Fluid overpressure as a control on sandstone reservoir quality in mechanical compaction dominated setting: Inferences from the Magnolia Field, Gulf of Mexico

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Running title: effect of fluid overpressure on reservoir quality

ABSTRACT

The reservoir quality (porosity and permeability) of deeply buried hydrocarbon reservoir sandstones in sedimentary basins is significantly affected by burial diagenesis. Many deep reservoirs develop anomalous fluid overpressures during burial. Previous studies on the effect of fluid overpressure on reservoir quality in these deep reservoirs have been inconclusive because of the difficulty in constraining the individual contributions of various porosity preserving factors which are simultaneously active in these reservoirs. Owing to its rapid burial and low burial temperatures, the Neogene turbidite sandstone reservoirs from the Magnolia Field, Gulf of Mexico, offers a unique opportunity to investigate in isolation the effect of fluid overpressure on reservoir quality. Examination of petrography, pore pressure, and routine core analysis datasets showed a positive correlation between high fluid overpressure and enhanced reservoir quality. This study confirms that fluid overpressure preserves reservoir quality in deeply buried sandstone reservoirs in compaction dominated, high sedimentation basin settings.

Introduction

As the quest for hydrocarbons moves into deeper and more complex petroleum basins, understanding the evolution of reservoir quality in sandstone reservoirs that have been exposed to high pressures and high temperatures for significant periods of geological time becomes paramount. Deeply buried sandstones are often expected to have poor reservoir quality as a result of porosity and permeability loss during burial compaction and later stage chemical compaction (e.g. Ehrenberg and Nadeau, 2005, Bjorlykke, 2014). In normally pressured reservoirs, upon burial, sediments will compact mechanically when the effective stress (expressed as the difference between mean stress and pore pressure acting on the sediments) due to the deposition of overburden increases, so that the porosity is reduced.

Mechanical compaction in sandstones is dominant to burial depths of ~2 km (>70-80 °C) (Bjørlykke, 1999, Bjorlykke, 2014). The porosity loss in sandstones is also very sensitive to grain size and sorting (Nagtegal, 1979, Bloch, *et al.*, 2002, Chuhan, *et al.*, 2002). Furthermore, poorly sorted sandstones have much lower starting porosity than well sorted sandstones but show less porosity loss by mechanical compaction (e.g. Fawad, *et al.*, 2010, Fawad, *et al.*, 2011). Commonly at burial depths greater than ~2 km (>70-80 °C) chemical compaction becomes an important process and is thought to be independent of effective stress (e.g. Walderhaug and Bjørkum, 2003). The transport and precipitation of silica from the adjacent shales (mudrocks) during illite to smectite transformation has also been attributed to the porosity loss and cementation in deeply buried sandstones (Boles and Franks, 1979, Sullivan and McBride, 1991). Conversely, localised pressure solution in the chemical compaction regime during burial has been credited to widespread quartz cementation and porosity loss in sandstones (Renard, *et al.*, 2000, Worden and Morad, 2000, Sheldon, *et al.*, 2003).

Factors such as the presence of clay mineral coats, microcrystalline quartz coats, early emplacement of hydrocarbon, presence of salt related thermal anomalies, mineral dissolution, and fluid overpressures can all play a crucial role in preserving anomalous high porosity in sandstones (e.g. Spotl, *et al.*, 1994, Worden and Morad, 2000, Taylor, *et al.*, 2010, Wilkinson and Haszeldine, 2011, Sathar, *et al.*, 2012, Nguyen, *et al.*, 2013). Fluid overpressure, defined as the excess pore pressure above the hydrostatic pressure for a given depth, is commonly encountered in deep High Pressure High Temperature (HPHT) reservoirs (Osborne and Swarbrick, 1999). Mechanisms such as disequilibrium compaction, tectonic compression, aquathermal expansion, volume expansion due to clay diagenesis, mineral transformations, kerogen maturation, gas generation, and buoyancy effects occurring in reservoirs can lead to fluid overpressures in subsurface reservoirs (Osborne and Swarbrick, 1997).

Previous studies on the effect of overpressure and its influence on reservoir quality has been inconclusive because under reservoir conditions, a multitude of factors act jointly to preserve reservoir quality (Osborne and Swarbrick, 1999, Bloch*, et al.*, 2002, Taylor*, et al.*, 2010), and isolating individual contributions of these factors in the evolution of reservoir quality is problematic. Ramm and Bjorlykke (1994) and Wilson (1994) reported relatively high porosity in highly overpressured reservoirs in the Haltenbanken area, Offshore Norway and in the Jurassic sandstones from the Viking Graben, North Sea respectively. Similarly, reduced amount of quartz cement was observed in overpressured HPHT reservoirs when compared to the normally pressured reservoirs in the Fulmar Formation, Central North Sea (Osborne and Swarbrick, 1999). However the relative contributions of different factors in porosity preservation were impossible to constrain in these studies because of the complex burial diagenesis that the sediments had undergone.

