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A potential dolostone reservoir in the Georgina Basin: the Lower Ordovician Kelly Creek Formation

B. M. Radke & P. Duff

The extensive dolostone unit of the Lower Ordovician Kelly Creek Formation in the Toko Syncline, Georgina Basin, has significant potential as a hydrocarbon reservoir with variable porosity and permeability characteristics. The porous dolostone is 107 metres thick. Measured porosities of 19 core plugs from this section average 11 per cent, average horizontal permeability (gas) was 234 md, and vertical permeability (gas) 28 md. Permeability is more variable vertically, being generally low but with random higher values. Porosity is dominantly intercrystalline in mottled and stratified distribution, with associated vug, channel, fracture and breccia types; the porosity developed late in diagenesis, during and after pervasive dolomitisation of the sequence. The dolostone interdigitates with overlying thin calcareous dolomitic sandstone beds which have higher porosity (19%) and permeability (Ka_H 270 md, Ka_V 54 md). Traces of liquid hydrocarbons in the dolostone and previously reported gas flows from the overlying sandstone in AOD Ethabuka No. 1 indicate significant potential for these porous units as a reservoir in suitable structural traps.

Introduction

The Georgina Basin has, overall, been regarded as having low potential for hydrocarbon accumulations because of the thin sequence and apparent fresh-water flushing in near-surface aquifers, even though traces of oil and bitumen have been found in previous drilling (Smith, 1972). The greatest potential in the basin is in the Toko Syncline (Fig. 1) in which the Cambrian-Ordovician sequence thickens to the southeast where it is covered by the Eromanga Basin. Anticlinal structures have been seismically defined at depth in the syncline, adjacent to the overthrusted western margin (Alliance Oil Development, 1975; Harrison, 1979). On the Ethabuka Structure, a moderate gas flow (estimated at 7080 m^3/day from open hole) was produced from a Lower Ordovician sandstone in AOD Ethabuka No. 1 (Alliance Oil Development, 1975), and bitumens were reported at and below the same interval in GSQ Mount Whelan 2 (Green & Balfe, 1980). The Geological Survey of Queensland drilled GSQ Mount Whelan 1 and 2 on the eastern limb of the Toko Syncline, to provide stratigraphic control for a concurrent BMR seismic survey across the syncline. This drilling enabled appraisal of hydrocarbon potential of the sequence from core examination. Harrison (1979, Table 1) considered likely caprocks to be the Nora and Mithaka Formations, and potential reservoirs to include the Georgina Limestone, Ninmaroo and Kelly Creek Formations. The Kelly Creek Formation has the greatest potential because of the gas flow from its upper sandstone unit, and a thicker porous dolostone immediately beneath.

Carbonates, as reservoirs, tend to have more varied and unpredictable petrophysical properties than sandstones (Landes, 1946); consequently our study was aimed at evaluation of the porous dolostone unit of the Kelly Creek Formation and Ninmaroo carbonates,

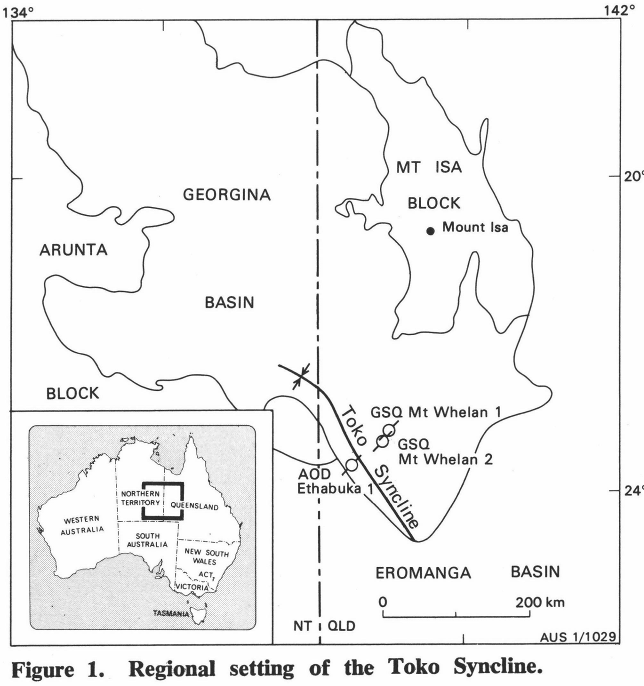

Figure 1. Regional setting of the Toko Syncline.

