5
Coorikiana Sandstone	5
SIMPSON BASIN.....	6
PEDIRKA BASIN	6
ARCKARINGA BASIN	6
FIGURES	7
TABLE	
11.1 Summary of Eromanga Basin porosity and permeability data.....	3

EROMANGA BASIN

Introduction

In South Australia most stratigraphic units from the Poolowanna Formation to the Murta Formation contain free-flowing oil reservoirs (Fig. 11.1), with the exception being the Adori Sandstone. Commercially producible oil has been discovered in the Cadna-owie Formation (Wyandra Sandstone Member) in Aldinga 1 and within the Coorikiana Sandstone in Ulandi 12. However, the often poor and variable reservoir characteristics of these upper formations suggest there is only limited reservoir potential. The Jurassic of the Eromanga Basin is a reservoir-rich, seal-poor sequence (Boult, et al., 1998) and multiple stacked oil pools are typical of the Cooper region (Heath et al., 1989).

The Hutton Sandstone has proved to be the most productive onshore unit within the Jurassic–Cretaceous. Nearly half the total oil produced from the Eromanga Basin in South Australia originates from the Hutton Sandstone sealed by Birkhead Formation (Fig. 11.1). It is also the principal reservoir unit of the largest discovered oil accumulation in the region, the Strzelecki Field, with total production in excess of 2.5×10^6 kL ($\sim 16 \times 10^6$ bbl).

Eromanga Basin oil and gas fields in the Cooper region are generally located either along the zero edge of Triassic seal units, at the Permian zero edge, or are associated with faults (Fig. 11.2). Although the Hutton and Namur sandstones are part of the Great Artesian Basin (GAB), the current hydrodynamic regime is considered to have little effect on oil migration. (Bowering, 1982; Muller, 1989). It is capillary pressure and buoyancy that are the current dominant controls on oil migration into these reservoirs (Boult, 1993). However, mathematical modelling and fluid inclusion data undertaken by Toupin et al. (1997) suggest that higher hydraulic gradients during the Tertiary had the potential to transport oil in Eromanga carrier beds for hundreds of kilometres. It was suggested by Toupin et al. (1997) that oil had been focused towards structural traps at the southern end of the Cooper Basin and is why the majority of Eromanga Basin oil accumulations are found in this region. The thickness of Hutton and Namur oil columns is controlled by seal efficiency (Boult, 1993; Boult et al., 1997) and is typically <20 m (Heath et al., 1989). As a result, no reservoir is filled to spill point.

Petrophysical data

The petrophysical properties of key Eromanga Basin reservoirs were studied in detail by Gravestock and Alexander (1986, 1988, 1989). A total of 270 m of core was logged and 638 plugs sampled over a range of grain sizes and facies. These were subjected to a variety of routine and special core analyses. Key results of the study, summarised from Gravestock and Alexander, (1988; Table 11.1) are as follows:

- Porosity–permeability trends are controlled by grain size and two trends can be readily identified — the RES trend for good to excellent quality reservoir rocks and the CAP trend for poorer quality reservoir rock and caprocks (Fig. 11.3).
- Density log porosity is the most accurate for all formations where hole conditions are good. Sonic log porosity can be used effectively where hole conditions are poor or a density log is not available. The exception is the thinly bedded Murta Formation, where typical log resolutions are insufficient to distinguish centimetre-scale bed thicknesses.
- Application of a density–neutron method, calibrated with cation exchange capacity, produces accurate shale volumes in Eromanga Basin reservoirs.
- Semi-quantitative x-ray diffraction analyses indicate that kaolinite is the dominant clay mineral (Fig. 11.4) and that clay rarely exceeds 20% by weight of bulk samples — even in siltstone and mudstone (Fig. 11.5).
- Clay conductivity contributes significantly to wireline log response in the low salinity (formation water resistivity ~ 2 – 8 ohm-m @ 25 °C) and high-temperature conditions prevalent in these reservoirs.
- The modified Waxman-Smits equation (calibrated with Eromanga Basin laboratory data) most accurately calculates water saturation in these reservoirs. A reduction in water saturation of 5–15% results from the Waxman-Smits method compared to the commonly used 'Indonesian equation'.

Table 11.1 Summary of Eromanga Basin porosity and permeability data

	Depth (m)	AKHC (mD)	APHC (frac.)	OKHC (mD)	OPHC (frac.)
<i>Murta Formation and McKinlay Member</i>					
214 samples					
Average	1447.5	28.20	0.22	21.03	0.13
Maximum	1804.7	999	0.251	661	0.245
Minimum	1199.4	0.007	0.045	0	0.008
Namur Sandstone					
128 samples					
Average	1499.3	884	0.20	601	0.19
Maximum	1615.4	10 000	0.28	4300	0.239
Minimum	1242.2	0.011	0.1	0.003	0.085
<i>Birkhead Formation</i>					
119 samples					
Average	1667.4	252	0.14	200	0.13
Maximum	2167.4	7620	0.258	4950	0.251
Minimum	1559.8	0.008	0.024	0.001	0.005
<i>Hutton Sandstone</i>					
118 samples					
Average	1801.4	1308	0.21	897	0.19
Maximum	1882.3	9780	0.273	5130	0.244
Minimum	1685.4	0.321	0.083	0.02	0.066
<i>Poolowanna facies</i>					
133 [*] samples					
Average	2310.7	423	0.13	364 [*]	0.08 [*]
Maximum	2667.5	3674	0.219	1917 [*]	0.15 [*]
Minimum	1806.4	0.001	0	0.002 [*]	0 [*]

^{*}Indicates the 29 samples from Beanbush 1 were measured at overburden pressure.