In this study, datasets from the Magnolia Field, Gulf of Mexico are utilized to investigate the effect of overpressure on reservoir quality where the influence of chemical compaction are negligible or absent. Turbidite reservoir sands in the study area have undergone rapid burial to depths of ~5200 m and experienced low burial temperatures of ~60-70 °C. The Magnolia Field provides a unique sedimentary setting to investigate the effect of overpressure on reservoir quality of sandstones in isolation to the onset of chemical diagenesis.

Study area and methods

Magnolia Field is located in the Garden Banks Block 783 within the Titan intra-slope minibasin, Gulf of Mexico (Fig. 1). The exploration wells were drilled in water depths of 1423 m to maximum depths of ~ 5200 m below sea level. The sediments are of Upper Miocene to Plio-Pleistocene in age and were deposited in a minibasin system formed by allochthonous salt sourced from Jurassic autochthonous salt accumulations (Weissenburger and Borbas, 2004, Kane*, et al.*, 2012). The reservoirs form part of an amalgamated turbidite system and are composed of channel complexes, mass transport deposits, levee deposits, and composite sheet sands (McGee*, et al.*, 2003). Based on these variations and age, the reservoir sand units were divided into sub-units namely B10, B15, B20, B25, B30, C50, C60, C70 and D10 sands.

Dataset from seven wells GB 783 #1, #1ST1, #2, #2ST1, #2ST2, #3, and #3ST1 are analysed for this study. Well logs (comprising Gamma-Ray, Sonic Velocity, Resistivity, Density, Lithology, and Neutron Porosity), Modular Dynamic Tester (MDT) pore pressure data, and routine core analysis data (comprising porosity and permeability measurements under formation confining pressures from core plugs sampled at selected depths) available from six wells have been analysed. The porosity values measured from routine core analysis were comparable to the log derived neutron porosity and density porosity. Petrographic studies were performed on thin-sections from core samples and core plugs from selected depth intervals within the reservoir units. In order to minimize the effect of reservoir heterogeneities associated with the varying distribution of clays on porosity and permeability measurements, the measured values were averaged for each reservoir unit and only the reservoir units with good permeability (≥100 mD) were considered in this study.

The pressure calculations in this study were performed assuming hydrostatic and lithostatic gradients of 0.01052 MPa/m and 0.02262 MPa/m respectively. The vertical effective stress was calculated by subtracting the fluid pore pressure from the lithostatic stress (overburden), and the fluid overpressure was determined by subtracting the estimated hydrostatic pressure from the pore pressure (Terzaghi, 1943, Mann and Mackenzie, 1990).

Results

The Magnolia Field reservoirs constitute coarse silt to very fine grained sandstones with angular to subangular grains and are moderate to well sorted (Fig. 2A). The sandstones facies is frequently inter-bedded within thick successions of mudstones. No diagenetic cements were observed in any of the studied thin sections. However, reworked detrital quartz cemented grains and detrital feldspar grains showing evidence of dissolution were observed (Fig. 2). The sandstones are feldspathic litharenites and are composed of 40-56 % quartz, 10-24 % feldspar, 11-18 % carbonate rock fragments and 5-8% heavy minerals.

All reservoirs are overpressured in the study area with a minimum overpressure of ~12.4 MPa to a maximum overpressure of ~35.2 MPa. Dissimilar pore pressure transitions were observed in different wells in the area (Fig. 3). In well #1, the pressure transition occurs gradationally from 66 MPa at 4420 m depth to 79 MPa at a depth of 4660 m. However, in well #1ST1, an abrupt pressure transition of ~15 MPa occurs between depths of 4755 m and 4880 m. Identical reservoir units in adjacent wells showed diverse pore pressures at similar depths. For instance, B30 sands in well #1 have a pore pressure of ~74 MPa at depth of 4570 m. However in wells #1ST1 and #2ST1, B30 sands experience a pore pressure of 69 MPa at 4720 m and 77 MPa at 5000 m respectively (Fig. 3). Miocene-Pliocene sediments have relatively higher pore pressures and hence higher overpressures than the younger Pleistocene sediments (Fig. 3). Also, prominent pore pressure transition zone occurs between the Pliocene and Pleistocene sediments in the area (Fig. 3).

The porosity-depth plot does not exhibit a systematic decrease in porosity with corresponding increase in depth (Fig. 4A). The average porosity values of the reservoir units ranged from 27-34 %. Higher porosities were generally observed in reservoirs experiencing relatively high overpressures (Fig. 4). Overpressure steadily increased with depth up to ~4570 m. At depths greater than 4570 m, two distinct sets of overpressures were observed (Fig. 4B). The porosity-VES plot displays an inverse relationship (Fig. 5B). Relatively higher porosity of up to ~34 % were observed in reservoir sands with higher overpressures than those experiencing lower overpressures which have a lower porosity of ~30 % (Fig. 5B). A weak inverse relationship exists between permeability and VES (Fig. 5D). Reservoir sands experiencing relatively low VES of ~8 MPa has a permeability of ~1000 mD whereas those experiencing relatively higher VES of ~20-25 MPa have relatively low permeability of ~600 mD (Fig. 5D).

