Marine and Petroleum Geology 77 (2016) 597–624

Contents lists available at ScienceDirect

Marine and Petroleum Geology

journal homepage: www.elsevier.com/locate/marpetgeo

Research paper

Sedimentological control on the diagenesis and reservoir quality of tidal sandstones of the Upper Cape Hay Formation (Permian, Bonaparte Basin, Australia)

Jessica Saïag [a, 1], Benjamin Brigaud [a, *], Éric Portier [b], Guy Desaubliaux [b], Agathe Bucherie [b], Serge Miska [a], Maurice Pagel [a]

[a] GEOPS, Univ. Paris-Sud, CNRS, Université Paris Saclay, Rue du Belvédère, Bât. 504, 91405, Orsay, France
[b] ENGIE EPI, 1 place Samuel de Champlain – Faubourg de l'Arche, 92930, Paris La Défense Cedex, France

A R T I C L E I N F O

Article history:
Received 10 March 2016
Received in revised form
28 June 2016
Accepted 4 July 2016
Available online 7 July 2016

Keywords:
Sandstone
Petrography
Permian
Bonaparte Basin
Reservoir
Clay coating
Diagenesis

A B S T R A C T

The deep siliciclastic reservoir (>3500 m) of the Upper Cape Hay Formation of the Bonaparte Basin (Petrel gas field, Petrel sub-basin, Permian) exhibits wide heterogeneity in porosity (2–26%) and permeability (0.001–2500 mD). To investigate this variability, 42 samples were taken from five wells drilled through this formation. Six facies were identified from core descriptions and microscopic study of the sandstones. These facies are typical of a tide-dominated estuary, and include (1) mud flat, (2) sand flat, (3) top of tidal sand bar, (4) middle of tidal sand bar, (5) bottom of tidal sand bar, and (6) outer estuary facies. The paragenetic sequence comprises the emplacement of early aggregates of ferrous clay mineral precursors, mechanical compaction, recrystallization of those ferrous clay mineral precursors to Fe-rich chlorite and crystallization of Fe-rich chlorite forming coatings around detrital grains, chemical compaction, development of quartz overgrowth, feldspar alteration, crystallization of dickite and illite-rich illite/smectite (I-S) mixed layers, and ferrous calcite cementation. The middle and top of the tidal bars generally exhibit the highest porosity ($\Phi > 10\%$) and permeability values ($k > 1$ mD). Feldspar alteration released silica and aluminium into the reservoir promoting the development of dickite and illite-rich I/S mixed layers, which tended to destroy porosity and permeability, as calcite cements and quartz overgrowths. Diagenetic chlorite coatings around detrital grains are restricted to the sand bar facies deposited at the end of the last third-order transgressive systems tract of the Cape Hay Formation. The formation and conservation of ferrous clay precursors seems to be possible in an estuarine environment where seawater and fresh water are mixed and tidal sand bars are formed. These ferrous clay precursors recrystallized to Fe-rich chlorite coating after mechanical compaction. These coatings inhibited quartz cementation and prove to be the key parameter behind good reservoir qualities.

1. Introduction

Porosity and permeability are one of the major uncertainities in hydrocarbon or geothermal exploration and production. Reservoir quality is difficult to predict because it depends on both the initial depositional conditions and the diagenetic history of the sedimentary formation (Morad et al., 2000). The initial porosity of sand is typically about 40% during deposition and declines with depth following the general curve of porosity loss with depth (Sclater and Christie, 1980; Halley and Schmoker, 1983; Ehrenberg and Nadeau, 2005; Bjørlykke, 2014). The initial porosity and permeability of a sediment are governed primarily by grain size, sorting, shape, mineralogy and sedimentary structures and therefore by depositional environment. The physical, chemical and biological processes affecting sediment after its deposition vary with the temperature, pressure and chemistry of fluids related to the burial history of the sedimentary basin (e.g. Loucks et al., 1984; Bjørlykke, 2014). The nature of fluids percolating through the reservoir during burial is also a key factor that modifies the chemistry of the reservoir system (Bjørlykke, 1993). Reservoir quality can be destroyed by quartz cementation and compaction, or preserved through the absence of

