PS Maturation profile at the Glyde Gas Discovery in the Southern McArthur Basin, Australia*

Sandra Rodrigues[1], Joshua Bluett[2], Benjamin R. Ferguson[1], Suzanne D. Golding[1], and Luke Titus[2]

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[1]School of Earth Sciences, The University of Queensland, St Lucia, QLD 4072, Australia (s.rodrigues@uq.edu.au)
[2]Armour Energy Limited, 111 Eagle Street, Brisbane, QLD 4000, Australia

Abstract

The Glyde gas discovery is situated within the Glyde Sub-basin of the Southern McArthur Basin in the Northern Territory. The McArthur Basin is an extensive Paleo- to Mesoproterozoic intracratonic basin of carbonate to siliciclastic sediments and lesser volcanic rocks. This basin has seen renewed oil and gas exploration activity in recent years, with operators targeting numerous prospective source rock formations. Within the middle McArthur Group, the Barney Creek Formation has been recognised for its hydrocarbon source and unconventional reservoir potential. To investigate the thermal and fluid flow history of the Glyde Sub-basin, organic matter maturation ("in situ" solid bitumen reflectance – organic petrography) and illite crystallinity (001 illite peak at 10Å – X-ray diffraction) were determined in 26 drill cutting samples from two wells, Glyde-1 (vertical well) and Glyde-1 ST1 (lateral well). These samples are representative of the Barney Creek Formation. Reflectance values of the solid bitumens were then used to estimate paleotemperatures. Observations from organic petrography revealed the presence of lamalginite kerogen (hydrocarbon precursor), and solid bitumens, which indicate the production of oil. The solid bitumen reflectance values and paleotemperatures placed the maturity of the samples in the oil window passing to gas window in both wells. Very weak correlation between illite crystallinity and the organic reflectance data was found, which is possibly representative of hydrothermal fluid-to-rock interaction, due to the organic particles being affected faster than the growth of illite can occur. Nevertheless, reflectance values and illite crystallinity profiles of Glyde-1 showed an erratic behaviour with depth suggesting that thermal history was influence by factors other than regional basin subsidence. The same observations were found for the lateral well Glyde-1 ST1, implying lateral variations in the maturation of the organic matter. These results suggest hydrothermal fluid interaction has influenced thermal maturation of the organic matter as expressed by the erratic character of the profiles. This type of study is fundamental to understanding hydrothermal influence on hydrocarbon accumulations in this region.