Discussion

In the Magnolia Field, due to the rapid burial of the sediments within a short time span of ~10 Ma, the sediments have undergone burial to depths of ~5330 m below sea level and fluid overpressures developed as a result of disequilibrium compaction (Fig. 6). The low thermal exposure and rapid burial of the sediments in the past ~2 Ma in the area did not facilitate chemical diagenesis irrespective of the presence of texturally and compositionally immature feldspathic litharenite sandstone reservoir units (Figs 2 and 6).

The Magnolia Field has multiple vertical and lateral seals. This is supported by diverse values of overpressure which has been recorded in different reservoir units (Fig. 3), and from fluid geochemical data which showed heterogeneous and unmixed reservoir fluids (Weissenburger and Borbas, 2004, McCarthy*, et al.*, 2005). In the case of highly overpressured sand units, the presence of stratigraphic flow barriers such as thick mudstone units will have provided adequate seals for the efficient trapping of pore fluids and overpressure development (Fig. 3). Faults and fractures may have formed as a result of the halokinetic processes in the area and facilitated in the loss of pore pressures in the case of low overpressured reservoirs (Kane*, et al.*, 2012). Furthermore, a distinct relationship between the geological age of the sediments and the degree of overpressure was observed in the Magnolia Field with older Miocene-Pliocene sediments experiencing relatively higher overpressures (~29-35 MPa) than the younger Pleistocene sediments (~19-25 MPa) (Fig. 3). The Miocene-Pliocene sands are relatively thin sands and are interbedded within thick successions of mudstones. Therefore, during the rapid burial of the sediments in the past few million years, the fluids expelled from the compacting mudstones will have generated relatively higher overpressures in these sand units as a result of more overburden being supported by the pore fluids in the sand units. On the other hand, in the case of geologically younger Pleistocene formations, the sand units are relatively thicker than the Miocene-Pliocene units and hence the fluids expelled from the compaction of mudstone during burial could dissipate into relatively larger volume of sands and therefore the overpressure generated were relatively small.

Unlike normally pressured reservoirs where porosity decreases progressively with depth, no systematic decrease in porosity was observed in the overpressured reservoirs (Fig. 4A). On the contrary, anomalous high porosity was observed at deeper depths when compared to shallower depths in the study area. Porosity in the overpressured reservoir rocks were significantly higher than those shown by the regional porosity depth trend for normally pressured reservoirs from offshore Gulf of Mexico (Ehrenberg, *et al.*, 2008) (Fig. 4A). The porosity between depths of ~4000 m to 4880 m was ~2-4% more than the regional porosity depth trend. At greater depths, the porosity was ~6-8% greater than the regional porosity depth trend for normally pressured reservoirs (Fig. 4A). The data identifies that high porosity is generally associated with high pore pressures in the Magnolia Field (Figs 3 and 4A). The overpressure-depth plot (Fig. 4B) demonstrates that high porosity is generally linked with high overpressures and vice versa.

In the Magnolia Field, fluid overpressures resulted in the reduction of VES which preserved up to ~8 % more porosity than normally pressured reservoirs in the area (Fig. 4A). Relative differences in the magnitude of overpressures experienced by different reservoirs also had significant effect on their porosity distributions. Reservoirs experiencing relatively higher overpressures tend to have up to 4% more porosity than those reservoirs experiencing low to moderate overpressures (Figs 4A and 5A).

The effect of relative variations in fluid overpressure on permeability is less distinct in the Magnolia Field. Nonetheless, highly overpressured reservoirs exhibited relatively higher permeability compared to low overpressured reservoirs in the area. The enhanced permeability in highly overpressured reservoirs suggests that an increase in overpressure leads to reduction in VES acting on the grain contacts which help in maintaining the pore throats open and hence results in high permeability. Conversely, at lower overpressures (high VES), the pore fluid pressures are not adequate to retain the pore throats open and hence they tend to have lower permeability (Fig. 5B). Moreover, the spread in the permeability dataset may be due to the variations in clay distribution within the samples.

The observations from the Magnolia Field demonstrate that fluid overpressure has a positive effect on reservoir quality during burial in mechanical compaction dominated settings, prior to the onset of any chemical compaction. This may result in a higher than average starting porosity during burial at the commencement of chemical compaction and lead to relatively higher porosities even in the chemical compaction regime. Moreover, in diagenetic settings where pressure solution is the dominant process, fluid overpressures will reduce the VES acting on the grain contacts and facilitate porosity preservation. However, in the case of deeper HPHT reservoirs in complex diagenetic settings, the reservoir quality will be controlled by a combination of early mechanical and later chemical diagenetic processes. Hence, in the case of complex overpressured (HPHT) reservoirs, reservoir quality prediction should take into account the role of fluid overpressure in arresting porosity loss through slowing the rate of mechanical compaction and enhancing reservoir quality prior to the onset of later chemical compaction processes.

