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Reservoir characterization of the Cardium Formation in the Ferrier Oilfield, west-central Alberta, Canada

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ABSTRACT

This thesis has the main aim of defining the lithostratigraphy, depositional architecture, post-depositional modifications and reservoir characteristics of the Cardium Formation in the Ferrier Oilfield, and how these characteristics can have great impact over production rates, GOR and produced fluid discrimination.

In the Ferrier area, the Cardium Formation is composed by a NE prograding clastic sequence made up of offshore to shoreface deposits sealed by marine shales.

The main reservoir is composed by sandstones and conglomerates interpreted to have deposited in a shoreface depositional environment.

Lithofacies and net reservoir thickness mapping led to more detailed understanding of the 3D reservoir architecture, and cross-sections shed light on the Cardium depositional architecture and post-deposition sediment erosion in the Ferrier area.

Detailed core logging, thin section, SEM and CL analyses were used to study the mineralogy, texture and pore characterization of the Cardium reservoir, and three main compartments have been identified based on production data and reservoir characteristics.

Finally, two situations showing odd production behaviour of the Cardium were resolved. This shed light on the effect of structural features and reservoir quality and thickness over hydrocarbon migration pathways.

The Ferrier example offers a unique case of fluid discrimination in clastic reservoirs due both to depositional and post-depositional factors, and could be used as analogue for similar situations in the Western Canadian Sedimentary Basin (WCSB).

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CHAPTER 1: INTRODUCTION

1.1: Study focus and objectives

The Cardium Formation has been a prolific oil producer since the first oil discovery in 1953 (Krause et al., 1994), when Socony Vacuum Oil Company and Mobil Oil first found hydrocarbons in the Pembina Oilfield drilling the well Socony Seaboard Pembina n° 1 (UWI: 100/04-16-048-08W5/00). (Parsons and Nielsen, 1954; Warke, 1955; Nielsen and Porter, 1984).

In the 1950s, in Alberta most of the hydrocarbons were produced from Devonian limestone reefs, and most of the plays were therefore identified looking at topographic bulges in seismic, that represented the reef buildup. in the reflection seismic sections of that time, the Cardium Formation wasn't that visible, due to the low quality of the data, the relative thinness of the sandstones and the absence of structural features.

Drilling the Devonian reefs of the Leduc Formation, geologists were aware of the Cretaceous Cardium Formation, but it was disregarded by most of the Geologists. As Arne Nielsen, the geologist of Mobil Oil who discovered the Cardium potential and the Pembina oilfield, said: " Cardium was good sandstone for hydrocarbon reservoirs, but it was always tight – lacking the porosity to produce oil or gas commercially. The wisdom at the time was that if it has previously produced oil in Alberta, as some old hands claimed it had, it was only in negligible amounts." (Nielsen and Newman, 2012).

Looking at well logs and seismic in a broad area, Nielsen was able to detect that the Cardium sandstones pinched out into shales going eastward, i.e. stratigraphically upwards. That means it could represent a regional stratigraphic trap for hydrocarbons.

At that time, an exploration geologist couldn't get a well drilled without the well being placed in a defined seismic location. Devonian reefs were quite easily identified in seismic, and each well could be placed in a precise position in seismic. Being the Cardium a blurred, almost flat, continuous line in seismic, gaining the approval of the bosses was very difficult, that's why exploration was focused on reefs for still a while.

After a few time, Mobil Oil approved the new and ambitious Cardium prospect, and the first well was drilled. DST tests detected the presence of economically exploitable light oil in the Cardium cuttings, and that marked the beginning of the geologic exploration of the Cardium and the other stratigraphic traps of the Western Canadian Sedimentary Basin (WCSB).

Since the oil discovery in 1953, the Cardium sands and conglomerates began to be targeted first in the Pembina, and then in other regions nearby.

First, the oil and gas exploitation was carried out through vertical wells, with no other EOR technique. Because of the initial high production decline rates, several enhancing oil recovery techniques were applied starting from a few years after the Cardium discovery.

Petroleum geologists and engineers soon began to test the impact of water flooding on production. Water flooding was applied first in the Cardium Pembina Oilfield in the 1960s with great success (Purvis and Bober, 1979), and the technique was therefore applied to the other oilfields a few years later as well. Water flooding led to higher peak production and much lower decline rates, and this method is still being used in the main Ferrier oil and gas reservoir.

As an example of the advantages brought by water-flooding, we can analyse the production curve of well 100/10-27-040-08W5/00. It was spudded in December 1967, and therefore it underwent both the non- and the water-flooding stages of production.

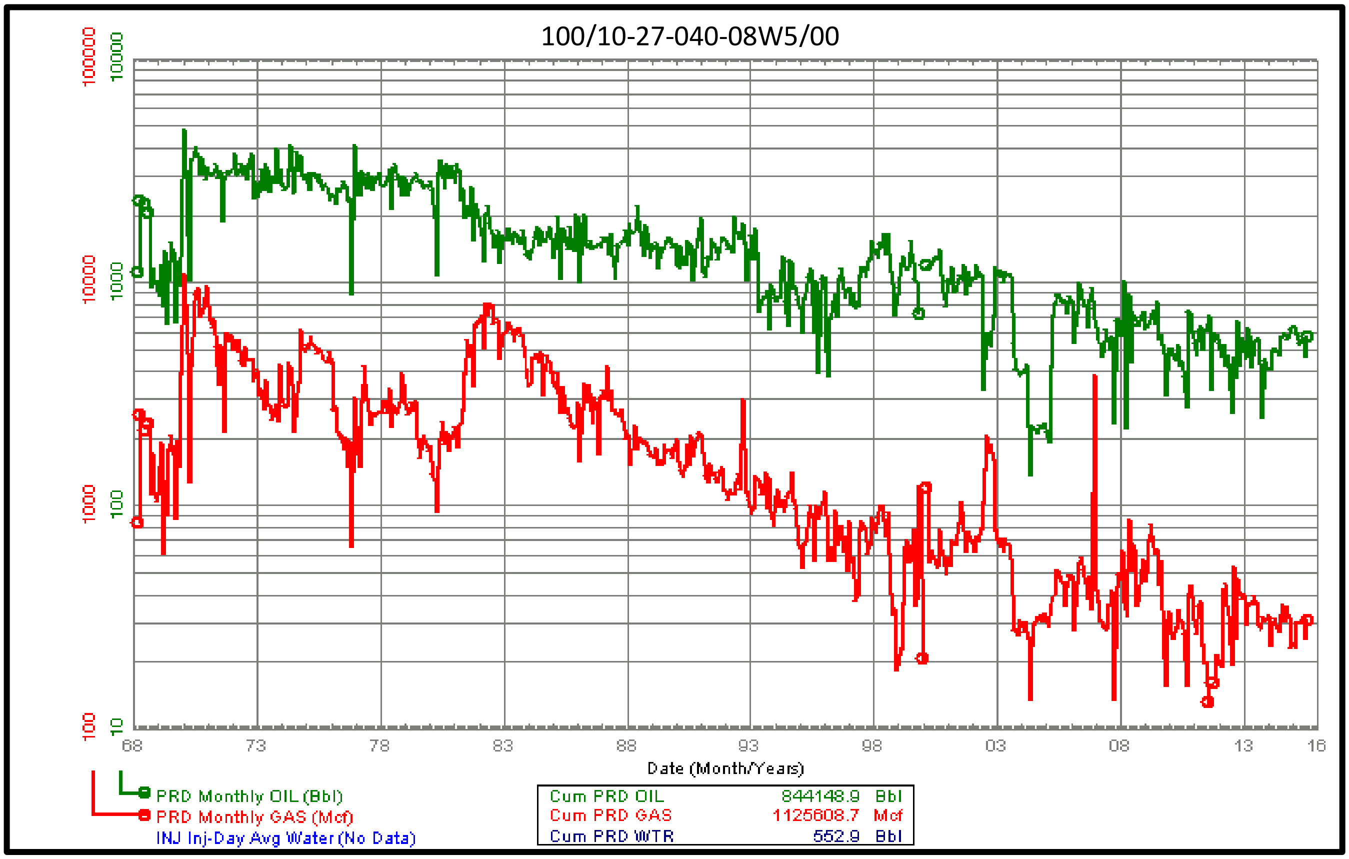
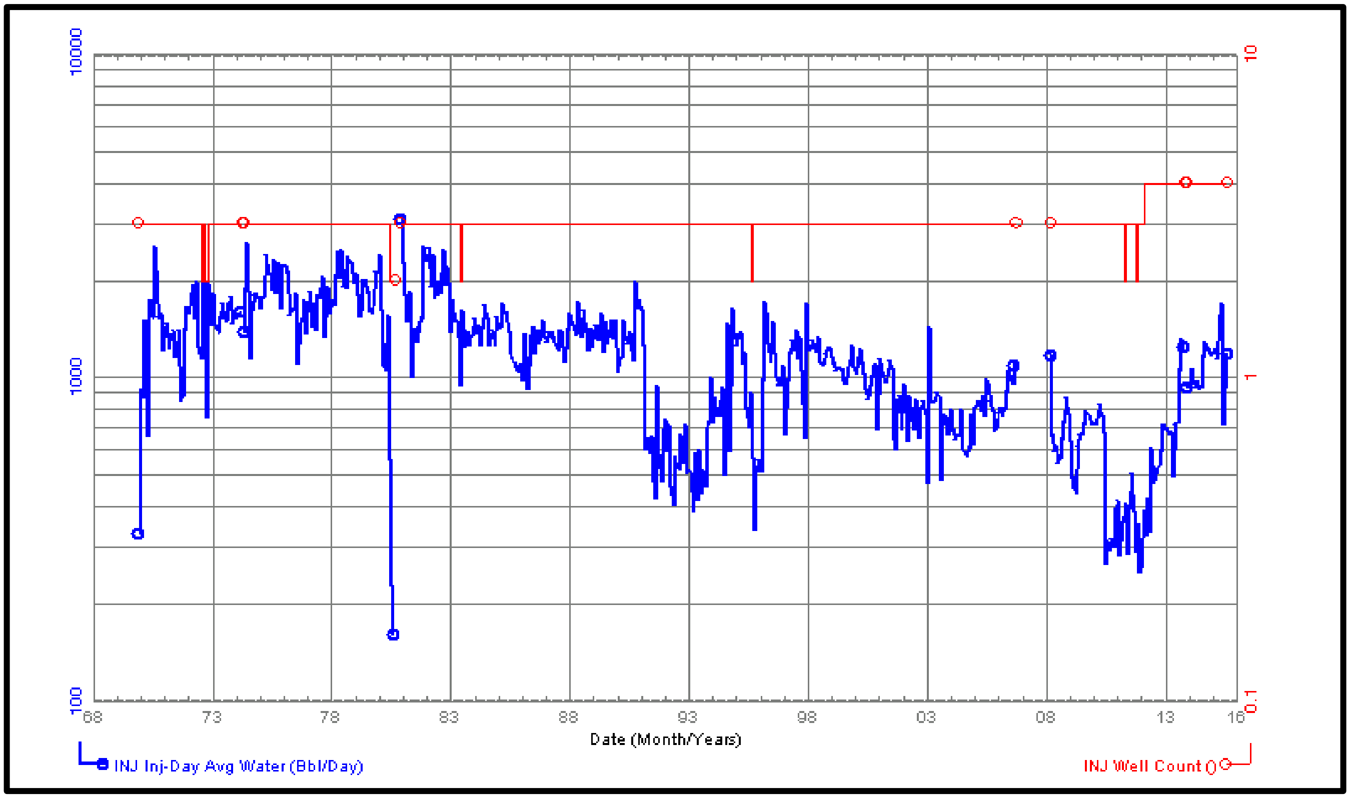


Fig.1: production analyses of 100/10-27-040-08W5/00. Water flooding has been applied from 1970, and that's exactly where an increase in hydrocarbon production and a decrease in production decline is observed.

As we can see looking at the graph, the production decline between 1968 and 1970-71 shows a deeply steep trend. However, from 1970-71 to the present day, the decline is linear and much slower than the first 2-3 years of production. The cause for this enhancement of production is the application of water-flooding that, as EOR method, can turn resources into reserves.

The picture below shows the daily average injected water by 4 water injectors (shown in orange circles) close to 100/10-27-040-08W5/00 (shown in red). As we can see, water injection starts exactly at the time when production decline abruptly decreases in the graph above. This testifies the excellent efficiency of the water-flooding techniques, that at the present day are still used in the main oil and gas reservoir as EOR techniques in many oil and gas fields around the world.



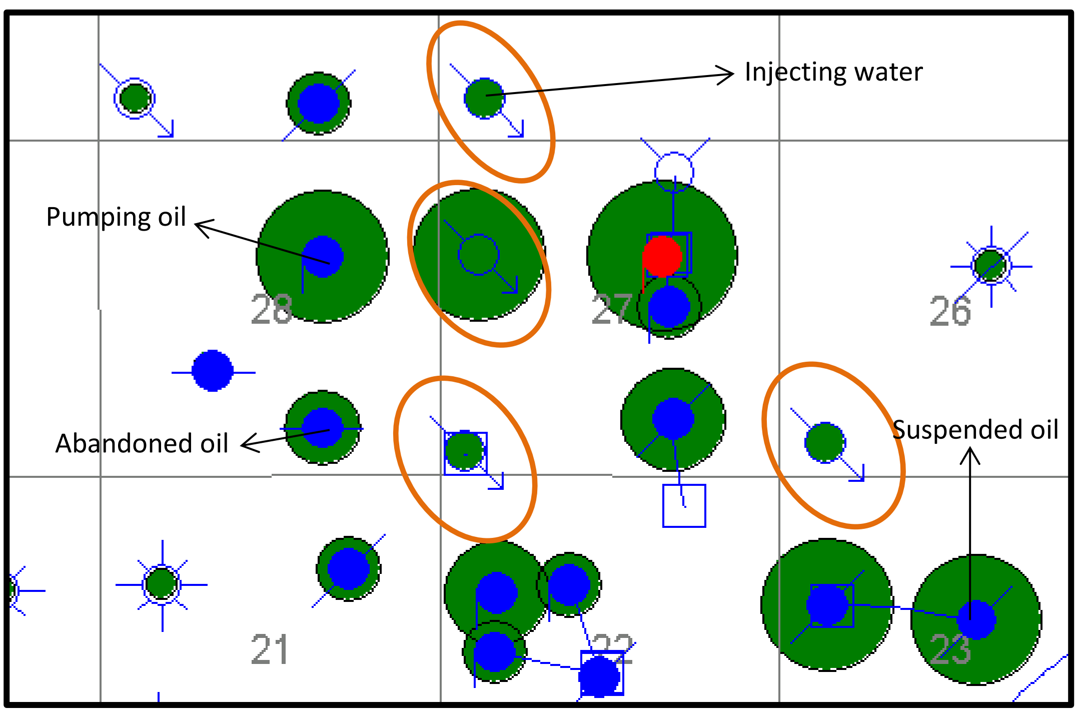


Fig.2a and 2b: injection analysis of the daily injected water by 4 injector wells near 10-27-40-8W5 (2a); injecting wells location (2b). Each well symbol corresponds to a current well status.

Around 2010, the first multi-stage horizontal wells targeted the low permeability facies of the Cardium formation. These technique turned out to be an excellent way to target the halo oil plays of the Cardium.
According to Clarkson and Pedersen (2011) “halo oil plays are defined as portions of conventional light oil accumulations that did not meet traditional pay criteria cut-offs for vertical well development”.

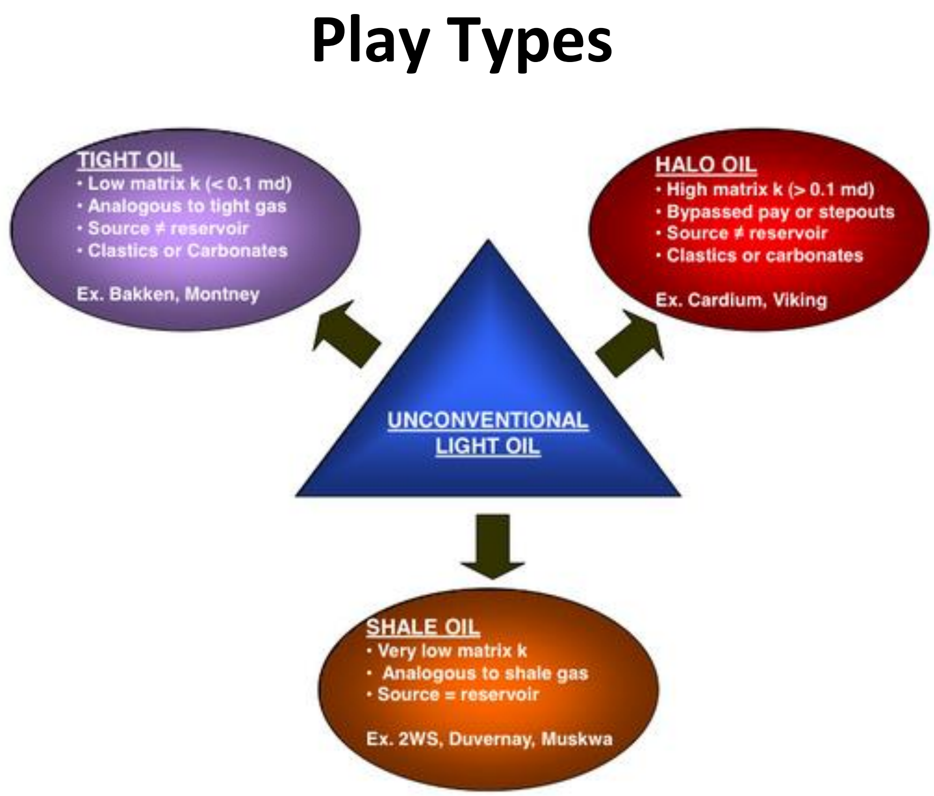


Fig.3: play types classification based on permeability, type of rock and coincidence or not between source rock and reservoir. (from the University of Calgary Tight Oil Consortium website: http://www.tightoilconsortium.com/)

As shown in the picture above, halo oil is held into the most permeable unconventional reservoirs. In this case, the reservoir is often not exploitable with the traditional methods because of its poor petrophysical characteristics, conversely with a conventional reservoir. Therefore, halo oil plays can be classified as “poor reservoir quality, bypassed pay zones”.
The exploitation of these portions of the reservoirs requires high performance EOR techniques, such as horizontal drilling and multi-stage hydraulic fracturing. Starting from around 2008, a lot of multi-stage horizontal wells have been drilled in the Cardium Formation with variable success.

The factors that control the success of these multi-stage fracking horizontals are currently still not clearly understood, as the “halo” portions of the reservoir are thinner and commonly show poorer petrophysical characteristics than the conventionally developed areas of the Cardium Formation.

Dealing with thin-, poor quality reservoirs means that subtle variations in reservoir characteristics such as depositional architecture, porosity, permeability, diagenesis and fluid saturation can have a major impact on the success of EOR techniques.

All of the above testifies that an accurate reservoir characterization must be performed for every oilfield targeted unconventionally, in order to focus on the best reservoir spots. In this study, we will focus on the reservoir characterization of the Cardium Formation in the Ferrier Oilfield, that is one of Alberta major Cardium oilfields, together with the Pembina and Willesden Green.

The lack of studies specifically focused on this topic in this oilfield makes this research one of the most accurate and updated projects about the geology of the Cardium in the Ferrier.

1.2: Aim of the project

This project was developed in collaboration with the Tight Oil Consortium at the University of Calgary (AB, Canada). The aim of this research is to perform detailed reservoir characterization of the Cardium Formation in the Ferrier Oilfield. This includes both the conventionally- and the unconventionally developed portion of the Cardium.

This study has been carried out using core logging, petrophysics, sedimentology and production data, and will uncover different facies and flow units within the Cardium Formation in the study area.

At the end of this project, new information about the depositional architecture of the Cardium Formation, the geologic controls over fluid production and the nature of produced fluid (gas vs oil, GOR) in the Ferrier oilfield will be revealed. This research has been developed in order to be a useful tool for the Oil industry to find new potentially economically profitable drilling locations for horizontal Cardium wells in the Ferrier area.

1.3: Role of the student

This thesis represents the final product of more than one year of work at the University of Calgary and the University of Bologna. Every analysis used and described in this thesis was undertaken by the master’s candidate, or with direct observation of the methodology by the student himself.

1.4: Study Area

The Ferrier oilfield is located in Alberta, Canada. More specifically, it's found in the west-central portion of Alberta, 80 km west from the city of Red Deer and close to the town of Rocky Mountain House.

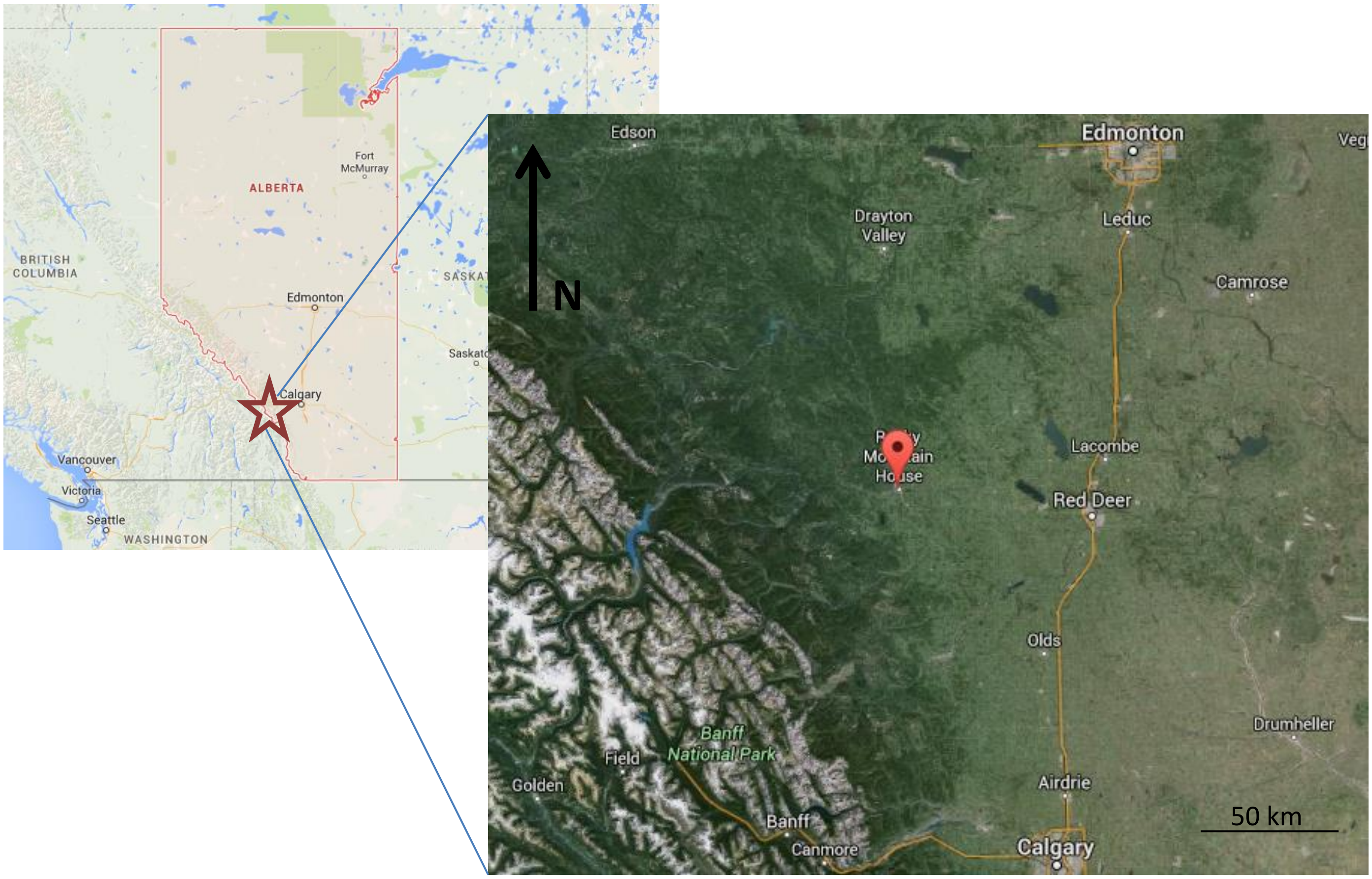


Fig.4: geographic location of the Ferrier Oilfield (picture taken from google maps)

The coordinates of each well location are expressed as Dominion Land Survey (DLS) coordinates, that is the most used in Western Canada. DLS coordinate system will be explained below, as it will be used throughout all this written report.

1.4.1: DLS coordinate system

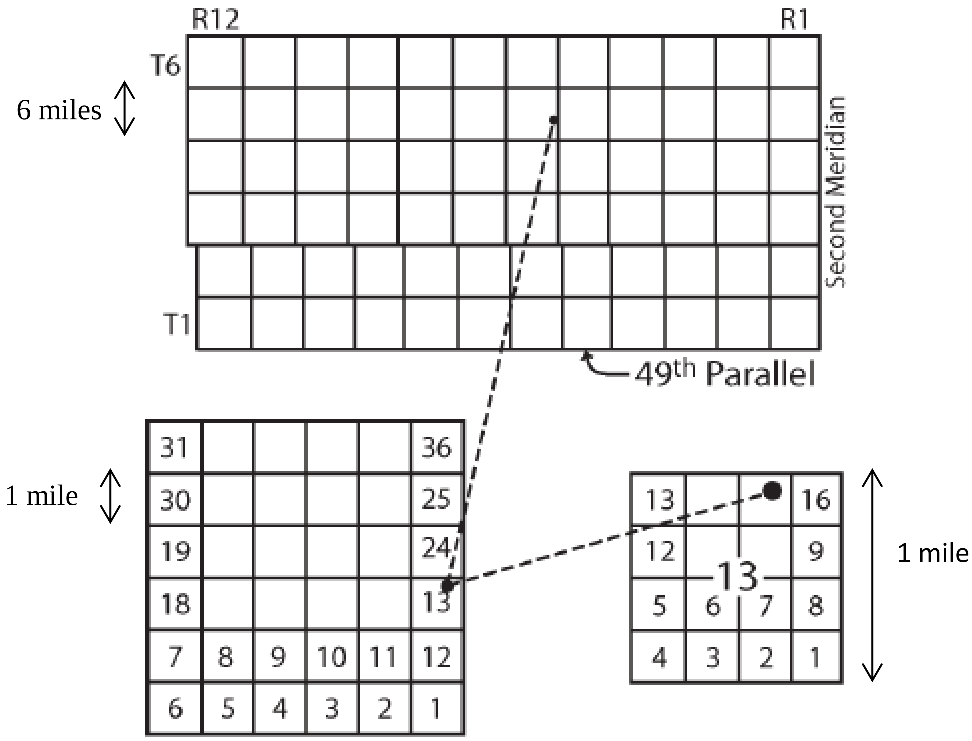
DLS coordinate system was well described in the notes of the GLGY 575 class at the University of Calgary. These notes, written by dr. Stephen Hubbard, Paul Durkin and

Benjamin Daniels (GLGY 575 – lab 1), will be in part used to provide the reader with a first introduction to the DLS.
The main characteristics of the DLS are summarized below:

• The basic unit of land is the Section, that is a square having the side 1 mile (640 acres) long;
• Thirty-six Sections are grouped into a Township, that is a square having the side 6 miles long;
• Rows of Townships are numbered from the International Boundary northward (S to N) in Western Canada;
• Columns of Townships (Ranges) are numbered west or east of arbitrary reference Meridians of longitude.

The location of any given point on the surface (or well penetration location) is known as Unique Well Identifier (UWI). Locations are given in the order:
1. Legal sub-division
2. Section
3. Township (T)
4. Range (R)
5. Meridian

In the picture provided below, the UWI of the black dot is 15-13-05-06W2. That means is 6 ranges west of the second meridian (06W2), in township 5 (T 05), section 13 and legal sub-division 15. The picture below shows the thinking process graphically.



1.4.2: Geographic location and play information

The study area is located in Townships 37-42 and Ranges 07-10W5. As of February 2016, the study area counts 957 wells that have/have had the Cardium Formation as production/injection formation.
810 wells over the total 957 are vertical or deviated, that means the horizontal penetrations producing from the Cardium in the Ferrier are 147.
The horizontal wells are mainly located at the edge of the main oil body and in the western portion of the oilfield, where they have been drilled to exploit a poor-quality reservoir portion. This is visible in the map below, where the HZ Cardium wells are shown in red, in contrast with the black dots (Cardium vertical wells).

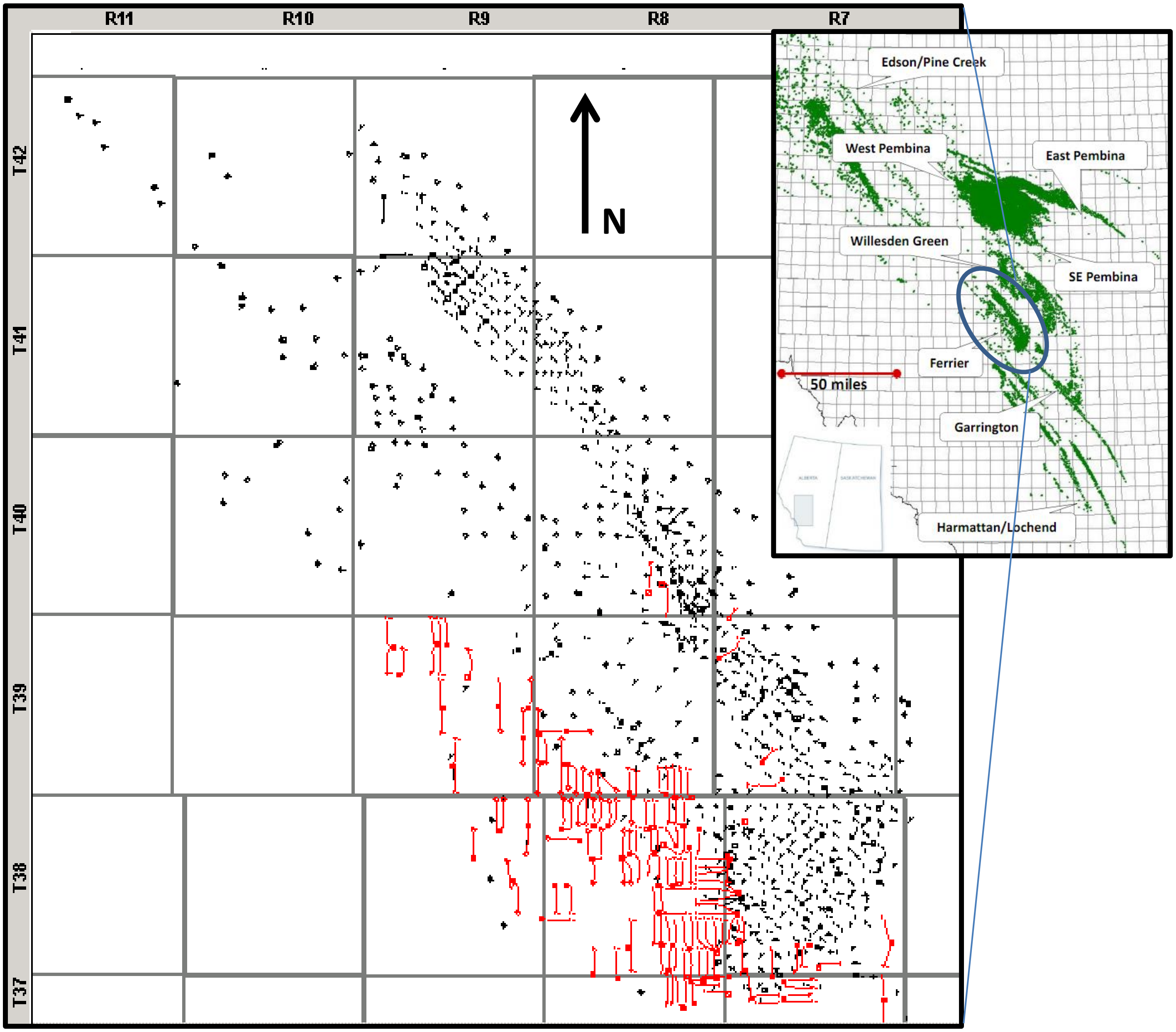


Fig.6: present-day status of the Ferrier Oilfield. The black wells represent the former or current vertical and deviated Cardium producing wells in the play. Red wells represent the Cardium horizontal producing wells. Each vertical penetration targeting deeper plays than the Cardium was not shown in the picture, although having been taken into account for reservoir mapping. The smaller picture offers an overview of the main Cardium oilfields in Alberta.

In the conventionally developed portion of the Ferrier, the well density is approximately 4-5 producers and 2 water injectors per section. In that portion of the studied oilfield, 163 vertical wells are currently injecting water in the Cardium, whereas 289 vertical or deviated wells are currently producing oil and gas from the Cardium, and 148 verticals are producing gas only. The latter are mainly located in the gas cap of the pool (E side, structurally up-dip) and in the northwestern side of the play, where another good quality gas-bearing reservoir is present and has been exploited since the late 1980s.
Finally, 162 wells have been suspended or abandoned due to low fluid rates or uneconomic well conditions.
The study area was selected based on several criteria including unique geology, available well logs and core data and unresolved geologic issues (e.g. abrupt differences in GOR in closely spaced wells).
More specifically, in the unconventionally developed portion of the reservoir, there is an abrupt change from oil and gas production to gas only, and researchers, as well as companies are interested in understanding what controls this shift in production for scientific and economic reasons. This is the first paper dealing with this production issue in the Cardium in the Ferrier area.

1.5: Materials and methods

1.5.1: Chapter 2

In chapter 2 a general geological framework of the Cardium Formation with particular focus on the Ferrier Oilfield is shown. The framework was shown using a total of 1337 vertical penetrations with available well logs in the Cardium (Gamma ray, Neutron/Density, Resistivity). To describe the lithofacies and calibrate the well log responses 13 cores have been directly described at the Alberta Energy Regulator – core facility, and the pictures of other 20 cores were taken into account for lithofacies description and distribution.
Optical microscopy, SEM and cathodoluminescence helped in identifying different lithofacies based on micro-scale features like texture, cementation, grain size, porosity and 2-D pore connectivity .
Together with core description work, cross-sections were used as a tool to unravel the stratigraphic framework of the Cardium Formation in the Ferrier Oilfield. Stratigraphic correlations shed light on the reservoir architecture and trapping mechanisms, as well as post-depositional modifications.
Core descriptions, facies analysis and core analysis data were used together with production data to determine net sand and net pay cut-offs for the productive intervals. The final product of chapter 2 will be lithofacies description and mapping and the depositional architecture of the clastic body in the Ferrier area.

1.5.2: Chapter 3

Chapter 3 focuses on the reservoir characterization of the Cardium Formation in the Ferrier Oilfield.

The reservoir characterization of the Cardium Formation has been made through the same analyses used in chapter 2, but run with different aims.

First of all, the 13 logged cores were considered as flow units. This involves a first lithostratigraphic differentiation, but there may be more than one flow unit in the same facies too. Looking at flow units in core is a tool to understand how and how fast hydrocarbons can flow within the Cardium.

Optical microscopy, SEM and cathodoluminescence were used to identify and characterize flow units at small scale of observation. More specifically, these analyses were aimed at detailed pore characterization of the Cardium, including the estimation of the degree of cementation, as well as the type of cement.

Well logs have been used as well to build a more detailed reservoir framework in the Ferrier area. 6% and 12% net reservoir maps have been built from well logs and routine core analyses.

This has been useful to propose a new model that may relate hydrocarbon migration and migration pathways to the current fluid distribution in the Ferrier.

The final product of chapter 3 will net reservoir mapping and detailed description and characterization of each producing body in the Ferrier. Every compartment has been described as a discrete unit, and then a model considering how each body is linked to each other and why and in what it is different from the adjacent ones has been developed and proposed. Chapter 2 and 3 contribute to understand hydrocarbon distribution compared to the geology and petrophysics of the Ferrier. This will be discussed in chapter 4.

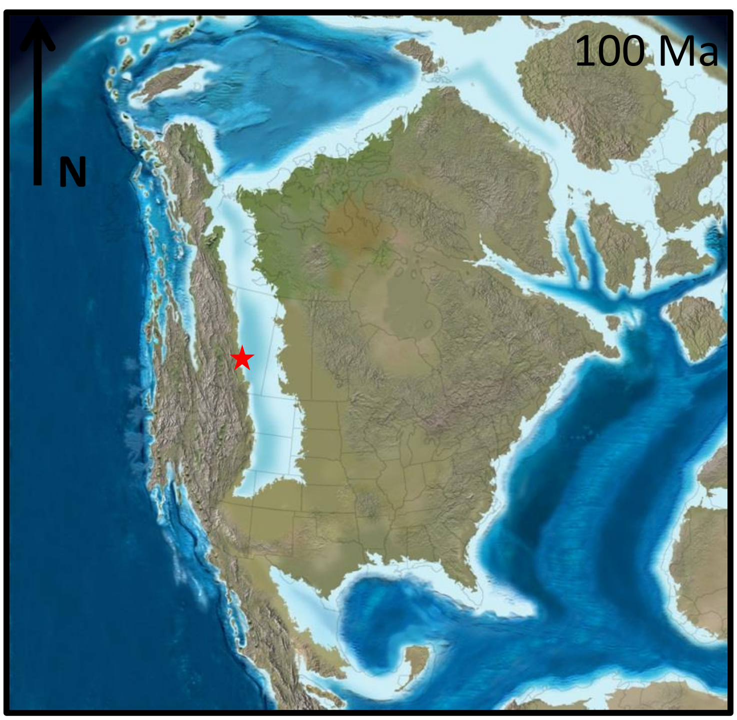
Chapter 2: Geology and reservoir architecture of the Cardium Formation in the Ferrier Oilfield

2.1: Geological framework of the Cardium Formation

The Upper Cretaceous Cardium Formation is a northeastward prograding clastic succession visible in outcrops and cores in the Western Canadian Sedimentary Basin (WCSB). It is made of fluvial deposits to shoreface sands to offshore muds and silts, and it pinches out into shales going eastward.