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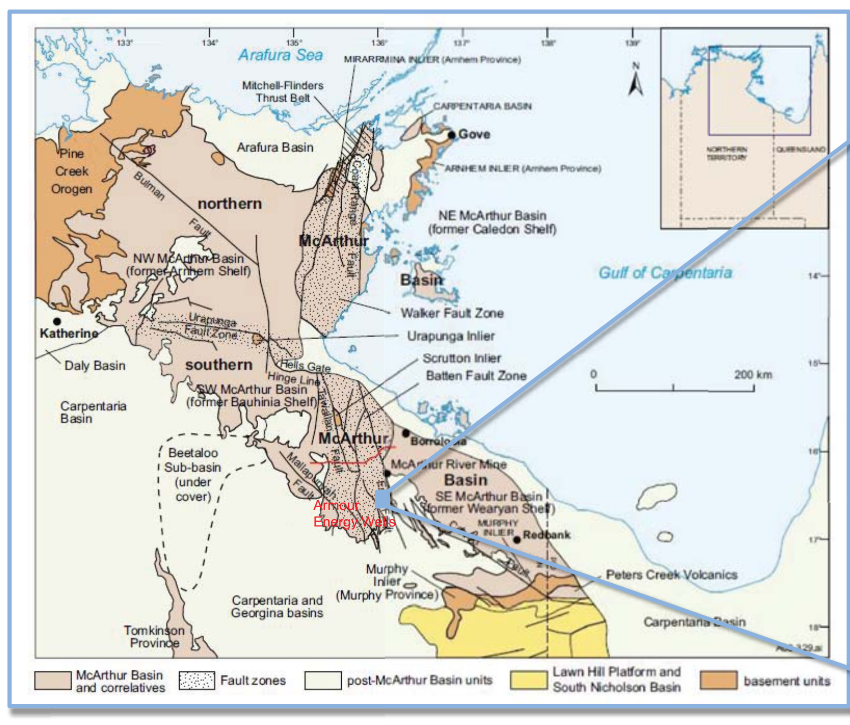
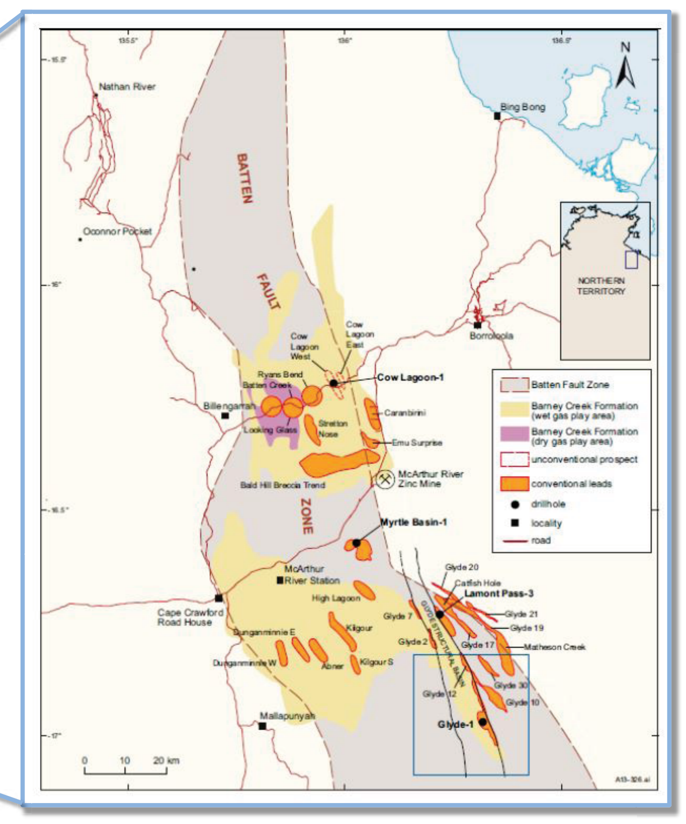
McArthur Basin – Batten Fault Zone

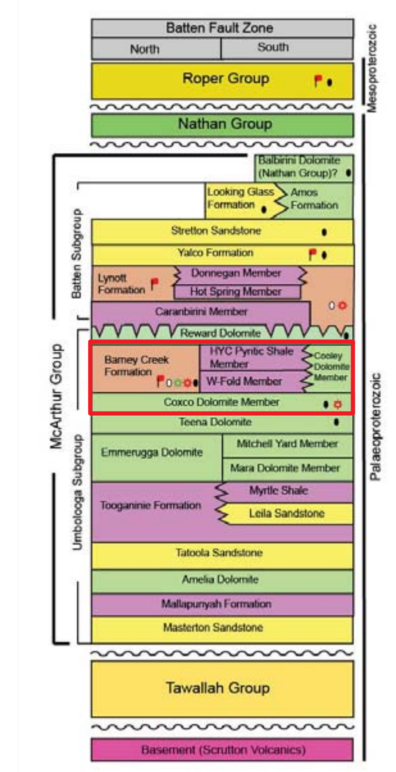


Palaeo- to Mesoproterozoic intracratonic **McArthur Basin** comprising **unmetamorphosed sediments** from fluvial, lacustrine to shallow marine environments.