Conclusion

Datasets from the Upper Miocene to Plio-Pleistocene turbidite sandstone reservoirs of the Magnolia Field, Gulf of Mexico demonstrate that high fluid overpressures can be developed and importantly maintained in geologically young sediments undergoing rapid burial. In this setting, where mechanical compaction dominates, fluid overpressures preserve up to ~6-8% of additional porosity compared to the regional porosity-depth trend in the highly overpressured reservoirs. Highly overpressured reservoirs generally tend to have better permeabilities. A diverse overpressure distribution associated to reservoir compartmentalization is likely to result in reservoirs with dissimilar reservoir quality. In deeper HPHT reservoirs, fluid overpressure is likely to play a major role in preserving reservoir quality by reducing the degree of primary mechanical compaction of the sediments, nonetheless chemical diagenesis and associated quartz cementation can also play a role in governing reservoir quality. The positive effect of fluid overpressure in the preservation of reservoir quality gives promise to future hydrocarbon exploration activities in deeply HPHT reservoirs.

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FIGURES

Fig. 1 – The location and stratigraphy of the study area. (A) Magnolia Field is located in the Titan minibasin, Garden Banks block 783, Gulf of Mexico. (B) Stratigraphy of the Titan minibasin showing Miocene-Lower Pliocene ponded zone, Lower Pleistocene ponded to channelized bypass zone, and Upper Pleistocene bypass zone (after Kane*, et al.*, 2012).

Fig. 2 - Photomicrographs showing that the reservoir sandstones have not undergone any burial diagenesis and cementation: A) well sorted sandstone with angular to subangular grains under plane polarised light. A reworked detrital feldspar (dF) grain with inherited dissolution features can also be seen (#2ST2, depth 4849m), B) well sorted grains with abundant grain fractures (fQ) under crossed polars (#2ST2, depth 4798m), C and D) quartz grains with detrital quartz cements (dQ) which have been reworked and re-deposited in the basin under crossed polars (#1ST1BP, depth 5014m and #3ST1, depth 5115m respectively). The rounded to subrounded outline of the quartz overgrowths (Fig. 2D) and the indentations within the quart cement (arrowed) formed due to transport of the quartz grain indicates that the grain is reworked. The scale bars are 100μm.

Fig. 3 – Pore pressure dataset from the Magnolia Field, Gulf of Mexico measured using the Modular Dynamic Tester (MDT). The reservoirs are overpressured with a minimum and maximum overpressure of ~12 MPa and ~35 MPa respectively. The lithostatic pressure gradient (black line) and hydrostatic pressure gradient (grey line) are 0.0226 MPa/m and 0.0105 MPa/m respectively. The varying magnitude of pore pressure transition in different wells reflects the efficiency of different vertical and/or lateral seals and compartmentalisation of the Magnolia reservoir sands. For similar depth range, geologically older (Miocene-Pliocene) formations have higher pore pressures and hence higher overpressures than the geologically younger (Pleistocene) formations in the area. SSTVD is Sub-sea true vertical depth.

Fig. 4 - Porosity and overpressure distribution to depth in the Magnolia Field. A) Porosity-Depth plot showing no decreasing trend in porosity with depth. The dashed line is the regional porosity-depth trend for normally pressured Neogene reservoirs from offshore Gulf of Mexico (after Ehrenberg*, et al.*, 2008), and shows that the reservoirs have higher porosity distributions than the regional trend. B) Overpressure-Depth plot showing three distinct sets of overpressure distribution in the area. At relatively shallow depths overpressure increased steadily with depth (i). At depths below 4600 m, some reservoirs showed relatively lower overpressure (ii) while others showed relatively higher overpressures (iii). SSTVD is Sub-sea true vertical depth.

Fig. 5 - The relationship of fluid overpressure on reservoir quality in the Magnolia Field. A) Porosity versus vertical effective stress (VES) plot showing the effect of the relative magnitudes of overpressure on porosity. Higher porosity were preserved in reservoirs with higher overpressure and vice versa. B) Permeability-VES plot showing the relationship between relative variations in fluid overpressure and permeability. Reservoirs with high overpressures generally have high permeability. The dashed lines indicate the overall trend in in the dataset.

Fig. 6 – Burial history model for well GB 783 #1 generated using basin modelling program PetroMod©. A) The sediments in the Magnolia Field are Miocene to Recent in age and have undergone rapid burial to depths of ~5000 m below sea level since the Pliocene epoch. The maximum temperature that the sediments have been exposed to is ~60-70 °C. B) The rapid burial in the last 2 Ma and associated disequilibrium compaction has resulted in the generation of anomalous fluid overpressures in the area.