Note: APHC = porosity (ambient pressure); OPHC = porosity (reservoir or overburden pressure); AKHC = Permeability (ambient pressure); OKHC = permeability (reservoir or overburden pressure).

Reservoirs and seals

Poolowanna facies

SEAL

Siltstones within the Poolowanna facies are intraformational seals, but the occurrence of stacked oil pools in fields such as Tantanna (Poolowanna, Hutton, McKinlay and Namur pools) and Taloola (Poolowanna, Hutton and Namur pools) indicates they are not wholly effective. Seal effectiveness is reduced by their limited areal extent, thickness and siltstone mineralogy. In these fields, the thickness of the Poolowanna facies in wells ranges from ~18–25 m while fields where Poolowanna reservoirs exist in isolation, i.e. Cuttapiirie and Mawson, the formation is ~60–75 m thick.

RESERVOIR CHARACTERISTICS

The Poolowanna facies contains the deepest reservoir in the Eromanga Basin, occurring at depths up to 2226 m. Deeper samples show the lowest average porosities due to the formation of quartz overgrowths. Poolowanna facies reservoir sandstones are quartzose with traces of potassium and plagioclase feldspar. Porosity distribution (Fig. 11.6) is a relatively even average of 18%. In thin section, porosity is predominantly primary with some development of secondary porosity via grain dissolution. Permeability distribution (Fig. 11.6) shows a spread of values, but high-permeability samples form a separate population (RES trend). Both CAP and RES trends are clearer on the plot of permeability versus porosity.

Algebuckina Sandstone

SEAL

Thick marine shales of the Wallumbilla Formation and Bulldog Shale form a regional seal to the Algebuckina Sandstone. Siltstones at the base of the Cadna-owie Formation may also act as seals.

RESERVOIR CHARACTERISTICS

The Algebuckina Sandstone has good to excellent porosity and permeability and forms a major artesian aquifer. Few laboratory measurements are available, but log-derived porosities average >20% (e.g. New, 1989). Reservoir properties can also be gauged from aquifer flow rates which are of the order of 500–1000 kL/day (Krieg, 1985).

Hutton Sandstone

SEAL

The Hutton Sandstone is sealed by a capillary type seal within the Birkhead Formation (Boult, 1993), and traps are rarely filled to structural spill point. The Birkhead Formation represents a change from the low-sinuosity fluvial facies of Hutton Sandstone to lower energy, high-sinuosity to lacustrine facies. Within this latter facies there is a sharp change of sediment source from cratonic to volcanic arc provenance (Boult et al., 1997). The contact is diachronous, with localised erosion and channelling on the edge of the basin. Diagenesis of lithic arenites within the volcanic-arc-derived sediment has altered feldspars and rock fragments to a framework of authigenic clays which has closed down pore throats and created a capillary seal (Boult, 1993). Another form of seal is shale interbeds in the lower Birkhead Formation, however these are not laterally extensive or thick enough to be regionally effective seals (Boult, 1993). There are indications that the wettability of the capillary seal within the Birkhead Formation may be changed with the onset of maturation and that prior to maturation, the seal is capable of retaining much larger oil columns than post maturation.

RESERVOIR CHARACTERISTICS

Hutton Sandstone reservoirs consist of mineralogically mature quartz arenites with minor amounts of feldspar (Gravestock et al., 1983). Kaolinite booklets, quartz overgrowths and sericite form the matrix. Excellent reservoir properties are indicated by porosity and permeability distributions (Fig. 11.7).

Birkhead Formation

SEAL

Birkhead Formation sandstone reservoirs are sealed by intraformational shales and diagenetic seals as described above.

RESERVOIR CHARACTERISTICS

In contrast to the Hutton Sandstone, porosity and permeability distributions show considerable spread and a bimodal pattern (Fig. 11.8) encompassing both CAP and RES trends. Birkhead Formation sandstones are lithic arenites with a significant proportion of labile volcanogenic grains (chloritised) and feldspar (kaolinitised). Calcite, siderite and dolomite cements occur, and quartz overgrowths, sericite and kaolinite fill pores.

Namur Sandstone

SEAL

The Namur Sandstone is either sealed by siltstones of the McKinlay Member or by interbedded low-permeability sandstones and siltstones of the lower Murta Formation. In the Murteree Ridge oil fields, seals are not effective and oil trapped in the Namur has migrated upwards along vertically connected sandstone beds into the Murta Formation (Williams et al., 1994).

RESERVOIR CHARACTERISTICS

The Namur Sandstone has similar porosity and permeability distribution to the Hutton Sandstone and plots on the RES trend (Fig. 11.9).