Being part of the Alberta Group, the Turonian-Coniacian Cardium Formation underlies the Campanian Wapiabi Formation and overlies the Cenomanian-Turonian Blackstone Formation (Hall et al., 1994; Krause et al., 1994).

The Cardium Formation is the fossil trace of an ancient fluvial to offshore depositional system active in the Upper Cretaceous and having as base level the western shoreline of the Western Interior Seaway. That was a broad inland sea stretching from the Arctic to the present-day Gulf of Mexico, that developed in the Cretaceous (Nielsen, 1957; Stott, 1963; Williams, 1975; Krause et al., 1994).



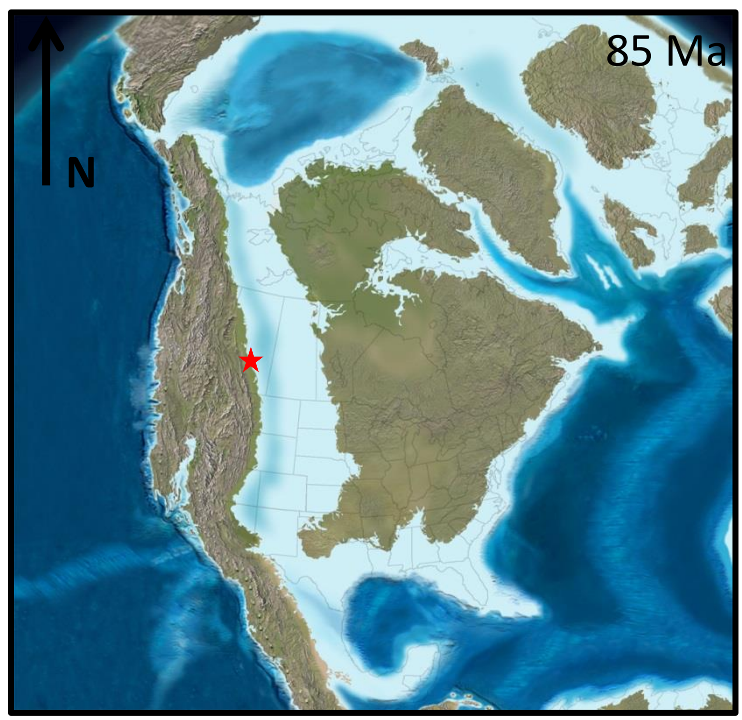


Fig.7: Interpreted Late Cretaceous paleogeography (modified after Blackey, http://cpgeosystems.com/nam.html).

The red stars represent the interpreted location of the deposition of the Cardium Formation in the study area.

In the Upper Cretaceous the Canadian Cordillera, located in Western Canada, was still rising through tectonic impulses. Authors claim that the Seaway developed when the Pacific and North American tectonic plates collided, causing the uplifting of the Rocky Mountains. The tectonic load of the uplifting wedge, joined to the back-arc extension of the subducting plate, caused the formation of a depression parallel to the mountain thrust front trend. This NW-SE oriented hollow became bigger and bigger after every tectonic impulse, and led to the formation of the Cretaceous Western Interior Seaway (Nielsen, 1957; Stott, 1963; Williams, 1975; Krause et al., 1994; DeCelles, 2004; Varban and Plint, 2008; Blakey, 2014).

The rising mountains were the primary sediment source of Western Canada, with the sediment being eroded from the orogeny. Few to no sediment came from the eastern side of the in-forming sea, that's why most of the observed paleocurrents were consequently towards the eastward-northeastward.

The deposition of the Cardium Formation was the consequence of one of the strongest tectonic impulses that contributed to the Cordillera raising process.

The Cardium stratigraphy has been studied by different authors, both with traditional and modern methods.

Ralph Rutherford was the first author to write about the Cardium Formation. In 1927, he identified as "Cardium Formation" three thin sandstone layers divided by three packages of shale outcropping along the Bow river (Rutherford, 1927).

After the success of the Socony - Seaboard Pembina n.1 well, interest in the Cardium Formation grew exponentially. In the 1950s, several works proposed stratigraphy and depositional models of Canada's new most perspective oil and gas play.

The depositional models proposed vary in depositional environment, paleoclimate, genesis and age of the formation. This is due to the high heterogeneity of the Cardium that, joined to the absence of sequence stratigraphy and other modern techniques, made the study of the Cardium Formation harder.

The most accepted theory until the 1970s was that Cardium was deposited as an offshore bar (e.g. Nielsen, 1957). Other papers identified the formation being deposited as a turbidity current (Beach, 1955), or a tidally-influenced delta (DeWeil, 1956; Michaelis, 1957).

A strong contribution to the study on Cardium architecture was given by allostratigraphy. This technique uses discontinuities as bounding surfaces for depositional sequences, in contrast with the traditional sequence stratigraphy that uses fixed bounding surfaces (Sequence Boundary, Trangressive Surface and Maximum Flooding Surface).

In complex geological settings, where is not easy to identify these conventional-, Exxon-type bounding surfaces, a good assistance can come from the detection of regional-scale unconformities. This is a new view of stratigraphy, and it has been extensively applied to the Cardium Formation since 1986, when Plint et al. developed a new depositional model for the Cardium Formation mainly based on allostratigraphy.

The authors showed that the sand bodies were stretched parallel to the Wester Interior Seaway sides, and therefore could represent a shoreline. They also detected the presence of pebble dominated mudstone portions just on top of the unconformities, and interpreted these layers as lowstand shorelines.

Plint was able to find 7 regional-scale discontinuities within the Cardium Formation: those unconformities could be transgressional (T), erosional (E, subaerial erosion) or composite T-E (Plint et al, 1986; Shank and Plint, 2013).
The E5 surface represents the top of the main Cardium reservoir, and therefore it was extensively studied after Plint's work. Walker and Eyles (1991), in their paper about the genesis and characteristics of the E5 surface, identified it as composite surface. They interpreted E5 as being initially subaerial and then modified by the subsequent transgression. The picture below shows Plint's depositional model for the Cardium formation, and it's widely used in bibliography. The author was able to sub-divide the Cardium into 6 main members bounded by regional discontinuities. Going stratigraphically upwards, the whole Cardium Formation is formed by the Nosehill, Bickerdike, Hornbeck, Raven River, Dismal Rat and Karr Member. These members are bounded by E / T / E-T combined surfaces visible in the picture provided below.

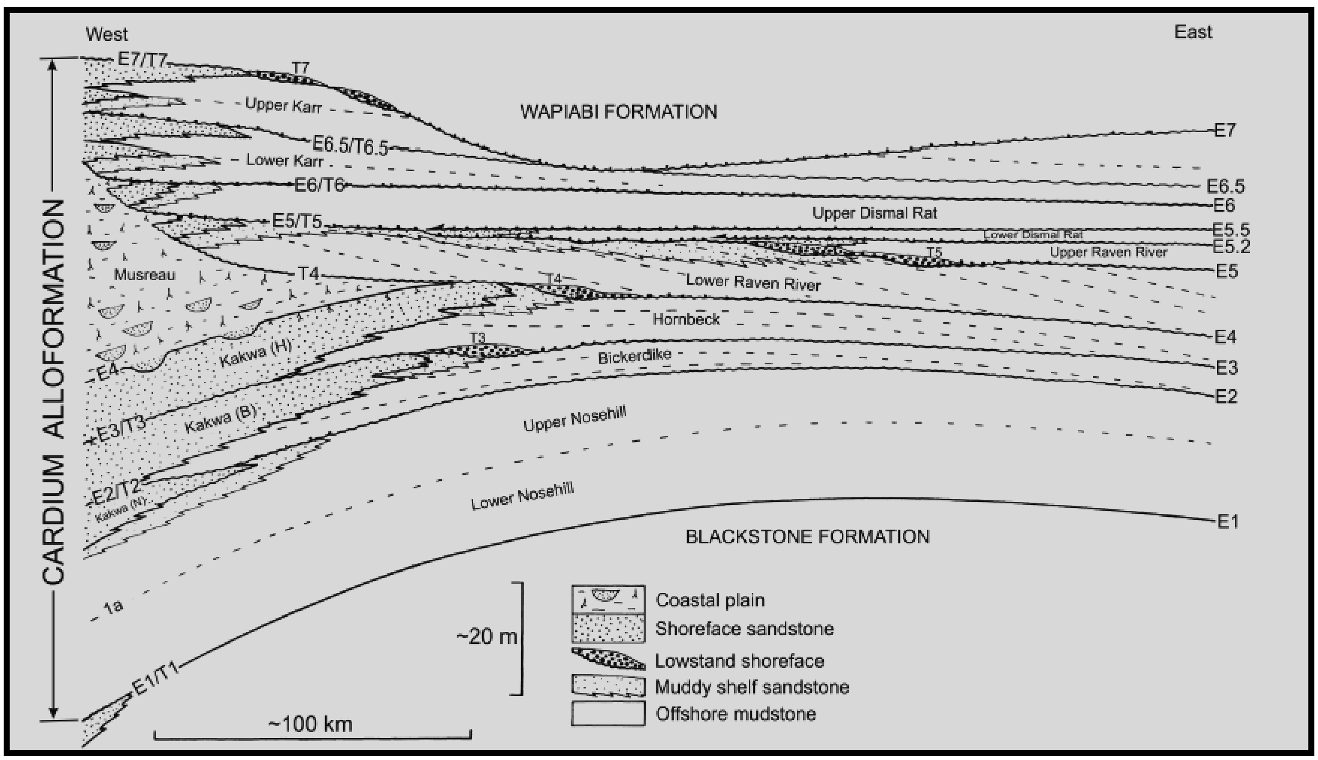


Fig.8: Shank and Plint's depositional model for the Cardium Formation (Shank & Plint, 2013). Each significant allostratigraphic surface is marked with a E and or a T (erosional – transgressional).Dotted area represent sandstones, whereas bigger dots represent pebble-rich areas, claimed to be lowstand shorefaces.

As we can see from the picture, the E5 surface marks the top of the lower raven River member of the Cardium Formation, that is the main hydrocarbon reservoir in the Ferrier area and in the most of Cardium fields.
Looking at the conglomeratic facies, many authors (e.g., Krause and Nelson, 1984; Plint et al, 1986; Shank and Plint, 2013) classified them as lowstand shorefaces built with coarse-grained scour material. Today, this model of conglomerate genesis is widely accepted in the scientific community.

2.1.1: Upper Cretaceous hydrocarbon generation and migration

The Cardium Formation is widely known as light (40 API) oil reservoir, and has as hydrocarbon source the shales of the Second White Specks Formation (2WS). These Late Cretaceous marine shales contain type 2 organic matter having a total organic content (TOC) up to 10% (Creaney & Allan, 1990; Furmann et al., 2015).
According to previous studies (Creaney et al., 1994), the Second white speckled shale reaches the onset of maturity at the depth of roughly 2.5 km, and peak oil generation occurs at 3.5 km.
Hydrocarbons generated start the migration process towards the surface, and the structurally upward pinching-out of the Cardium reservoir facies prevents the hydrocarbon from escaping further, making it an ideal stratigraphic trap for oil and gas.
The sourcing rock of the Cardium is claimed to be responsible for the oil accumulation in the Belly River Formation as well. The hydrocarbon stored within the two formations shows the same chemical characteristics. According to Creaney et al. (1994), “the oil present within the Belly River could be the result of the overspill oil from the 2WS, that failed to reach the Cardium reservoir”.
Also, hydrocarbon migration gets more tricky if biogenic gas is generated in the early burial phase. According to Fuex (1977), if biogenic gas starts filling a trap, then oil, that is generated afterwards, can fail to enter the trap. This facilitates the long-distance migration of oil and makes the understanding of hydrocarbon distribution within the same body much more complicated.

2.2: Introduction to the Ferrier Oilfield

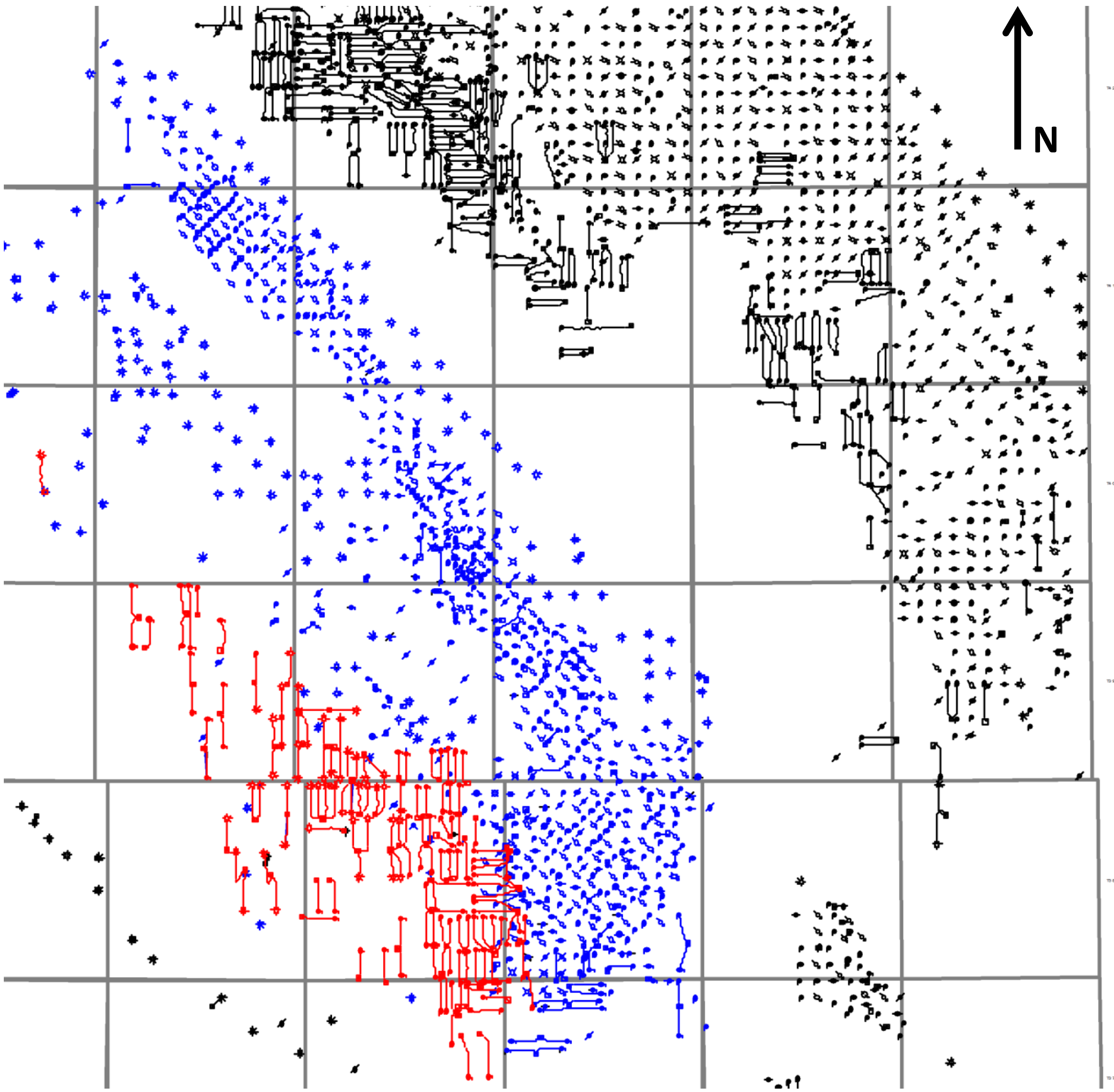


Fig.9: Ferrier location with respect to other Cardium fields and pools. Black wells represent Cardium producing wells outside the Ferrier edges. In the NE area there is the Willesden Green field, whereas the Cardium U Pool can be observed in the SE region. The latter is identifiable thanks to its odd triangular shape (Venieri et al., 2015).

The Ferrier oilfield is around 55 km long and 20 km wide, and oil and gas have been exploited from the Cardium Formation since the 1960s. Other productive horizons are present in other formation in the Ferrier area (e.g. Viking Fm, Spirit River Fm, Belly River Fm), but the Cardium is by far the greatest reservoir for hydrocarbon volume and number of drilled wells.
The wells in black represent each Cardium producing well adjacent to the Ferrier area. In the NE portion of the map part of the Willesden Green field is shown; in the SE we can find the Cardium U Pool, identifiable because of its odd triangular shape.
The wells in blue represent the Cardium vertical and deviated wells formerly or currently producing hydrocarbons in the Ferrier oilfield. These wells have mainly been drilled from the '60s to the late 90's, even if some deviated wells are still being drilled to target by-passed pay zones.
With the beginning of horizontal drilling and multi-stage fracking a lot of fields were rejuvenated, including the Ferrier. Since the 2010 more than 150 horizontal wells have been drilled to target the halo portions of the Cardium. Horizontals are still being drilled in the Ferrier, and their number is quickly increasing. These wells are marked in red in the map.

2.3: Materials and methods

Examination of more than 1200 well logs and 13 cores taken within the pool boundaries led to the identification of 5 main facies, named 1 to 5 from the stratigraphically deepest to the shallowest. These 5 facies are always present in every core, but in different proportion and thickness. Isopach maps of each sedimentary facies will be computed and provided in this paper after the facies description.

2.3.1: Core logging

To describe the lithofacies and calibrate the well log responses 13 cores have been directly described at the Alberta Energy Regulator – Core Research Centre.
Cores have been selected based on several criteria including: good-quality GR, DPhi/NPhi and Resistivity well logs (other log types were an advantage), fluid production, type of produced fluid, availability of good-quality core sample data (phi, k, fluid saturation), core recovery close to 100%, well location close to zones of geologic interest (e.g. heterogeneity in geologic maps based on well log responses) and other.
Particular focus has been observed in logging the most representative sedimentological features of the Cardium Formation in core including: lithology, thickness, bedding, colour, grain size, mineralogy, estimated sand volume (or mud volume), nature of contacts with the units above and below, degree of cementation, presence of fossils or ichnofacies, sedimentary features, degree of bioturbation, depth of interpreted E/T surfaces, presence of fractures, presence of possible flow barriers and other.

A stratigraphic log has been drawn for each described core, also a detailed written logging report has been associated to the graphic log.
In addition to the cores described, the pictures of other 20 cores have been taken into account for lithofacies description and distribution.

2.3.2: Core sampling

Core sampling allows to study a small portion of a core in high detail. The AER research centre allows to take core plugs and other part of a core for thin section purposes.
This research already had lots of porosity and permeability data, that's why we didn't require any additional core plug data. Conversely, we thought it could be very useful to look at particular portions of some cores in thin section and SEM. This had the aim to understand smaller-scale geological features such as packing, mineralogy, porosity and cementation degree through point analysis and SEM scanning.
6 cores out of the 13 logged were sampled. 18 samples from those 6 cores were submitted to AGAT labs, that cut the thin sections.
Besides the petrographic description, thin sections were also used to run SEM and cathodoluminescence analyses.

2.3.3: Optical microscopy

Mineralogy, fabric and grain size distribution have been observed using planar- and cross-polarized light in optical microscope. Thin sections were prepared by AGAT labs (Calgary, AB) with polishing and staining techniques depending on the purpose of the study. For customary petrographic description aluminium was used to polish the sample, whereas diamond was used to polish samples for cathodoluminescence studies.

2.3.4: SEM and Cathodoluminescence

To describe in detail the grain shape and packing, 12 samples coming from 6 out of 13 cores were analysed under the electronic microscope. Out of these 6 sampled cores, 3 came from the main oil body and the other 3 from the unconventionally developed area of the Cardium.
The main aim of this high detailed analysis was to compare the conventional and unconventional area of the Cardium in the Ferrier. This was necessary once it was found out that these two areas didn't just differ in large-scale features like sand content or net reservoir thickness. Moreover, the difference in the type of produced fluid (oil vs gas) in the unconventionally developed area could be attributed just to reservoir petrophysical characteristics. SEM and cathodoluminescence analyses were mainly performed to have more data on mineralogy (chemical element maps of the thin section or sample surfaces) and

pore characterization (influence of clay type and volume on pore size, presence of quartz or calcite cement, 2-D pore connectivity, number of cementation phases).

The secondary electron microscope (SEM) is a tool that generates an image of a sample by shooting it with an electron beam and analysing the electron response. This analysis can be performed in low- or high-vacuum.

BSE (high-energy electrons) microscopy is characterized by low vacuum of the pressure chamber (typically 50 Pa) and high voltage (e.g. 10,000 V). Conversely, ETD (low-energy electrons) microscopy is performed with high vacuum (pressure down to 10^{-4} Pa) and lower voltage (e.g. 2,000 V).

As final product several BSE and ETD pictures were acquired. BSE (back-scatter electrons) images have lower quality, but at the same time a lot of advantages such as the possibility to discriminate different minerals based on shades of grey and to run EDX maps (chemical element mapping).

Conversely, using the ETD (secondary electrons, Everhart-Thornley Detector) tool, the colour just represents topographic relief, so it's not possible to detect different minerals in the sample. However, ETD provides very high quality in the images taken, and can therefore be helpful to characterize very-small scale features such as grains and clays morphology, clay distribution and other up to a magnification of approximately 30,000 – 50,000x.

Finally, cathodoluminescence (CL) analysis registers the emission of light that occurs when the atoms of the surficial grains of the sample, after having been excited by high-energy electrons, switch from a temporary state of high-energy to their ground state (McLemore and Barker, 1987).

Cathodoluminescence analysis had the main aim to get information about the type and volume of cement and

As strongly dependant and the atomic number Z, BSE can't discriminate between different growing phases of the same mineral, as the grain is composed by the same element (e.g. quartz) with the same atomic number.

distinguish each cementation phase.

Conversely, the discrimination between different growing phases of the same mineral is possible using CL due to different amounts of trace elements, as sourced in different time and/or from different areas.

This differentiation can't be made using BSE imaging, as grains of the same mineral have the same Z, or EDX mapping, as trace elements are below detection limits, therefore they would appear as background noise.

Because of its high sensitivity to trace elements, CL can easily discriminate between different growing phases of a crystal or cement, as trace elements depend on the sediment sourcing area and the age of crystallization (the same area can have different trace elements in different times due to geologic reasons).

Finally, CL analysis has been used to detect the presence of chert grains, visible because of the absence of quartz overgrowth.

2.3.5: Petrophysical characterization

In the Ferrier area, a total of 196 wells cored the Cardium sandstone reservoir unit. Out of these, 189 had available core plug and full diameter data on GeoScout. These include depth, porosity, permeability, density and fluid saturation.
Porosity and permeability data have been used to petrophysically characterize the reservoir both in the conventionally- and in the unconventionally developed area of the Cardium.
In chapter 2, Phi and k values have been adopted to find net reservoir and net pay cut-offs for reservoir mapping based on average reservoir values.
This topic will be deeply dealt with in chapter 3, that focuses on reservoir mapping and characterization.

2.3.6: Geological Mapping

Once well log cut-offs were established, a detailed reservoir mapping was performed.
The provided maps have been first contoured on GeoScout using the Surfer software, in order to understand the gross trend of the contour lines in the study area. After that, hand-contoured maps were drawn to shed light on smaller bodies and other smaller scale geological features.
In this study several maps will be provided for high-detail reservoir characterization. Among these, lithofacies mapping is shown in chapter 2 and gross reservoir and net reservoir/net pay maps are presented in chapter 3.
The net sand map (facies 3 map) represents the thickness of the reservoir interval whose GR signature was lower than 60 API. This cut-off has been picked looking at cores and well logs. The observed cores showed the presence of clean sandstones (low GR reading), and also looking at well logs we can detect the presence of a package of sediment with 30-60 API just below the E5 surface. A GR cut-off of 60 API was therefore set to discriminate between sandstones and shales in the reservoir interval.
Facies 4 mapping has been carried out looking at what was on top of facies 3. Conglomerates are identifiable because of their extremely low density porosity (usually 0 to -15% if mud supported and sideritized) and the GR reading between 60 and 75 API.
The net reservoir map shows the thickness of the good-quality (high porosity) reservoir portion of the Cardium Formation.
In this case, net reservoir maps represent net pay maps as well, because the Cardium Formation is completely hydrocarbon saturated in the Ferrier area, therefore it doesn't contain a water leg.
In this study we will provide with two net reservoir maps with different cut-offs. The reason is that two different cut-offs are required to reflect the difference between the conventionally- and unconventionally developed portion of the Cardium in the Ferrier.
We can define net pay as the aggregate vertical thickness of reservoir quality rock that contains hydrocarbons.

Due to the difference between the verticals and HZs recovery factors, horizontal wells are able to produce hydrocarbons even in lower porosity conditions, that is not possible using vertical producers.
According to this, a Density Porosity (DPhi) cut-off was set at 12% for the conventionally-developed reservoir and a 6% for the unconventionally-developed one.
These cut-offs were established based on estimated permeability thresholds for production. A value of around 0.3mD has been set as permeability cut-off for vertical production. 0.1mD is the customary reservoir permeability dividing a conventional and unconventional play, but a permeability threshold of 0.3mD has been set after looking at the production conditions of most of the vertical wells of several companies in the Cardium.
Looking at the main oil body cross-plot provided in picture 45, 0.3mD of permeability roughly matches to a core porosity of 12%. Approximating the real porosity to the density porosity, a DPhi cut-off of 12% has been accordingly proposed.
For what concerns the unconventionally-developed area of the Ferrier, the density porosity cut-off was just used to find the most perspective areas with porosity lower than 12%. Horizontal wells can produce hydrocarbons even in ultra-tight conditions (e.g. Bakken Formation, Saskatchewan), therefore a porosity cut-off for HZ wells is not used to discriminate net pay from the other portion of the reservoir. We used the 6% DPhi cut-off to discriminate between the medium-quality reservoir and the extremely tight reservoir portions.
Both these areas could be exploitable with HZ wells, but the higher the net pay and porosity*metres value and the more profitable the well will be.
It’s important to point out that, as specified above, conglomerates in well logs have usually density porosity lower than 0%. However, when the conglomerate is clast-supported and does not contain mud matrix, it has great density and core porosity. This happens in the northern gas cap area and in a small portion of the western Ferrier. Net reservoir mapping was performed using density porosity cut-offs of 6% and 12%, so in most of cases conglomerates are not included in reservoir mapping. This has been done because, if mud supported, conglomerates can be much less permeable than sands. This means a conglomerate evaluation has to be made case by case, also because it doesn’t show a linear porosity vs permeability trend like the sandstones.
Another tool we used to describe the reservoir architecture is cross-sections. Several sections were made using the highest quality well logs to unravel the geology of the Cardium in the study area.
We built cross-sections both for a general study of the pool and to solve geologic issues, such as the erosion marked by the E5 surface, quantified through parasequences correlation.
The Datum for the cross sections was changed from section to section, in order to find the most suitable one.
Usually the Cardium E6 surface works pretty well in the Cardium and it has been widely used in literature (e.g. Shank and Plint, 2013, Venieri et al, 2015). In case E6 wasn’t a good datum because of erosional steps or other features that would have distorted the Cardium geometry, another surface was picked in the section. To find the most suitable horizon to set as datum, several parasequences were correlated and tested as potential datum; then, the

best one was selected. This is well described in the "reservoir architecture" chapter (chapter 2.4.3.4).

2.4: Results

2.4.1: Lithological characterization

Detailed core logging led to the identification of five main facies in the Cardium Formation based on mineralogy, grain size, sedimentary structures, degree of bioturbation and estimated shale volume. In case of variability within the same facies, sub-facies were identified and described as a single geologic unit.
Each facies is described below from the stratigraphically deepest to the shallowest.

2.4.1.1: Facies 1 – dark grey mudstone with thin silt laminae and few sand-sized grains

Facies 1 is composed of dark-grey, slightly to medium bioturbated mudstones with few siltstones, associated with rare discontinuous sandy horizons. The sandstone volume is approximately 5-10%, and the sandstone is concentrated in discontinuous horizons and bioturbated spots.
Sand percentage increases going stratigraphically upwards along the core, and grain size also slightly increases from shale to fine-grained siltstone.
Facies 1 shows some peculiar characteristics. First of all, it often shows pyrite-rich interval, detectable because of their colour and shininess. Iron is present also in form of siderite concretions, noticeable because of their colour and high density. Siderite concretions can be present at the top of facies 1 and 2 and are always present at the top of facies 3, also they are commonly associated to flooding surfaces. Common trace fossils are *planolites sp.* and *chondrites sp.*, other ichnofossils are rare.
Chondrites sp. are a marker of open marine influence, therefore facies 1 has been interpreted to have deposited in a distal offshore depositional environment. The sand present in the mudstones and siltstones most likely comes from the reworking of tempestites.

Fig 10: facies 1 seen in core. The few sand is present as bioturbated spots (10a); a siderite concretion in facies 1 (10b).

2.4.1.2: Facies 2 – bioturbated mudstones with silty and sandy horizons

Facies 2 is made of highly bioturbated mudstones and very fine to fine sandstones, with the mud volume decreasing stratigraphically upwards. At a certain depth of the core, the sand volume increases from 20-25% to 35-45%, that's why facies 2 has accordingly been sub-divided into facies 2a (less sandy) and 2b (more sandy).

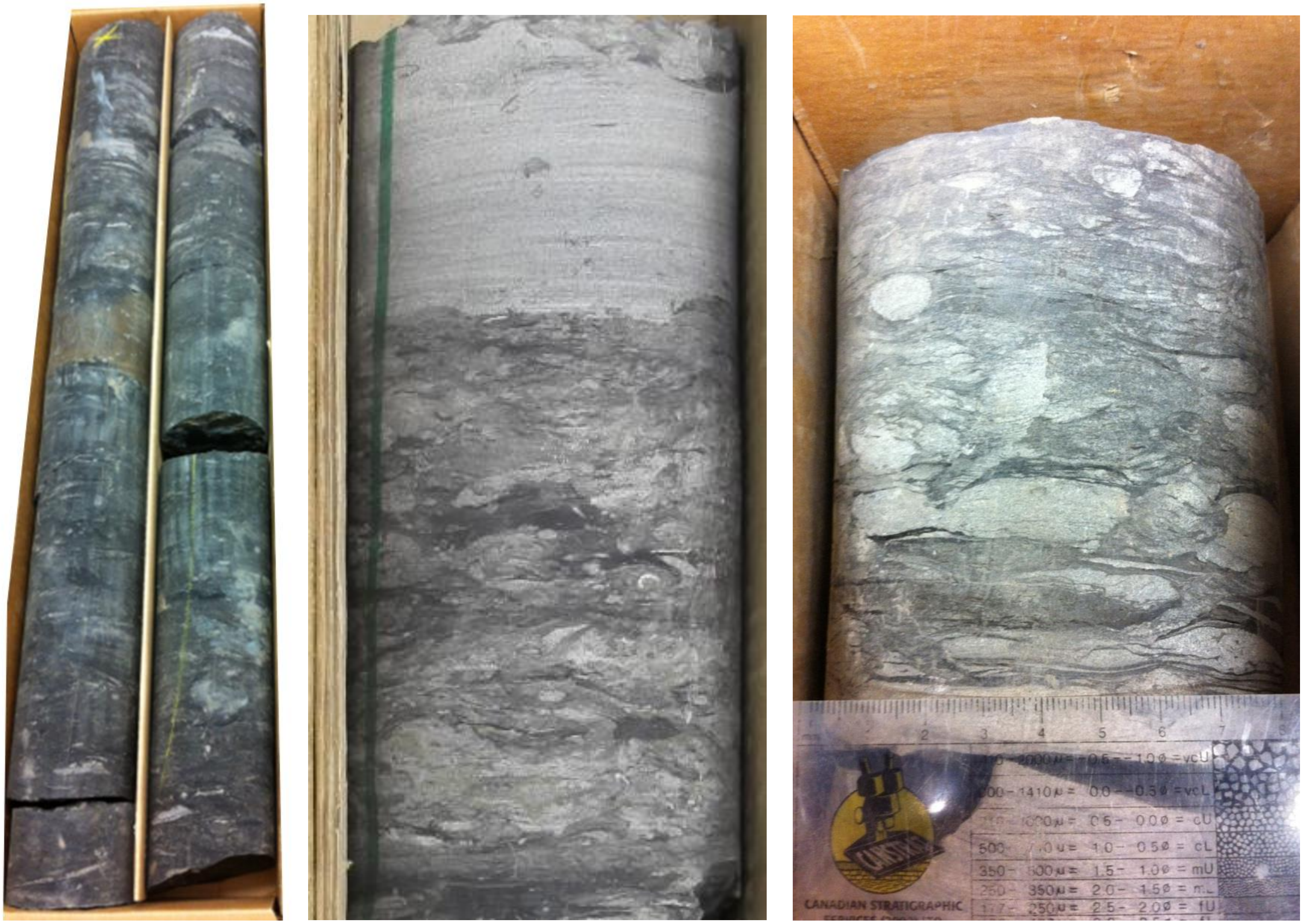
In facies 2a, sand usually occurs in bioturbated spots and burrows fill, whereas in facies 2b is pretty common to find 5-10cm thick sand beds, usually showing starved ripples or Hummocky Cross Stratification (HCS).

Bioturbation degree is medium to high, and common trace fossils are *zoophycos sp.*, *chondrites sp., skolithos sp., rosalia sp.* and burrowing.

Conversely with facies 2 of other Cardium fields and pools nearby (Venieri et al., 2015), Cardium facies 2 in the Ferrier looks too tight to be considered a potential halo play. Also, burrows don't look 3D connected in core, that's why the reservoir potential of facies 2 is almost negligible in the Ferrier area.

However, in the Western portion of the oilfield (unconventionally developed), a facies similar to facies 2 is observed between the top of the sandstones of facies 3 and the pebble lag deposit of facies 4. This facies, that we will call 2c, shows high bioturbation degree, large and connected burrows and a sand volume up to 60-70%. This facies, when present, is around 1-1.5 metres thick, and could be a potential target for horizontal wells.

Facies 2 is interpreted to have been deposited in a proximal offshore environment (offshore-transition). Water depth is interpreted to have been slightly below the fair weather wave base level. The sandy horizons most likely represent tempestites, i.e. storm deposits, whereas the main deposited sediment is silt- and mud-dominated.



Facies 2a Facies 2b Facies 2c

Fig.11: facies 2 seen in core. Facies 2a is the sub-facies with the least sand content, but higher than facies 1 (11a). 2b contains around 35-40% sand volume, but bioturbation doesn't include large burrows, so 3-D connectivity is medium-low (11b). Facies 2c has slightly more sand volume than 2b, but is characterized by the presence of large vertical and horizontal burrows, that ensure great 3-D connectivity (11c).

2.4.1.3: Facies 3 – clean HCS sandstones

Facies 3 is composed of clean, very fine- to medium-grained sandstones. They show visible presence of hummocky cross-stratification, which led to the interpretation of wave reworking processes in a lower shoreface depositional environment.

HCS is constant in each facies 3 interval, however other geological features can be common. Among those, the most important are ripple evidence, presence of imbricated mud clasts, fracturing, compaction faults and other.

The bioturbation degree is very low, however sometimes sands show ichnofacies like *thalassinoides sp.* and *ophiomorpha sp.*

Most of cores analyzed have an interval in facies 3 where the customary clean sands are interbedded with laminated and undulated mudstones, with presence of bioturbation (e.g. *thalassinoides sp.*). We call this facies 3a.

The shaly portions may possibly act as flow barriers, but cores are too spatially limited to prove this assumption. Anyway, the degree of bioturbation in this sub-facies of facies 3 is medium, and the big burrows and *thalassinoides sp.* present in this interval could help in gaining additional permeability.

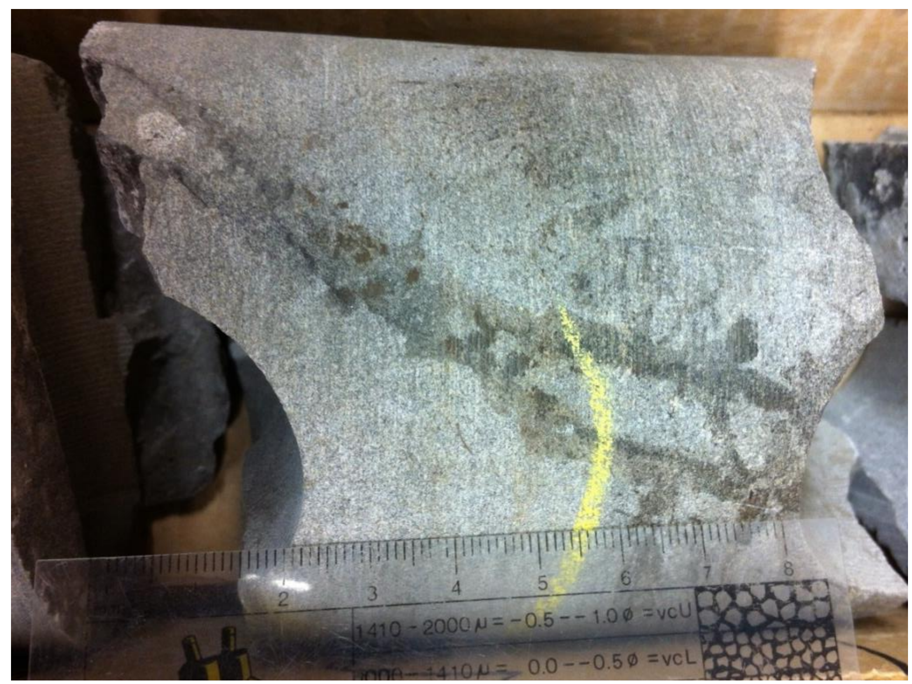


Fig.12: facies 3 is characterized by high sand volume and Hummocky cross-stratification (12a). Bioturbation degree is usually very low due to the high energy of deposition, but sometimes ichnofacies like *ophiomorpha sp*. are present (12b).