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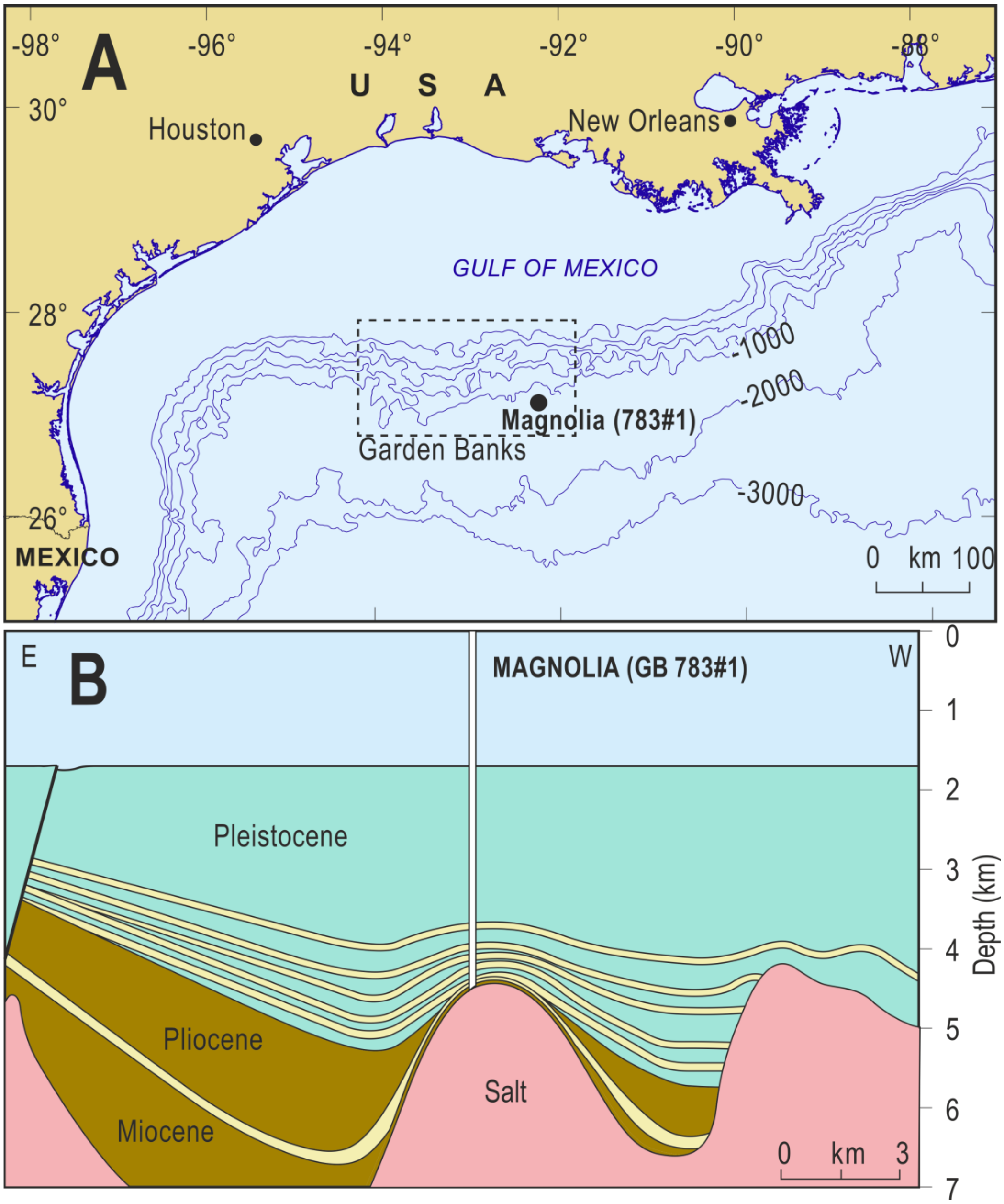
FIGURE

FIGURES

Fig. 1:


A
-98°
-96°
-94°
-92°
-90°
-88°
30°
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U S A
Houston
New Orleans
GULF OF MEXICO
-1000
-2000
-3000
Magnolia (783#1)
Garden Banks
MEXICO
0 km 100
B
E
W
MAGNOLIA (GB 783#1)
Pleistocene
Pliocene
Miocene
Salt
0 km 3
Depth (km)
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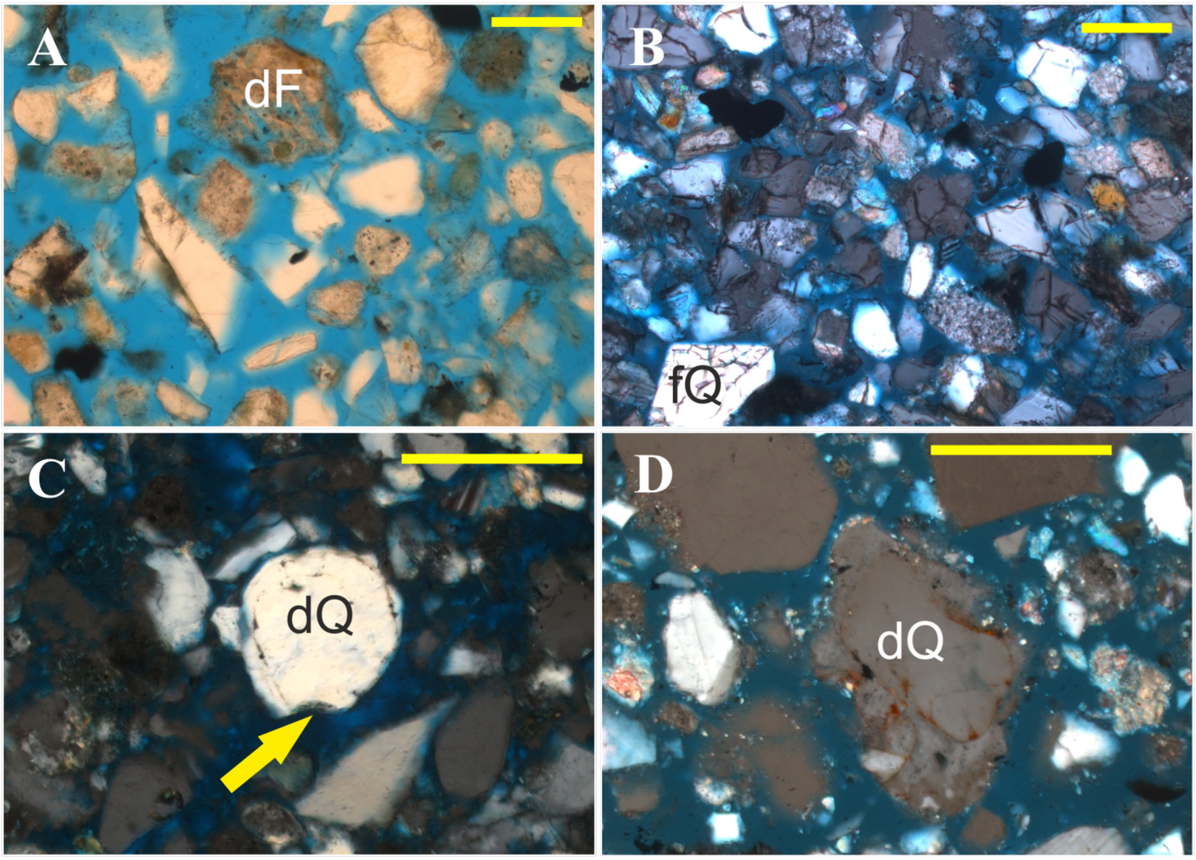
3
4
5
6
7

Fig. 2:



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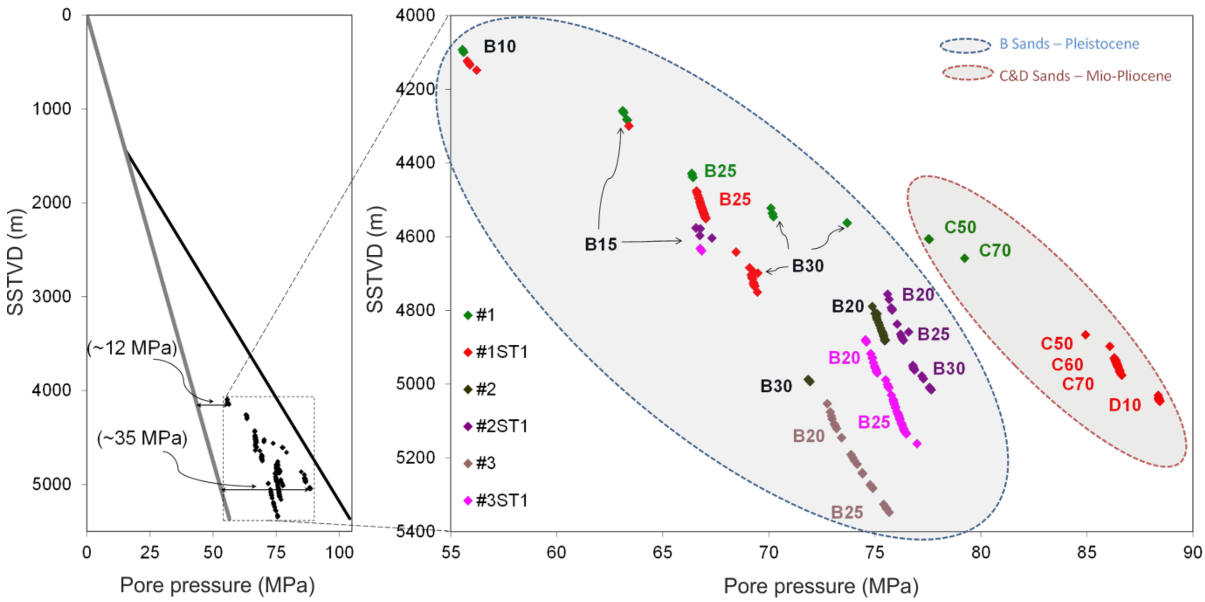