Murta Formation and McKinlay Member

SEAL

Interbedded low-permeability sandstones and siltstones of the lower Murta Formation form capillary seals to the Namur Sandstone and McKinlay Member (Boult et al., 1997). However these seals are not effective, as oil and water from the Namur Sandstone – McKinlay Member pool is produced from the Murta Formation in fields on the Murteree Ridge (Williams et al., 1994). The shaly M1 unit at the top of the Murta Formation forms a regional seal for thin sandstones within the Murta Formation (Williams, 1994) and hence the entire lower non-marine succession of the Eromanga Basin. In South Australia this upper seal is effective — economic accumulations of oil have not been discovered above the Murta Formation.

RESERVOIR CHARACTERISTICS

Murta Formation sandstones are quartz arenites and form two types of reservoirs (Williams, 1994): a high-permeability sandstone (up to 0.3 m thick), and thin low-permeability very fine to fine-grained sandstone interbedded with siltstone (<50 mm thick). Boult et al. (1995) compared core plug and probe permeametry data and concluded that detailed permeametry measurements provided a more accurate reservoir model of a thin-bedded unit like the Murta Formation.

Porosity distribution shows a spread up to a peak of 20% and then an abrupt cut off at higher porosities. Permeability distribution also shows a spread with a peak at 1 millidarcy (mD) and a tail off at higher values (Fig. 11.10); most Murta Formation samples fall on the CAP trend. The transitional nature of the McKinlay Member is reflected by the porosity–permeability continuum from the CAP trend to the RES trend (Fig. 11.10).

Wyandra Sandstone Member of the Cadna-owie Formation

SEAL

Thick marine shales of the Wallumbilla Formation and Bulldog Shale form a regional seal to the Wyandra Sandstone Member and Cadna-owie Formation.

RESERVOIR CHARACTERISTICS

Sandstones are quartzose, with lithics and potassium feldspar (Green, Brain et al., 1989). In Tintaburra 1 (Queensland), sandstones contain up to 40% feldspar and rock fragments and authigenic clay and calcite cement occlude porosity (Newton, 1986). A drillstem test recorded flows of 534 kL oil and 2138 kL water per day through a one-inch choke in Tintaburra 1 (Newton, 1986). Wyandra Sandstone Member forms a significant aquifer in Queensland. In South Australia, drillstem tests in the Cadna-owie Formation have recovered only small amounts of oil, and oil- and gas-cut mud. No core analyses are available for this unit from South Australia, even though it forms an important aquifer within the GAB.

Coorikiana Sandstone

SEAL

Thick marine shales of the Allaru Mudstone and Oodnadatta Formation form a regional seal to the Coorikiana Sandstone.

RESERVOIR CHARACTERISTICS

The Coorikiana Sandstone has not been cored in petroleum drillholes. The formation flowed small amounts of gas on test in Mina 1 and Strzelecki 4 and produced strong gas shows in Marabooka Field (drillstem tests were

unsuccessful). The occurrence of diagenetic calcite cement, coupled with a relatively labile mineralogy (glauconite, feldspar and lithics), indicates that reservoir quality is likely to be extremely variable.

SIMPSON BASIN

Sandstone interbeds within the thick Peera Peera Formation may form reservoirs in shallower parts of the Simpson Basin. Measurements from 11 core samples in Walkandi 1 (2841.7–2850 m), located within the Poolowanna Trough, indicate poor reservoir quality in this relatively deep location. Porosity ranges from 2.8 to 8.8% and permeability from 0.005 to 0.3 mD. No data are available for the Peera Peera Formation at shallower depths or for the underlying Walkandi Formation.

PEDIRKA BASIN

Permian reservoirs in the Pedirka Basin include sandstones within the Crown Point and Purni formations and, in the Eringa Trough, Mount Toondina Formation equivalent. Laboratory measurements for the Mount Toondina Formation equivalent (893.6–903.7 m) and Crown Point Formation (1299–1317.3 m) in Mount Hammersley 1 indicate good to excellent porosities (13.5–24.5%) and permeabilities (91–1998 mD; Fig. 11.11).

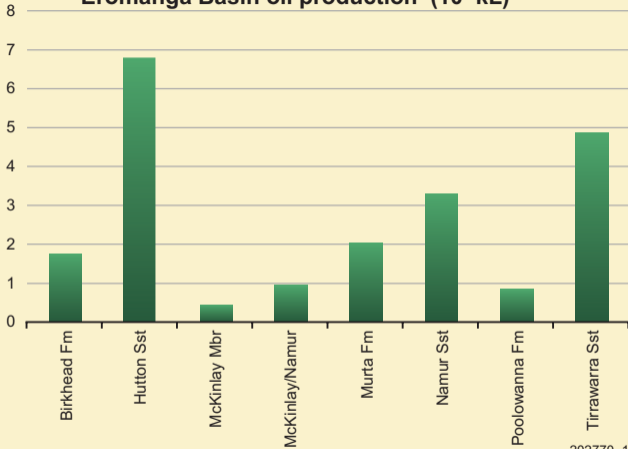
ARCKARINGA BASIN

No laboratory measurements of porosity and permeability are available for Permian formations in the Arckaringa Basin. However, porosity calculated from company log analysis ranges from 10 to 20% (average ~15%) for the Mount Toondina, Stuart Range and Boorthanna formations (Hanns Knob 1; Martin, 1988).