Sub facies 3a occurs when wavy mud interbeds are present within the HCS

2.4.1.4: Facies 4 - conglomerates

Facies 4 is composed of conglomerates with a mudstone/siltstone (occasionally sandstone) matrix. The contact with facies 3 is usually sharp with scouring evidence, which has led to an interpretation of an erosional surface. According to Plint et al. (1986), the conglomerates most likely represent a transgressive pebble lag deposit, i.e. a residual deposit left in place by the rising relative sea level.

Conglomerates of facies 4 are well-rounded, poorly sorted and usually matrix supported, but clast supported horizons are present. Where present, the clast supported conglomerates may account for a significant local contribution to the permeability of the reservoir, but just if fractured or encased into sandy matrix.

Concerning grain mineralogy, multi-colour chert seems to be the most common among coarse-sized particles.

A lot of debate is still present among different scientists about the pebble deposition and the source area.

First of all, to erode and transport gravel-sized particles, the sourcing area of the pebbles must be close to the basin, and also the stream competence must be high enough to transport coarse-sized grains.

Pebbles of facies 4 don't represent a random, one-in-a-while flooding event, as the lag is visible in each Cardium field and always on the top of facies 3 sandstones.

Because of the mountains proximity, a first interpretation is that the raising cordillera was the source area of the gravel. As an in-forming orogeny, the Rocky Mountains grew through several tectonic pulses. This is probably the reason for the erosion and transport of the coarse-sized grains, as any raising body becomes more and more affected by isostasy due to different potential energy between topographic highs and lows.

Gravel sourcing area must have been close to the basin, so that the gravel could reach the deposition site.

This has probably been made possible because of an increase in impulse strength. The thrust front consequently migrated basinwards, and the distance between the sourcing area and the basin decreased.

This is also supported by the fact that conglomerates are mainly made of chert. Several studies documented exposures of Paleozoic limestones with abundant chert beds and nodules in the cordilleran thrust belt at the time of deposition of the Cardium clastic wedge (e.g. Bergman & Walker, 1987; Bergman and Walker, 1988; Walker & Eyles, 1988).

Once deposited, the pebbles have been re-organized by wave energy and/or oceanic currents in gravel bars, as described in facies 4 mapping (chapter 2.4.3.3). Reworking processes also scientifically explain the well-roundness of the chert grains.

Re-organization od pebbles into bars is also well documented in previous studies (e.g. Bergman and Walker, 1987; Plint, 1988; Walker and Eyles, 1988; Pattison and Walker, 1992; Shank and Plint, 2013; Wiseman, 2014).

Talking about sequence stratigraphy, the pebbles are interpreted to have deposited during a relative sea level drop caused by the huge amount of sediment eroded from the raising mountains. After the pebbles depositional event, relative sea level rose when the tectonic impulse ceased, or when it decreased in strength and sediment supply could no longer keep up with sea level transgression. Pebbles have afterwards been reworked by wave action in the shoreface.

If this theory is reliable, then tectonic impulses of the growing Cordillera could have played a huge role in the Cardium architecture and facies.

According to this interpretation, some of the Cardium oilfields could have been generated in the following way:

- step 1: mountains raising rate is constant, sediment is eroded, transported and deposited as sand-sized particles (longer transportation and greater distance from the gravel front, that is more landwards)
- step 2: a tectonic impulse occurs and the growing rate of the mountains becomes very high. To contrast the raising Cordillera, a lot of sediment is eroded.
  Tectonic impulses obviously match with a faster migration of the thrust front towards the basin. This makes the gravel front and the sourcing area get closer to the basin. Gravel sized-particles are then transported and deposited beyond the shoreline.
- Step 3: the impulse decreases in strength, that means the sediment is not enough to prevent relative sea level from rising. Facies 5 is deposited and mud deposition begins.

Fig.13: facies 4 seen in core. Conglomerates are poorly sorted and can occur as thick (>1m) horizons or centimetric spots interbedded with mudstones. Facies 4 can be either clast- or mud-supported. The first situation is the most favourable for production, but conglomerates can be a prolific producer also if mud-supported thanks to fracturing and other geologic features.

2.4.1.5: Facies 5 – laminated, bioturbated dark grey mudstones

Facies 5 is composed of dark-grey, laminated mudstones and siltstones, interpreted to have been deposited in a low energy offshore depositional environment. Facies 5 is discernible from facies 1 due to its very low bioturbation degree, with respect to the slightly more bioturbated fine grained deposits classified as facies 1.

Fig.14: facies 5 seen in core. Although similar to facies 1, facies 5 stands out for the almost total absence of bioturbation. In these facies sometimes the E6 surface is visible in core. It is placed either when sands stops to be visible or in presence of a pebbly horizon, marking a minor flooding surface.

2.4.1.6: Cardium type log

In the Ferrier oilfield, the type log for the Cardium Formation is shown in well 100/02-30-039-7W5/00. This well has a core in the Cardium producing interval. The core has been logged, and in this well we can see all the log responses of the different lithofacies described in the previous chapter.

Facies 1 has high GR reading (>90 API), low density porosity (<3%) and low resistivity.

Facies 2a is very similar to facies 1, and therefore difficult to quantify in well logs, due to its low sand content and the gradational contact with facies 1.

Facies 2b can be identified in well logs because of the slight decrease in GR (increasing sand content), and the increasing density porosity.

Facies 3 is easily detectable in petrophysical logging because of the generally sharp contact with facies 2, the low GR and high density porosity and resistivity (if hydrocarbon saturated like in the Ferrier area).

In case this facies shows small and thin bumps towards higher GR, that is index of facies 3a.

Facies 4 is visible in well logs due to the GR signature usually ranging from 60 to 75 API, i.e. slightly higher than facies 3 and lower than facies 1-2a and 5. Moreover, density porosity is lower down to -15 %. This because the pebbles are encased in mud, and there are cement concretions that tighten the rock and increase its density. However it’s important to remember that secondary porosity and permeability make the conglomerate the most permeable reservoir in the Ferrier area.

The resistivity log is not shown in the picture as its importance is secondary for the purpose of the picture itself, as Gamma Ray, Density and Neutron logs are much more efficient to distinguish facies based on petrophysical values. Also, the Cardium Formation is all hydrocarbon saturated in the Ferrier area, therefore resistivity logs are not primary sources of information except eventually identifying eventual zones with higher gas saturation (higher resistivity value).

100/02-30-039-7W5/00

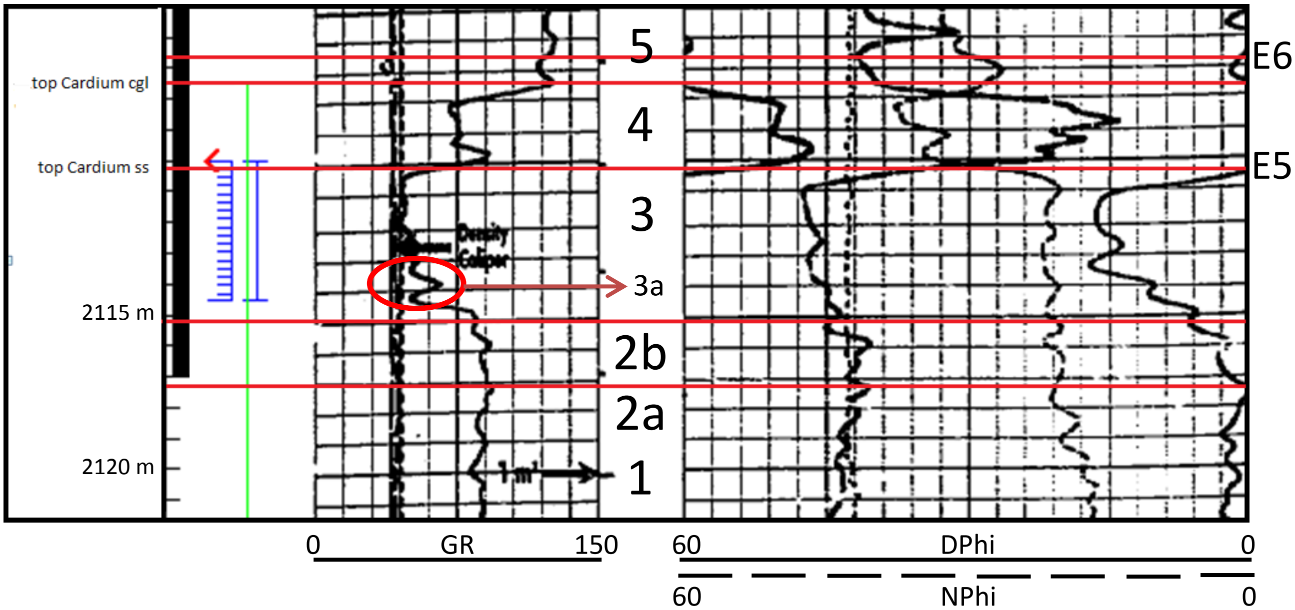


Fig.15: Gamma ray and density/neutron logs of the Cardium Formation in the type well of the Ferrier. Each facies in identified from the variation of one or more log readings.The black box represents top and bottom depth of the core taken in the Cardium reservoir, whereas the blue comb and the adjacent blue line represent the completed interval of the well, as well as the Enhanced Oil Recovery (EOR) technique, that in this case consists in fracturing of vertical wells.

The principal E-T surfaces are marked, as well as the top and bottom limits of the sedimentary facies.

The well log also shows the depth range of the cored interval (black box), that is roughly from 2117m to the top of the picture. As this core has been logged, a detailed core logging sheet is posted below to show the match between well logs thicknesses and core ones.

100/02-30-039-07W5/00

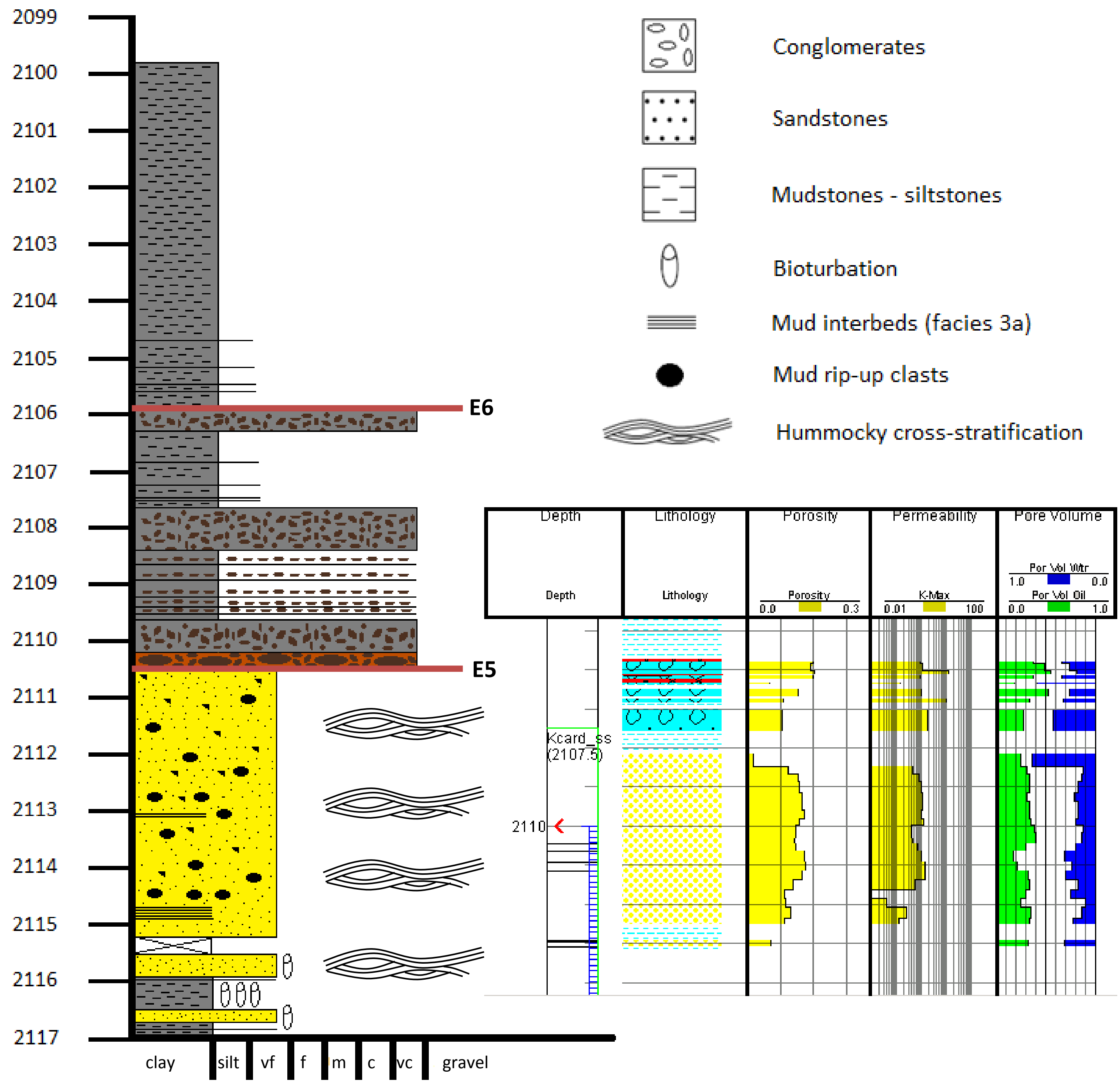


Fig.16: core logging sheet and core plot of well 100/02-30-039-07W5/00. Facies 3 thickness is around 5 meters, and the main pebble-rich horizon is around 2.5 meters thick. There is great match between well logs, core plot and physical core logging thicknesses.

2.4.2: Petrological characterization

Petrological characterization has been applied to the fine-grained facies of petroleum interest, i.e. facies 3.
Facies 2 has been observed as well to have a first idea of its petroleum potential, as routine core analyses had never been taken in this tight facies before in the Ferrier area.
In the following sections, porosity appears as blue spots due to the presence of the epoxy resin.

2.4.2.1: Facies 2

Facies 2a wasn't considered because of its negligible petroleum potential. Facies 2b and 2c have been analyzed in thin section in several contests using multiple magnifications. Facies 2b was sampled both in sand filled burrows and in interbedded storm beds.
The first shown picture shows the geological micro-features of facies 2 as sand filled burrow. Burrowing can account for a significant amount of permeability, but not in this case, as burrows are thin and not enough long and laterally extended to be a decent reservoir.
This thin section has been taken in a strongly burrowed portion of facies 2b in the cored well 100/06-17-038-07W5/00. When large burrows are present, the sandstone often has much better reservoir properties than undisturbed facies 2.
As visible from the thin section, most of the mineralogy is composed by quartz grains (around 75% of the minerals), then there is presence of lithic grains (20-25%) and 0 to 2% of mica. Usually this facies is very tight, but in some spots, like the one shown below, a few porosity can be present. However, the low lateral extent of the burrows and their non-interconnection make the porosity much less effective.
Porosity and permeability is medium in sand filled burrows due to biotic reworking. When facies 2b occurs as bioturbation of thin (max 10-15 cm thick) sand storm deposits, reworking is noticed to be less efficient, that mean porosity and permeability are extremely low.
This can be observed in well 100/02-30-039-07W5/00, where one of these bioturbated sandy horizons has been sampled.
In this case, as we can see from the thin section, the sample is much tighter and cemented, and has much lower reservoir characteristics even having the same grain size.

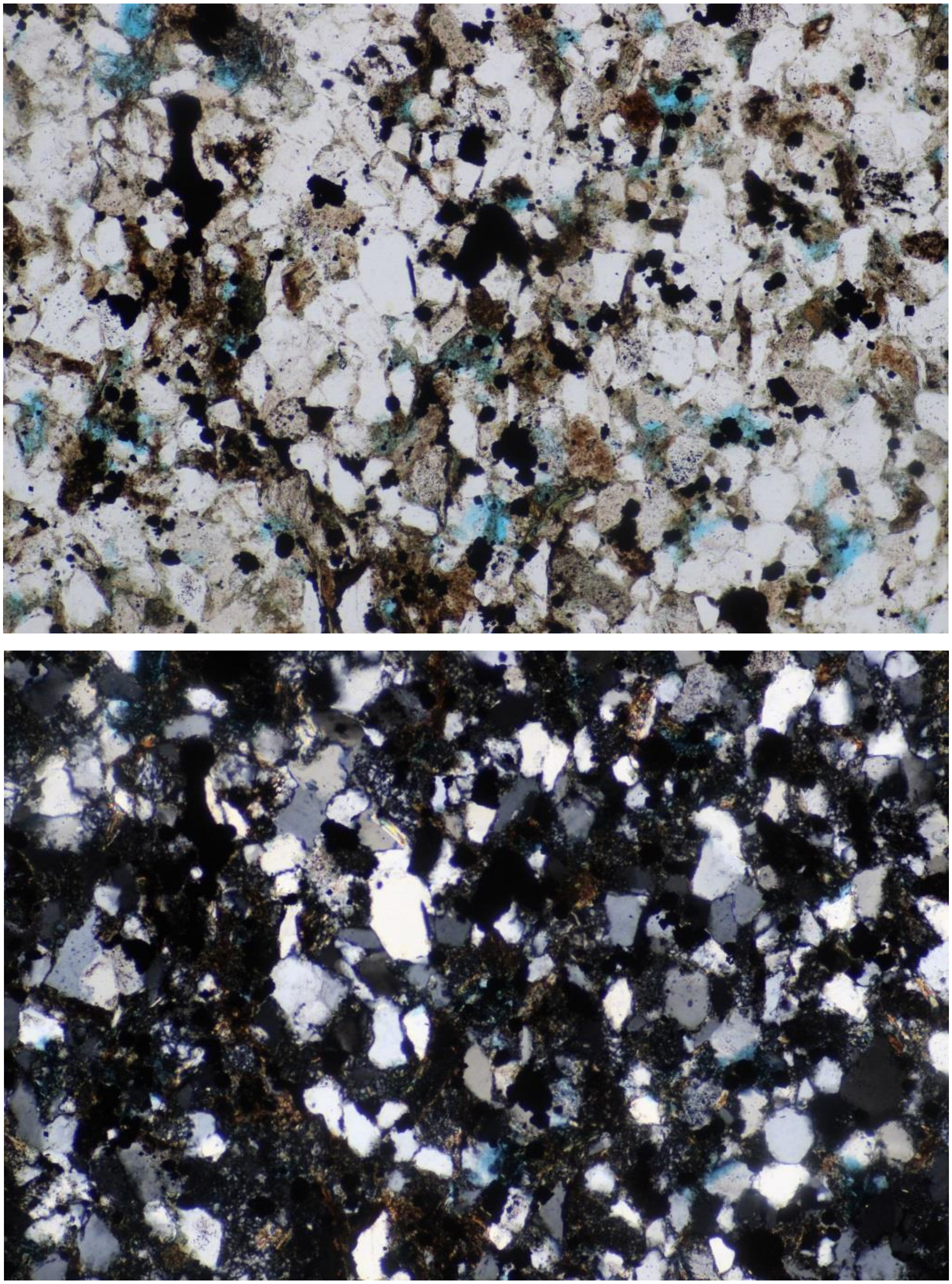
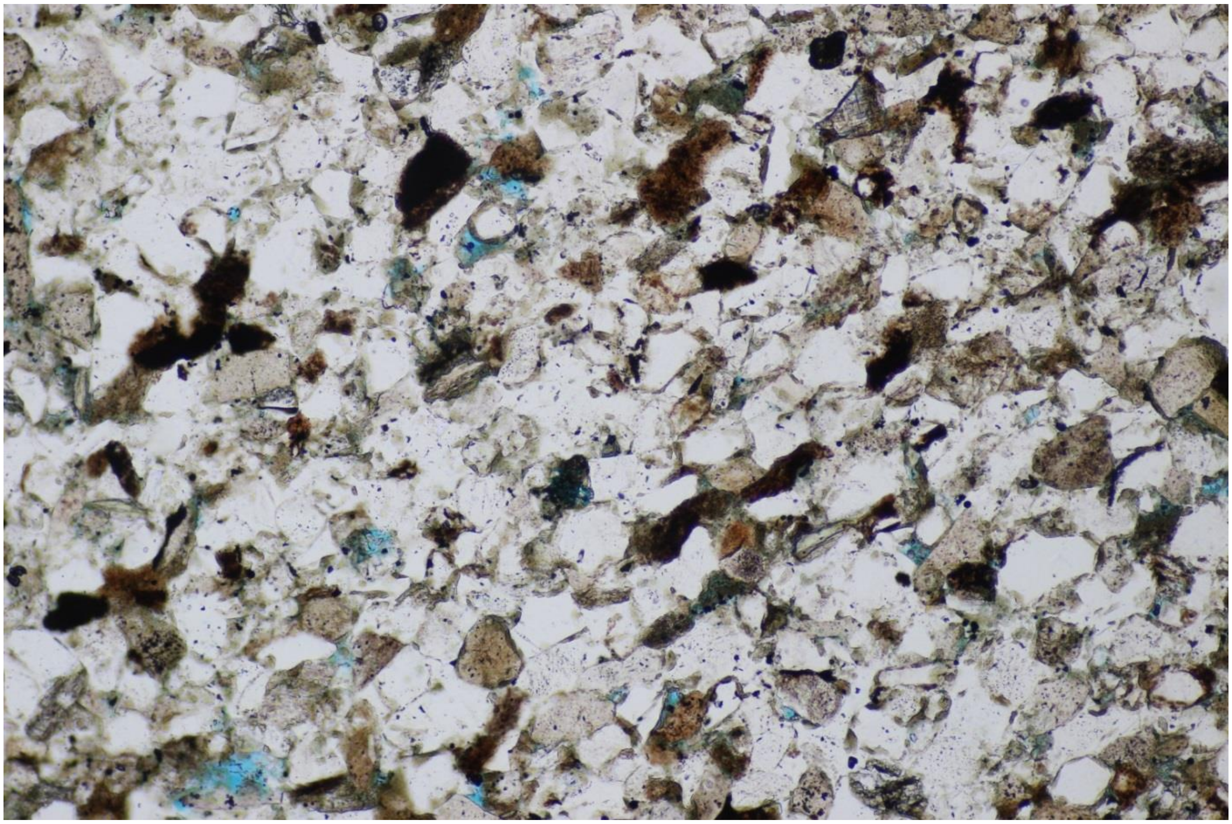


Fig.17: sand filled burrow (facies 2b) in well 100/06-17-38-07W5/00 seen in planar- and cross-polarized light (10x). Quartz and rock fragments accounts for the majority of the clasts, and a few microporosity is present in localized spots.



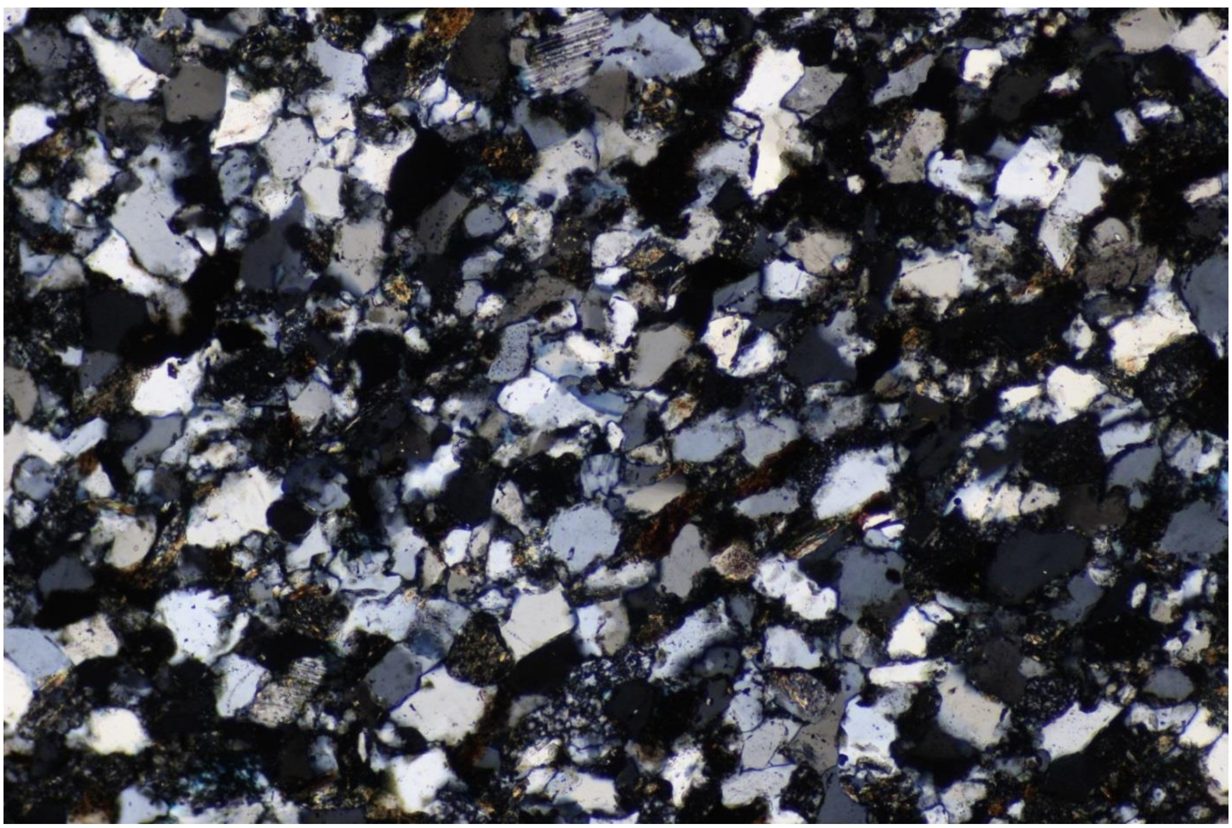


Fig.18: sand storm bed (facies 2b) in well 100/02-30-039-07W5/00 under planar- and cross-polarized light. Very few micro-porosity evidence and mineralogy analogous to the previous picture. Magnification is 10x.

Facies 2c has been observed in thin section as well to assess its petroleum potential. The sample has a medium quantity of porosity. This is most likely 3D connected, because of the interconnection between large burrows.
The mineralogy of this strongly burrowed interval is very similar to facies 2b, with quartz and lithics being the most common grains.

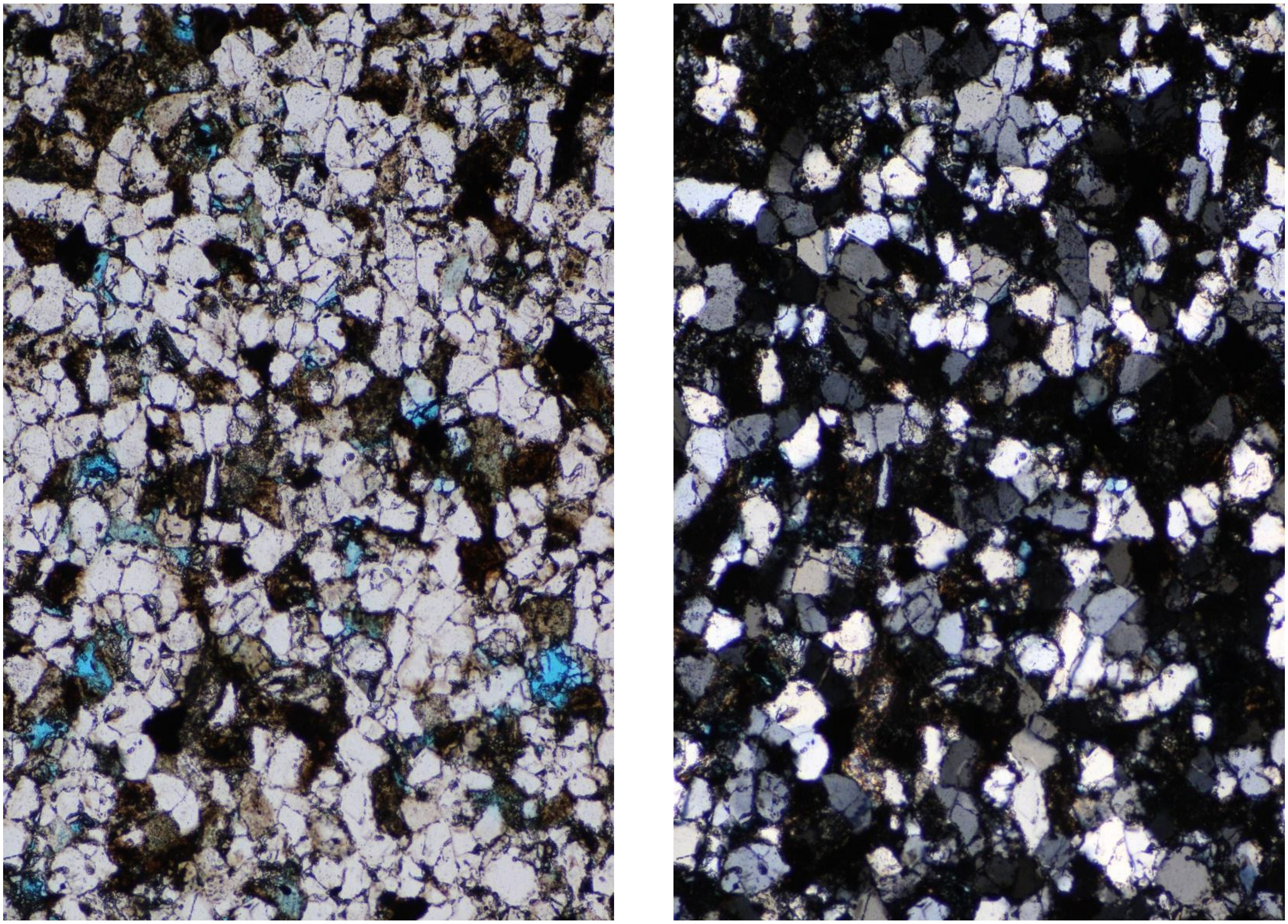


Fig.19: facies 2c under planar- and cross-polarized microscope in well 100/16-15-038-08W5/00. Effective intergranular porosity is present. Being this facies characterized by large inter-connected burrows, it could be a next target for halo play in the Cardium Formation in the near future. Magnification is 10x.

2.4.2.2: Facies 3

Most of the optical microscopy and all of the SEM work has been applied to facies 3. First of all because it's the main oil and gas producer together with facies 4, and also to understand the difference between the conventionally- and unconventionally developed Cardium reservoir.

Particular attention has been payed to sub-facies 3a (HCS sandstones interbedded with laminated and undulated mudstones) to characterize potential flow barriers among the clays. The next picture shows how facies 3 looks like in its top portion, just deeper than the customary cemented sandstones that we always observe in core.

The mineralogy is very similar to the sandstones of facies 2b and 2c, with a major percentage of quartz grains, a few lithics and rare mica and plagioclase. In the provided pictures, micas and plagioclases are visible in cross-polarized light. With both the polarizers inserted, micas show bright colours and plagioclases show visible geminates .

The thin sections shown can give an idea of the reservoir characteristics of facies 3. The sandstones in the main oil body have great porosity and permeability. The sand shown below has a porosity around 18% and a permeability of 2 to 3mD.

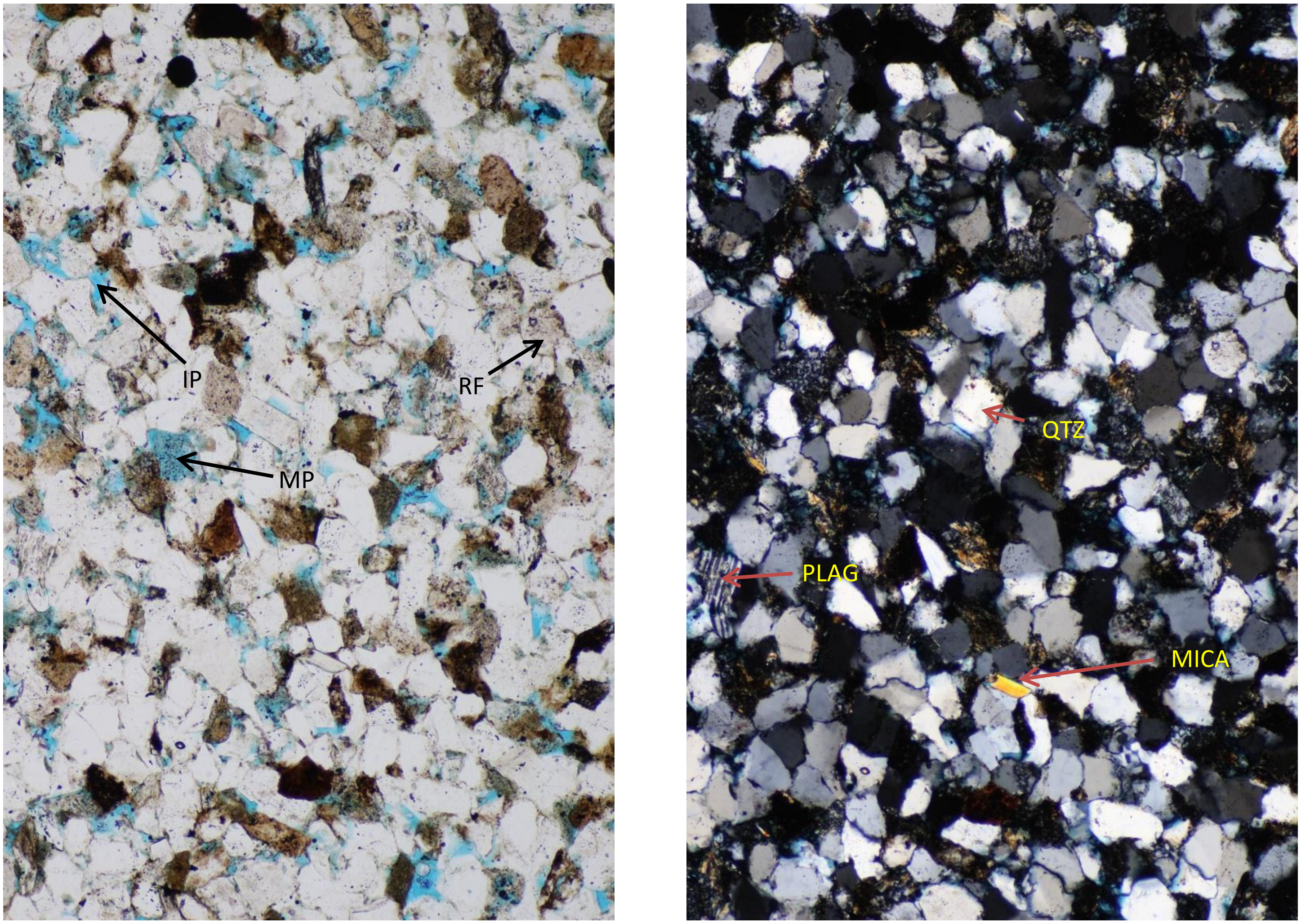
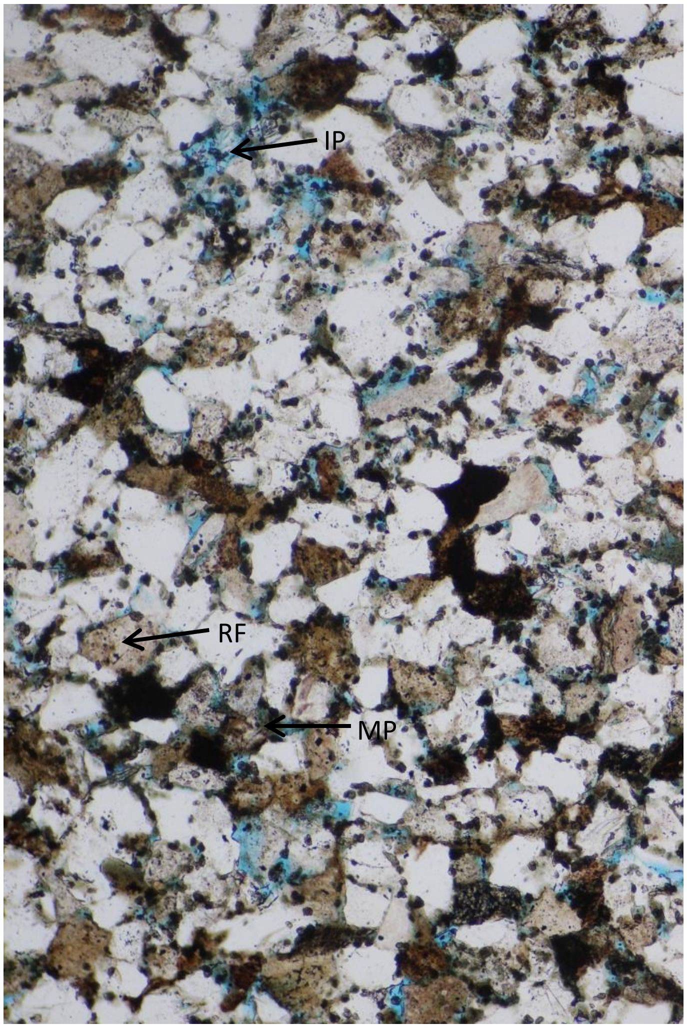


Fig.20: top portion of facies 3 under planar- and cross-polarized light in well 100/02-30-039-07W5/00. Mineralogy doesn't change from the one observed in facies 2b and 2c. The main mineralogical and petrophysical features are marked in the pictures (MP: micro-porosity; IP: intergranular porosity; RF: rock fragment; QTZ: quartz; PLAG: plagioclase; MICA: mica). In evidence the great porosity of the sample, that is around 20%.