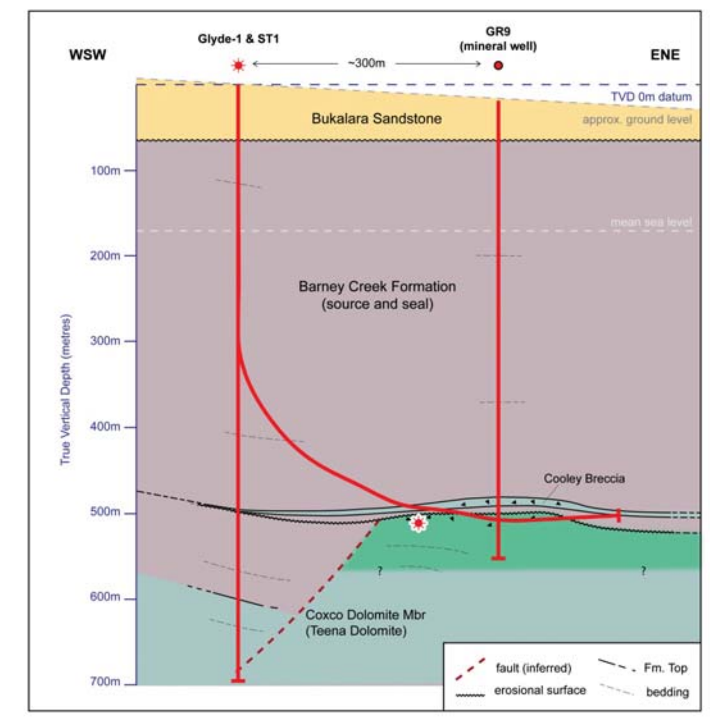
The Batten Fault Zone is a complex **fault system** that provided conduits for **hot fluid** circulation (mineralised and non-mineralised).

Stratigraphy



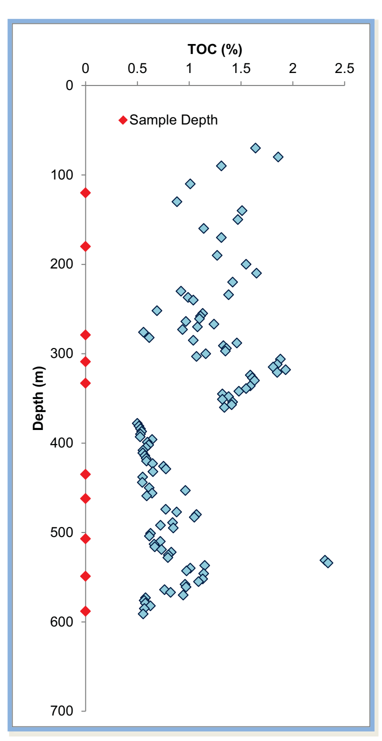
The southern McArthur Basin has been targeted for **conventional** and **unconventional reservoirs** (oil and gas).

Glyde Wells



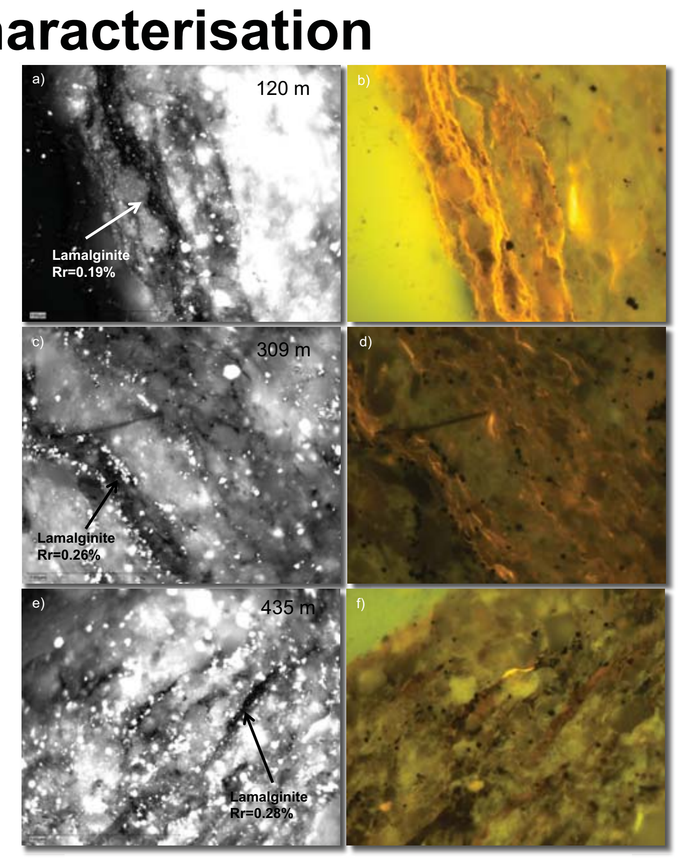
Glyde-1 (vertical well) and **Glyde-1 ST1** (lateral well) conventional gas discovery wells drilled through the Bukalara Sandstone (Ediacaran age) that lies unconformably on the sediments of the **Barney Creek Formation** (Paleoproterozoic). The gas reservoir is in the underlying **Coxco Dolomite Member** of the Teena Dolomite.