FIGURES

- 11.1 Oil produced from the Eromanga Basin by formation. (202770_137)
- 11.2 Oil and gas fields in the Cooper and Eromanga basins, South Australia. (202770_006)
- 11.3 Porosity–permeability trend of key Eromanga Basin reservoirs. (202770_138)
- 11.4 Distribution of bulk and clay fraction mineralogy in key Eromanga Basin reservoirs. (202770_139)
- 11.5 Distribution of bulk and clay fraction with grain size in key Eromanga Basin reservoirs. (202770_140)
- 11.6 Porosity and permeability distributions and porosity–permeability trend for the Poolowanna Formation. (202770_141)
- 11.7 Porosity and permeability distributions and porosity–permeability trend for the Hutton Sandstone. (202770_142)
- 11.8 Porosity and permeability distributions and porosity–permeability trend for the Birkhead Formation. (202770_143)
- 11.9 Porosity and permeability distributions and porosity–permeability trend for the Namur Sandstone. (202770_144)
- 11.10 Porosity and permeability distributions and porosity–permeability trend for the Murta Formation and McKinlay Member. (202770_145)
- 11.11 Porosity–permeability trend (ambient) for the Crown Point Formation and Mt Toondina Formation equivalent, Mt Hammersley 1. (202770_146)

Eromanga Basin oil production (10⁶ kL)



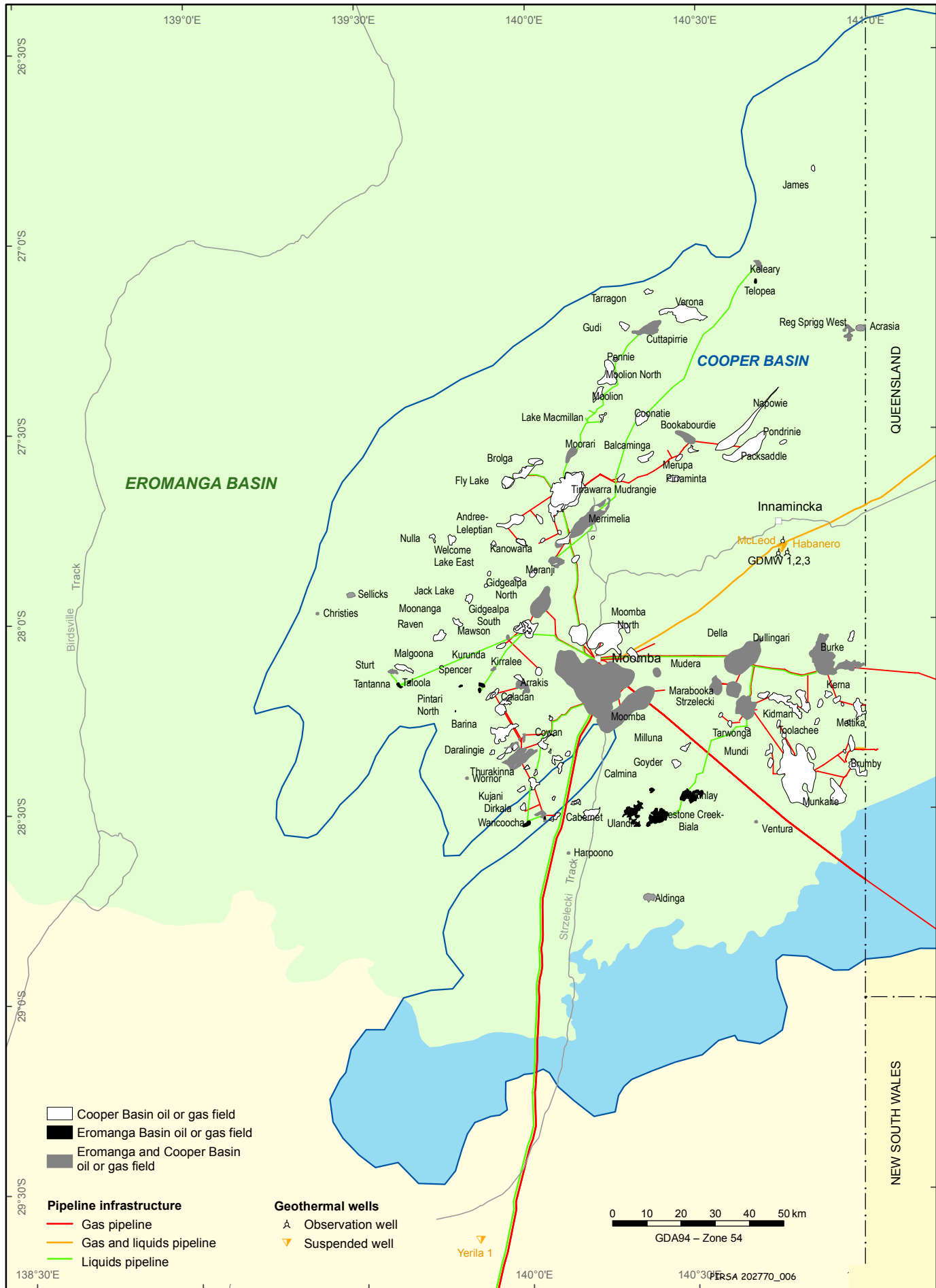
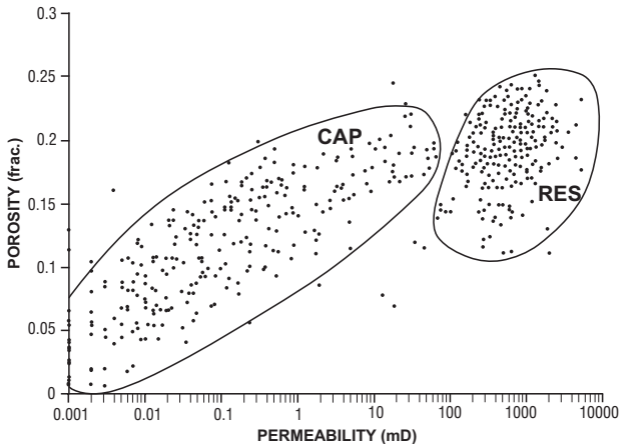
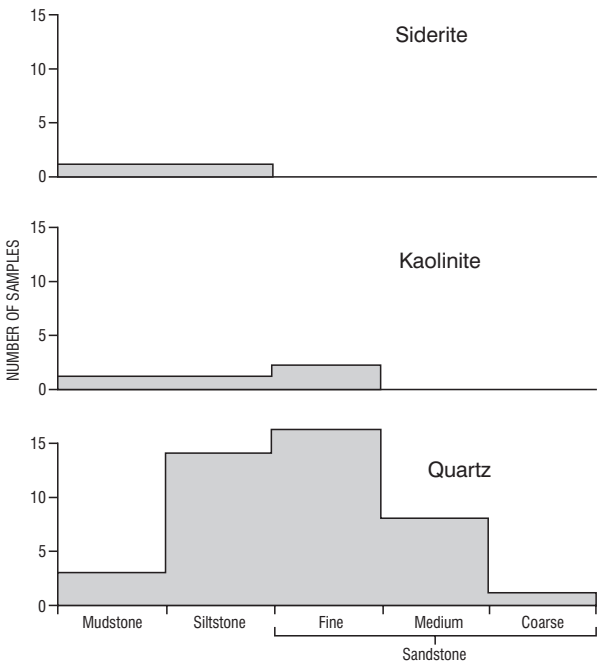