The following pictures show how the sand looks like in the middle-lower portion of the reservoir. The petrophysical properties are worse than the top part, but the mineralogy doesn't change.
The thin sections, shown in both planar- and cross polarized light, still show massive presence of quartz, few lithics and very few plagioclases and small mica flakes.
Porosity, marked by the blue epoxy-filled spots, is lower than the top portion of the sandstones, but the sample still shows profitable reservoir characteristics.



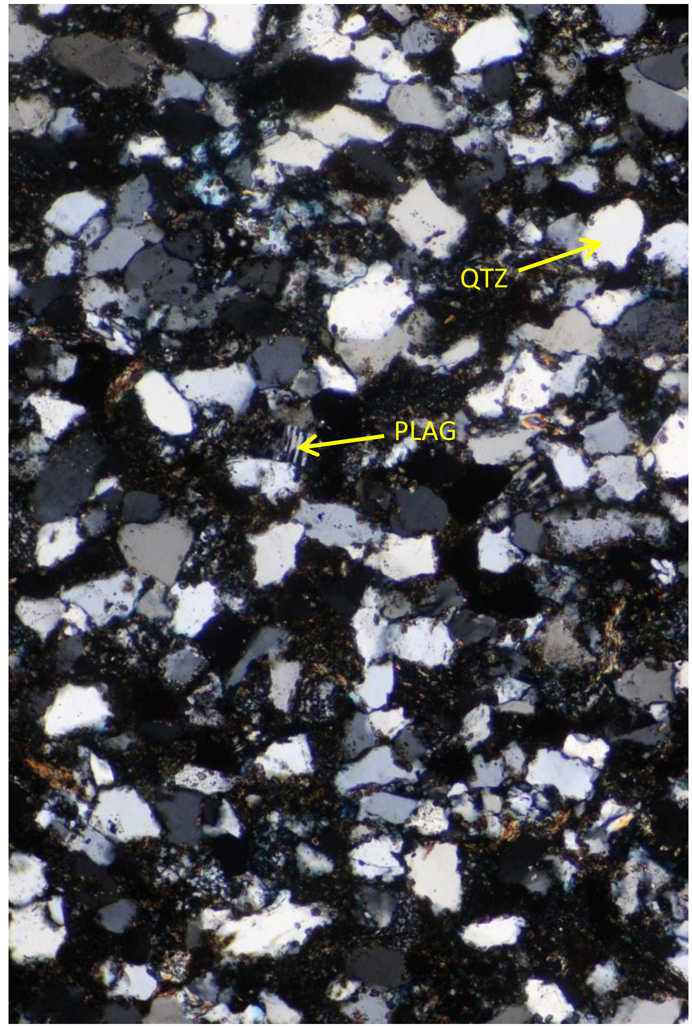


Fig.21: middle portion of facies 3 observed under planar- and cross-polarized light in well 100/02-30-039-07W5/00. Mineralogy is analogous to the one observed in the previous picture. The sample shows lower petrophysical characteristics than the top portion of the reservoir. The main mineralogical and petrophysical features are marked in the pictures (MP: micro-porosity; IP: intergranular porosity; RF: rock fragment; QTZ: quartz; PLAG: plagioclase).

Concerning small-scale features of facies 3, detailed SEM and EDX (chemical element) analysis have been performed. The following picture shows the general grain shape and packing. Quartz grains, detectable from conchoidal fracturing and proper shape and aspect, don't appear weathered. The other grains, conversely, appear fractured and altered by physical and chemical weathering. The latter most likely represent other minerals less stable than quartz, or simply grain coating due to authigenic clays growth.

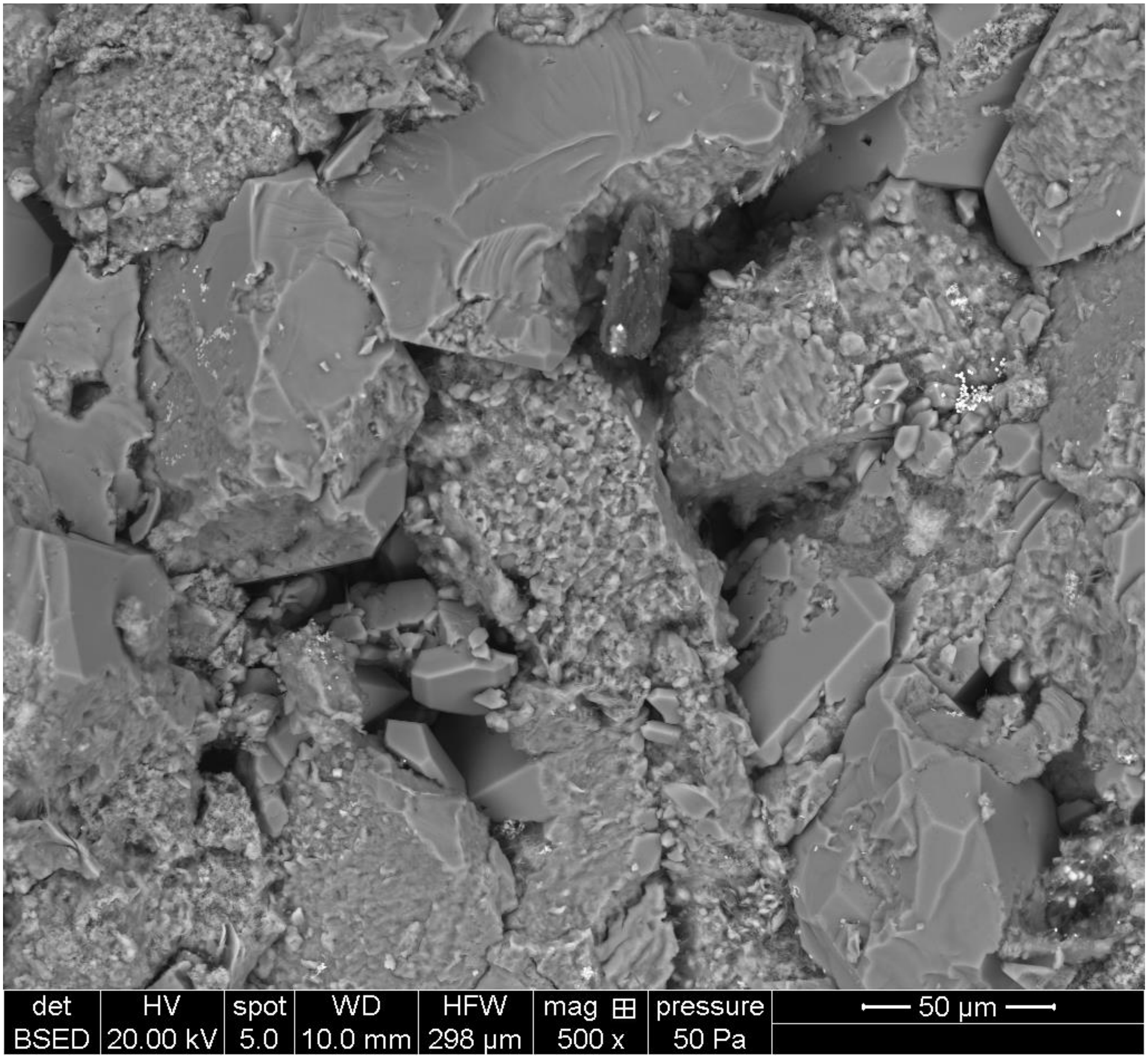


Fig.22: an example of how facies 3 looks like under the SEM. This picture has been used as base map for EDX (chemical element) mapping shown in the next pictures.

EDX mapping is a useful tool to understand the mineralogy of the sample. Sample 4 of well 100/02-30-039-07W5/00 has been analyzed under low vacuum and high voltage, and EDX analyses have been performed. In the next page, detailed EDX pictures are provided, as well as the SEM-derived base map.

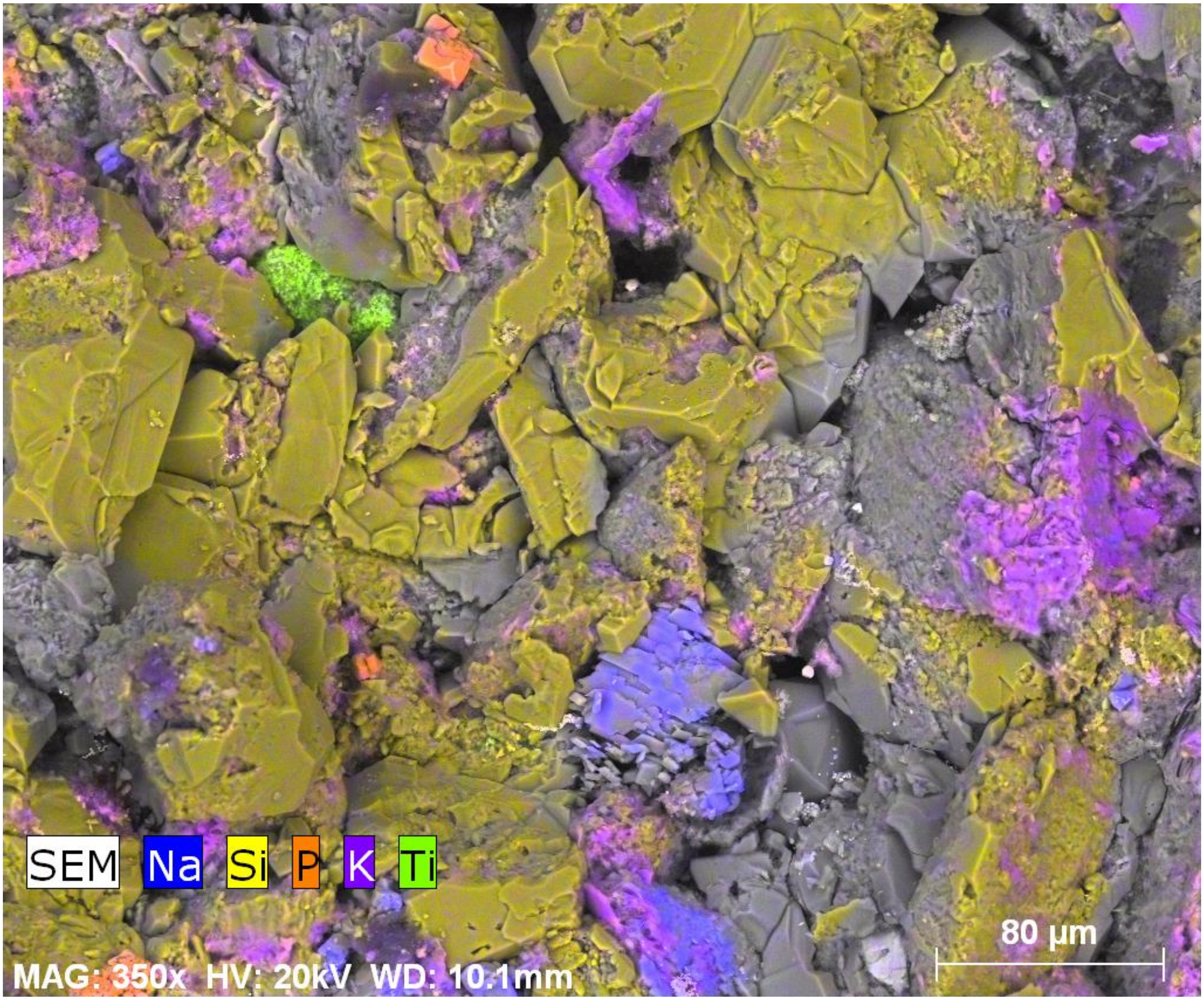


Fig.23: EDX mapping run on the base map shown in picture 22. As the topography of a cutting is rough and not smooth, electron counts only come from the smooth portions of the sample. Rough areas have the effect of scattering electrons, so they appear in grey, that is the colour of the SEM base map used for EDX mapping (figure 22).

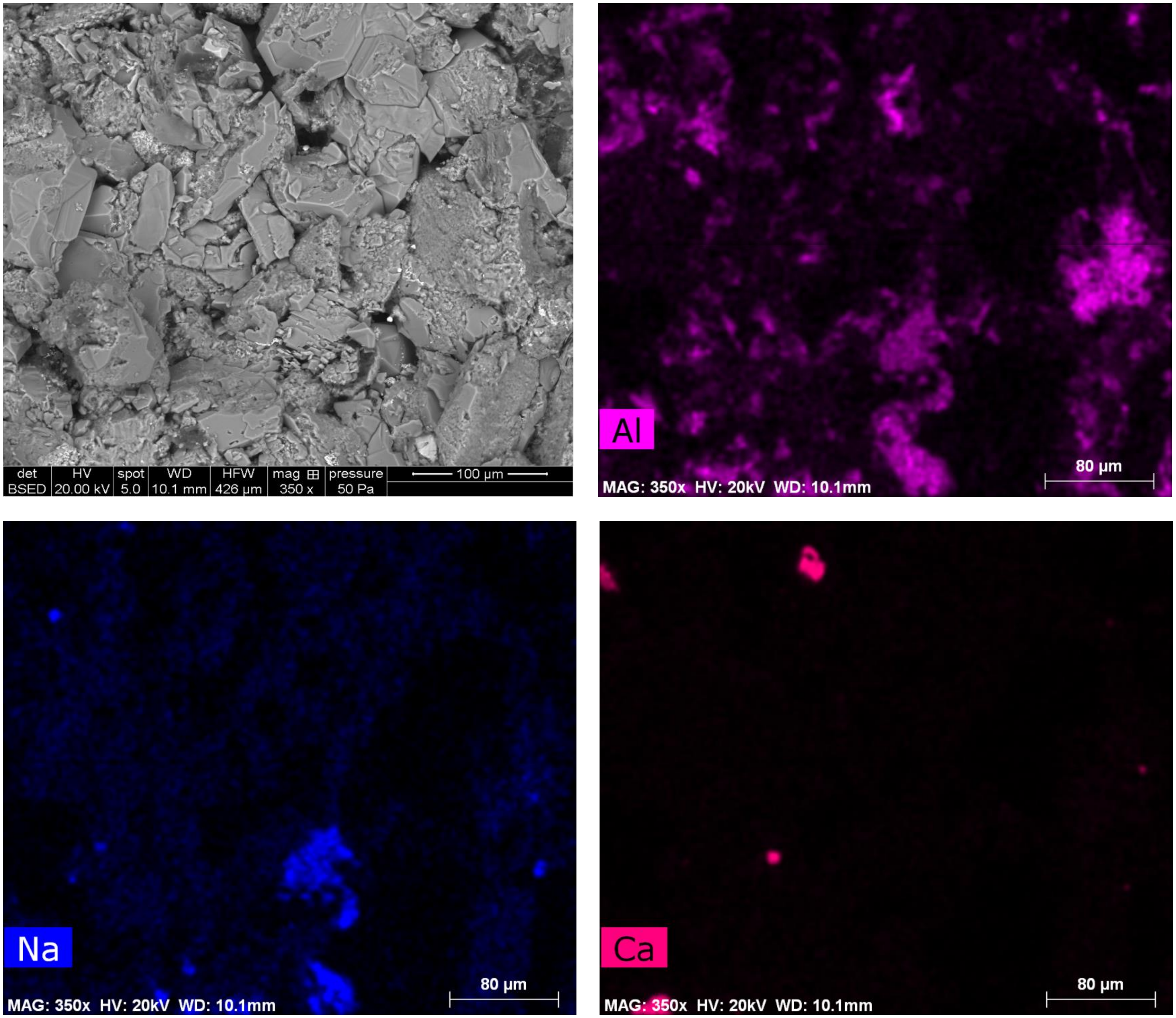


Fig.24: EDX (chemical element) mapping of some chemical elements in the sample shown in picture 22. Al is mainly found in the pore space, and represents clays and other silicates rich in aluminum (e.g. plagioclases). Na represents Albite (sodium feldspar), that appears quite weathered. Ca represents mainly calcite, but in the NW area it could represent anorthite (Ca-rich feldspar), as the colour is less bright, that means the grain is more weathered.

EDX analysis shows the distribution of chemical elements in the sample. The roughness of the sample prevents depressed areas to receive high electron count rates, therefore they are shown in grey like the SEM base map.
Quartz grains are the greatest majority of the rock volume, and they are shown as silica-rich particles.
The space between quartz grains is occupied by potassium- and aluminum-rich particles. They represent clays, that are rich in those elements, and other Al-rich silicates (e.g. plagioclases). Clays have most likely formed during the diagenetic process weathering other mineral present in the rock, like feldspars. According to this interpretation, in the EDX map a weathered, residual crystal of Na-rich plagioclase (albite) is visible.
Ca is present as calcite cement and Ca-rich plagioclase (anorthite). We detect the difference between the two minerals as calcite assumes a more brighter colour than the weathered anorthite.
Also a small amount of Titanium and Phosphorous is present, respectively as Rutile and Apatite.
EDX mapping confirms that quartz grains are the most common in the Cardium sandstones. Clay-coated, weathered, non-quartz grains account for a 15-20% of the mineralogy. Residual plagioclase grains are present and testify the mineral alteration due to diagenetic processes. Authigenic minerals present are clay-minerals and micas (muscovite is more present than biotite).
Detailed pore characterization of the reservoir will be discussed in chapters 3 and 4. However, a first clay description will be provided below.
SEM analysis led to the identification of two main types of clay in the analyzed samples. Illite is the main occurring clay-type, and a minor quantity of kaolinite has also been observed.
The two clays mainly differ in their aspect in picture: illite fibers form a sort of “lettuce leaf” shape, whereas kaolinite looks more like a piling up of thin prisms.
To get more detailed pictures of illite fibers at great magnifications, ETD (high vacuum) mode was used to characterize clay types. Kaolinite prisms were conversely studied in BSD mode because of their greater magnitude.
Illite is the most common clay type in this area of the Cardium, and it’s one of the reasons the weathered grains looked Al- and K-rich in the EDX maps, with higher contents of K ions reflected by the brighter K colour in chemical element maps.
Relative quantification of these two clay types is a key-topic in reservoir characterization, as will be discussed in chapter 3.

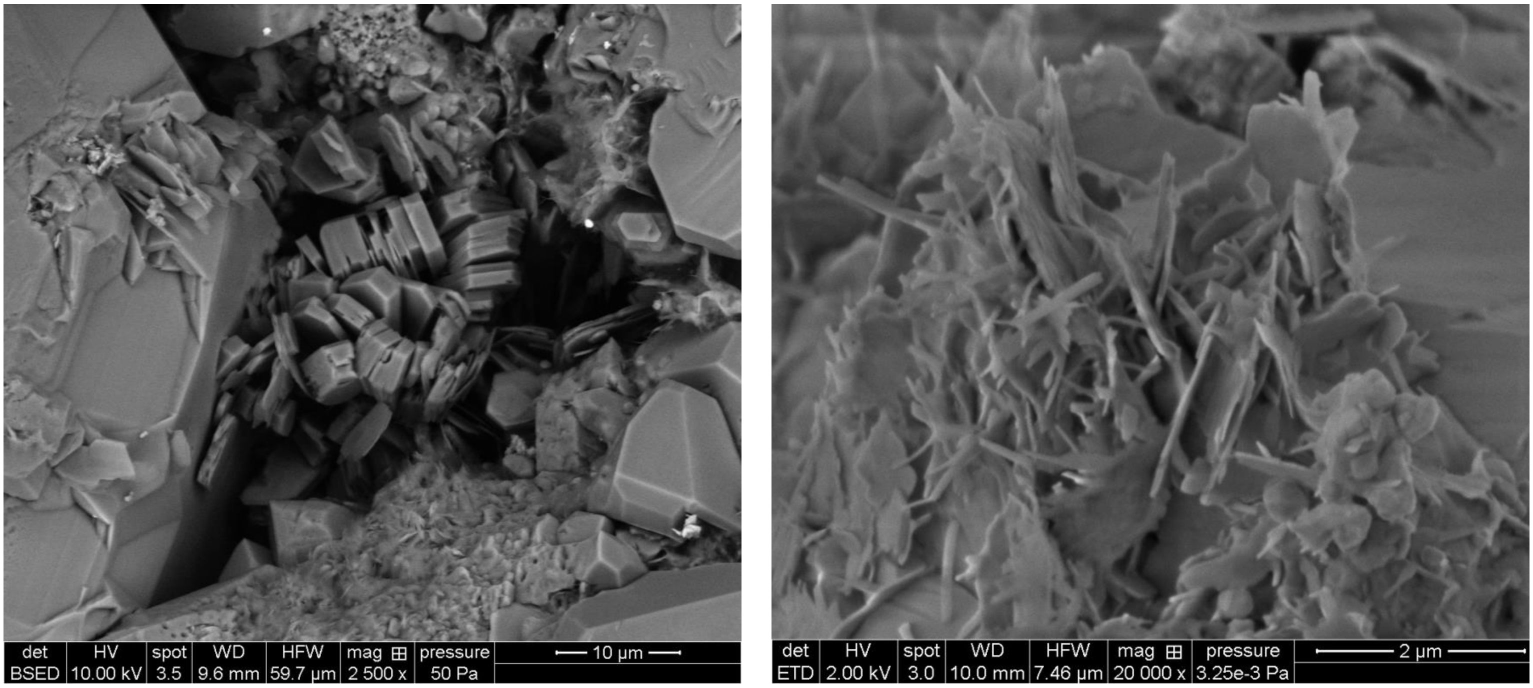


Fig.25: two types of clay in the pore space of facies 3 sandstones. Kaolinite (25a) and Illite (25b). The two clay types are distinguishable looking at their external aspect.

Facies 3a has been analyzed as well to estimate the mineralogy and grain shape of this transitional facies.
Thin sections of 4 sampled cores show that the sand in facies 3a is tighter and slightly finer-grained than the one in facies 3, even if the mineralogy is very similar.
Sandstone porosity is very low, around 5-7%, and quartz is the dominant mineral in the horizons between clay-rich layers. Concerning clays, they appear like continuous, undulated clay-rich horizons, showing higher mica content than any other portion of the core. The genesis of the mica is most likely due to a diagenetic process involving clays as well.

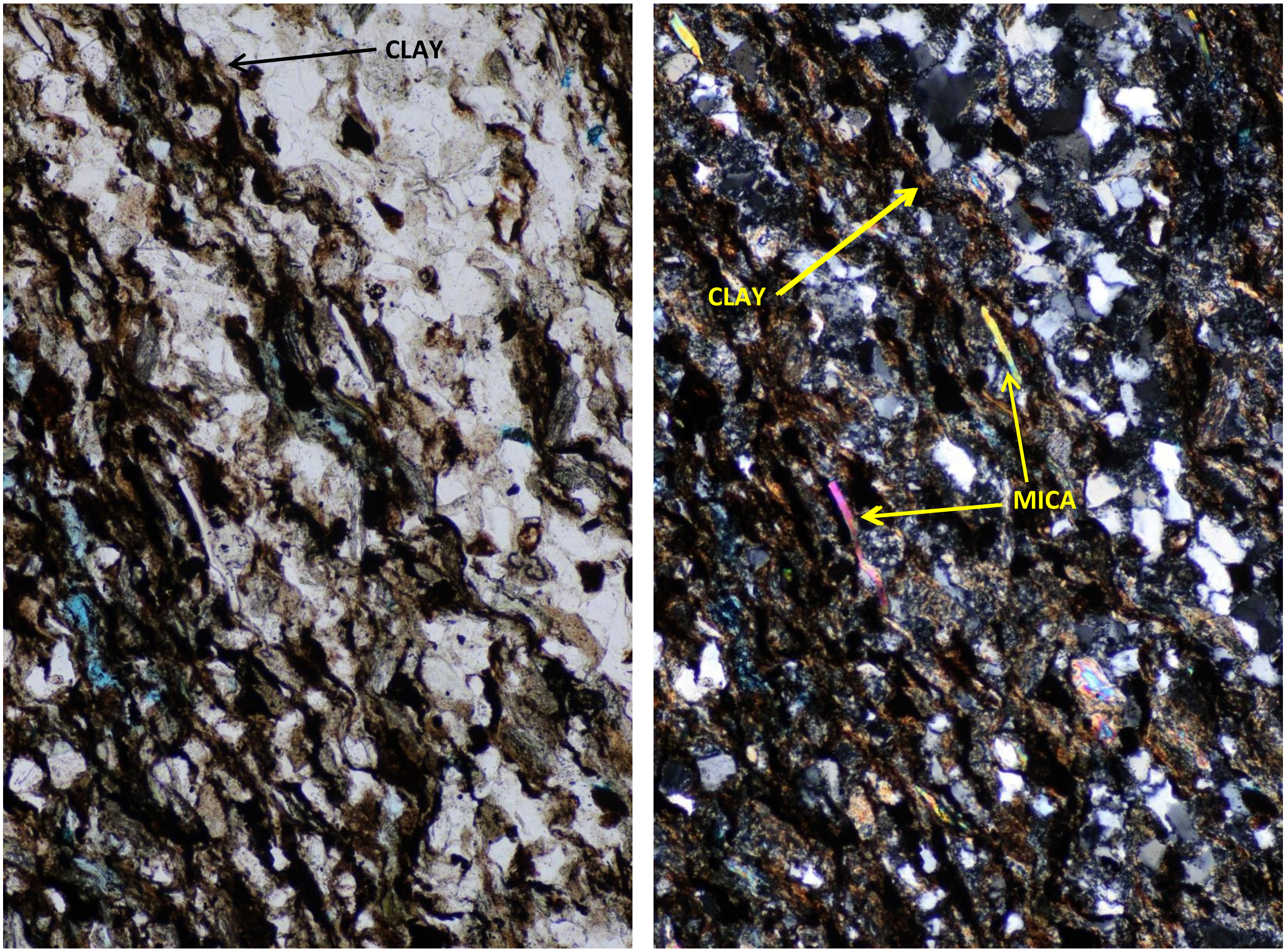
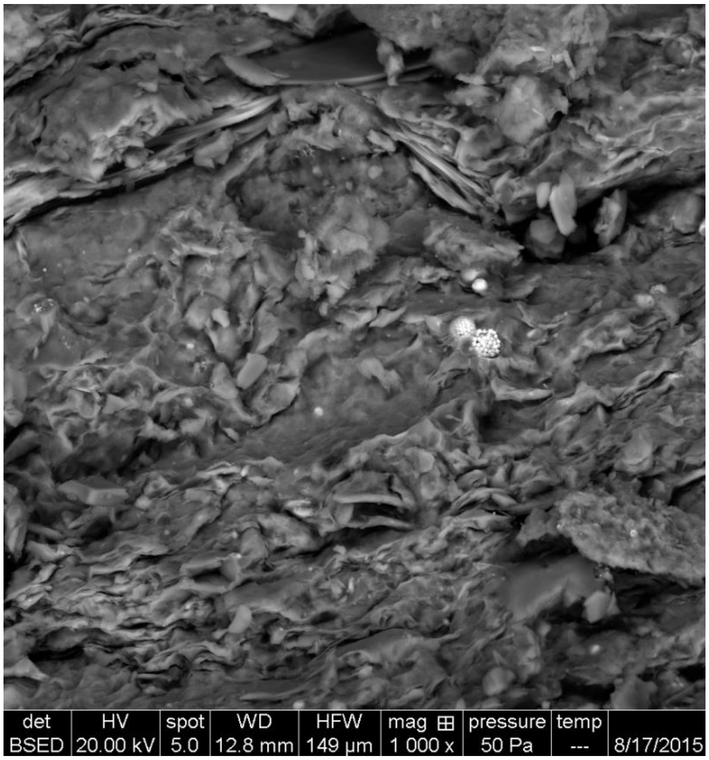


Fig.26: facies 3a under planar- and cross-polarized light in sample 100/06-17-038-07W5/00. The main feature of this facies is the presence of wavy clay laminae interbedded to facies 3 sandstones. Mineralogy doesn't change from facies 3, but in the spots with great presence of clay, an increase in mica presence has been observed. Muscovite seems much more present than biotite and chlorite.

In the SEM pictures, facies 3a looks like the customary facies 3 with the presence of clay-rich sheets that act as grain coatings. When laterally continuous, this facies can be a serious issue for production.



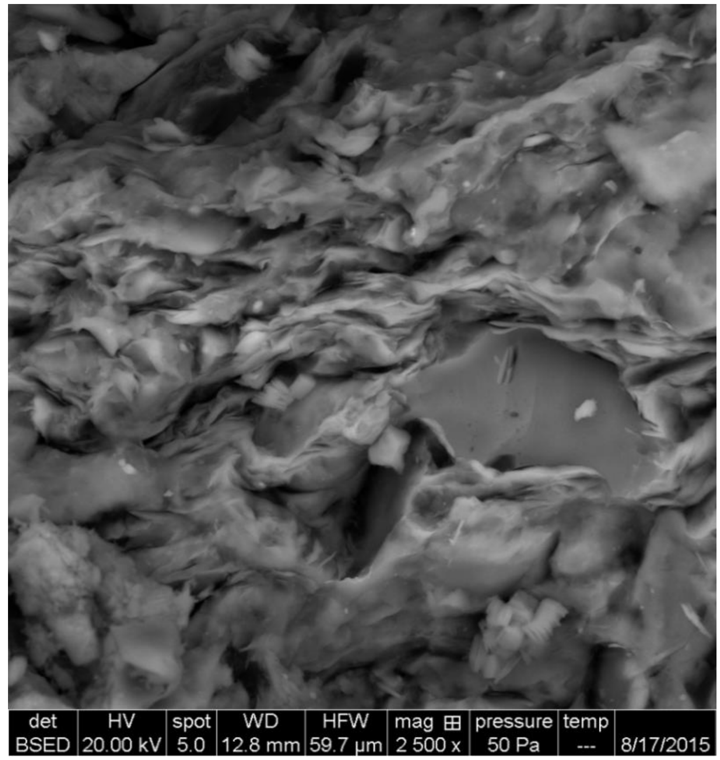
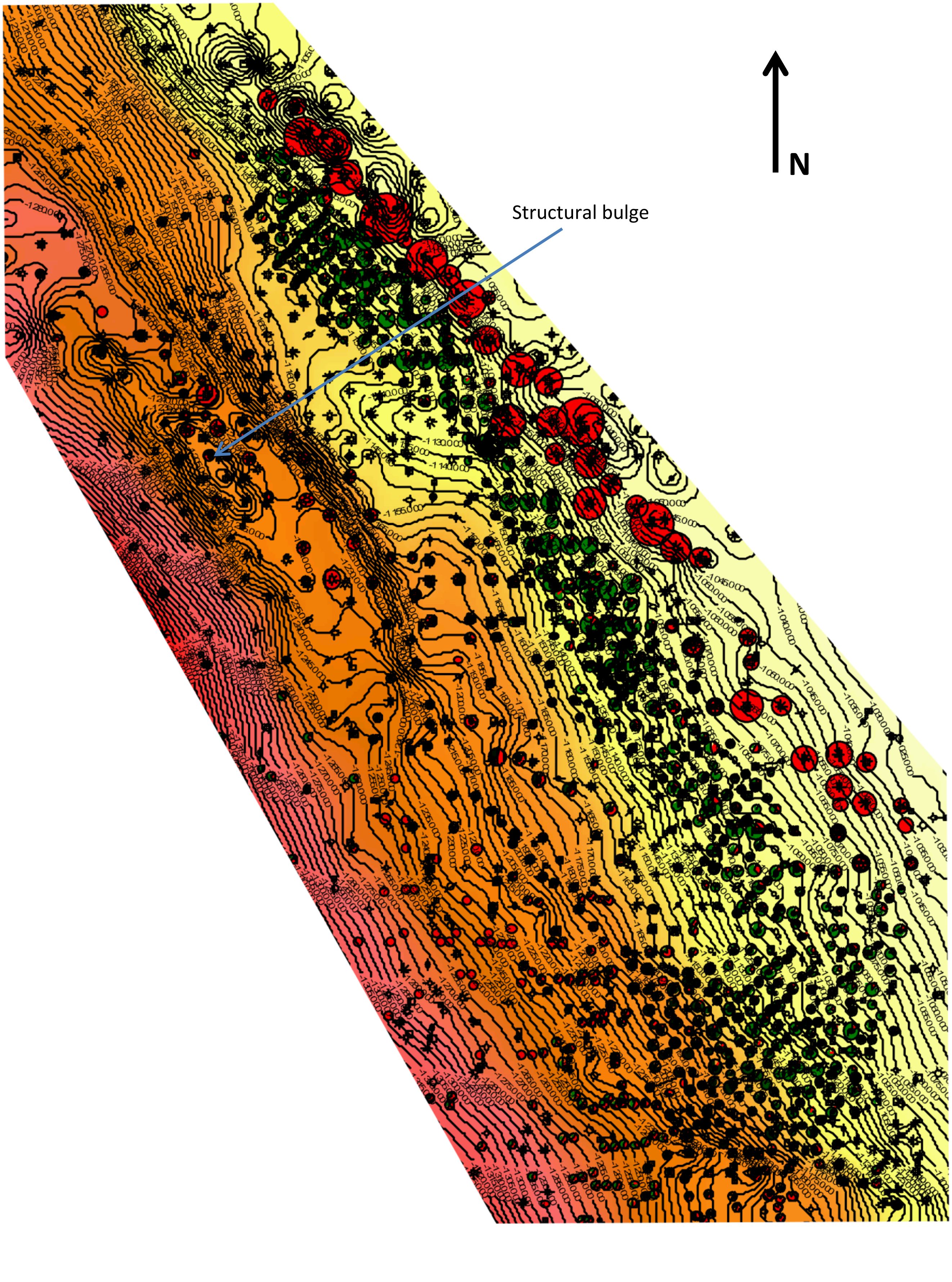


Fig. 27: facies 3a seen under the SEM in well 100/02-30-039-07W5/00. Picture 27a shows the large-scale aspect of the clay laminae, whereas the small-scale view is offered in picture 27b. In this figure it's evident that the clay laminae act as grain coating of the sand clasts. Pyrite framboids are visible due to their bright white colour in picture 27a.

2.4.3: Facies mapping and reservoir architecture

2.4.3.1: E5 surface structure map

The E5 surface (top of the Cardium sandstones) was picked in each well with available well logs. At the end of the picking process, 1337 wells were considered in a 1500 km^2 area.
As we can see from the map, the general dip of the Cardium is towards the ESE because of the Rocky Mountains load on the crust. E5 depth ranges from 2000 m in the NE region down to 2570 m in the SW (-1010m to -1430m as elevation with respect to the mean sea level).
Average SW dipping angle is very low (estimated 0.013° in average for the whole field) and generally constant in all the Ferrier area.
However, a structurally anomalous portion of the top of the Cardium does exist in the NW area of the Ferrier, where production charts show 100% gas production, with high production rates as well.
To facilitate the 3-D visualization of the E5 structure a 3-D model has been built. The model is posted below.
From the representations we notice the presence of a bulge shape. This bulge is around 50m high and it most likely didn't form syn-deposition. This is claimed because shoreface sandstones tend to deposit as low angle clinoforms, bulges are more typical in carbonate environments (reef buildups). This bulge could actually have been formed before the deposition of the Cardium, but if so the sand thickness in that area should be much lower than the normal deposition areas (lower sediment preservation on topographic highs). We don't notice that in the net sand map (see also fig.74, chapter 3). Conversely, that area matches with a portion of the reservoir where sands and conglomerates are thick and permeable. That suggests the bulge most likely reflects a structural feature, probably a fault.
A core taken right on the bulge was logged in detail to understand the causes for the excellent productivity of the area. This topic will be dealt with in the "Reservoir Characterization" chapter of the paperwork.