SSTVD (m)
Pore pressure (MPa)
(~12 MPa)
(~35 MPa)
B Sands – Pleistocene
C&D Sands – Mio-Pliocene
B10
B15
B20
B25
B30
C50
C60
C70
D10
#1
#1ST1
#2
#2ST1
#3
#3ST1

Fig. 4:

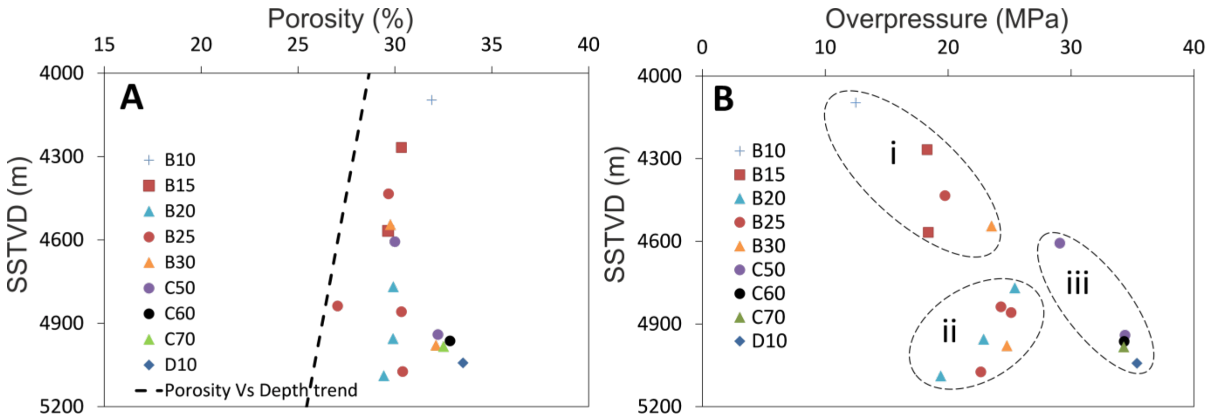

A
Porosity (%)
15
20
25
30
35
40
SSTVD (m)
4000
4300
4600
4900
5200
B10
B15
B20
B25
B30
C50
C60
C70
D10
Porosity Vs Depth trend
B
Overpressure (MPa)
0
10
20
30
40
SSTVD (m)
4000
4300
4600
4900
5200
B10
B15
B20
B25
B30
C50
C60
C70
D10
i
ii
iii

Fig. 5:

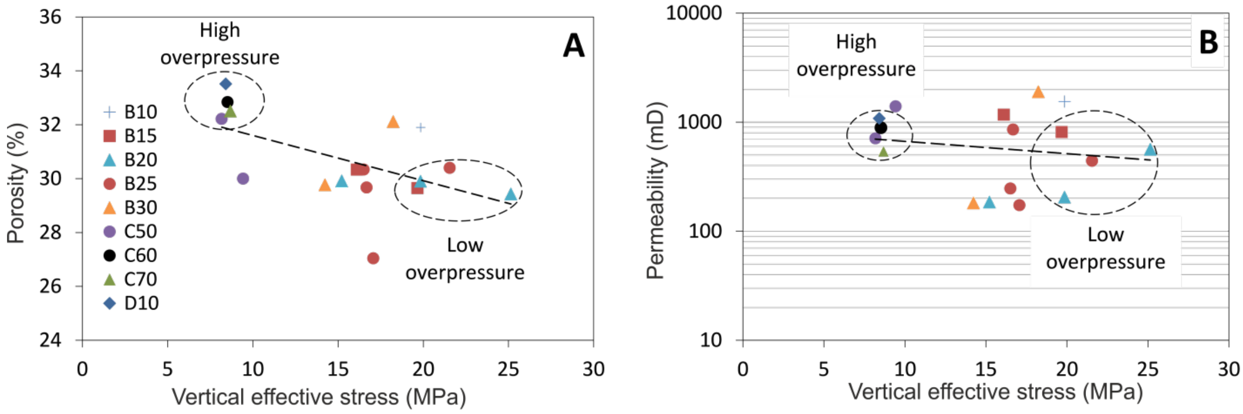
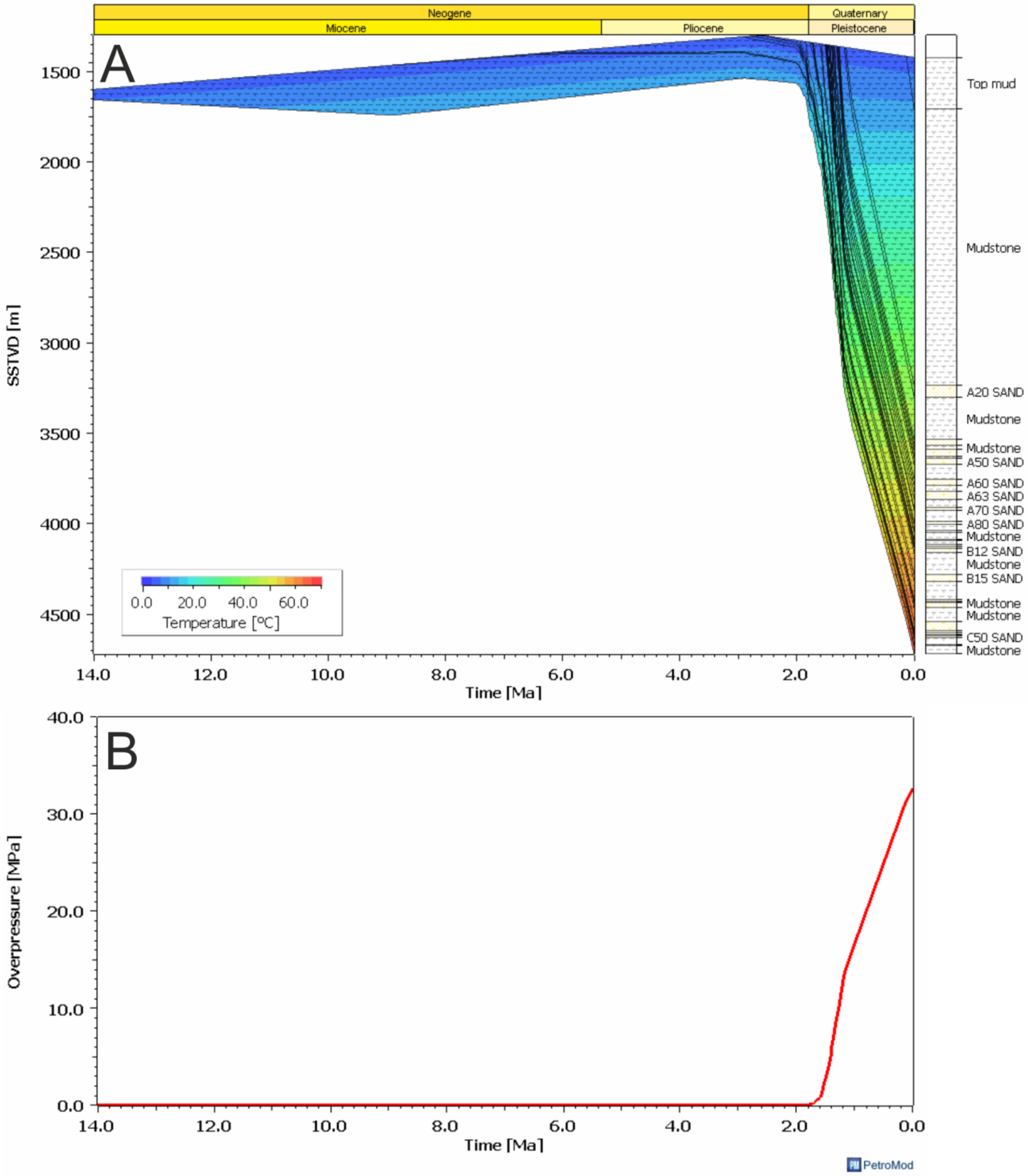

High
overpressure
A
B10
B15
B20
B25
B30
C50
C60
C70
D10
Porosity (%)
Low
overpressure
Vertical effective stress (MPa)
36
34
32
30
28
26
24
0
5
10
15
20
25
30
B
High
overpressure
Permeability (mD)
10000
1000
100
10
Low
overpressure
Vertical effective stress (MPa)

Fig. 6:


Neogene
Quaternary
Miocene
Pliocene
Pleistocene
A
SSTVD [m]
1500
2000
2500
3000
3500
4000
4500
Top mud
Mudstone
A20 SAND
Mudstone
Mudstone
A50 SAND
A60 SAND
A63 SAND
A70 SAND
A80 SAND
Mudstone
B12 SAND
Mudstone
B15 SAND
Mudstone
Mudstone
C50 SAND
Mudstone
0.0 20.0 40.0 60.0
Temperature [ºC]
14.0 12.0 10.0 8.0 6.0 4.0 2.0 0.0
Time [Ma]
B
Overpressure [MPa]
40.0
30.0
20.0
10.0
0.0
14.0 12.0 10.0 8.0 6.0 4.0 2.0 0.0
Time [Ma]
PetroMod