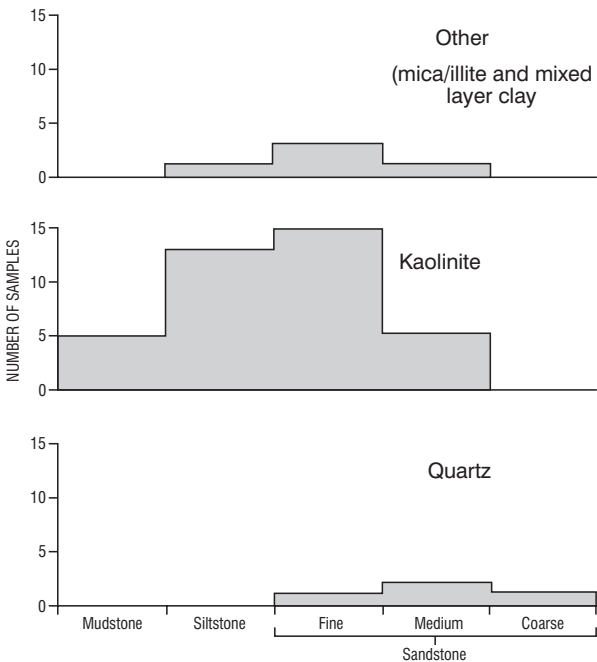
Figure 11.2 Oil and gas fields in the Cooper and Eromanga Basins, South Australia