Structural bulge
N

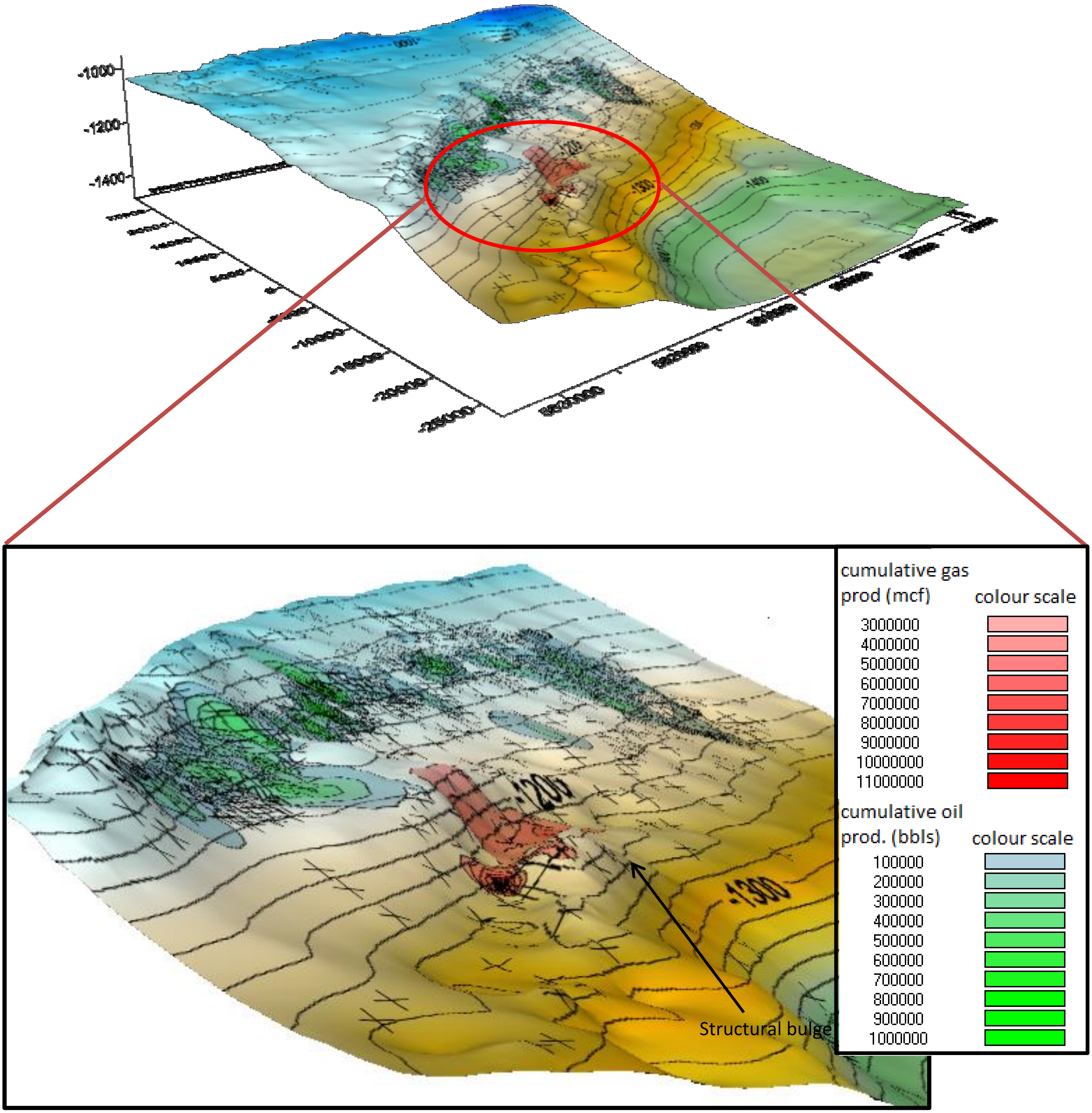


Fig.28: contour map and 3-D structure map of the E5 surface overlain by the contour lines of cumulative oil and gas production to identify the two compartments of the Cardium reservoir. “X” symbols represent wells with picked top sand value. Depth values are expressed in metres with respect to the average sea level.

2.4.3.2: Facies 3 thickness map

Facies 3 has been mapped in cores and well logs, and facies 3 thickness has been plotted for each of the 1314 wells with available gamma ray log in the Ferrier area.
An important issue with facies 3 mapping is that the sandstones and clast supported conglomerates usually are not easily distinguishable in well logs. A core calibration has been made, but conglomerate distribution, as will be shown in facies 4 mapping, is not constant along the study area. This means several interpretations can be made about the thickness of the conglomeratic interval for each well.
This problem however is a real issue just in the northeastern portion of the gas cap area and the eastern edge of the conventionally developed, gas producing area in the western Ferrier. In these two confined areas the clast-supported conglomerate thickness can reach values up to 8 metres, and well log signature is very similar to the sand one.
This problem has partially been solved calibrating sand thickness values with the ones shown by physical core logging and routine core analysis data. However, in the gas cap wells variations in sand content can occur at a quite small scale. Generally, according to what observed in core and core analysis data, the greater the conglomerate thickness and the thinner the preserved sandstone package.
Two gas cap wells have been logged: in one case there was the total erosion of facies 3, with an abrupt shift between facies 2B and facies 4; in the other case, around 3 metres of sand were preserved and located beneath the conglomerates.
This is to confirm that understanding how many meters of sand have been preserved without looking at a core is not immediate, having the sands and the conglomerates also very similar log signatures in the gas cap area.

Fig.29: differential erosion of the E5 event in two different locations displaced by 15 km. In figure 29a (100/10-16-042-09W5/00), sands are still present beneath the pebble bar. In figure 29b (well 100/10-10-041-08W5/00) facies 3 has been completely eroded, and facies 4 places on top of facies 2b. In this specific example, the well that eroded facies 3 most is the one with greatest thickness of facies 4. This assumption has been verified comparing facies 3 and facies 4 relative thicknesses in routine core analyses, and seems to work for most of the wells in the Ferrier area.

The provided map shown in the following page represents facies 3 thickness in the study area. Colour scale goes from white to yellow, orange and red. Colours vary through 0.25 m steps.
The map shows that the sand bodies are NW-SE stretched. Bodies follow the trend of the shoreline at the moment of the Cardium deposition. The edge of the in-forming Western Interior Seaway was NW-SE oriented, as well as the growing cordillera structural trend.
Highest sand thickness values are visible in the northern portion of the main oil and gas body. Good sand thickness values go on until T39 R7W5, where sand thickness values are lower by around 1m (transition from orange to yellow).
Just western of this sand body, starting from the area with a few sand missing (T39 R7W5), a NW-SE oriented area with very few to 0 sand metres begins. These area has only a small belt in which the sandstones are preserved, and this is visible in T40 R8. Several cross-sections of this small area will be shown, as it's believed that this small sand belt may play a major role in reservoir compartmentalization, as it will be discussed in chapter 3 and 4.
Going even more structurally down-dip (i.e. towards the SW), a third body is present. It's parallel to the two bodies described above, and contains a good amount of facies 3 sand. However, the sand doesn't seem to be constant in thickness like the most structurally up-dip body. This could be also due to the lower well control in this portion of the Ferrier with respect to the most eastern body.

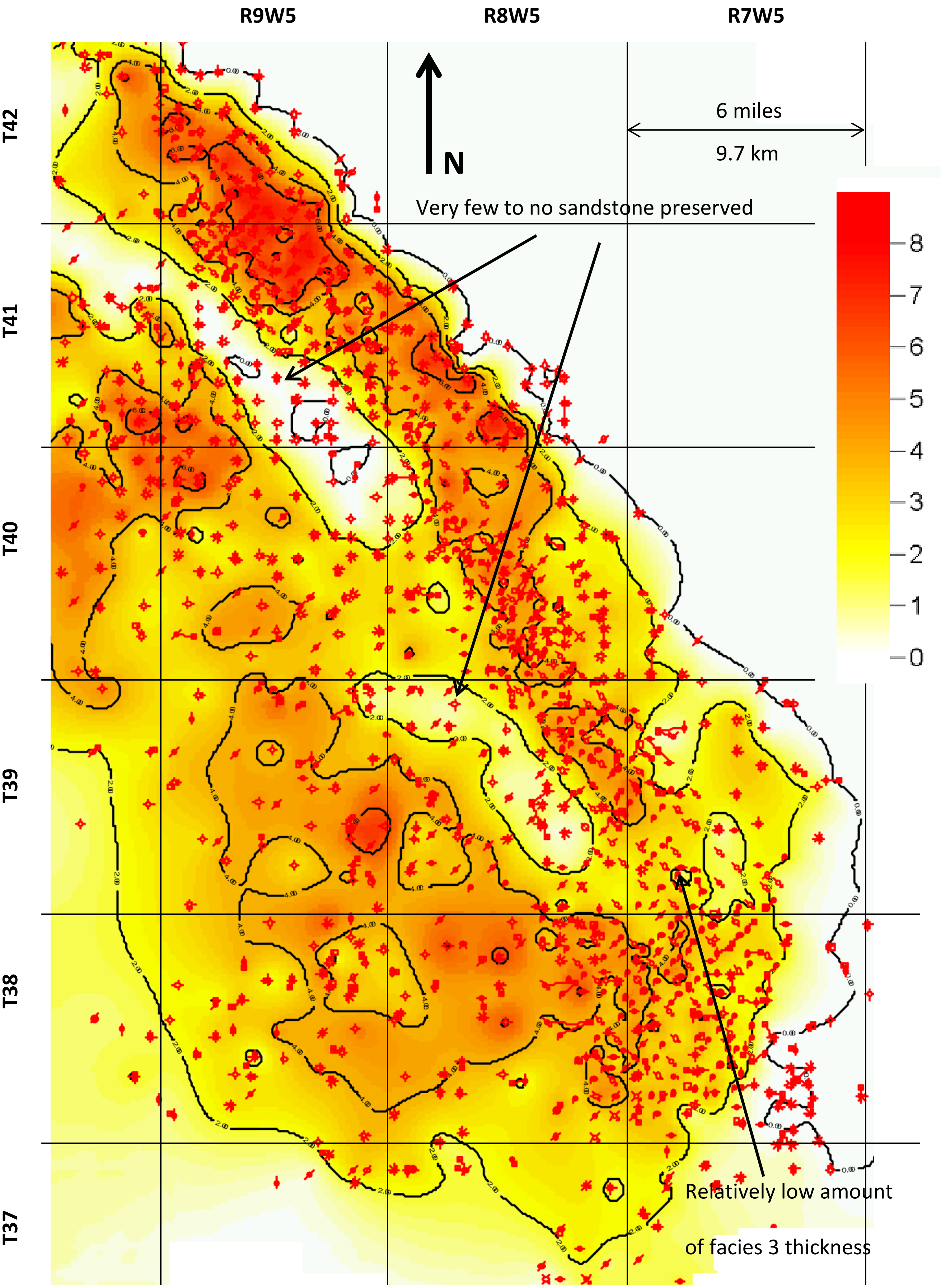


Fig.30: facies 3 thickness map in the Ferrier area. Red spots represent wells with estimated facies 3 thickness value.

2.4.3.3: Facies 4 thickness map

Facies 4 thickness has been mapped using mainly core data. 187 Cardium cores have been selected and the net thickness of the conglomerate was posted for each well. Then, the values have been hand contoured and digitalized.

This process is claimed to be the most reliable to map the conglomerate distribution with respect to computing a difference between the top of conglomerates and the top of the sandstones in well logs.

This last method is a good approximation if the conglomerate is mud-encased and matrix supported, but if it's clast supported and has good thickness it's difficult to discriminate between facies 3 and 4 in well log data.

To overcome this obstacle, routine core analyses were considered. Although they don't always have great thickness, conglomerates are the main producing interval in the Ferrier. Because of their good petrophysical properties, the companies tend to characterize the coarse-grained deposits by taking plugs or full-diameter samples and running porosity and permeability analyses. This has been observed in each one of the 13 cores directly logged, where the conglomerates, when present and thick, were always sampled.

In the "core" tool of GeoScout, core analyses are available for each cored well. What has been done for facies 4 mapping is considering just the conglomerates and adding each conglomeratic sample that was analyzed.

This is claimed to be a very good approximation for facies 4 thickness, and this is confirmed by the good match between conglomerate thickness computed with this method and the one directly observed in the 13 logged cores.

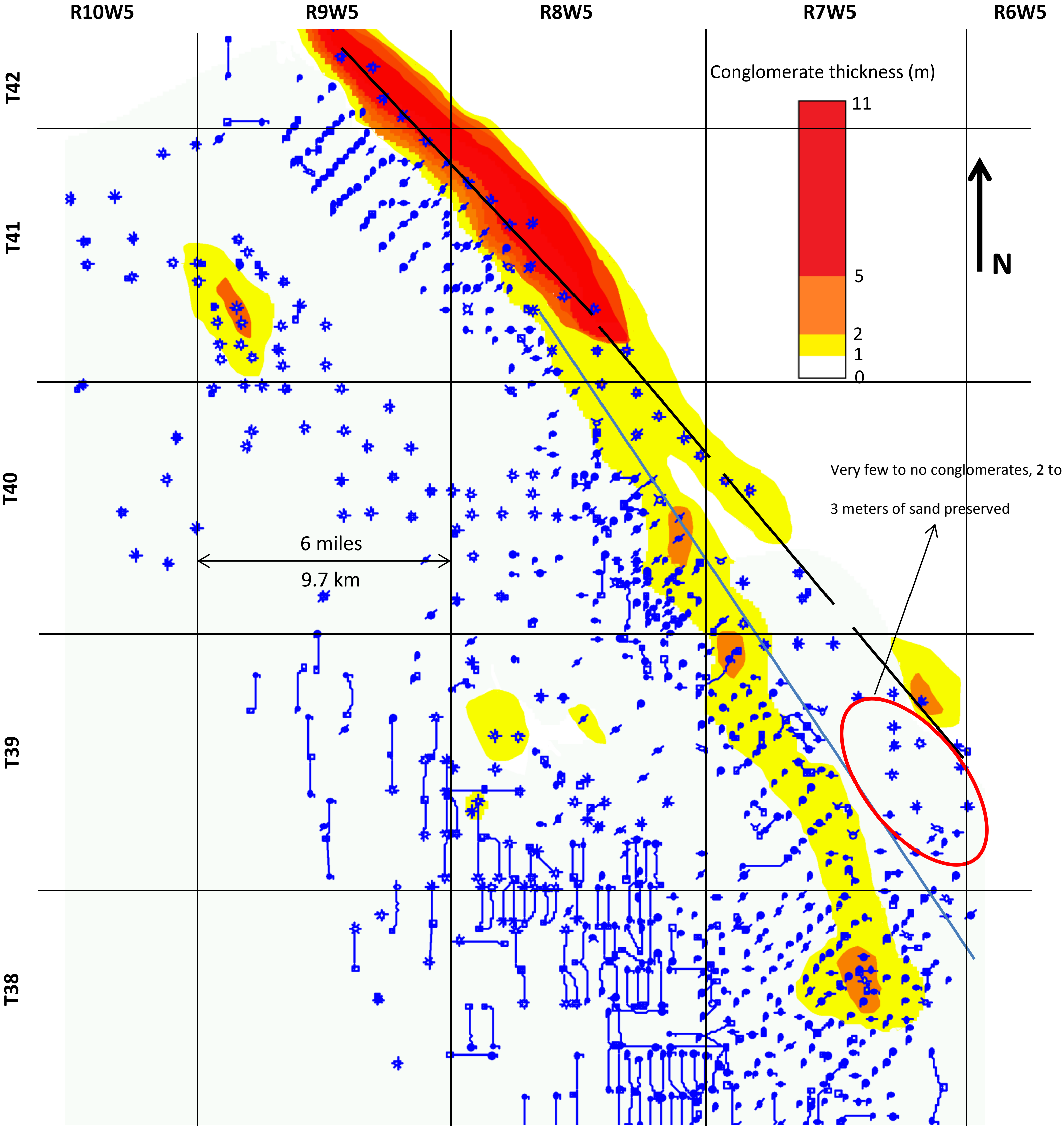


Fig.31: facies 4 thickness map of the Ferrier area with the relative legend. The blue line represents the current oilfield E edge, whereas the black line represents the interpreted pre-E5 erosion Ferrier boundary. The red circle marks an area where a few sand is preserved eastern from the pebble-rich bar. This area accounts for the southern gas cap.

This is the map of facies 4 thickness in the Ferrier area. Blue wells represent the Cardium producers in the Ferrier area.
First of all, it's important to say that each logged well showed a customary pebble lag thickness lower than 0.5m, and this is visible both in cores and in well logs. Therefore, colour scale has been set in a way not to make the thin conglomerates show up. Yellow spaces detect wells with 1-2m conglomerate thickness, orange 2-5m and red >5m.
According to the contour map, conglomerates are organized in bars roughly parallel to the paleo-shoreline. This has been observed in other Cardium oilfields, like the Pembina (Wiseman, 2014).
The map shows that the conglomerates reach the maximum thickness in the NE zone, with thicknesses up to 12m. This area is the main gas cap of the Ferrier, and the massive presence of this top-class reservoir facies explains the excellent productivity of the gas cap wells. However, the conglomerate bar (or bars) follows the paleo-shoreline just for roughly 15 km, and then it seems to deviate towards the SSE. This causes the conglomerates to be the main reservoir of the gas cap in the NE portion of the field, but not in the SE area, as the conglomeratic body cuts the southern portion of the oilfield becoming an oil reservoir (see fig. 49, chapter 3).
As the conglomerates are claimed to have reworked in response to a trangressional event, conglomeratic bars will most likely be stretched perpendicularly to the direction of transgression. As the pebbles are parallel to the paleo-shoreline just in the north portion and then deviate towards the south in spite of the sand orientation being constant, this can be interpreted as an example of oblique transgression.
In the picture shown above it's clearly visible that the shape of the reservoir body changes as soon as the conglomerates start cutting the sand body. This is particularly visible in the eastern edge of the Ferrier, with the black line marking the interpreted pre-conglomerates edge and the blue line marking the current boundary (except the few sand in the SE portion that accounts for the southern gas cap).
This becomes even more interesting comparing the interpreted current edge of the Ferrier with the Cardium U Pool trend. This smaller play is a quite recent discovery (around 2000) and it has an odd triangular shape that hasn't been interpreted yet. This pool has been recently studied by Venieri et al. (2015), and according to the AER it genetically belongs to the Willesden Green field, that is just a few kilometers north of the Ferrier.

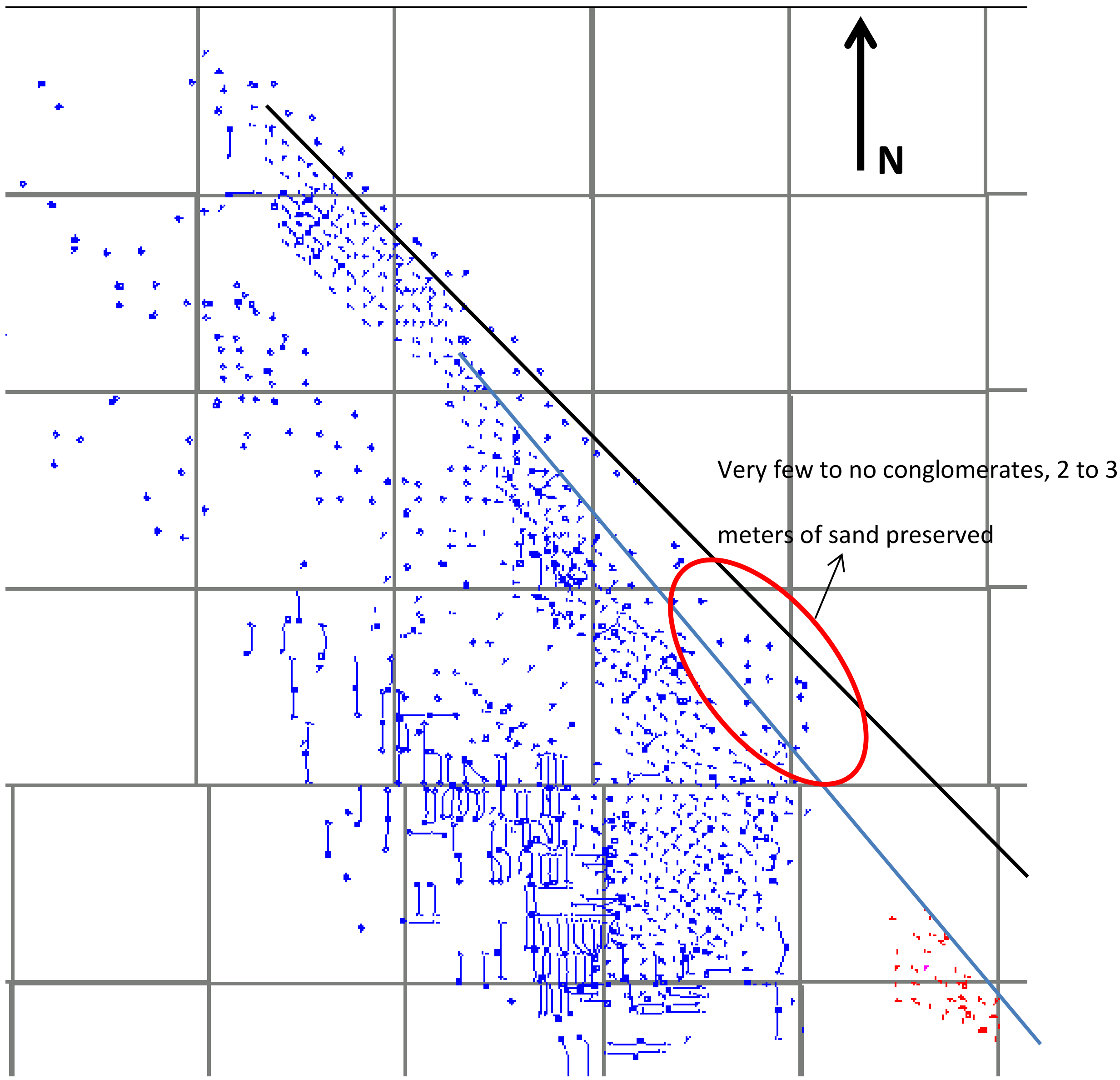


Fig.32: Base map of the Ferrier (blue wells) and Cardium U Pool (red wells). If extended towards the SE, the current Ferrier edge matches pretty well with the E edge of the Cardium U Pool. The two plays could therefore be genetically connected in some way, although more detailed studies are required.

The picture above shows that the Cardium U Pool NE edge is close to be the natural extent of the Ferrier edge towards the SE. This could be an index that the two plays are genetically connected, although more detailed studies are required.

In the SE portion of the Ferrier, east of the blue line and west of the black one there is an area (marked with a red circle in fig. 31 and 32) were few sand is preserved. That means in spite of the E5 erosional event, medium quality sandstones are still present in the SE portion of the Ferrier, eastern from the conglomeratic bar. These sandstones and, occasionally, a few tens of centimeters of conglomerate, are the main reservoir of the southern gas cap. The difference in reservoir quality between the thick northern conglomerates and the thinner southern sandstones explains the difference in gas production between the northern and the southern portion of the gas cap in the Ferrier (production bubble maps are shown in chapter 3 , picture 49).

2.4.3.4: Reservoir architecture

The next step after facies thickness maps has been to unravel the depositional architecture of the Cardium sandstones in the Ferrier area, as well as any modification that may have occurred after-deposition to the Cardium sediments.
In the facies 3 thickness map it was visible that, western from the main oilfield, there are two NW-SE stretched areas where there was very few to no preserved sandstone evidence. These portions of the Cardium have elliptical shape and average dimensions are around 13 x 4 km. The two areas are separated by a portion of the same body where conversely the sand is preserved, creating a belt that links the western Ferrier with the main oil and gas zone.
To understand the facies vertical and lateral distribution and variability in the Ferrier area, 5 cross-sections have been built and interpreted starting from well logs and, when available, core data.
Concerning the orientation of the cross-sections shown in this paperwork, two of them are oriented along depositional strike (roughly NW-SE), whereas the other three cut the Cardium along its depositional dip (roughly SW-NE).
Each section will be shown and described, then a discussion will be shown to link the sections together and unravel the depositional architecture and post-depositional modifications of the Cardium in the Ferrier area.
Each section includes a gross-reservoir base map of the Cardium reservoir with the respective section trace location, and the traces of each of the 5 sections are shown together in the base map shown below.
It’s important to point out that each dip section crosses the strike section in a well shown in both the sections involved. This was made to have a common point between two sections with different orientation.

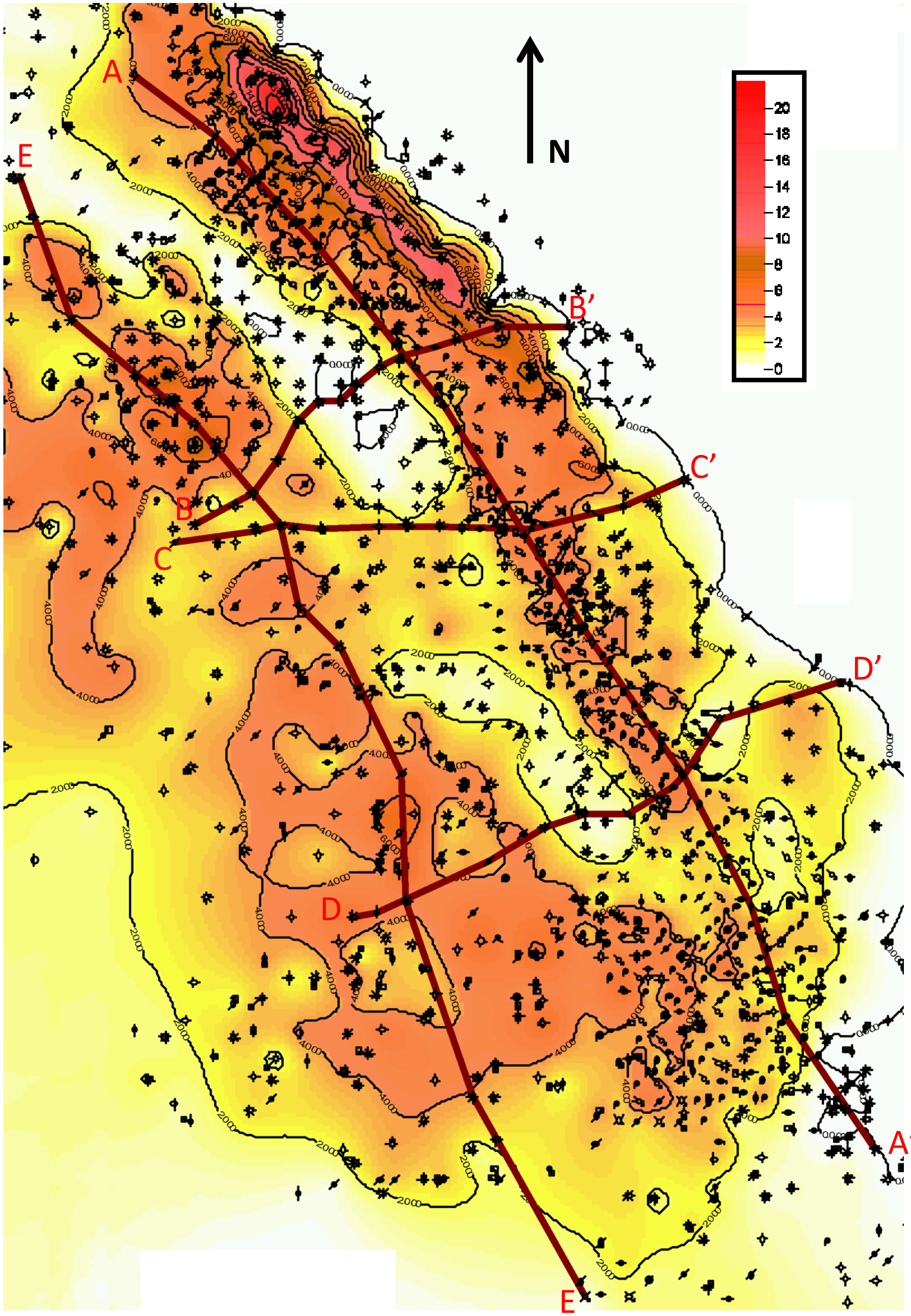


Fig.33: gross reservoir base map (facies 3 + facies 4 thickness) with shown the cross-section lines of each one of the 5 cross-sections shown in the next 2 pages.

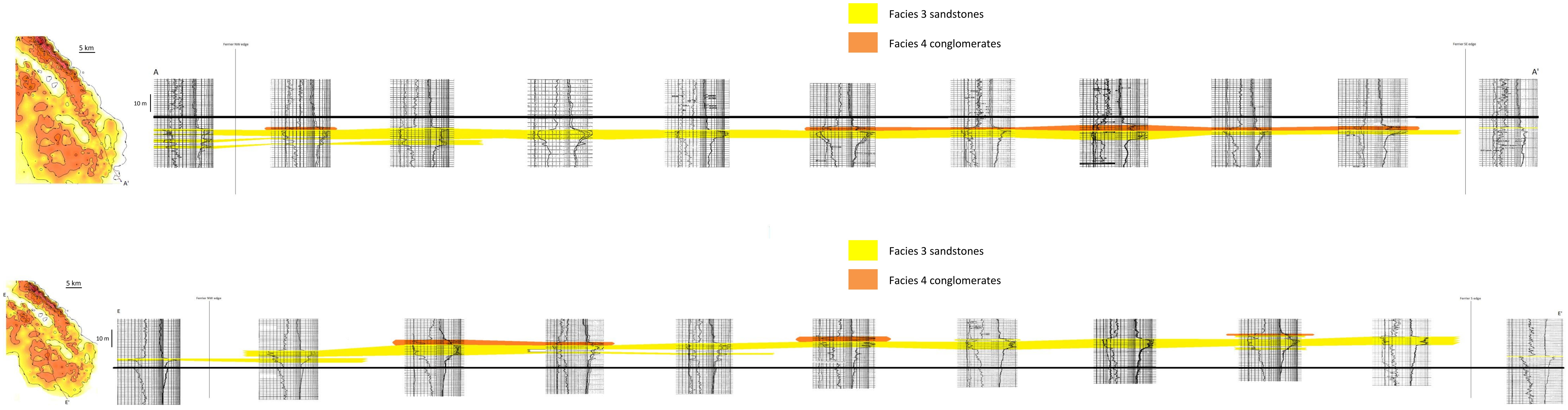


Fig 34: strike cross-sections of the Ferrier oilfield. A-A’ cuts the eastern oil and gas body, whereas E-E’ cuts the W Ferrier area. Yellow bodies identify sands, and orange bodies identify conglomeratic bars. A base map with the section trace is provided for each section. Datum is shown in black. Ferrier edges are shown.

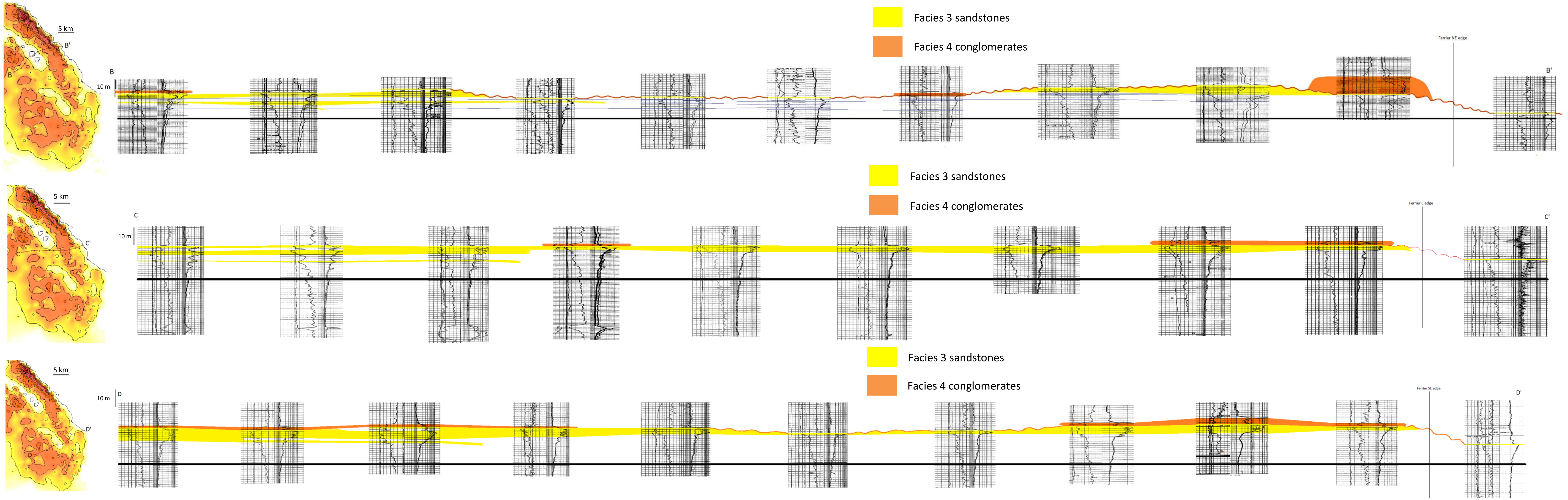


Fig 34: dip cross-sections of the Ferrier oilfield. B-B’ cuts the Ferrier in its northern portion, C-C’ in the preserved sand belt and D-D’ in the southern portion. Yellow bodies identify sands, and orange bodies identify conglomeratic bars. A base map with the section trace is provided for each section. Datum is shown in black. Ferrier edges are shown.

The five cross-sections shown are stratigraphic sections, that means they don't take account of the current topography of the E5 surface, but they aim at describing the depositional architecture at the moment of Cardium deposition. To do that, a datum must be set for each section. The datum is supposed to be a laterally continuous surface that is claimed to have had chronostratigraphic significance in the considered basin.

Regional-scale flooding surfaces are usually a good pick for a datum. In the Cardium bibliography, the E6 surface is the most used by the authors as datum for stratigraphic cross-sections. The E6 is visible in well logs as a surface marking an increase in GR, a very sharp increase in neutron and a decrease in resistivity.

In the Ferrier area the E6 can be a good datum in some cases, but there are some issues. The main problem is that in the Ferrier area the E6 is laterally continuous but not an horizontal surface, as it is visibly characterized by several erosional steps along its way. This because of the erosive action of the relative transgression the formed the E6. Setting as datum an erosional surface distorts the geometries, that therefore would look like going up and down with no scientific significance.

As a consequence of this evaluation, another flooding surface was taken as datum in the areas where the E6 erosion was not negligible. This surface is located roughly 30m deeper than the top of the Cardium sandstones, and characterizes a smaller-scale relative sea level rise, with GR values roughly going from 90-95 to 110-115 API.

This surface has proved to be a reliable datum in the Ferrier area, and it has been used for 4 of the 5 sections presented in this paperwork.

The three dip-cross sections use the same datum. This has been done in order to see if the sand bodies identified were roughly at the same distance from the datum. As this is confirmed in the sections, the body is a single unit and not a lateral juxtaposition of several sand bars or similar.

Overall, the five provided cross-sections show the presence of a clastic body that accounts for the major portion of the Cardium reservoir. Reservoir sediments are sand- to gravel-sized, generally showing a slight coarsening upward succession within the reservoir unit. High resistivity values also show that the Cardium Formation is completely hydrocarbon saturated, and that the pool doesn't seem to have any water leg.

Talking about depositional architecture, the strike sections show that the reservoir is made by a single clastic body in the eastern Ferrier (main oil and gas area), whereas well logs show the presence of multiple (2 to 3) stacked sand bodies in the W of the Ferrier area.

These stacked sand bodies are vertically separated by flooding surfaces and generally show lower thickness values with respect to the oil producing, conventionally developed portion of the Ferrier (eastern portion of the study area).

It's important to point out that one single interval with Gamma Ray reading lower than 60 API can include more than one sand depositional sequence. In this chapter we want to shed light on the architecture of sand bodies, whereas core analyses are required to distinguish between sand sequences in the same sand body.

The depositional architecture above described, with multiple sand bodies in the western Ferrier and one single thicker body in the eastern Ferrier, is confirmed by the dip sections as well.

Three dip cross-sections are shown in this paperwork. Two of them cut the Cardium in the two “0 m sand spots”, whereas the other one cuts the sand belt located in between.

The dip cross-sections have great scientific value, as they show the evidence of a post-depositional sand erosion. Through parasequence correlation, B-B’ and D-D’ show that an erosional event occurred to the top of the Cardium reservoir creating two elliptic-shape spots with few to no sand preservation. These bodies are oriented along depositional strike, so they are most likely index of shoreline erosion because of nearshore or longshore events. C-C’ shows a portion of this belt where conversely the sand has been preserved.

It’s important to say that the sand bodies identified in each dip section can be correlated across depositional strike, and therefore they represent the same body analyzed in a different geographic location.

The bodies have been correlated also because they roughly show the same vertical distance from the flooding surface picked as datum.

Parasequence correlation across the Ferrier also shows that sand bodies can be correlated both across strike and dip in the field, and therefore the play is mainly composed by one thick and laterally continuous sand body. This has been done connecting clastic bodies in the C-C’ section, that is the only one with continuous sand linking the western to the eastern area of the Ferrier. The other two dip-sections occur in areas where the sand has been in part or completely removed, and therefore it would have been much harder and scientifically incorrect to evaluate the connection between the two bodies in these spots.

Concerning the distribution of conglomerates, their thickness is very poor in the western Ferrier area, as shown by well log signature, as well as core data. In this area of the pool conglomerates, when present, are thin and often not laterally continuous. The only slight exceptions are a small portion of the SW zone of the study area (section D-D’) and in the NW (close to the structural bulge), where the conglomerate lag deposits seem to be a bit thicker and more laterally continuous.

The situation totally changes for the eastern portion of the Ferrier. As it has been described in the previous chapter, the main conglomeratic bar cuts the Ferrier main oil and gas body into two portions. That means each cross-section will cut the bar in the medium to distal (towards the E-NE) portions of the conventionally developed body.

This is shown in each of the three cross-sections, with the pebble bar thickness generally decreasing from the north (up to more than 10 meters of conglomerates) to the south (around 2-3 meters in the thickest areas of the bar).

In the areas marked by massive presence of conglomerates, especially in the northeastern Ferrier, erosion of facies 3 sands has been observed. In some cores sand is almost preserved, whereas in other it’s completely absent (see fig. 29).

Generally, it has been observed that the greater the conglomerates thickness and the more sand has been eroded. This is confirmed by physical core logging and routine core analyses.

Cross-sections also show the trapping mechanism of this play. The structure map didn’t mark any major structural feature besides the bulge in the NW Ferrier, therefore a mainly stratigraphic trapping mechanism has been interpreted. The sections show that the sand body tends to dip towards the E-NE and it pinches out into shales going basinwards. As the play becomes structurally shallower going towards the NE, this is a clear example of stratigraphic trap, and the same trapping style can be observed in the most of Cardium oilfields, like the giant Pembina.

2.5: Conclusions

Detailed sedimentological and petrophysical work unraveled the mineralogy, sedimentology and depositional architecture of the Cardium Formation in the Ferrier Oilfield.

Physical core logging showed the presence of a siliciclastic succession. Facies vertical stacking suggests a general coarsening upwards sequence from offshore mudstones to lower shoreface sandstones.

Five main facies have been identified in core based on sediment mineralogy, grain-size, bedding, bioturbation style and shale volume.

Facies 1 and 2 are interpreted to have been deposited in a distal (facies 1) and proximal offshore (facies 2) depositional environment. The sand deposits of facies 3 deposited in a lower shoreface environment, as well as the conglomerates of facies 4, that are interpreted to have deposited in the shoreface as well. Facies 5 is made of distal offshore mudstones that act as vertical and lateral seal for the Cardium reservoir.