Organic Matter Characterisation



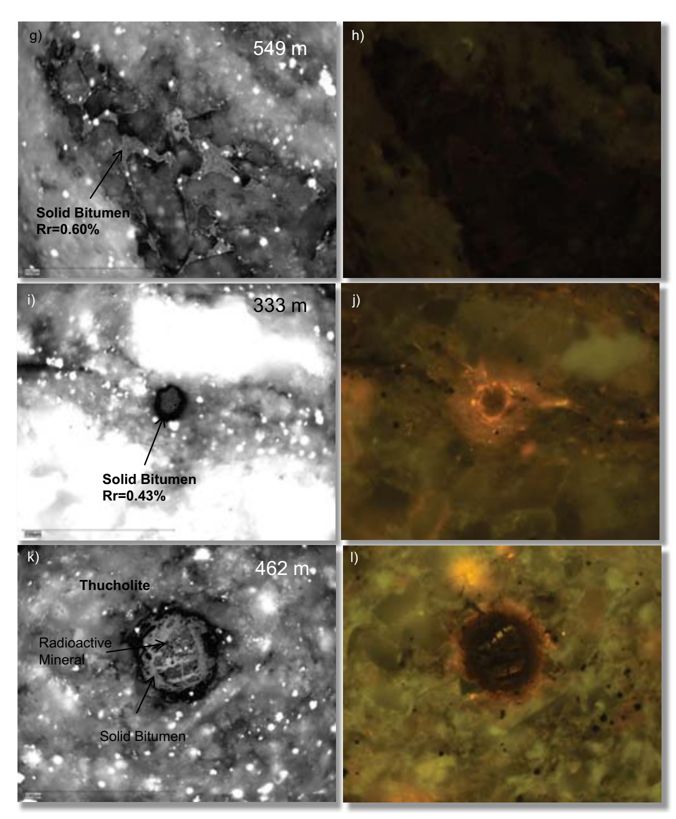
Total Organic Carbon (TOC) for Glyde-1 well and depths of petrographic samples (red symbols).

Samples considered have >0.5% TOC and S2 values > 0.2 mg HC/g rock.



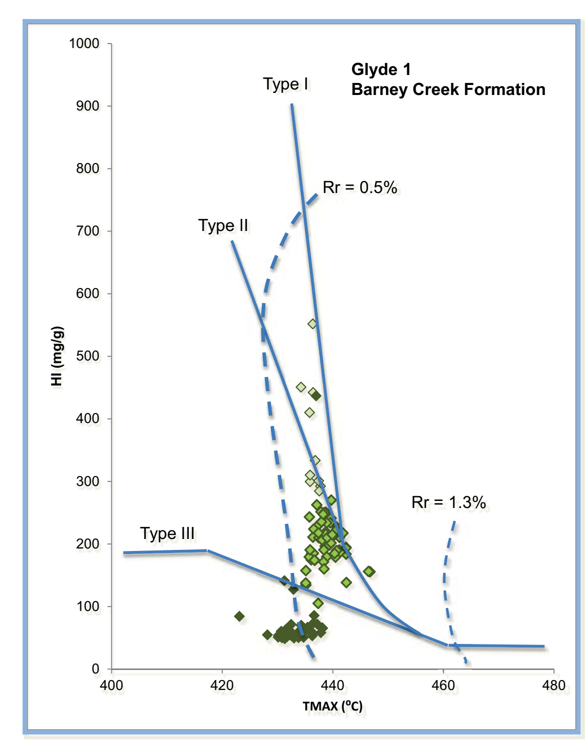
Lamalginite:

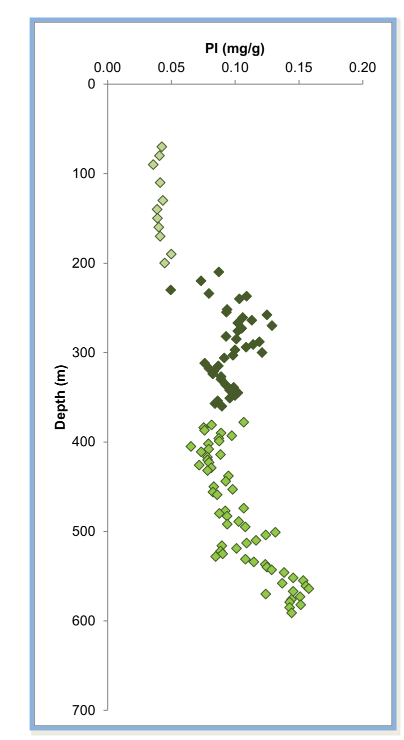
1) Lamellae oriented perpendicular to the bedding.
2) Strong fluorescence in the first 200m, decreasing in intensity down hole.
3) Main component in the samples at 200m, decreasing its occurrence down hole. Below 500m is no longer recognised.



Solid Bitumen:

1) Occurs mostly as infills in vugs or intercrystalline spaces.
2) Two main types occur: one with lower reflectance and with fluorescence (in situ source), and the other with high reflectance and without fluorescence.
3) Main component in the lower part of the Barney Creek Formation.