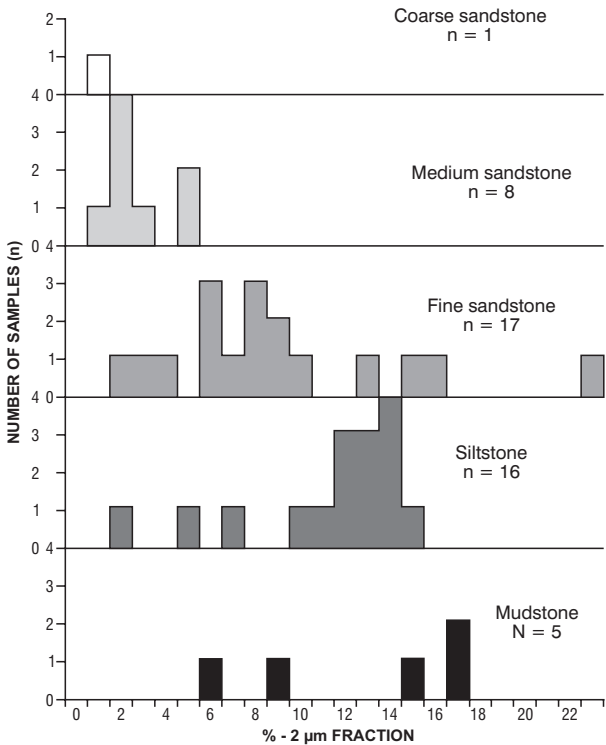


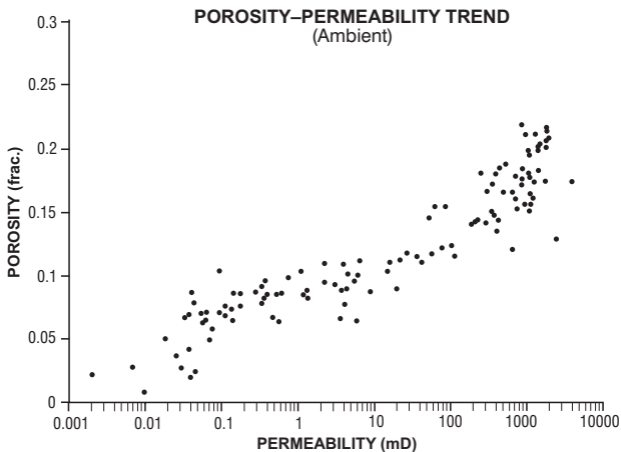
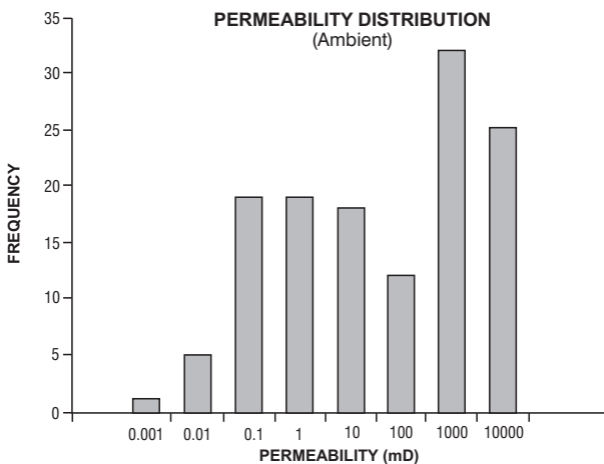
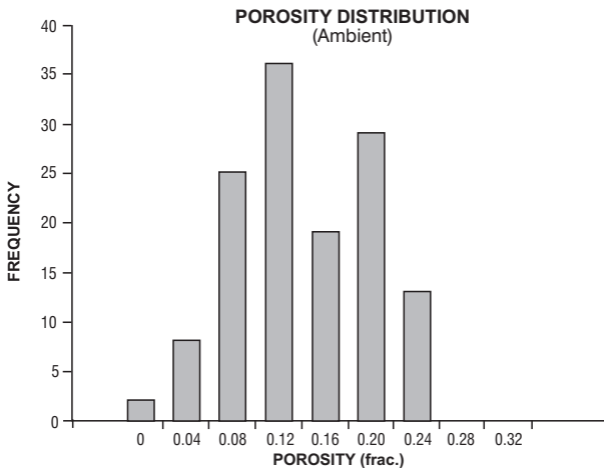
BULK SAMPLE