This study focuses most on facies 3 and 4, as they account for the major portion of the reservoir.

Facies 3 sandstones are very fine to medium grained, and mainly composed by quartz and lithics; other minerals are rare. When the sands are interbedded with wavy mud laminae an increase in mica presence is observed.

Facies 3 thickness map (net sand map) shows that the sand body is NW-SE oriented accordingly to the shoreline trend of the time. Map also shows sand thicknesses ranging from 0 to around 8m.

On the top of the sandstones, marked by the E5 surface, conglomeratic deposits take place. Conglomerates are mainly made of rock fragments and chert particles and generally show well-roundness and poor sorting. These coarse-grained deposits are interpreted to have been deposited in response to the tectonic pulses that accounted for the raise of the Canadian cordillera.

This model claims that pebble-sized grains have been eroded in the mountains and carried towards the shoreline. This happened during the relative sea level drop caused by the abundance of sediment eroded from the raising Canadian Cordillera. After the deposition the pebbles have been reworked by wave action in submarine bars. The subsequent sea level transgression eroded away any evidence of eventual paleosoils or channel activity that might have formed during the moment of pebble erosion and transport towards the shoreline.

In very few cores thin layers (0.5-1 cm) of coal are observed, that could confirm sea level transgression, as coal forms in terrestrial environments.

Conglomerate thickness map shows that the conglomerates are organized in bars roughly parallel to the shoreline trend. This is visible in several Cardium oilfields. What is unique in the Ferrier is that conglomerates follow the sand depositional trend just in the northern portion of the play, and then they deviate towards the west. This causes the pebble bar(s) to cut the oilfield going south. This conglomerate depositional trend can be interpreted as index of oblique transgression.

This has great impact over the shape and extent of the main body of the Ferrier, as its configuration visibly changes when conglomerates start deviating towards the south and going on top of the sands. Conglomerate thickness ranges from 0 to 11 meters and tends to decrease going southward.

In the western portion of the Ferrier the conglomerates show maximum thickness values of 2m but, according to the well logs observed and most of the cores logged in detail, the average pebble lag thickness is around 30 cm or even less.

In some portions of the western Ferrier it has been observed the presence of a proximal offshore facies between the top of facies 3 and the base of facies 4. This facies looks like facies 2b, but sand volume is higher thanks to the high bioturbation degree. This facies, when present, has a maximum thickness of 1.5 meters.

There are no major mineralogical differences between the sands present in facies 2 and the ones in facies 3.

Both strike and dip cross-sections have been built to understand the reservoir architecture in a 3-D system.

Cross-sections show that the Cardium reservoir in the western portion of the Ferrier Oilfield is characterized by the presence of several 1-2 meters thick discrete sand horizons. These bodies tend to merge going eastward, so that, in the eastern portion of the play, the Cardium reservoir is composed by a unique body having thickness up to 8 meters.

Parasequences correlation shows that sand bodies can be connected from the western Ferrier to the eastern area of the oilfield, and therefore the presence of a single prograding sand body is interpreted.

Gross sand maps show the presence of two NW-SE oriented spots where very few to no sand is preserved due to a major erosional event that scraped off the top portion of the Cardium reservoir. A preserved sand belt is present in between.

Chapter 3: Reservoir Characterization of the Cardium Formation in the Ferrier Oilfield

3.1: Introduction

This chapter has the aim to offer a detailed reservoir characterization of the Cardium Formation in the Ferrier Oilfield.
The geological framework interpreted in chapter 2 led to the identification of different hydrocarbon bodies in the main reservoir. These bodies differ in petrophysical parameters, such as porosity, permeability, produced fluid, cementation and other.
A first reservoir characterization of the whole Ferrier will be discussed at the beginning of the chapter, than each body will be treated independently. In chapter 4 importance will be given to how these different reservoir compartments can interact with each other.
Production data are one of the most important tools to discriminate between different hydrocarbon-filled bodies. Looking at the whole study area, 3 main bodies can be identified based on production analyses:

- a conventionally developed oil and gas body with gas cap in the Eastern portion of the study area;
- an oil and/or gas producing, unconventionally developed portion in the Western-southwestern area;
- a 100% gas producing, conventionally developed body in the Western-northwestern zone.

The next picture shown this division within the Ferrier oilfield. The area in red represents the eastern, main oil and gas body; the blue area identifies the gas producing, conventionally developed portion of the western Ferrier; the black area shows the unconventionally developed portion of the Ferrier.
Production data have been shown as bubble maps, red for gas and green for oil. The bigger the bubble, the higher the hydrocarbon produced volume, bubble data are always expressed as BOE (barrels of oil equivalent) setting a standard BOE ratio of 10:1.

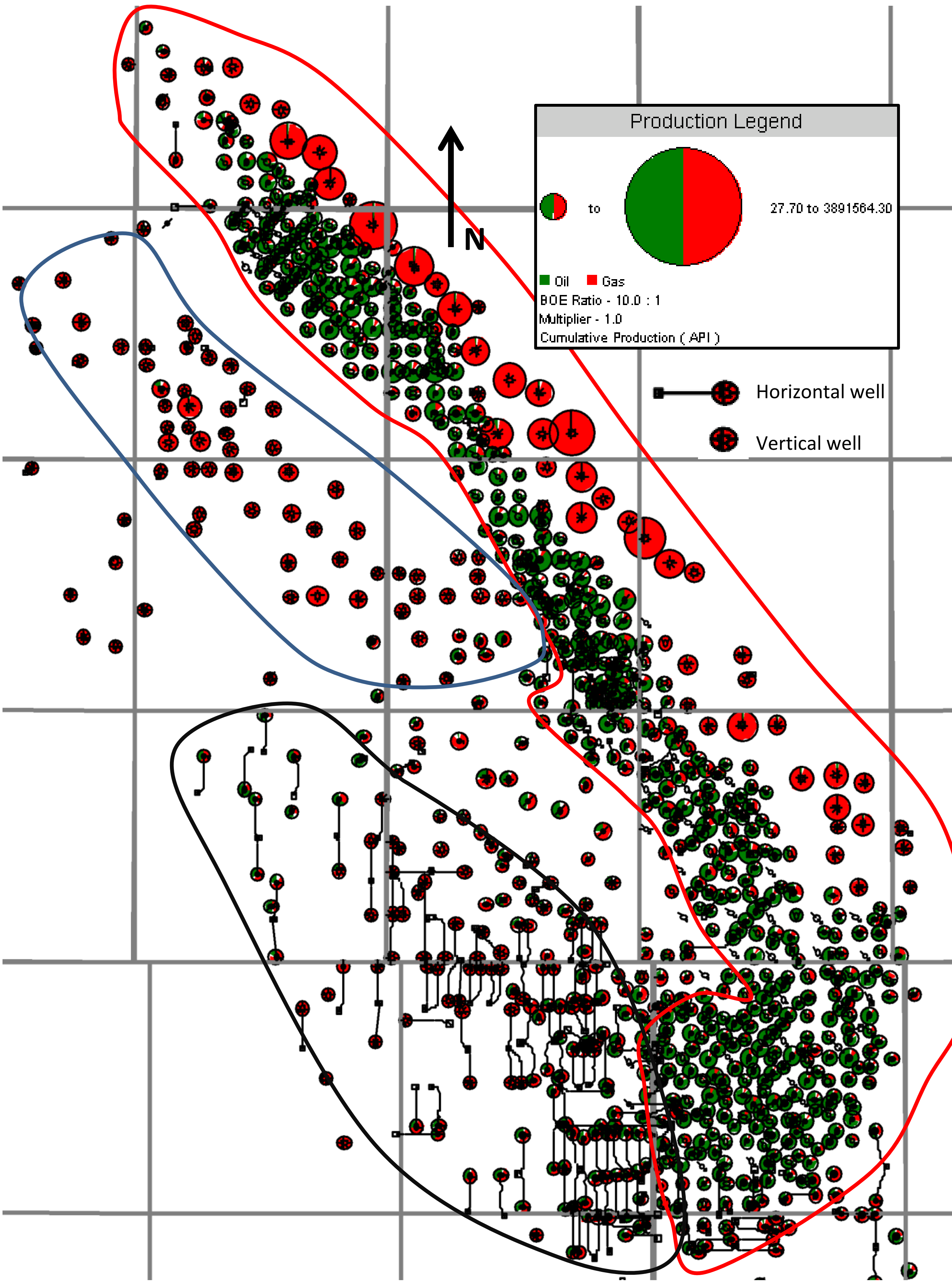


Fig.35: base map of the production behaviour of the Cardium Formation in the Ferrier Oilfield.

unconventionally developed area of the field, and major interest has been focused on what controls the differences in production between areas extremely close to each other (300-500m).

Furthermore, these changes seem not to depend on depth (i.e. hydrocarbon maturity). In the Ferrier, oil and gas can be found at the same depth in wells spaced by a few hundreds of metres, and also the gas charged body is beneath the oil one.

One of the aim of this research was to understand what controls the production behaviour of the Ferrier. This includes geologic controls over production at large scale, but also smaller-scale production changes.

Detailed petrophysical framework of the different compartments of the reservoir has to be performed in order to detect large- and small-scale differences and anisotropies within the reservoir.

To build a petrophysical reservoir framework to work on, detailed mapping was carried out for the whole field. Gross reservoir and 6% and 12% DPhi net reservoir maps were drawn respectively based on 1193, 964 and 929 wells with available well log data.

These cut-offs have been picked looking at cores, well logs and production data.

Cardium sandstones in the Ferrier show an average API value of 45 to 60 and appear very clean in core, therefore a cut-off of 60 API was set.

Net reservoir mapping was run with 6% and 12% DPhi cut-off. The double cut-off was adopted to discriminate between the conventionally- and unconventionally developed portion of the Ferrier.

To pick the two most proper DPhi values, first the author had to estimate the minimum average permeability required for conventional exploitation.

Generally, 0.1mD is worldwide adopted to differentiate between conventional and unconventional reservoirs.

As the main exploited fluid in the Ferrier is oil, a conservative permeability threshold of 0.3mD has been adopted for conventional production due to higher viscosity than gas fluids.

To detect which porosity matched with 0.3mD permeability, a phi vs k cross-plot was computed in the main oil and gas body. Data show that 12% porosity roughly matches with the adopted permeability threshold (see fig.45)

The cut-off has therefore accordingly been set to 12% DPhi, assuming a good match between real porosity and density porosity.

Starting from the stratigraphic framework interpreted in chapter 2, the final product of chapter 3 will be a detailed reservoir characterization of each different compartment of the Ferrier oilfield. At the end of this chapter, new information about the reservoir properties of each Ferrier compartment will be revealed.

3.2: Reservoir mapping

Reservoir maps are a plan-view representation of reservoir properties, and have therefore to be 3-D visualized.

In this study, contour maps represent one of the most important data used to describe the reservoir architecture and properties.

Maps represent several parameters of the whole reservoir or just one portion of it. Every Cardium horizon was picked in each well, and the thicknesses of interest were taken and saved on GeoScout.

Gross reservoir map has been built considering 1193 wells; 6% net reservoir map counts 964 wells and the dataset for 12% net reservoir map is composed by 929 wells.

As already described in chapter 2, it's important to point out that conglomerates in well logs have usually density porosity lower than 0%. However, when the conglomerate is clast-supported and does not contain mud matrix, it has great density and core porosity. This happens in the northern gas cap area and in a small portion of the western Ferrier, that matches with the structural bulge identifies in the E5 structure map. Net reservoir mapping was performed using density porosity cut-offs of 6% and 12%, so in case of mud-supported conglomerates these are not included in reservoir mapping. This has been done because, if mud-supported, conglomerates can be much less permeable than sands. This means a conglomerate evaluation has to be made case by case, also because this facies doesn't show a linear porosity vs permeability trend like the sandstones.

All of the above means that net reservoir mapping includes rocks more porous than 6% or 12%, but conglomerates can be very permeable although being not porous. In presence of permeable conglomerates (most of the cases), conglomerate thickness has to be added to the net reservoir value to have the real net reservoir thickness. The maps show the portion of the reservoir when it's 100% sure to find reservoir quality sediments, whereas additional studies have to be made to assess the permeability of the mud-supported conglomerate to have a better petrophysical characterization of the reservoir itself.

3.2.2: Gross reservoir map

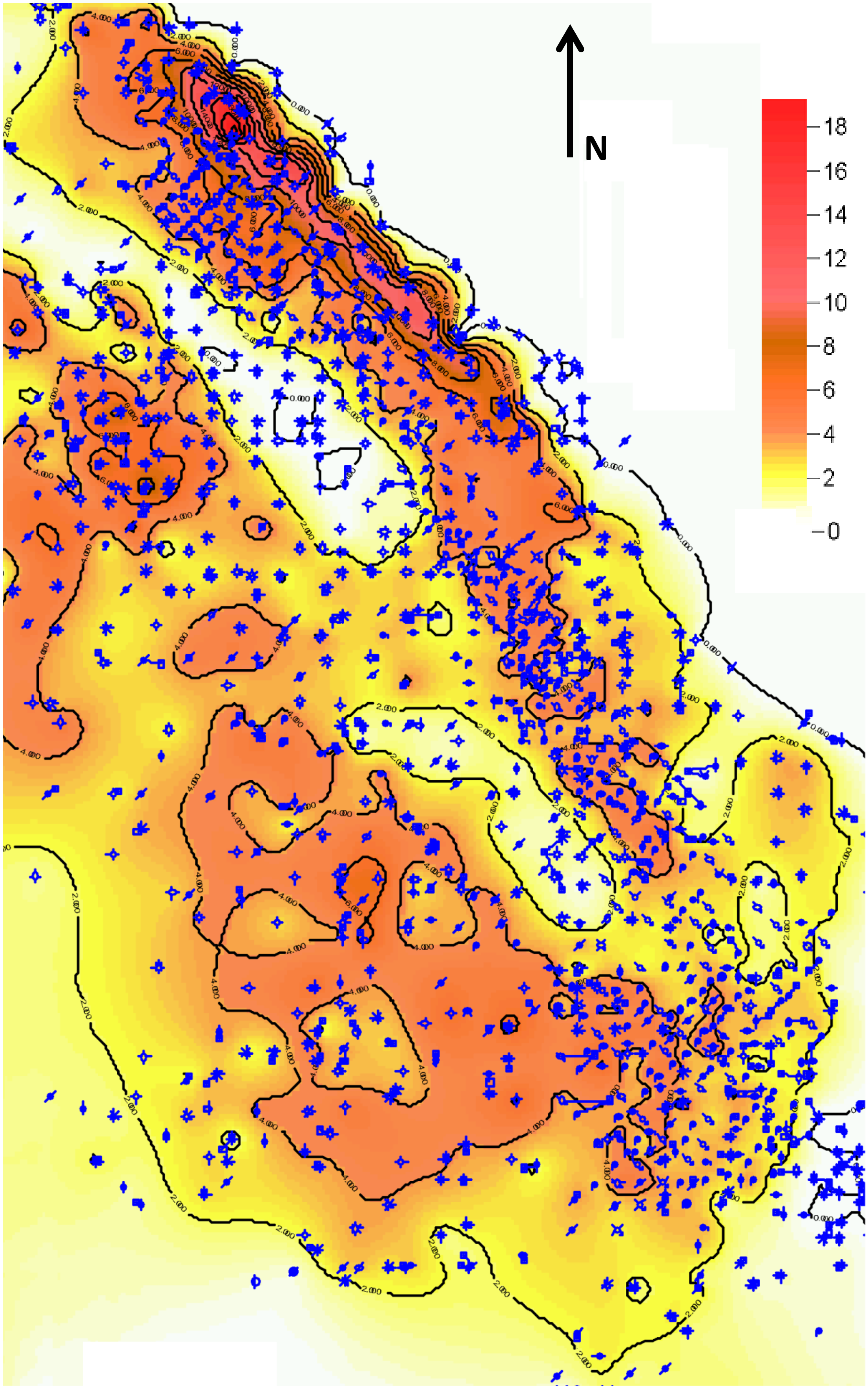


Fig.36: Gross reservoir map of the Ferrier Area

3.2.3: 6% net reservoir map

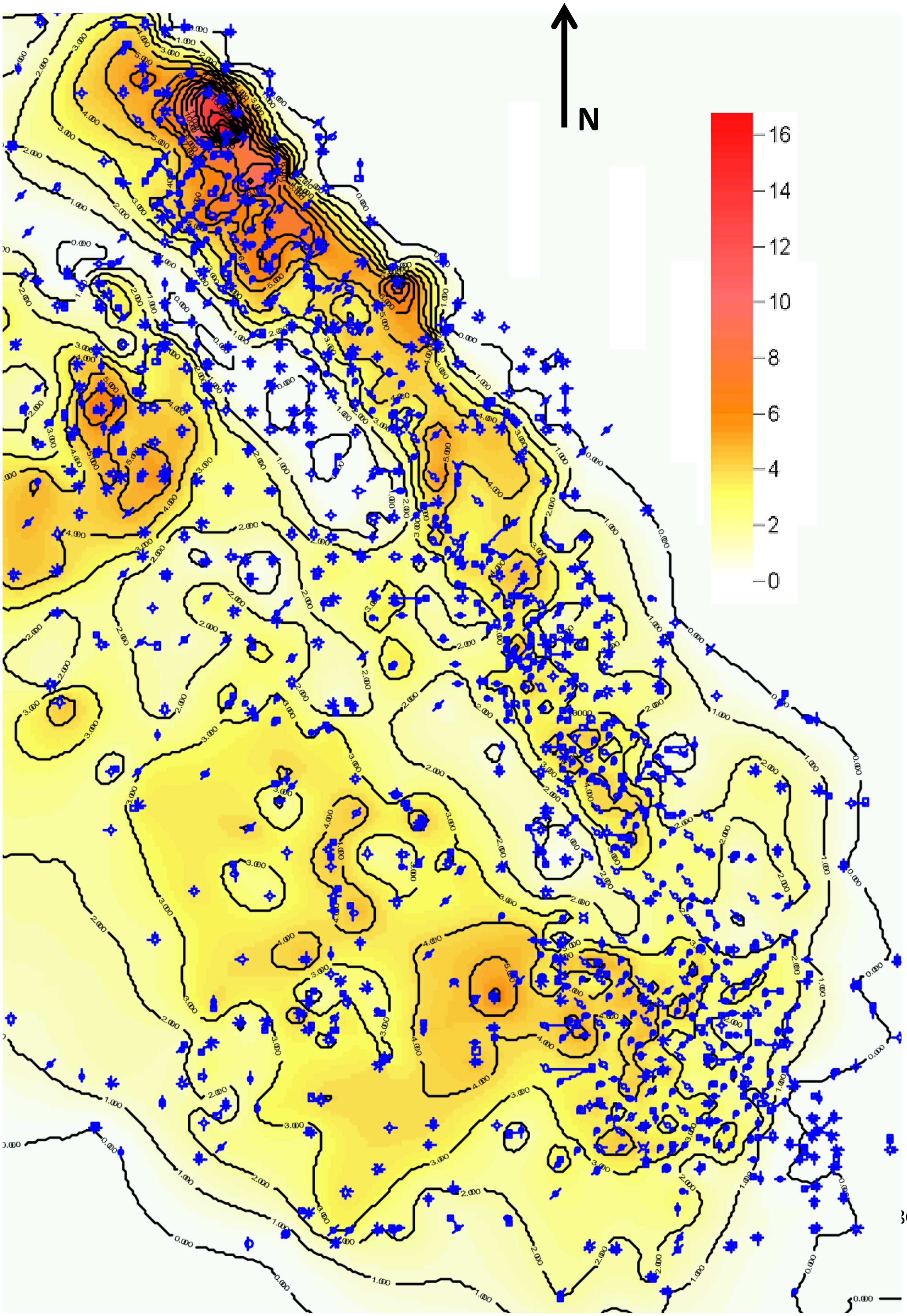


Fig.37: 6% net reservoir map of the Ferrier Area

3.2.4: 12% net reservoir map

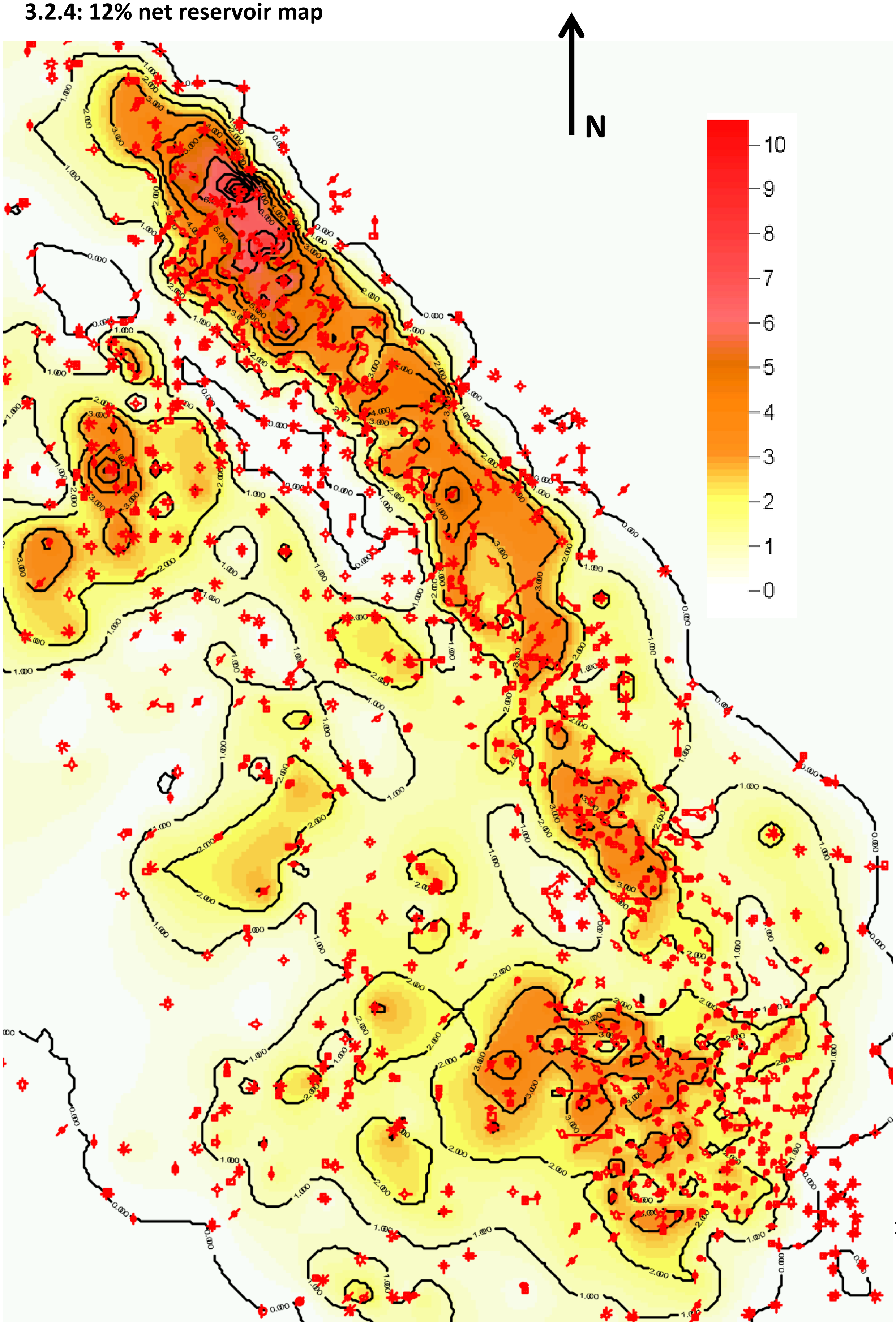


Fig.38: 12% net reservoir map of the Ferrier Area

1

3.2.5: Discussion

The three maps have been built using each vertical and deviated penetration in the Cardium formation with available well logs. As well density is much higher in the eastern Ferrier, it is evident that maps have higher resolution in this portion of the field rather than in the western Ferrier area. More than 300 cores have been taken in the Cardium in the study area; these cores have been considered as additional data for a more detailed reservoir mapping.

The gross reservoir map shows the distribution of the cumulative thickness of facies 3 and facies 4 in the study area. In the NE thickness values are high due to the great sand and conglomerate thickness, but overall the average gross reservoir value seems to be from 5 to 6 meters (light orange areas in the map). In some spots the preserved sand thickness is close to three meters (yellow areas).The two areas where the reservoir thickness is close to 0 meters are evident in the map, and their origin is erosional as demonstrated in chapter 2.

Gross reservoir thickness ranges from 0 to 18 meters.

6% and 12 % net reservoir maps match pretty well with the gross reservoir thickness map. Again, the thickest areas are in the NE and in the structural bulge area, where the conglomerates are thick and clast-supported, that ensures very good porosity and permeability values.

In the main body, average values for 6% and 12% DPhi are respectively 4 and 3 meters. In the unconventionally developed portion of the Ferrier, these values go down to 3m and <1m respectively.

This is also confirmed by core plots and routine core analyses, that show that it's rare to have porosity values higher than 12-14% in that area. This is demonstrated by the fact that applying a core porosity cut-off of 16% it's easy to differentiate between the main oil and gas body and the other 2 compartments of the Ferrier described at the beginning of chapter 3. This is shown in picture 39, where cores with at least one porosity value over 16% in the Cardium have been highlighted in red. The picture shows that the red wells matches perfectly with the main oil and gas body, with just very few good-quality samples outside of it.

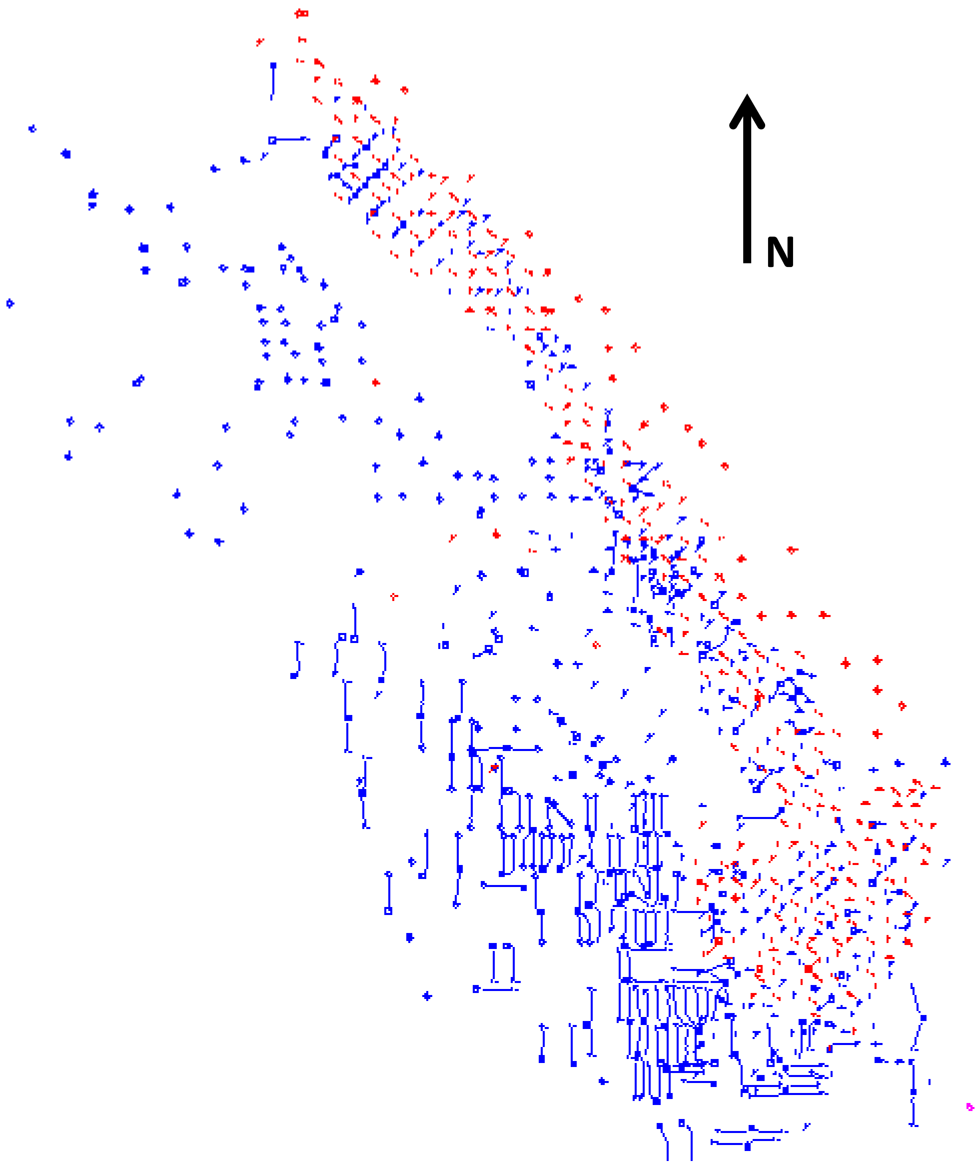


Fig. 39: the red dots represent cored wells where at least one Cardium value shows real porosity higher than 16%. Blue wells identify vertical, deviated and horizontal Cardium producers.

3.3: Discrete reservoir bodies characterization

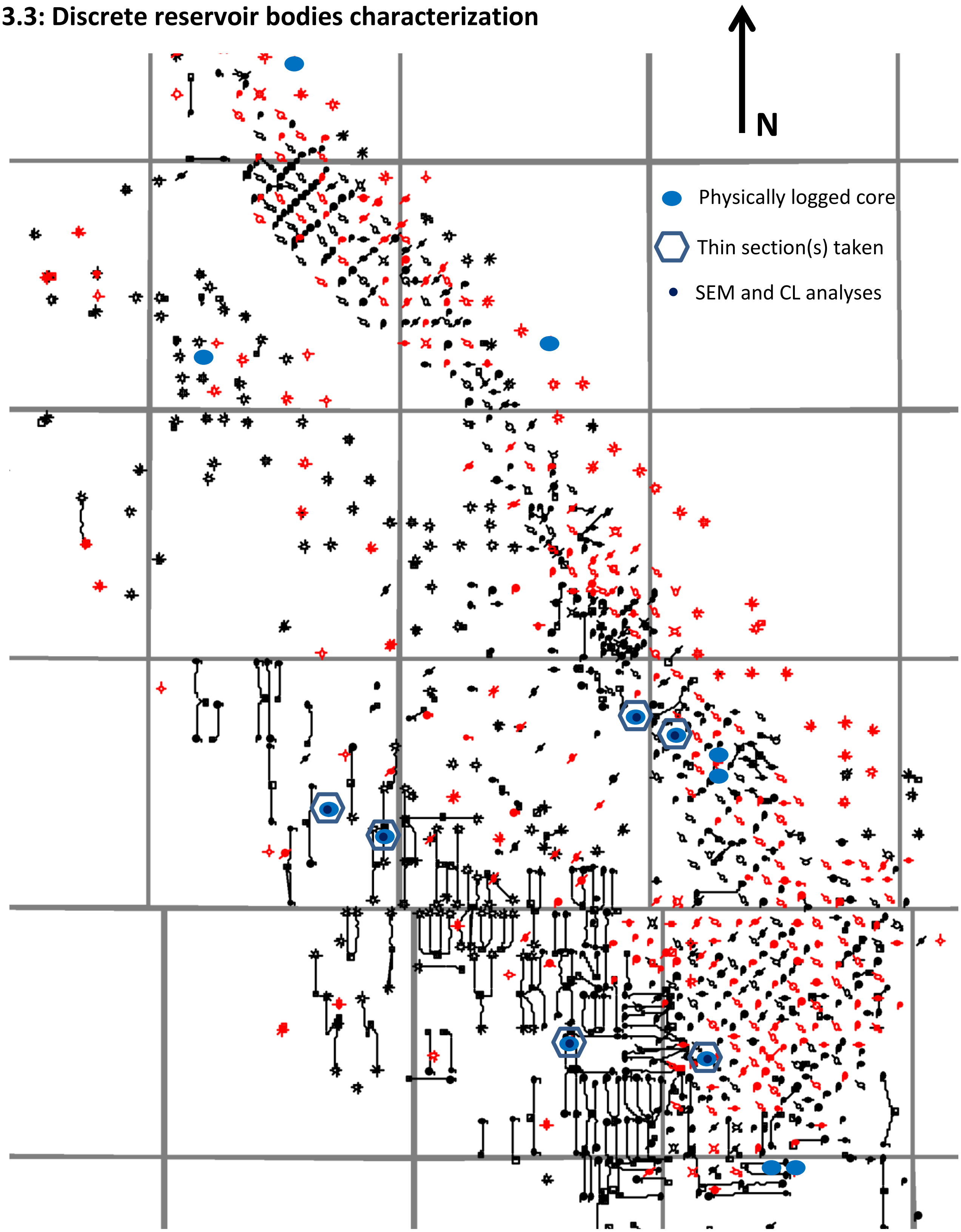


Fig.40: dataset for the petrophysical characterization of the Cardium Formation in the Ferrier Oilfield. Black wells represent Cardium producers and red wells identify each Cardium core taken in the area with available routine core analyses. The symbols in the provided legend refer to well locations where the researcher asked for additional analyses.

3.3.1: Conventionally developed, main oil and gas body

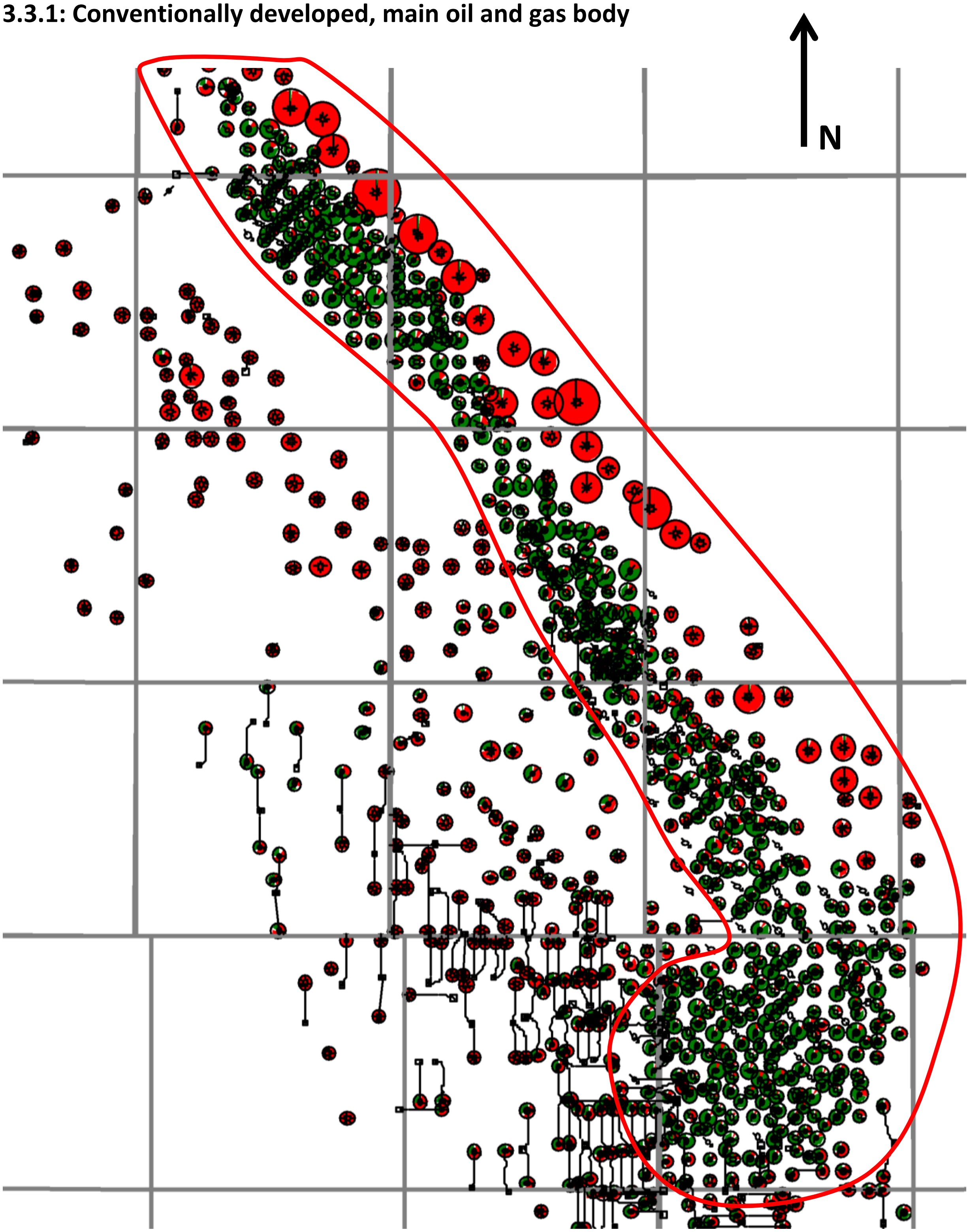
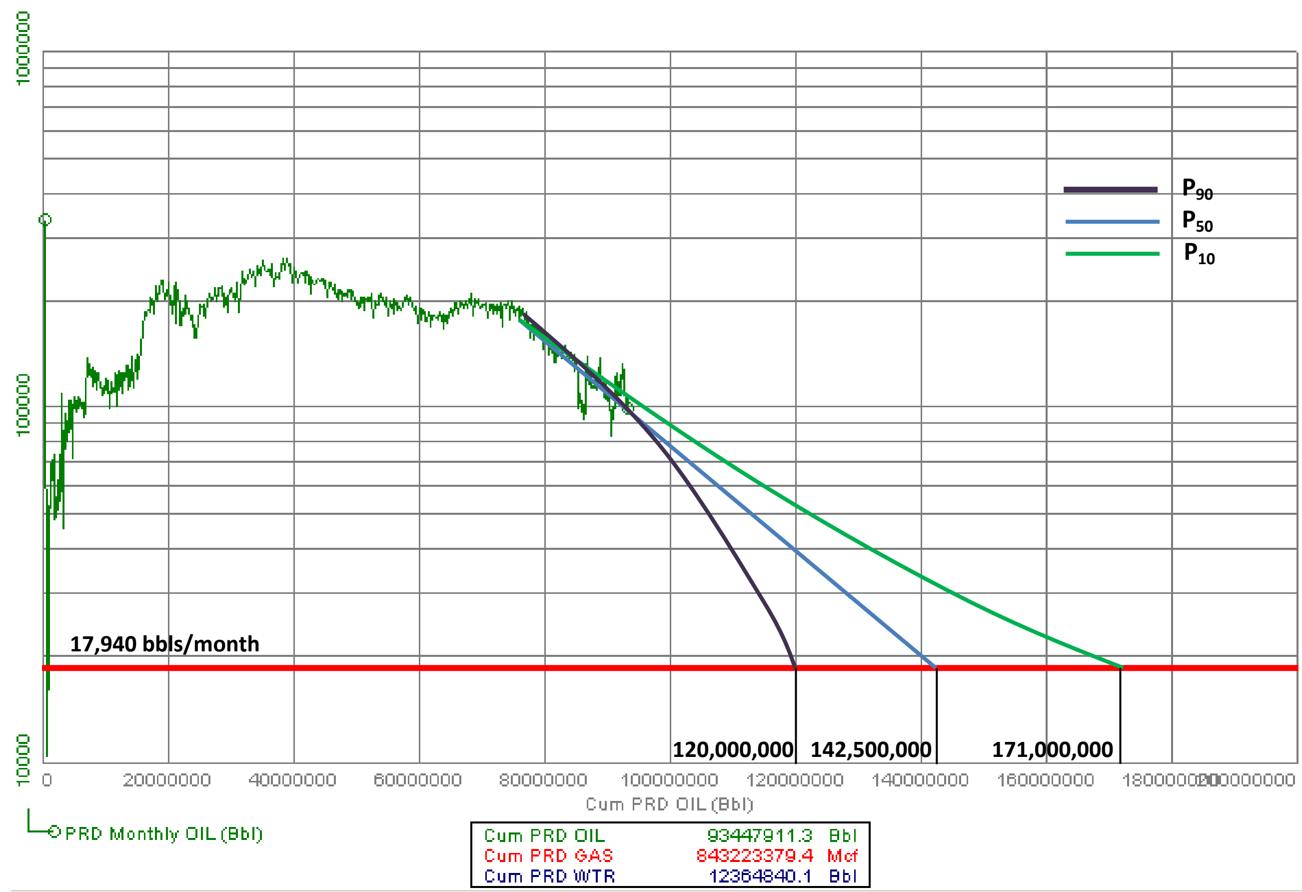


Fig.41: geographic location of the conventionally developed, oil and gas body with Cardium cumulative oil (green bubbles) and gas (red bubbles) production plotted as bubble map for each well.