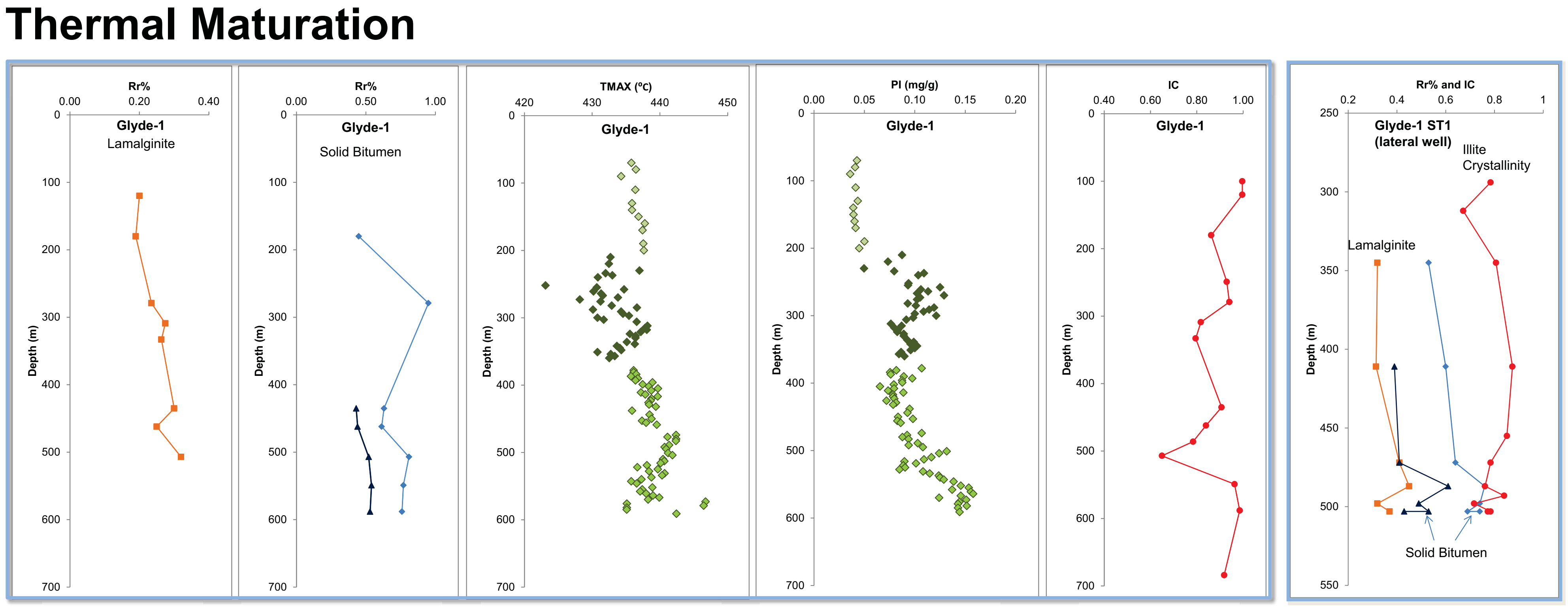




Types of organic matter - petrography vs Rock-Eval:

1) Lamalginite is mainly represented by kerogen **Type I** (higher HI values) kerogen.
2) The presence of solid bitumen indicates that the formation of hydrocarbons (oil/gas) occurred, and they are mainly represented by the **Type II** and III kerogen, with **Type III** representing higher reflectance solid bitumen.
3) Migration of hydrocarbons within the Barney Creek Formation may be responsible for the higher values of PI (Production Index) between 200 and 350 m and suppression of T_{MAX} values (dark green samples) where also the high reflectance solid bitumens occurs.

Thermal Maturation



Thermal maturation Index Profiles:

1) **Reflectance** values of lamalginite tend to increase relatively smoothly with increasing depth.
2) **Solid bitumen** shows two reflectance trends. The **lower reflectance** solid bitumen shows an increase with depth and may have a direct relationship with the lamalginite in the samples; while the **higher reflectance** solid bitumen may have migrated from somewhere else and show an erratic profile with depth.
3) T_{MAX} and **PI** show erratic profiles with depth. T_{MAX} is strongly affected by the **type of kerogen**. In the first 200 meters T_{MAX} is high due to the presence of Type I kerogen, which has relatively high decomposition temperatures during pyrolysis. Below 200m, the presence of solid bitumens (especially higher reflectance solid bitumen) supresses T_{MAX} values. PI is strongly affected by **migrated hydrocarbons** especially between 200 and 350m.
4) **Illite Crystallinity (IC)** profile shows an influence of **hydrothermal fluids** circulating through the fracture system. These fluids may also have interacted with or even generated hydrocarbons since IC shows a similar profile to PI.
5) In **Glyde ST1** lateral well, erratic profiles for reflectance values and illite crystallinity can be seen, indicating that **lateral variation** also occurs.

1) Lamalginite reflectance values (Glikson et al., 1992) indicate **vitrinite (VR%)** values between 0.6 to 0.8 VRr%.
2) The **conversion** of the **solid bitumen** reflectance to **vitrinite reflectance (VRr%)** by the Landis and Castaño (1995) formula gives:
   Solid bitumen with low reflectance – 0.76 to 0.86 VRr%
   Solid bitumen with higher reflectance – 0.78 to 1.24 VRr%.
   Reflectance measurements, either in the lamalginite or solid bitumen phases, placed the samples in the **oil window passing to gas window.**
3) T_{MAX} values, where these are less affected by the presence of solid bitumens, indicate that the samples are **immature to marginally mature** for hydrocarbon generation.(Crick et al., 1988).

The relationship between petrography and organic geochemical parameters gives a good approach to understand the thermal maturity achieved by the organic matter in relation to hydrocarbon generation.

It also shows that vertical and lateral variations of the profiles are frequent within a stratigraphic level.

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