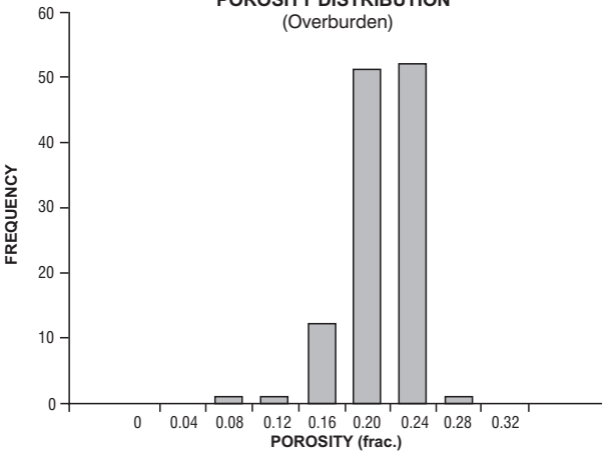
- 2 μm FRACTION



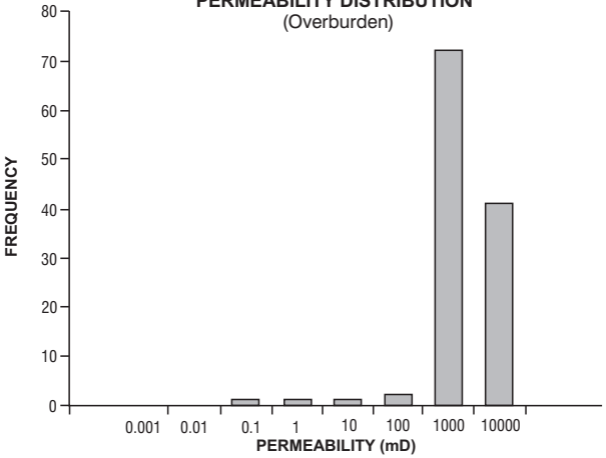




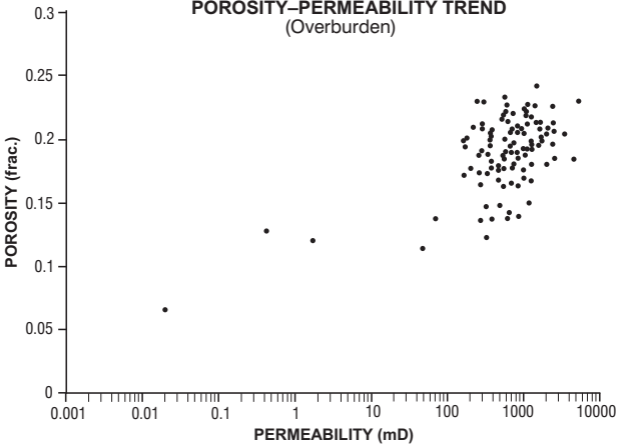
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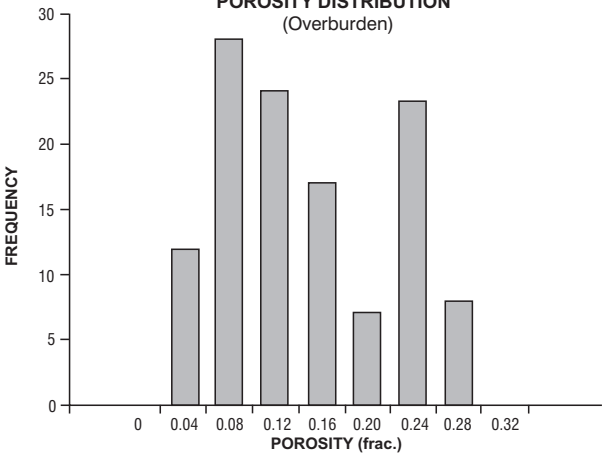
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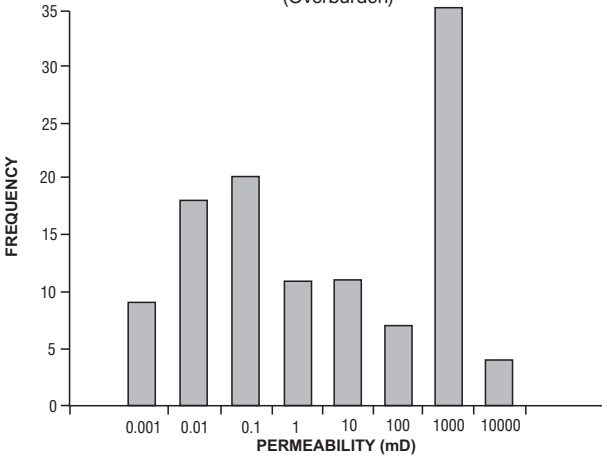
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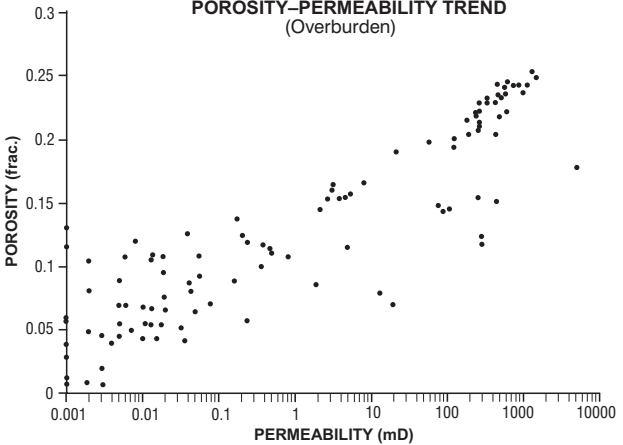
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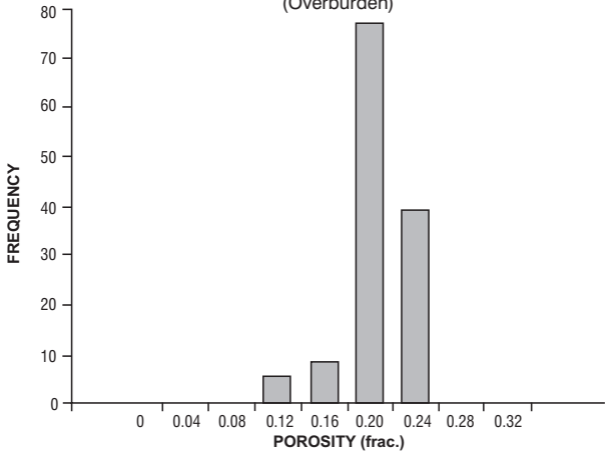
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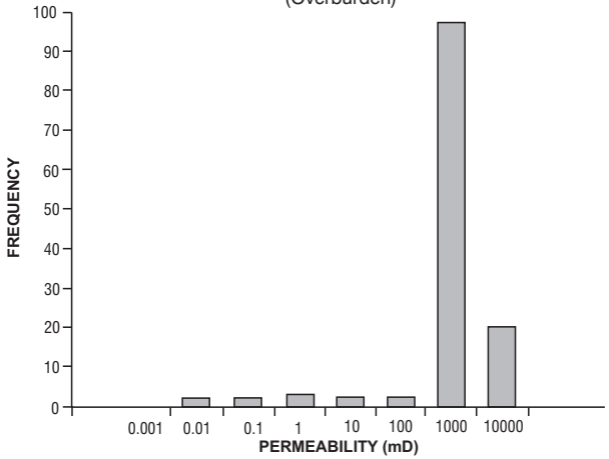