The main oil and gas body is the first Cardium hydrocarbon bearing reservoir ever exploited in the Ferrier Oilfield. The first well was drilled back in the 1960s, and companies are still drilling this body with directional and horizontal wells targeting by-passed pay.
Without considering the gas, the current amount of produced fluid goes from a few tens of thousand barrels of oil up to more than 900,000 bbls, with an average value of around 160,000 bbls per well (injector wells are not considered if they were formerly oil producers). This testifies the excellent economical profitability of this body since the 1960s.
The development technique of this portion of the Ferrier is almost all conventional (vertical or deviated wells). Very few horizontals are present in the body to target by-passed pay spots.
Starting from the late ‘70s, water flooding has been applied leading to higher production rates and lower production decline rates. Currently, well density per section is around 4-5 producers and 2 water-injecting wells. The field development strategy is therefore 2-2.5 producers per injector.
At the present day, this body of the Ferrier Oilfield counts 299 wells that are actively producing oil from the Cardium, and also 32 gas producers, mainly located in the gas cap area.
To estimate the EUR of the body keeping a conventional field development, each formerly or currently oil producing well was considered and a standard economic threshold of 2 bbls/day per well was set for each of the 299 currently producing well, that makes the threshold go up to 299*2bbls/day*30 days= 17,940 bbls/month.
With the current development setting, the pool is interpreted to have a P_{90} EUR of 120 million of bbls, a P_{50} EUR of 142.5 million of bbls and a P_{10} EUR of 171 million of bbls. This body is expected to produce oil until 2026, 2036 and 2047 according to P_{90}, P_{50} and P_{10} respectively.



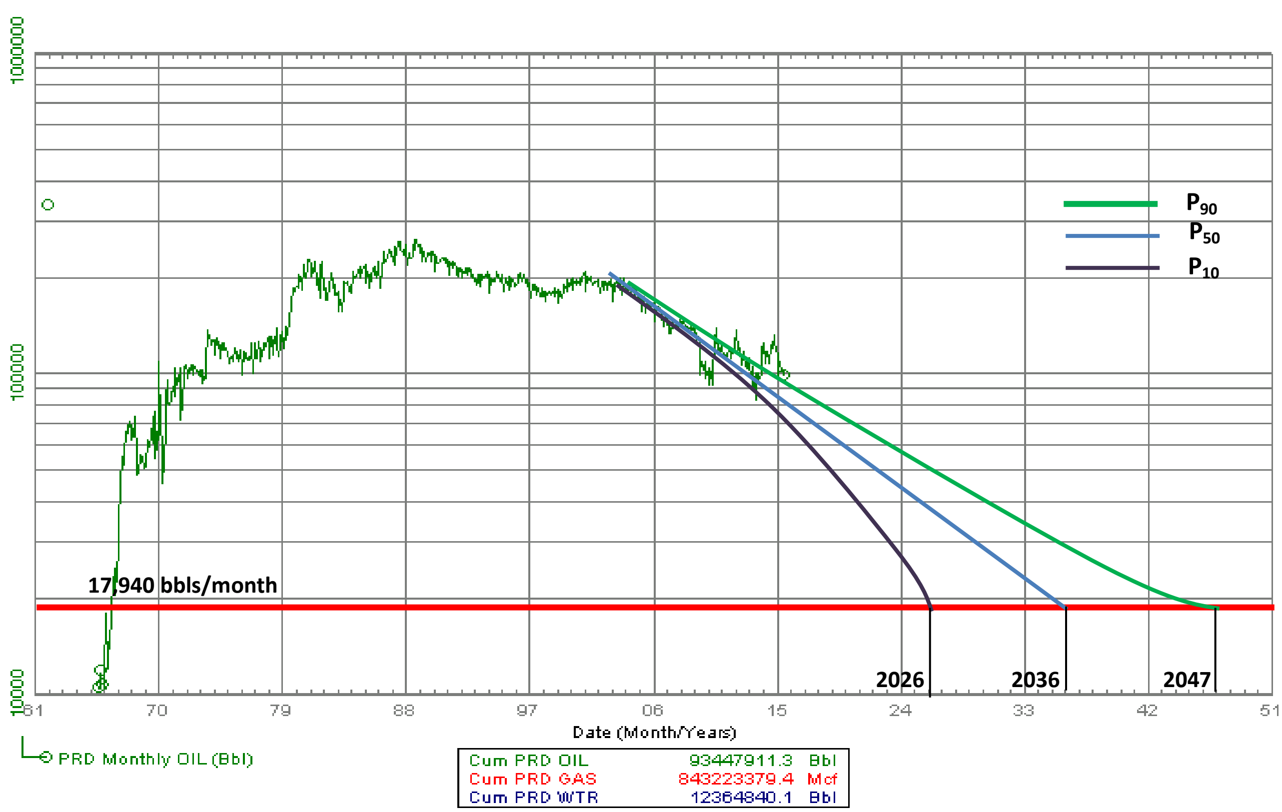


Fig.42: production decline analyses of the main oil and gas body of the Ferrier. Estimation of the EUR and remaining life of the pool according to P_{90}, P_{50} and P_{10}.

100/10-27-040-08W5/00 has been picked as the type well for the reservoir compartment studied in this sub-chapter. It was spudded in December 1967, and therefore it underwent both the non- and the water-flooding stages of production.
The well has been picked as standard for this body due to its fairly good reservoir characteristics (around 1m of conglomerates and 4m of good reservoir quality sandstones).
Production analysis shows that 100/10-27-040-08W5/00 has currently produced around 850,000 bbls of oil and more than 1 Bcf of gas in 48 years of activity. Production rates range from 3000 bbls of oil per month at the beginning of production to 600 bbls of oil per month at the present day.
Production decline has been slowed down through several water injection phases, starting from the late 60s. this is clearly visible in the figure provided below, where the injection data of the water injectors near the considered well are plotted. The picture also shows the match between volume of injected water and volume of produced hydrocarbons.

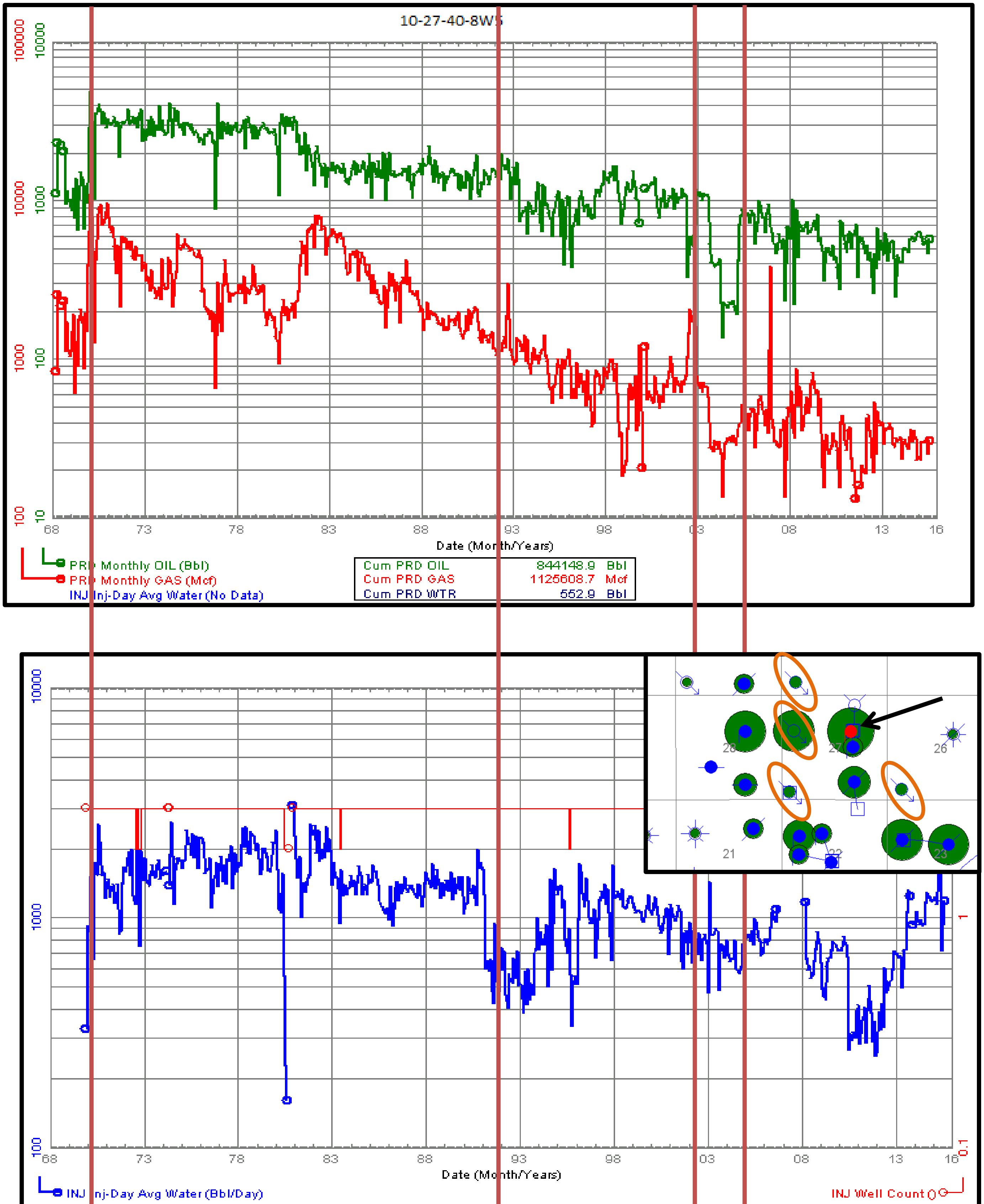


Fig.43: relation between volume of injected water and production decline. Water flooding pushes oil towards the borehole and ensures great hydrocarbon production. The more water is injected, the more the production decline slows down.

3.3.1.1: Cross-plots

Two porosity vs permeability cross-plots have been computed. The two sets of values represent the areas north and south of the small belt with lower net sand thickness (identified in fig. 44 and fig.30). The reason for the double cross-plot pick is that the southern area is not constant in depth, therefore the sandstones show different petrophysical values than the northern area, that is structurally shallower. This is due to increasing mechanical compaction and chemical diagenesis with increasing depth.

The provided cross-plots show the porosity vs permeability of Cardium sandstones and conglomerates in the Ferrier Oilfield. This plots have been computed considering each routine core analysis of every cored well in the Cardium in the Ferrier area. Totally, more than 1000 sand samples and 100 conglomerate plugs or full diameter core sections were considered for this analysis.

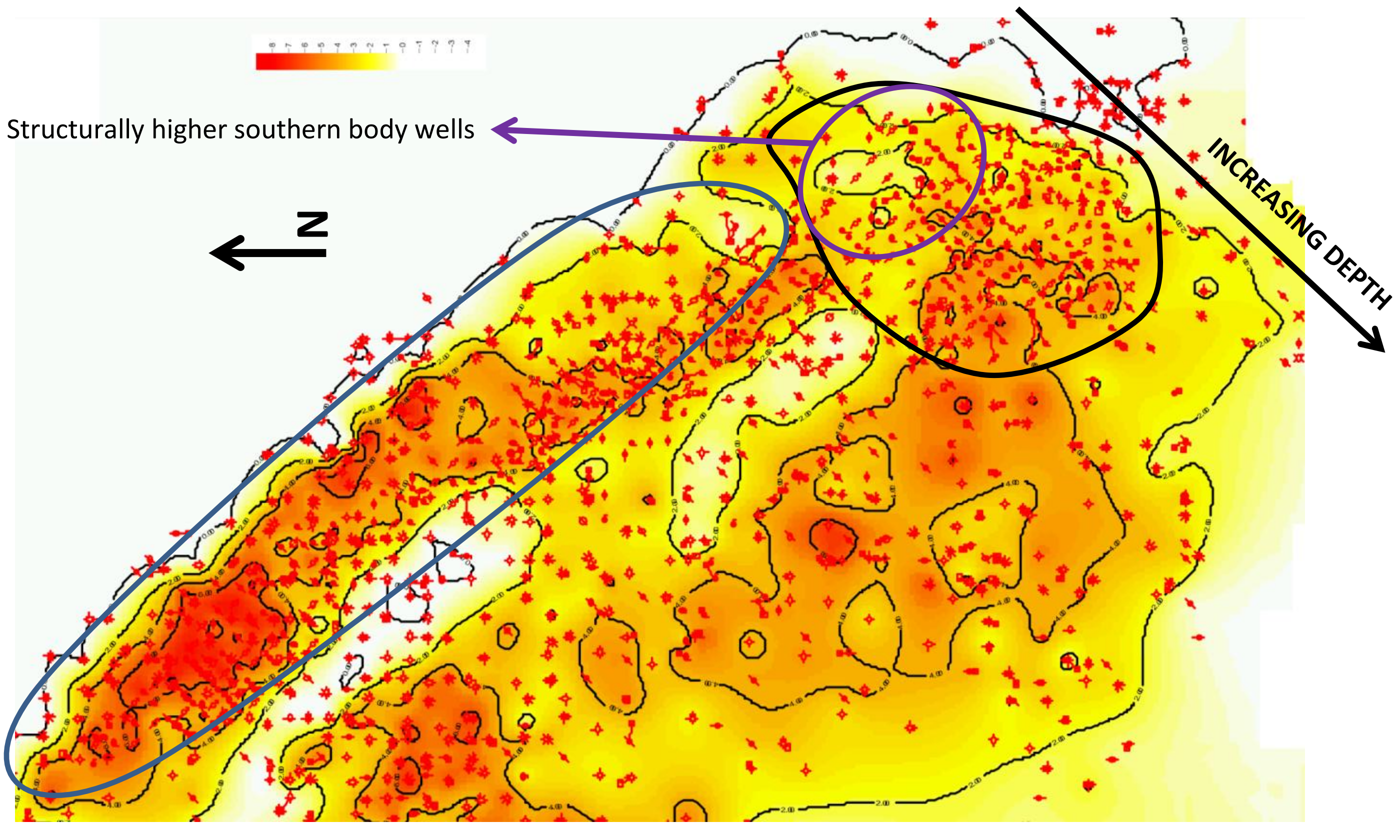
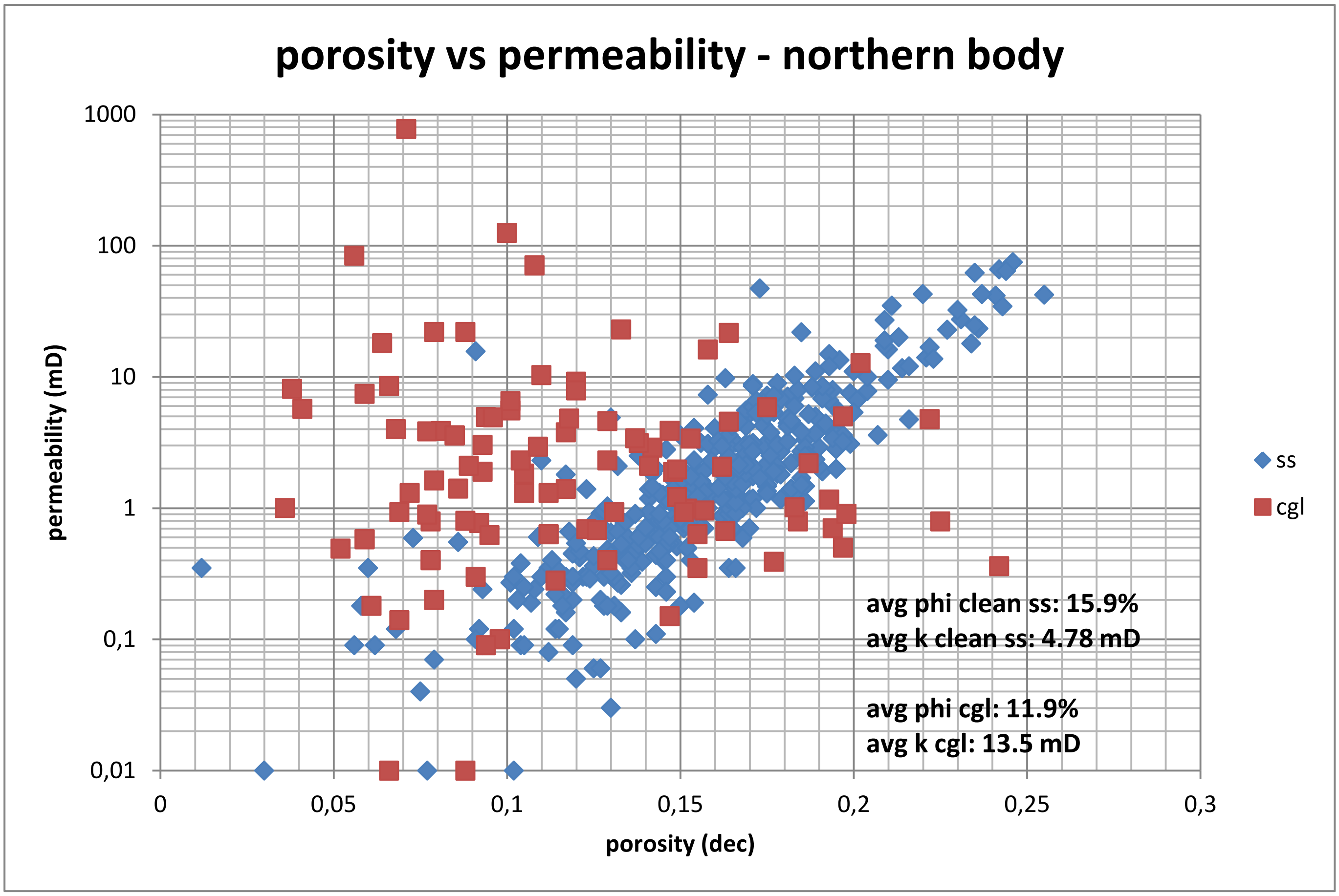


Fig.44: facies 3 thickness map shown in fig.30. The blue area represents the northern part of the main oil body of the Ferrier, and the black area represents the southern portion of the compartment. A porosity vs permeability cross-plot has been made for each of these two units. The violet circle identifies the structurally higher southern body wells.



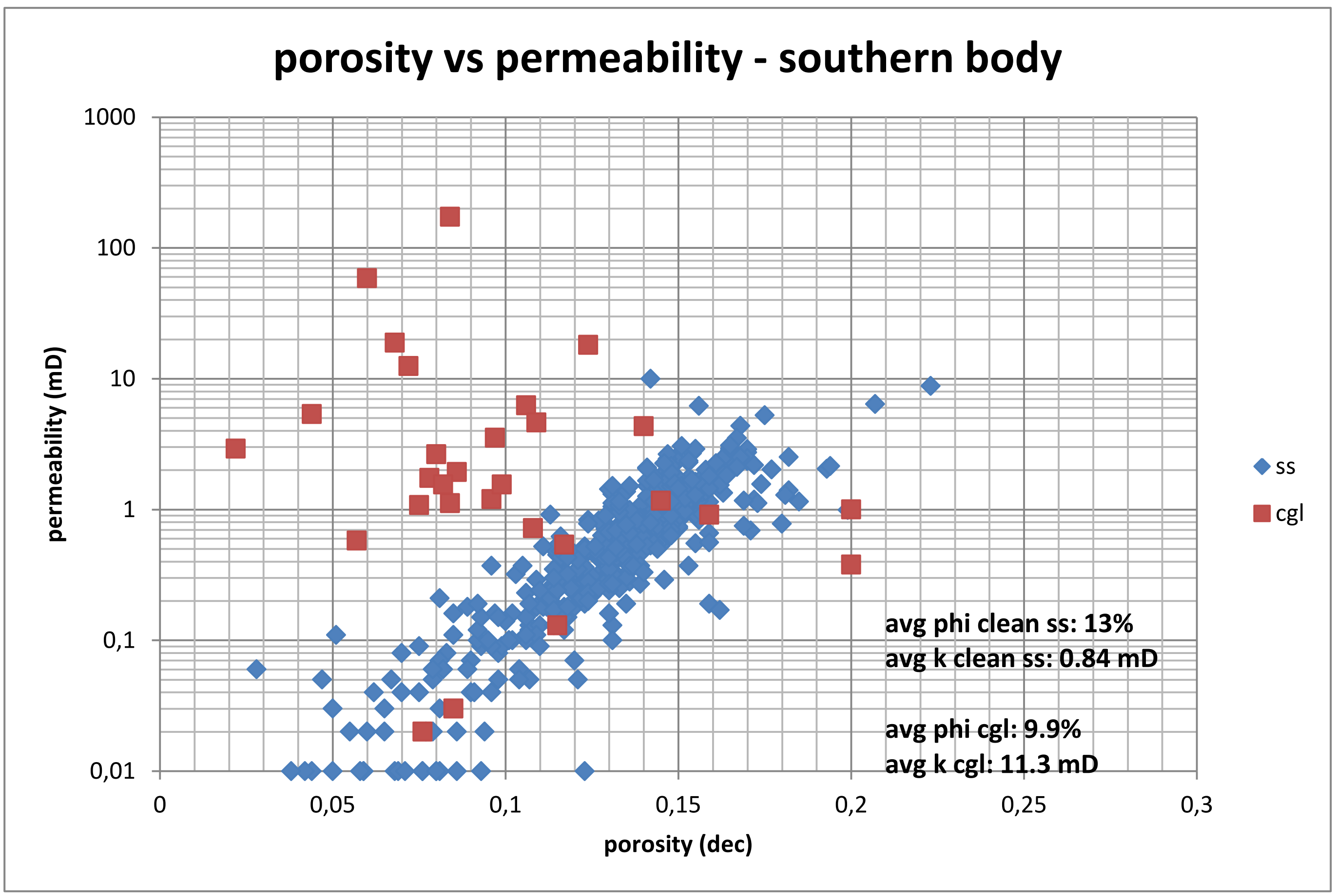


Fig.45: porosity vs permeability cross-plots of the northern (45a) and southern (45b) portions of the main oil and gas body.

The two cross-plots show similarity between the two portions of the main body of the Ferrier, but also major differences.
First of all, in both the cross-plots 0.3mD matches fairly well with 12% core porosity considering clean sandstones. This testifies that we are most likely talking about the same body and not two different ones.
However, major differences in petrophysical properties are shown. In spite having the same porosity vs permeability trend line for the data points, the sands of the northern portion of the oil body reach porosities up to 26%. This is not visible in the southern portion of the reservoir, where the maximum porosity is close to 22%, but with only two samples exceeding 19%. This is most likely due to the greater depth (i.e. mechanical compaction) of the Cardium in the great majority of the southern body (see fig.44).
For the same reason, great differences in permeability were detected, with the average permeability of the southern sands being around 1/5 of the northern sands.
However, greater burial doesn’t fully explain the lower reservoir quality of the southern body. This because part of that body is as deep as the northern portion of the Ferrier. This means that, if pre- and post-depositional history of the Cardium was the same, then the southern body should have around the same max porosity and permeability values of the northern area of the compartment, but conversely values are much lower also considering just the wells in the southern compartment that are located at the same depth of the northern body (it’s important to point out that the southern body reaches greater depth than the northern one, that influences reservoir quality). We will call these wells “structurally higher southern body wells” (see violet circle in fig. 44).
Considering just these wells, values still do not match. This analysis led to the conclusion that the “structurally higher southern sands” have average porosity of 14.3% and permeability of 2.11 mD.
These data testify that greater burial plays a major role in lowering the reservoir quality of the sandstones, but it’s not the only cause for that, as values don’t match even if cleaned from the wells where the Cardium Formation is deeper and, therefore, more compacted and cemented.
As what is missing from the southern portion of the body are the greatest porosity (20-25%) and permeability (10-100mD) values that are conversely found in the northern area, maybe the top sand interval (that is usually the one with the best reservoir quality) was partially eroded in the southern portion.
This could be reliable because the considered body is located just south of a portion of the Ferrier where an important sand erosion has been observed with respect to the areas nearby (see fig. 30).
The following picture shows porosity and permeability ranges divided between facies 3 and facies 4. This analysis has been made keeping the northern and the southern body separated.

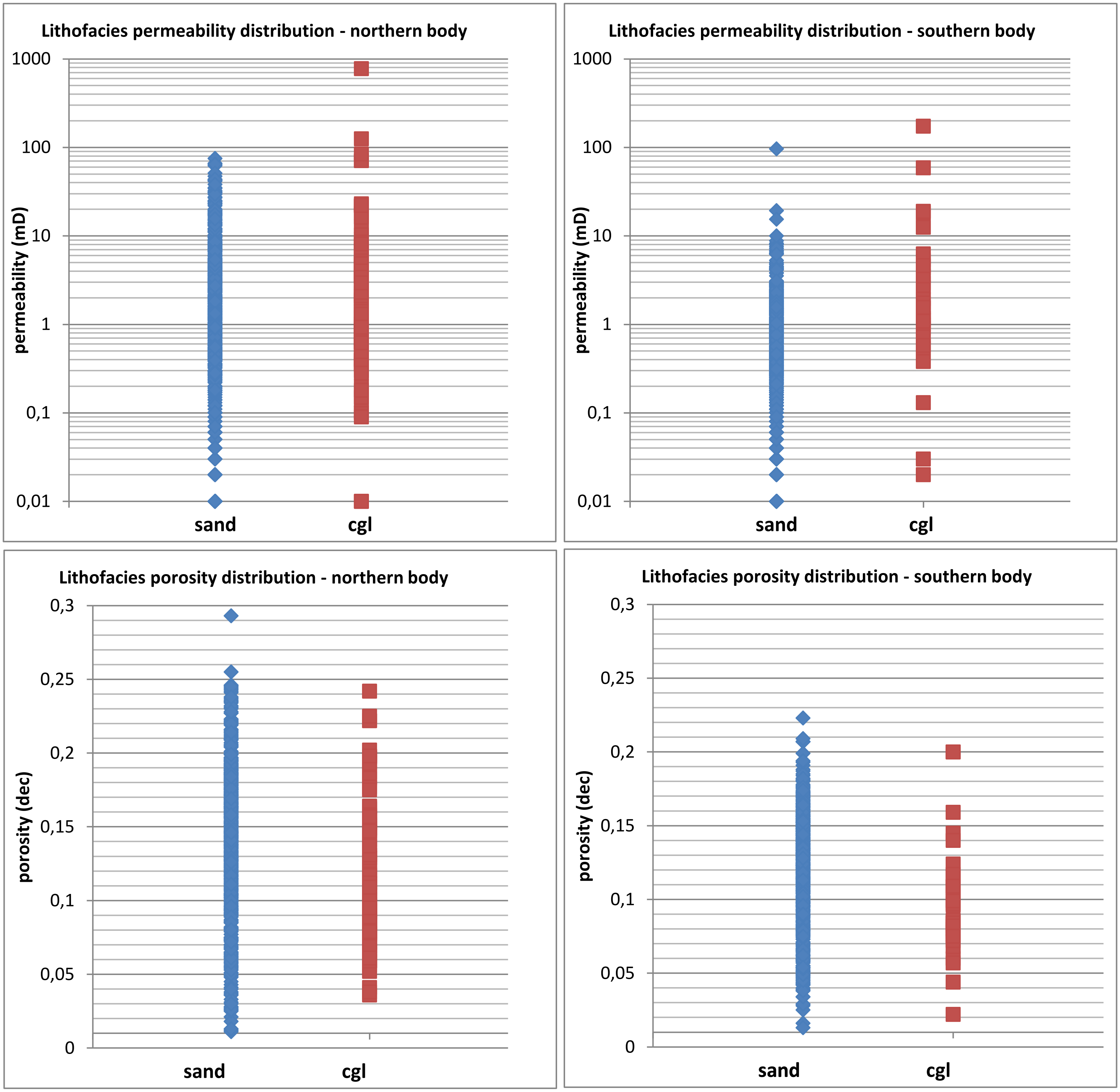


Fig.46: lithofacies porosity and permeability distribution in the northern and southern compartments of the Ferrier main oil and gas body. The northern compartment shows much better reservoir quality.

The greater reservoir characteristics of the northern body are shown also in the lithofacies porosity and permeability distributions, that testify that the southern body lacks in sand samples more than 20% porous, and therefore in the 10-100mD permeability range.
Finally, average oil saturation measured using core data is around 28% in the whole oil and gas body and 18% in the gas cap. As almost no oil is produced in the gas cap wells (the average is around 350 barrels of oil for almost 50 years of production), most likely oil mobility decreases because of the higher gas saturation in the gas cap area (decrease in oil relative permeability).

3.3.1.2: Pore characterization

Pore characterization has been run through SEM analysis aimed at identifying the presence of clays in the reservoir, and quantifying the relative volume of inter-pores clay with respect to the other analysed bodies, especially the unconventionally developed one.
Clay presence can be a major issue for hydrocarbon flow into the reservoir. Some clays have much more impact than others, so clay characterization is an important point to shed light on for field development purposes.
The analyses made shown the presence of three types of clay. From the most present to the least, the analyses detected the presence of illite, kaolinite and chlorite.
Specifically focusing on this body, the relative volume of clay is quite low. Detailed pore characterization showed that most of the grains are coated with a few clay, but it's very rare to find a whole pore occluded by authigenic clays. Each of the 3 recognised clay types in the whole Ferrier has been noticed in this body.
Grain coating is caused mostly by illite growth (rare chlorite); inter-pores clay is mostly composed by illite, and a few kaolinite is present as well.
The visualized effect of clay presence in the analysed compartment of the Ferrier is to slightly reduce porosity and pore throat size, but without significantly decrease hydrocarbon mobility. This explains the excellent reservoir quality of the sands and conglomerates in this area.
An exception to that is facies 3a, where extensive grain coating significantly drops the reservoir quality of the sandstones. If laterally continuous, mud laminae can act as flow barriers.

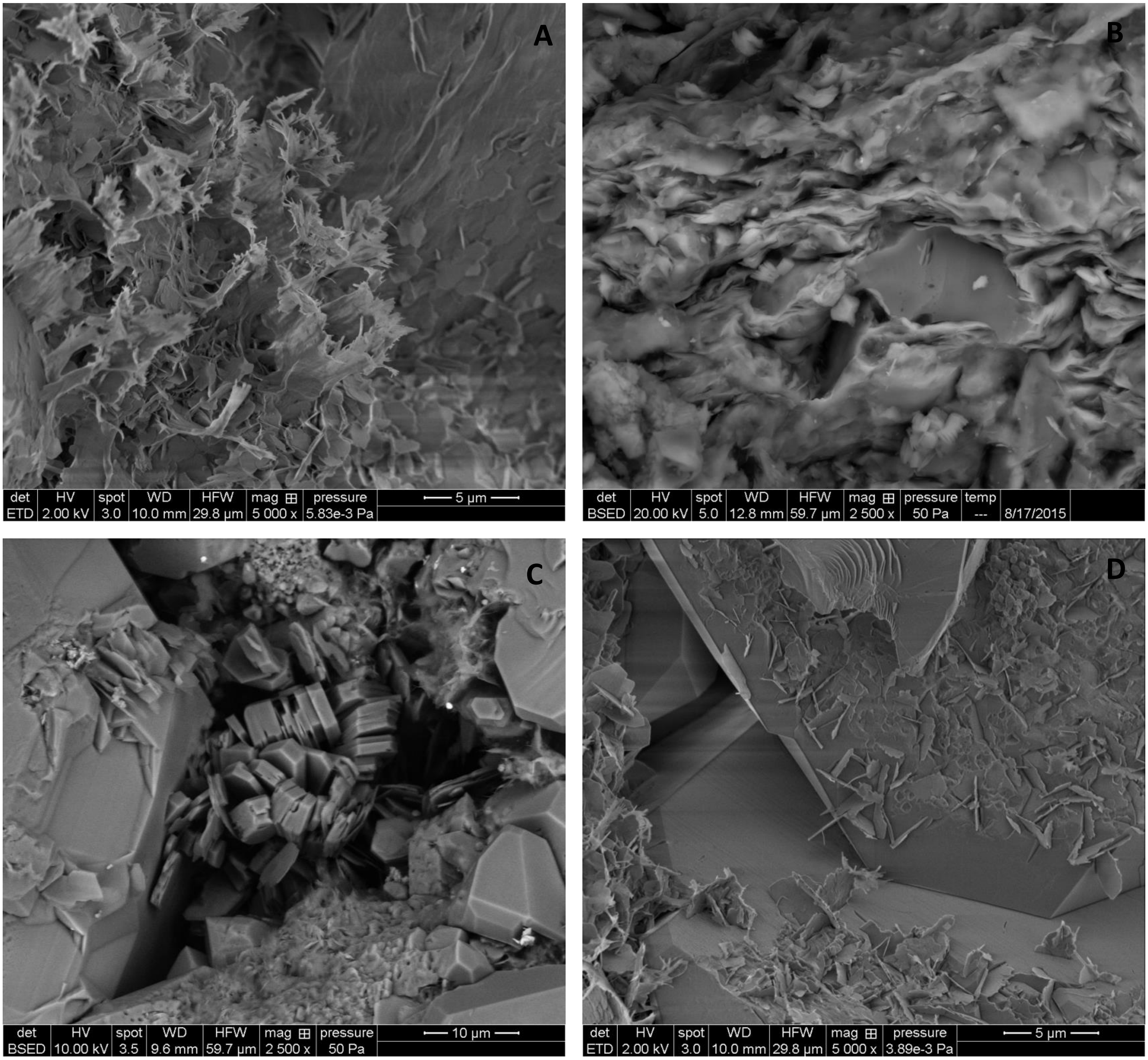


Fig.47: clay cementation occurrence in Cardium pores: pore partially occluded due to Illite growth in well 100/02-30-039-07W5/00 (47a); facies 3a under the SEM in a sand sample taken in well 100/02-30-039-07W5/00 (47b); kaolinite growth in pores in a sand sample taken in well 100/10-25-039-08W5/00 (47c); chlorite plates coat sand grains in a sand sample taken in well 100/06-17-038-07W5/00 (47d).

Clay is not the only cement present in the Cardium pores in the Ferrier area. Core logging detected the presence of siderite concretions located near flooding surfaces, like the E5. This was common to almost each physically logged core, where the top 0.5m of sandstones were sideritized and showed low reservoir quality, except when affected by fracturing. One of these siderite concretions has been sampled and analysed with SEM and optical microscopy to quantify siderite volume and texture.
Microporous chert is present as cement as well, and has the effect of sealing the reservoir, as its pore throats are extremely narrow, as detected by SEM analyses.
These two non-clay cements are shown and described in the pictures below.