Formation	Rock type	Depth metres	Sample length cms	Apparent grain density	Effective porosity % B.V.	Permeability (gas) horizontal position A	position B	md vertical	Porosity type Inter particle	Moldic	Inter-crystal	Vug	Channel	Breccia fracture	Porosity distribution
	POROUS, DOLOMITIC SANDSTONE	450.74	13	2.84	19.3	241	306	54	X	XXX					Uniform
Kelly Creek Formation	POROUS, CALCAREOUS DOLOSTONE	473.94	14	2.81	12.7	12	7	1.8			XXXX				Mottled, following bioturbation; stylolite confined.
		476.44	19	2.82	9.8	77	92	0.4			XXXX	X			Mottled, following bioturbation and sulphate fabric; stylolite confined.
		485.40	9	2.84	5.6	43	<	0.2				XXXX			Stratiform along bedding.
		492.78	12	2.84	5.8	4.4	18	<			XX	XXX			Localised patches.
		494.88	21	2.80	13.7	156	186	19			XXXX	X			Interconnected mottling.
		501.35	17	2.80	1.05	<	<	<				XXXX			Scattered ?fenestrae.
		505.69	9	2.89	11.5	24	23	1.9			XXXX	X			Mottled (30% rock).
		508.32	15	2.86	13.9	111	346	12			XXXX	X		X	Mottled (bitumen stained).
		515.05	13	2.83	10.5	308	4.3	0.8			XX		XX	X	Mottled; stylolite confined.
		517.33	17	2.79	13.1	73	93	2.0			XXXX	X		X	Mottled; stylolite confined.
		530.07	13	2.81	16.5	287	387	17			XXXX	X	X		Follows bedding and in matrix of a conglomerate.
		541.23	25	2.80	6.4	144	245	0.1			XX	X	XX		Stratified.
		552.16	14	2.85	17.0	556	791	336			XXXX	X	X		Pervasive.
		553.73	15	2.87	11.4	428	390	72			XX		XXX		Cement-occluded in patches.
		563.66	8	2.81	17.0	351	320	18			XXXX				Mottled, variable with bedding.
		571.53	11	2.85	11.2	298	198	<			XX	XX			Bands occluded by anhydrite; bitumen staining; sphalerite.
		573.30	28	2.81	10.8	215	208	0.4			XXXX	X			Follows lamination.
		577.17	19	2.79	15.0	159	142	3.1			XX	X	X	X	Mottled, variable with bedding.
		580.72	4	2.79	6.3	1160	521	43			XX			XXX	Random intercrystal patches.
Ninmaroo Formation	POROUS, DOLOMITIC CALCAREOUS SANDSTONE	709.16	14	2.82	24.3	271	314	144	XXXX	X					Pervasive.

Comments. 1. X — 0-25%; XX — 25-50%; XXX — 50-75%; XXXX — 75-100%; < — less than 0.1. 2. Common range of Apparent Grain Densities (Core Laboratories, pers. comm.): limestone 2.68-2.76; dolostone 2.78-2.82 (2.86-2.93 — Deer & others, 1962); limestone/dolostone 2.72-2.80; sandstone 2.65. 3. Core diameter 48 mm. 4. Whole core analysis procedure of Bynum & Koepf (1957), American Petroleum Institute (1960). 5. Horizontal permeabilities of orthogonal directions, A & B. 6. $\frac{\text{Kbrine}}{\text{Kgas}}$ was 38% for Kgas 144 md; 17% for Kgas 72 md.

Table 1. Porosity and gas permeability characteristics, GSQ Mount Whelan No. 2.