* Corresponding author.
E-mail address: benjamin.brigaud@u-psud.fr (B. Brigaud).
[1] Present address: Biogéosciences, UMR 6282, Univ. Bourgogne Franche-Comté, 6 Bd Gabriel, 21000, Dijon, France.

http://dx.doi.org/10.1016/j.marpetgeo.2016.07.002
0264-8172/

cementation or enhanced by mineral dissolution (Worden and Morad, 2000). The intensity of these diagenetic processes increases overall with increasing temperature and pressure during burial. Generally, deep burial diagenesis reduces the porosity of sandstones through two major processes: (i) compaction, which is a physical and chemical process governed by lithostatic/hydrostatic pressure and (ii) the formation of authigenic cements, especially quartz overgrowth, which is a chemical process governed by the pressure-temperature-chemistry history of the sediment in the course of burial (Worden and Morad, 2000; Bjørlykke, 2014). In some instances, abnormal high porosity of deep siliciclastic rocks (>3500 m) as observed in the North Sea, implies that other parameters should be taken into account (e.g. Ehrenberg, 1993). The presence of well-developed clay coatings around detrital grains or the presence of microquartz around quartz grains and/or fluid overpressure are factors recognized as inhibiting siliceous cementation and so preserving porosity (Heald and Larese, 1974; Wilson and Pittman, 1977; Pittman et al., 1992; Ehrenberg, 1993; Billault et al., 2003; Gould et al., 2010; Ajdukiewicz and Larese, 2012; Dowey et al., 2012; Worden et al., 2012; Bahlis and De Ros, 2013). By contrast, the presence of a fine tangential coating of illite promotes pressure-dissolution between detrital quartz grains, thus reducing porosity (Tournier et al., 2010). Diagenesis may lead to a marked increase in porosity through the creation of secondary porosity further to the late dissolution of detrital grains (feldspars) or cement (carbonate), thereby improving reservoir quality (Henares et al., 2014). The physical and chemical processes are therefore multiple and quite complex. It is therefore fundamental for the exploration of deep clastic reservoirs (>3500 m) to be able to constrain and predict the distribution of diagenetic processes such as the development of grain coatings or shallow (<1500 m) development of fluid overpressure (Bloch et al., 2002).

The tidal sandstones of the Cape Hay Formation (Permian) of the Petrel gas field in the Bonaparte Basin (Northern Australia) are deeply buried (>3500 m; pressures of 350 bars and temperatures of 130 °C; Bhatia et al., 1984; Kloss et al., 2004). This clastic reservoir was subjected to a high diagenetic overprint resulting in marked reservoir heterogeneity, with porosity (Φ) ranging from a few percent up to 25%, and permeability (k) varying from 0.001 mD to several hundred milliDarcy (Robinson and McInerney, 2003). These values are abnormal at these depths and correspond to porosities usually encountered at depths of 1000 m. However, over the reservoir as a whole, porosities are far lower (<10%) and the values correspond to what would be expected at this depth. This field is therefore a prime subject for investigating the impact of sedimentology and diagenesis on reservoir properties. Initial studies by Bhatia et al. (1984) indicate that sedimentology influences the evolution of sandstone diagenesis although no trend has yet been clearly identified. The objective of this study is to better determine the depositional environments and the diagenetic sequence of the Upper reservoir zone of the Cape Hay Formation (Kloss et al., 2004) in order to constrain the reservoir quality. The previous study by Bhatia et al. (1984) suggested the potential impact of clay coating on reservoir heterogeneity. Other objectives of this study are: (1) to evaluate the role of clay coatings in burial diagenesis, (2) to propose a reliable depositional environment for early clay mineral precursors, (3) to propose a timing for the chloritization process, and (4) to link reservoir quality to depositional facies and early and burial diagenetic processes. This study should provide insight into the connections between sedimentation, diagenesis and the preservation of reservoir qualities in the course of basin history since the Permian and should also indicate whether a particular sedimentary environment engenders a particular diagenetic evolution. This connection is an interesting challenge to better predict and better model reservoir levels.