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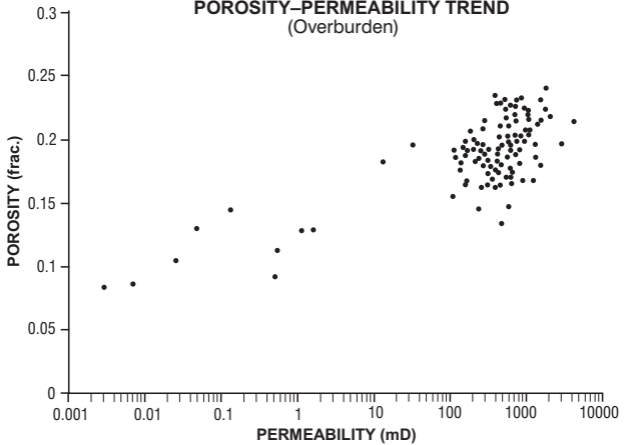
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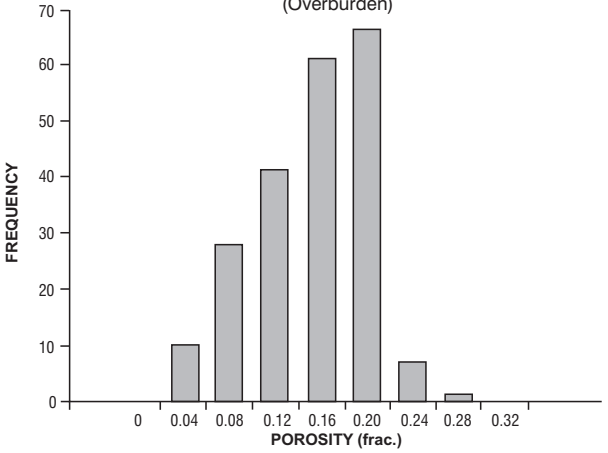
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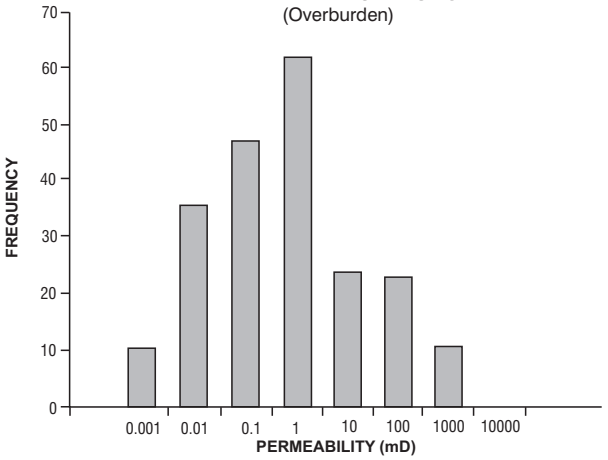
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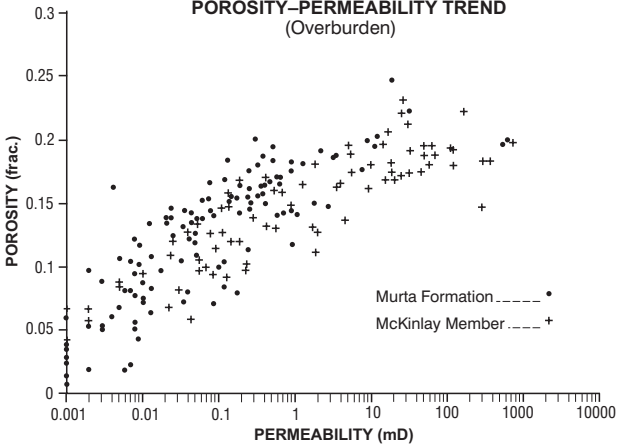
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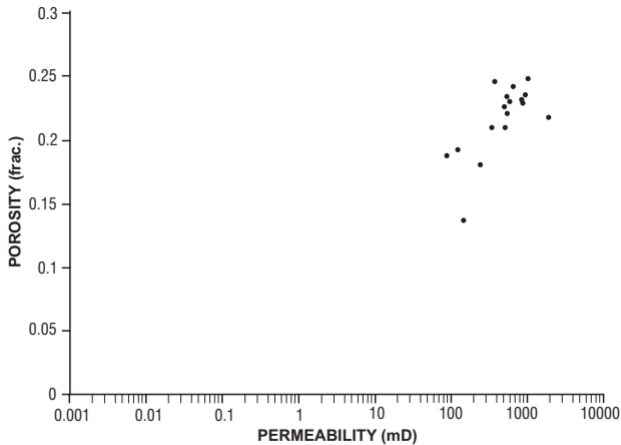


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