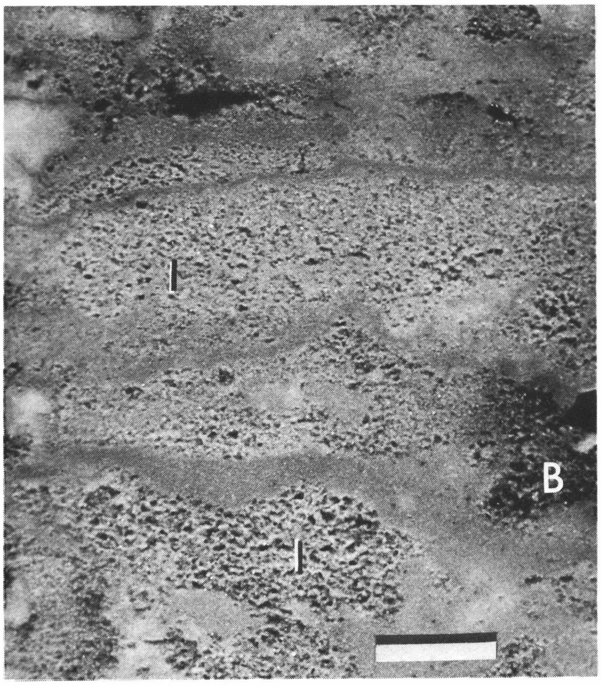

Figure 2. Intercrystalline porosity (I) comprising small and large mesopores in the dolostone, confined by thin, less permeable laminae. Embayed area of porosity is bitumen-stained (B). ϕ16.5%, Ka_H337 md, Ka_V 17 md. Bar scale 1 cm. Core slab from GSQ Mount Whelan No. 2, 530.07 m.

based on whole-core petrophysical analysis of material from GSQ Mount Whelan 2.

This note outlines the petrophysical and petrographic characteristics of the Kelly Creek dolostone unit. For a lithological comparison, characteristics are given for two porous sandstones that are in close proximity to the dolostone. Ninmaroo carbonates were characteristically much lower in porosity and consequently are not included.

The Kelly Creek dolostone unit is apparently continuous throughout the Toko Syncline, and has been mapped from the west around to the eastern limb as the Withillindarmna Dolostone Member (Druce, pers. comm.). The unit was intersected over 107 m in GSQ Mount Whelan 2 (Green & Balfe, 1980), and 103 m in AOD Ethabuka No. 1 (Alliance Oil Development, 1975), overlying limestone or calcareous sandy dolostone and interdigitating upwards into a calcareous dolomitic sandstone.

In this note, porosity terminology follows that of Choquette & Pray (1970).

Petrophysical and petrographic characteristics

Dolostone

Average petrophysical values (19 whole core plugs) for the interval of dolostone from 473.94 to 580.72 m (Table 1) are:

Effective porosity (Ø) 11%
Horizontal permeability (Ka_H) 234.4 md
Vertical permeability (Ka_V) 27.8 md

Porosity is dominantly intercrystalline throughout the unit, with lesser vug, channel, fracture and breccia types. In the reduction or absence of intercrystalline porosity and permeability from 501.35 to 485.40 m, vug porosity is dominant. Channel and fracture porosity occur only in the lower part of the unit below 508 m.

Intercrystalline porosity is in small and large mesopores (Fig. 2) which were solution-enlarged prior to subsequent reduction by further growth of dolomite rhombs. This porosity occurs in an idiotopic dolostone host and where well developed, is pervasive and uniform in distribution, obliterating primary structures. More commonly intercrystalline porosity is not pervasive, but has a mottled distribution selectively following bioturbation or sulphate-crystal pseudomorphs, or is laminated and stratified where it selectively follows specific lithologies. Vugs are an extension of intercrystalline porosity where leaching has enlarged the pores to large meso or megapore size (Fig. 3). Where vugs have stratified distribution and have coalesced, channel porosity developed. Fracture and breccia porosity have limited random distribution, usually cutting across impermeable beds and interconnecting other porosity types.

Permeability data indicate good horizontal permeability which generally increases towards the bottom of the unit, but a lower and more variable vertical component. Stratification from alternating permeable-impermeable beds or laminae causes this. Localised vertical impermeability is controlled by these bedding variations, and by stylolites lined with insolubles and bitumen residues. These stylolites are probably discontinuous laterally over several metres. Where porosity is in irregular or embayed patches, bitumen plugging and probable oil staining is common. This bitumen may have been emplaced as a residual product during hydrocarbon migration through the zone.

Dolomitic sandstone

Porous dolomitic sandstone was sampled from two horizons, one from the upper unit of the Kelly Creek Sandstone above the dolostone (450.74 m), the other