2. Geological setting

The Petrel gas field lies offshore, 260 km WSW of Darwin in northern Australia on the boundary between West Australia and the Northern Territory (Earl, 2004). It is located in the Joseph Bonaparte Basin, in the centre of the Petrel Sub-Basin (Earl, 2004; Zhixin et al., 2012; Seebeck et al., 2015; Fig. 1). The 329 000 km^2 Bonaparte Basin is an established petroleum province of the NW Australia platform, reportedly containing about 500 million barrels of petroleum reserves, about 500 million barrels of condensates and about 4000 million barrels of oil equivalent of natural gas (Earl, 2004). In the Petrel Sub-Basin, the reserves of gas in the Permian petroleum system are located in three fields (Petrel, Tern and Blacktip; Figs. 1 and 2). The reserves of gas within the Petrel field are estimated to be about 100 million barrels of oil equivalent of natural gas (Earl, 2004). The Petrel Sub-Basin (Fig. 1) is an asymmetric northwest trending aborted rift of Late Devonian–Carboniferous age (Gunn, 1988; Earl, 2004). The Petrel Sub-Basin preserves considerable (>15 km) sedimentary deposits from Devonian to Holocene in age (Baldwin et al., 2003; Earl, 2004). It is bounded to the south by the Precambrian basement. Sedimentation in the Petrel Sub-Basin began with a pre-rift sequence composed of extensive evaporite deposits, but their age is poorly known (Ordovician, Silurian or Devonian, Kennard et al., 2002). From Mid-Devonian to Carboniferous times, the zone was controlled by NE–SW crustal spreading forming a series of NW–SE-trending rifts along the Australian margin, in the Petrel Sub-Basin (Earl, 2004). This extensional phase can be correlated with rapid southward drifting of the Australian plate (Gunn, 1988). A sizeable clastic and carbonate series was deposited during the syn-rift phase in fluvial to shallow marine environments. This period was marked by basin subsidence (Kennard et al., 2002). From the Late Carboniferous to the onset of the Permian, a NE–SW extension along the Australian plateau, north of the Bonaparate Basin, in the vicinity of Timor, reactivated the aborted rift faults of the Petrel Sub-Basin (Earl, 2004). This Westralian phase is related to the rupture of the continental crust and the Neo-Tethys ocean floor, which propagated along the Australian margin (Kennard et al., 2002). From the Carboniferous to the Trias, post-rift sediments filled the Petrel Sub-Basin with thermal subsidence (Kennard et al., 2002). In the Late Trias and Early Jurassic, regional uplift and compression movements occurred on a large scale. These events have been correlated with the Fitzroy movements, which are well described by O'Brien et al. (1996). From the mid-Jurassic to the Tertiary, the Sub-Basin experienced the final period of subsidence, evolving into a passive margin as the Australian plate drifted northwards towards its current position. Fault reactivation (Westralian and Fitzroy) and sediment overburden (syn-rift subsidence and post-rift thermal subsidence) caused the evaporites deposited in Ordovician–Silurian times to flow in several successive phases, forming slugs and diapirs, particularly in the vicinity of Sandpiper and Tern wells (Lemon and Barnes, 1997). This salt tectonism generated the traps in the Petrel Sub-Basin. This rising of salt created small depressions laterally, hence the antiform of the Petrel field due to accommodation. This salt tectonism has been modelled by Lemon and Barnes (1997).

3. Sedimentological context

The Permian deposits are subdivided lithostratigraphically into four components, the Treachery Shale, the Keyling Formation, the Fossil Head Formation and the Hyland Bay sub-group (Fig. 2; Bhatia et al., 1984; Kloss et al., 2004). The Hyland Bay sub-group comprises six formations (Gorter, 1998): Torrens, Pearce, Cape Hay, Dombey, Tern and Penguin (Fig. 2). These lithostratigraphic units have been