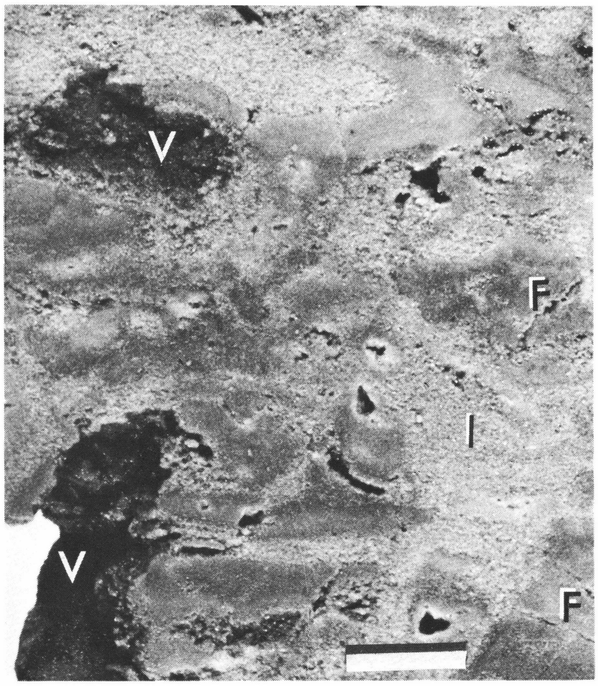

Figure 3. Vug (V), intercrystalline (I), and fracture (F) porosity in the dolostone. ϕ15%, Ka_H 151 md, Ka_V 3.1 md. Bar scale 1 cm. Core slab from GSQ Mount Whelan No. 2, 577.17 m.

below (709.16 m) at the top of the Ninmaroo Formation. These sandstones have high porosities (19-20%) and permeabilities (both horizontal, Ka_H 241-314 md, and vertical Ka_V 54-144 md). Porosity in this rock type results from a combination of primary interparticle and secondary moldic components. Moldic porosity has apparently formed after carbonate particles in the sandstone have been leached out. Interparticle pores are partially reduced by carbonate cements.

Porosity history

Porosity in the dolostones is entirely secondary and developed during and after dolomitisation of the host limestones. While dolomite precipitated as replacement euhedral rhombs, interstitial and host carbonate was being leached more readily, producing intercrystalline porosity. Further enlargement of these pores by both dissolution and collapse has produced vugs and channels. Counteracting this solution-enhancement process has been later reduction and even occlusion of porosity by precipitation of cements—mostly calcite and saddle dolomite, with some anhydrite and traces of pyrite and low-iron sphalerite. This mineral suite is epigenetic, generally related to hydrocarbon migration (Dunsmore, 1973; Radke & Mathis, in press) or post-dating it. Evidence for this is the lack of hydrocarbon staining on these later cements which have precipitated from fluids migrating through the permeable zones. It is most likely that, where traps developed after the first dolomitisation phase, accumulation of hydrocarbons has reduced water saturation in the porosity, thus preventing subsequent occlusion of porosity by these later cements.

Discussion

Hydrocarbon reservoirs in carbonates, where porosity has resulted from dolomitisation, have previously been unknown in Australia although they are common in North America. Examples of such reservoirs are the Clear Creek field, Williston Basin (Stout, 1964); Trenton field, Ohio and Indiana; Adams and Deep River fields in Michigan (Landes, 1946); and 'Midale' carbonates, southeastern Saskatchewan (Robinson, 1966). A common characteristic of such fields is the unpredictability of porous pay zones (Landes, 1946). However, average porosities of such carbonate petroleum reservoirs is between 5 and 15 percent (Choquette & Pray, 1970).

The Kelly Creek dolostone is comparable to these reservoirs in having an average porosity of 11 percent, variability in porosity distribution, and consequently permeability variations. This variability is on the mesoscopic scale (whole core), but over larger areas may still be effective because of randomly distributed fracture and breccia porosity which is penetrative, interconnecting porous patches that would be otherwise isolated by impermeable beds or stylolites.

Interdigitation of permeable dolomitic sandstones above is an ideal relationship where the sandstone acts as an extensive stratiform conduit that could localise hydrocarbons from the thicker dolostone below. The gas flow in AOD Ethabuka No. 1 was from this sandstone, called Coolibah Formation by Alliance Oil Development (1975). Apart from poor cut and bitumen traces, no oil was recorded from the dolostone in this well and no electric logs were run to this level because of drilling problems. Core from the dolostone in GSQ Mount Whelan 2 has considerable surface hydrocarbon staining and residual hydrocarbons were extracted, indicating an 'oil' saturation of 0.7 percent two years after drilling. This oil comprises 28 percent saturated, 15 percent aromatic and 57 percent polar compounds, had a density of 0.9485 $gm.cc^{-1}$, and a pristane/phytane ratio of 2.5, which is comparable to other hydrocarbons extracted from the sequence in GSQ Mount Whelan 1 and 2 (K. Jackson, pers. comm.).

In conclusion, our data indicate that the dolostone unit of the Kelly Creek Formation has significant porosity and permeability. Recurring evidence of hydrocarbons in the unit implies its potential as a carbonate reservoir in a suitable structural setting.

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