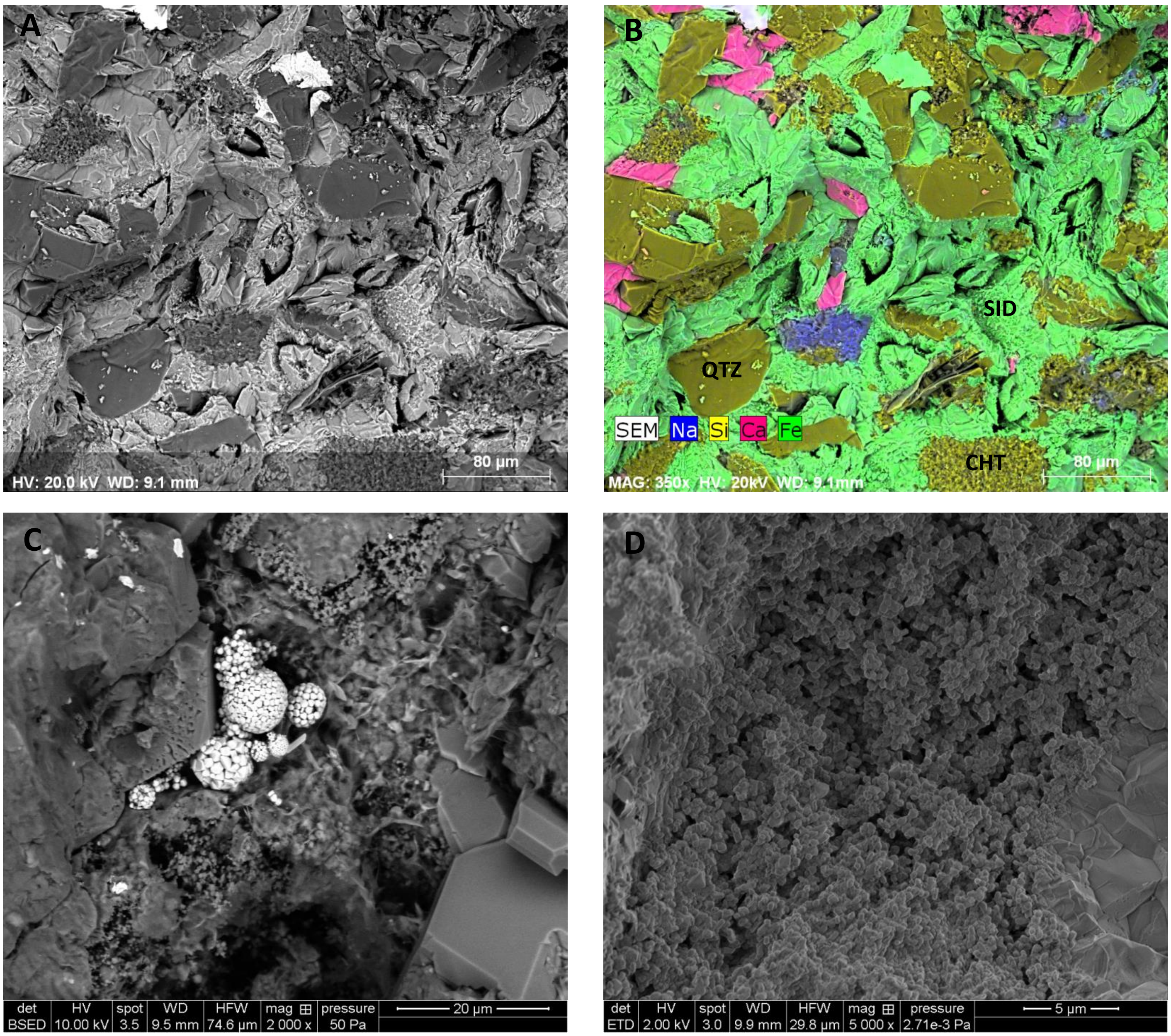


Fig.48: non-clay cement occurrence in the Ferrier main oil and gas body: SEM and EDX mapping of a siderite concretion cored in well 100/10-25-039-08W5/00. Quartz (QTZ) and chert (CHT) can be differentiated as chert shows micro-crystalline texture (48a and 48b); pyrite framboids in well 100/10-25-039-08W5/00 (48c); micro-crystalline chert in well 100/02-30-039-07W5/00 (48d).

The SEM analyses point out that the relative degree of cementation of this Ferrier specific body is pretty low. Where present, cement does not seal the reservoir, as it mainly occurs as grain coating. Authigenic clays can be an issue for reservoir flow just when illite is present inside the pore, whereas chlorite and kaolinite are not a major issue for fluid flow.
Microporous chert is claimed to be an issue for oil mobility, but its occurrence in the analysed samples was low.
Finally, siderite cementation occurs at the top of facies 3 sandstones and, more generally, can be found at the top of any flooding surface within the Cardium. Siderite cementation is claimed to strongly affect fluid flow. However, this type of cement doesn’t occur in the middle of the reservoir package but at its top edge, so it doesn’t significantly affect fluid flow into the reservoir.

3.3.1.3: Facies influence over production

This study points out that facies have great influence on the volume of produced hydrocarbons, as well as their production rates.
While drilling the thick sand spots of the Cardium in the Ferrier area, geologists realised that there was not a perfect match between sand thicknesses and production. Production map shows that great production can occur when sand thickness is just 1-2m, and vice-versa very few production can match with areas showing great sand thickness.
The match is slightly better using net reservoir maps instead of gross sand maps, but again the match is not perfect. To understand the facies control over production, facies have been considered as different flow units.
Without considering any halo play facies, i.e. facies 2b and 2c, facies 3 and 4 are the main flow units.
Several porosity vs permeability cross-plots have been provided in the previous pages. What is visible from these graphs is that sandstones and conglomerates have a different steepness of trend line, with the one fitting the conglomerates being more steep (i.e. wide range of permeability for a small range of porosity).
Moreover, the conglomerates are much more affected by cementation and fracturing, that means that several permeability values can match with a single porosity value due to post-depositional events.
More specifically, usually conglomerates have greater permeability values than sandstones with the same porosity, and overall the highest permeability values have been registered in conglomeratic samples. This means that, most likely, hydrocarbons (but also injected water) flow faster in the conglomeratic bar(s) seen in reservoir mapping than in the shoreface sediments.
The theory pointed out in this research is that this difference in fluid velocity between sand and conglomerate can have a major impact on the volume of produced hydrocarbons of each well.

What is claimed is that hydrocarbon production is directly proportional to the conglomerate thickness of the reservoir. This is caused by the greater drainage area guaranteed by the better reservoir quality of the conglomeratic body with respect to the sandstones.

When conglomerates are present and thick, hydrocarbons are exploited faster and in higher volumes from a single well, and this is due to the higher drainage capacity of the well itself.

Having thick sands too is an asset, as conglomerates can guarantee drainage, but their porosity, i.e. their hydrocarbon storability, isn't as great as the sands. Therefore, an ideal situation requires a few meters of conglomerates and a good sand thickness, so that hydrocarbons can be exploited faster.

To test the proposed theory, the conglomerate thickness map shown in the previous pages has been overlapped to the production map of each Cardium Ferrier well.

The final result is shown in the picture below. The map shows a very good match between conglomerate thickness and production values. For the whole length of the pebble-rich bar, production values are much higher than in the adjacent areas of the reservoir. Values do not match in the N portion of the main oil and gas body, where the conglomerates are not present (the bar is more eastward), but a much higher sand thickness than the customary values has been observed in cores. In this portion of the Ferrier, sand thickness can reach values up to 7-8 m (see fig. 30), with the average values for the Ferrier being around 4-5 m.

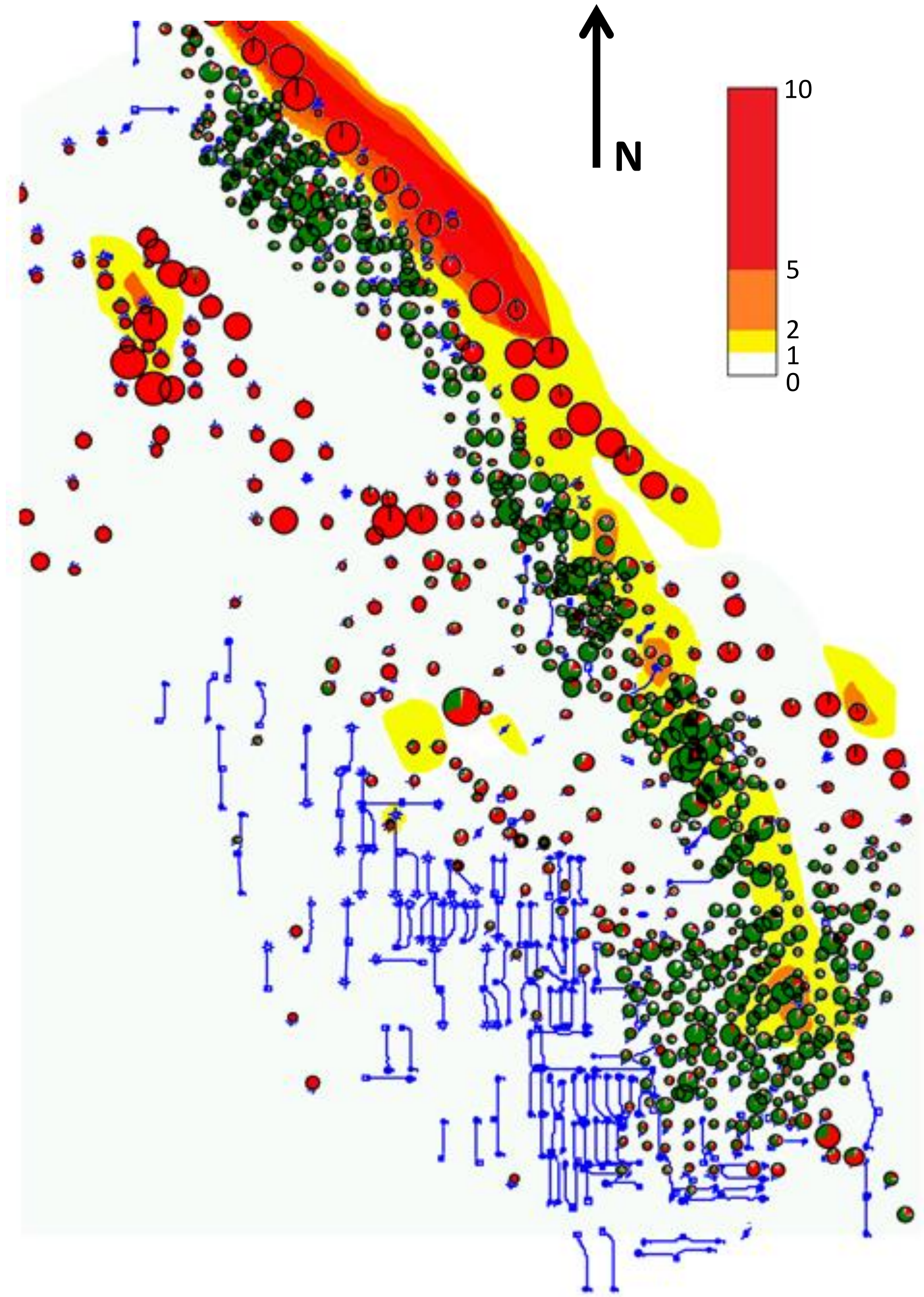
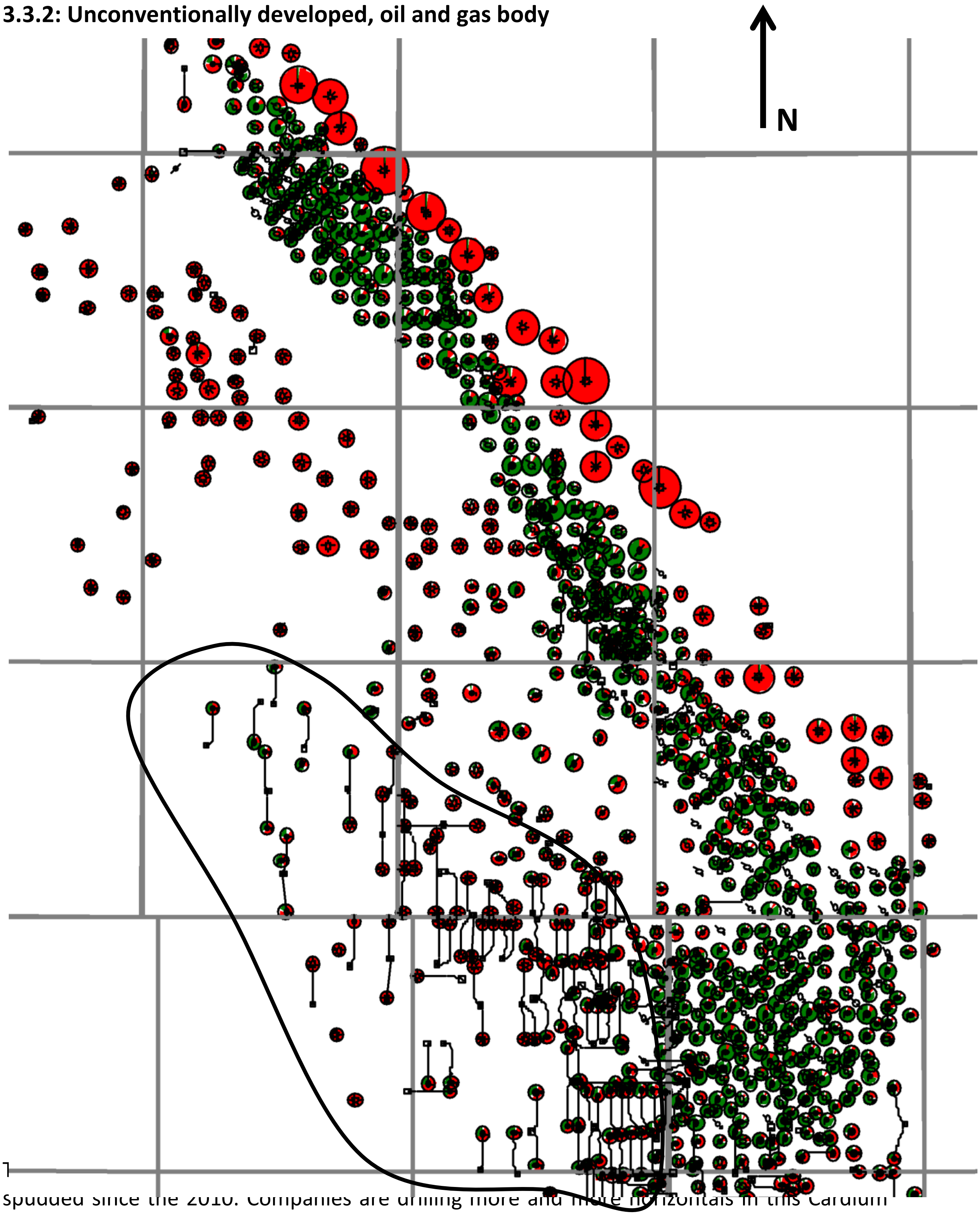


Fig.49: production map overlapped to facies 4 thickness map. There is great relation between conglomerate thickness and production values. This explains why some areas show different production values despite having the same gross reservoir thickness. Having the same thickness of facies 3 and 4, facies 4 generally ensures better production.

3.3.1.4: Conclusions

This chapter described the petrophysical properties of the main oil and gas body of the Ferrier. This body is the most prolific oil and gas producer of the Ferrier area, and generally shows low GOR values, i.e. a great quantity of oil is produced.
Since the '60s, vertical wells have targeted the Cardium Formation is this play, and more recent exploration techniques identified new by-passed pay areas. These spots have consequently been targeted with deviated/directional or horizontal wells.
Keeping the current number of producing wells and field development plan, this compartment is estimated to produce 120, 142.5 and 171 million barrels of oil according to P_{90}, P_{50} and P_{10} respectively. Active research of other by-passed pay zones would increase the EUR (estimated ultimate recovery) values for the play.
Several cores have been taken in this body. 6 of these were directly logged, whereas routine core analyses from the other ones were considered for the petrophysical characterization.
The petrophysical characterization pointed out that the sands are up to 100mD permeable and 29% porous, whereas conglomerates are up to 800mD permeable and 24% porous. Maximum petrophysical values are located in the northern portion of the body. It has been observed that sand samples of the southern portion of the body reach permeability values up to 10mD and porosity up to 20%. This part of the Ferrier seems missing sand sample with porosity ranging from 20 to 26% and permeability in the range 10-100mD.
Average oil saturation is around 28%, and this value decreases down to 18% in the gas cap area.
Pore characterization of the samples detected the presence of three types of clay cement (Illite, kaolinite and chlorite) and other two cements (siderite and micro-porous chert). Absence of massive cementation ensures great reservoir-quality of the reservoir.
Great match between conglomerate thickness and production values has been observed. This is due to the high permeability of the conglomerates, that ensures greater drainage area.

3.3.2: Unconventionally developed, oil and gas body



T

spudded since the 2010. Companies are drilling more and more horizontals in this Cardium

Fig.50: geographic location of the unconventionally developed, oil and gas body with cumulative Cardium oil and gas production plotted as bubble maps for each well.

body with variable success. However, what controls the success of these horizontals is still not completely understood.
Moreover, there is a huge difference in production within the body, as in the central part is gas producing only, whereas oil is produced in the northern and southern portion together with gaseous hydrocarbons, with C1 (methane) being around 80% of the total gas volume.
Companies are particularly focusing on this area, as it's the one with the highest upside potential in the Ferrier, being the other two bodies already extensively exploited. However, horizontals have been drilled with very variable success. As very few conglomerates are present in the unconventionally developed area, that means there is another major control over production in this area different by the one interpreted for the main body.
The unconventionally developed body of the Ferrier had first been drilled with vertical wells starting from the '60s. Due to the generally poor reservoir characteristics of the Cardium, this area was soon neglected and attention was focused on the main body of the Cardium, that was much economically profitable with the same drilling techniques.
With the arise of horizontal drilling and multi-stage fracking, this formerly neglected area, western from the main body, has extensively been targeted as halo play with new techniques, and the number of drilled horizontals is still growing in the Ferrier area, although being lower than bigger oilfields like the Pembina and Willesden Green.
Finding what controls the production and GOR of the Cardium in the unconventionally developed area of the Ferrier is one of the main aims of this research.
There are no recent studies on the geology of the Ferrier, therefore this research is the most updated work about this topic. This study aims to be a valuable contribution to every exploration project targeting the Cardium Formation in this area of the Ferrier light oil and gas play.

3.3.2.1: Introduction

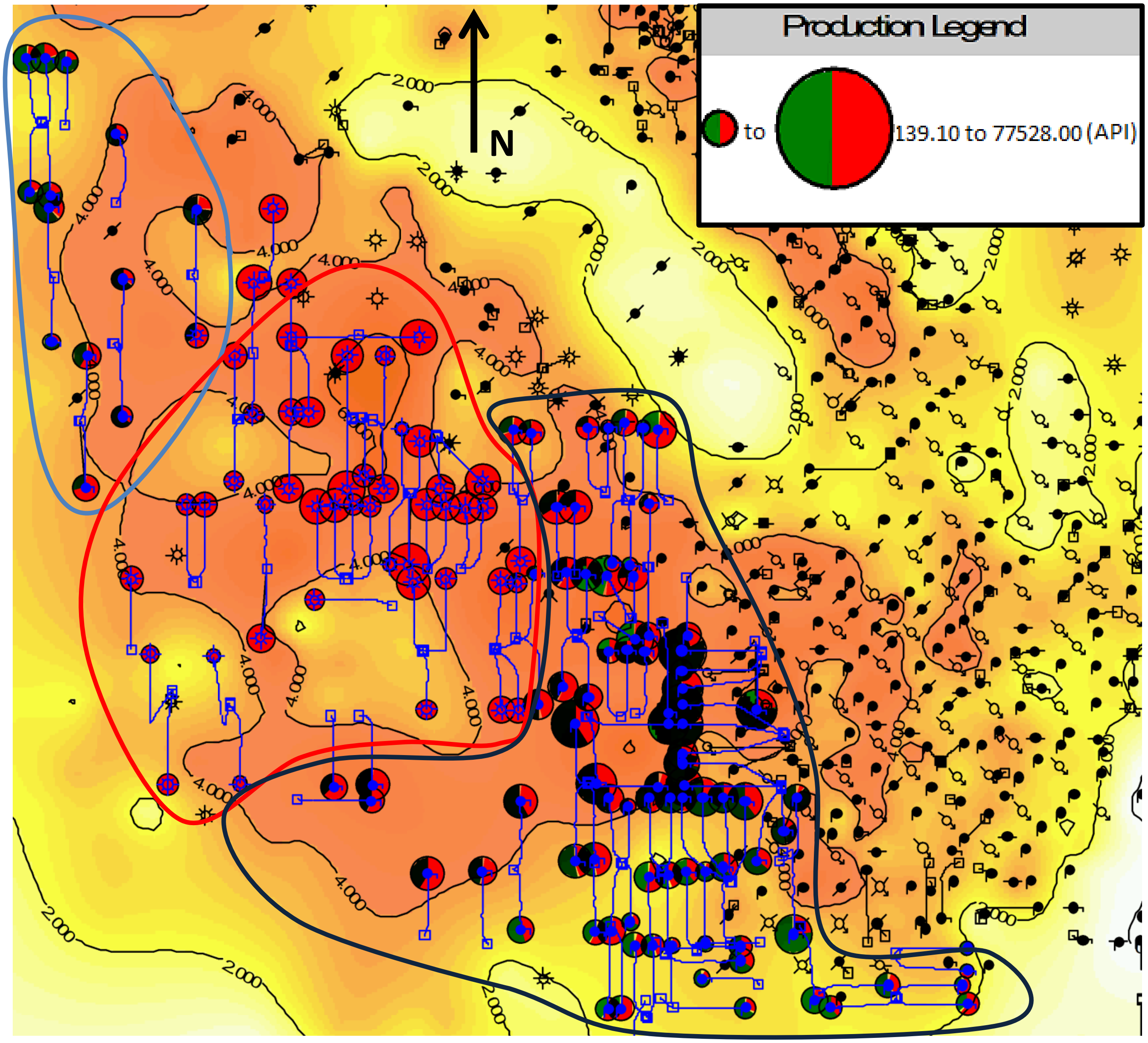


Fig. 51: gross reservoir map in the unconventionally developed Ferrier area. The bubble map represents production data relative to the first six months of production of each Cardium horizontal producer. This map has been preferred to a cumulative production map to avoid biases due to different cumulative hours of production among different wells. Three sub-compartments can be identified based on production data. Light blue: northern sub-body; red: central sub-body; dark blue: southern sub-body.

The unconventionally developed area of the Ferrier includes the W-SW portion of the field, just western of the main body and southern of the conventionally developed, gas charged one.
In its southern edge, this body looks to be connected to the main body, whereas in the northern portion, a belt with much lower sand content, as well as lower net reservoir thicknesses separates it from the gas producing area (see fig. 36, 37 and 38).
Production data show that the body can be divided into 3 different portions, each one having unique GOR and/or production rates (see fig.51). More specifically, in the middle of the unconventionally developed body there is an area where no oil is produced, and the northern and the southern portion differ by hydrocarbon production rates: the northern body shows oil and gas production at lower rates than the southern body (smaller bubbles in the map).
To characterize each sub-body, the adopted method was to focus on horizontal production data matched with cores taken as close as possible to those wells. The aim of this process was to demonstrate weather or not reservoir properties (seen in routine core analyses) are the main cause of the production issue seen in the unconventionally developed portion of the Ferrier. Detailed core logging was performed in each sub-body, and core sampling was implemented for thin section, SEM and CL purposes.
Each one of the 3 sub-bodies will be treated separately in the next sub-chapters, and then a conclusive chapter will be provided.

3.3.2.2: Southern sub-body

The southern sub-body is located in an adjacent position with respect to the southern portion of the main oil and gas body (see fig.51).
Production data show that this body is the one with highest volume of produced hydrocarbons per well. This is also confirmed by routine core analyses, that points out that this body is the one with the best reservoir quality among the three.
19 cores with available data have been taken in this body, and the cross-plot of the sandstones is shown below. It’s important to notice that each sand sample was considered, and not just the clean ones. This is a key point in reservoir characterization because the reservoir has to be considered at its current status.

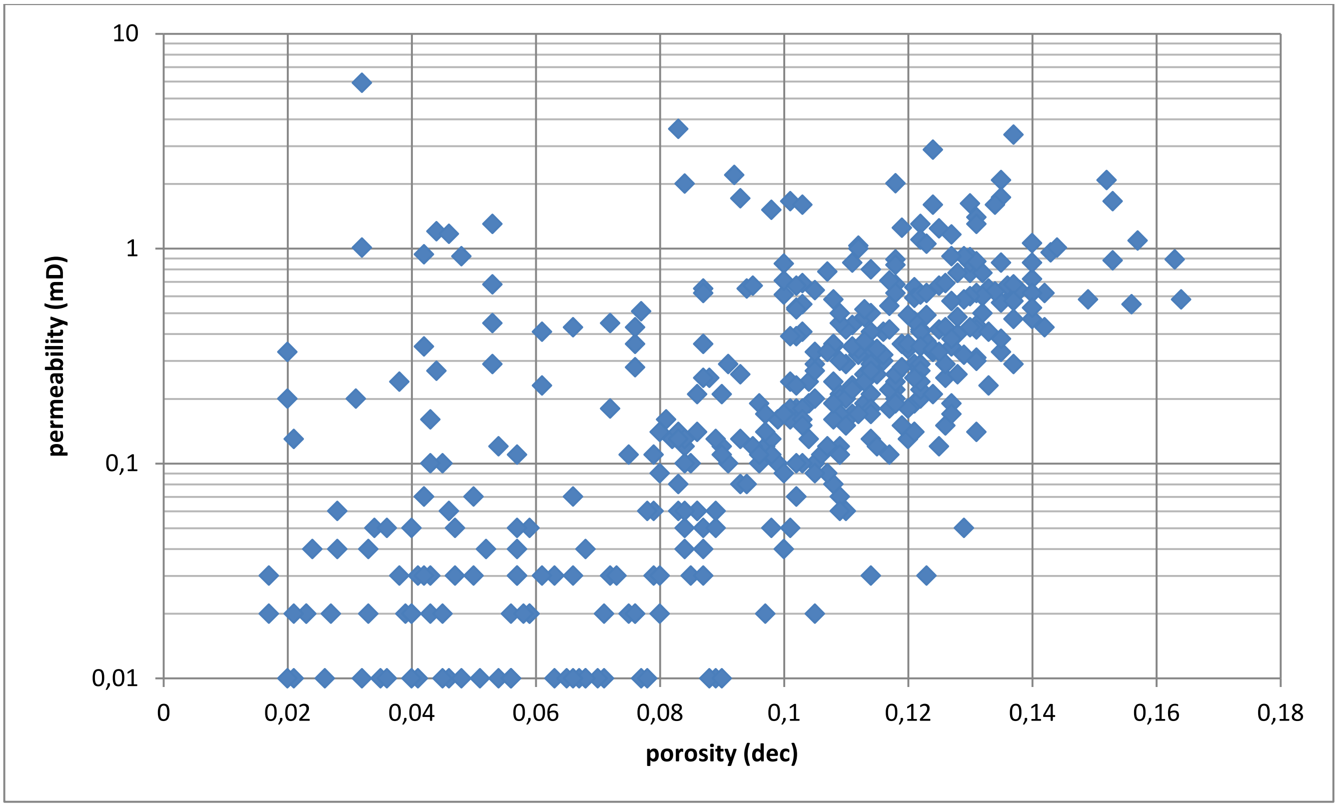


Fig.52: porosity vs permeability cross-plot of the southern sub-compartment of the unconventionally developed area of the Ferrier.

The porosity vs permeability cross-plot shows that most of the samples show porosity ranging from 10 to 14% and permeability from 0.1 to 1mD. Permeability values lower than 0.1mD occur in the basal portion of the reservoir, where the sands are tighter. This was noticed in the main body as well.

Estimated permeability average in the body is around 0.55mD, and core oil saturation values have an average of roughly 29.5%.

After looking at routine core analyses, 100/16-15-038-08W5/00 has been picked as the type well for this sub-body. This is not a Cardium producer, as the whole zone is unconventionally developed. This well penetrated the Cardium Formation to target deeper pay zones, but a core was taken in the Cardium as well. This core is close to many horizontal producers, and can therefore be compared with production data as well, and that's what will be discussed further in this paper.

Detailed core logging and sampling led to detailed lithostratigraphic description of the reservoir interval.

Being each tray around 68cm thick, the core shows the presence of roughly 5 meters of sand.

The basal tray shows thin (1-2 cm) wavy mud interbeds, then the sand looks clean. Bedding and sedimentary features aren't as visible as in the main body, and this is most likely caused by the higher cementation degree and slightly finer-grained sandstones.
At the top there is presence of conglomerates, that are around 20-25 cm thick.
Facies 3 has been analyzed in thin section to have an idea of its reservoir potential in this area. The picture shows that the mineralogy is analogous to the one observed in the main body. Thin sections were taken in the middle and top portions of the reservoir, and show max porosity value of around 13-14%.
The thin section taken in the top reservoir portion of the core is shown in picture 54 with a 4x magnification.

Fig.53: Cardium core taken in well 100/16-15-038-08W5/00. The red circle marks the position of the thin section shown in fig. 54.

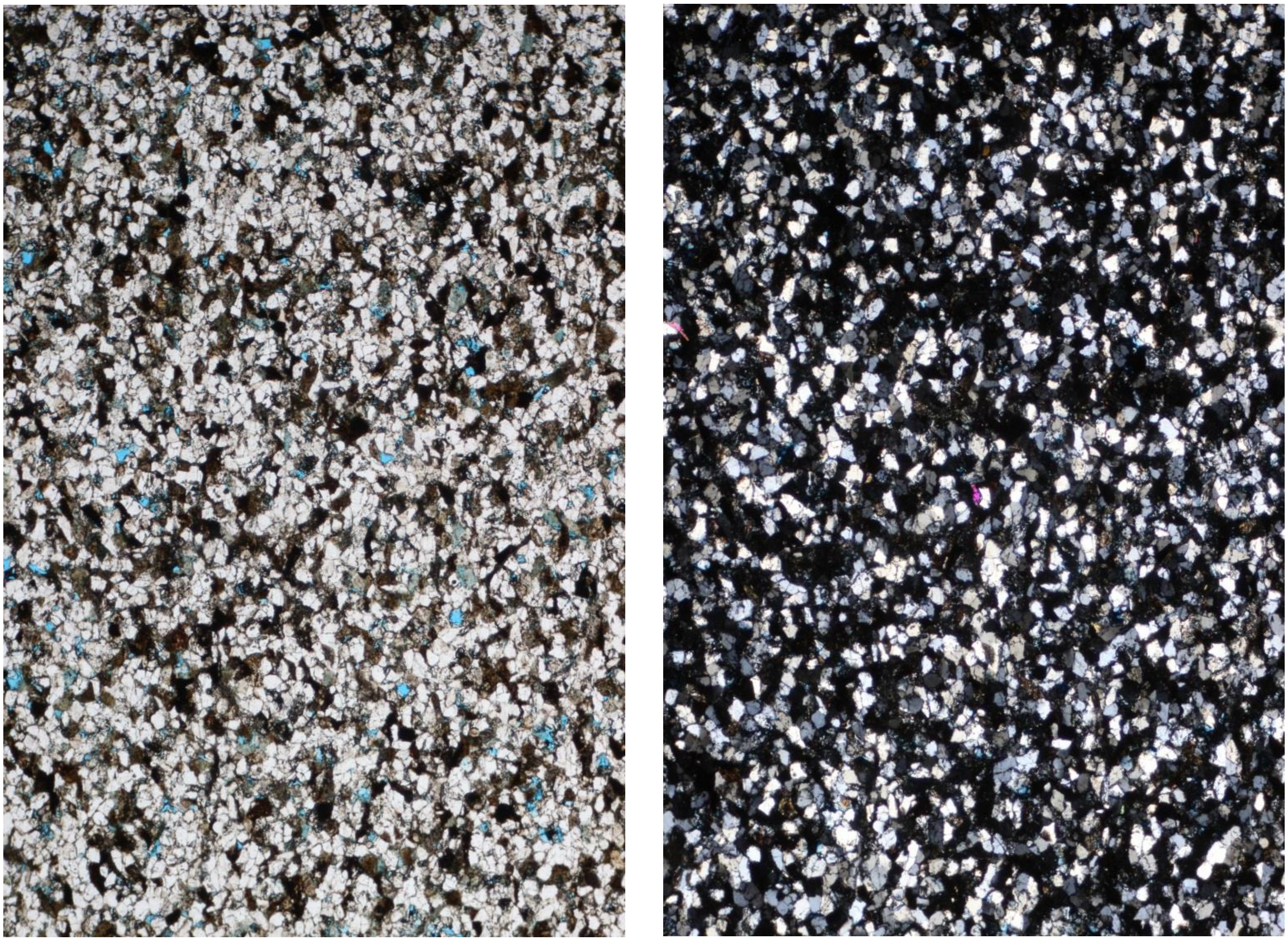


Fig.54:thin section taken in the top Cardium reservoir sandstones of well 100/16-15-038-08W5/00. Thin section magnification is 4x.

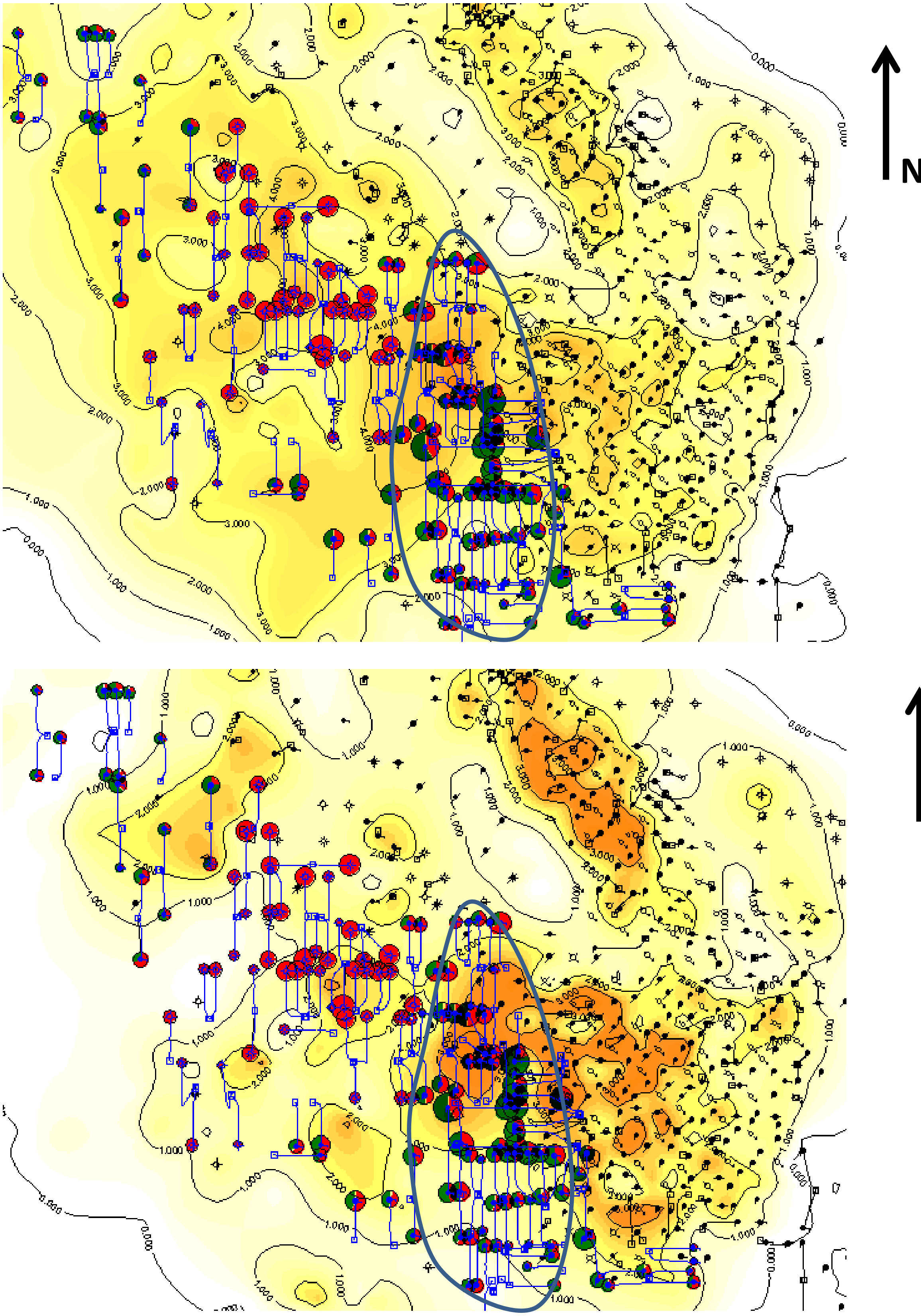


Fig.55: 6% (55a) and 12% (55b) net reservoir maps of the unconventionally developed compartment of the Ferrier. 1st six months production data of each Cardium HZ producer are posted. It's evident that the southern sub-body shows the greatest reservoir quality with respect to the central and the northern sub-compartments.

Looking at the cross-plot, production data and focused net reservoir maps, it's visible that the best quality reservoir within the unconventionally developed portion of the Ferrier occurs in the southern sub-body area. Porosity and permeability data point out that this sub-compartment is very similar to the main oil and gas body in the porosity vs permeability trend and absolute values. As it's directly linked to the main body (just S and W of it), this sub-body (or at least part of it) can be considered as its reservoir edge.
This theory is supported by several factors:

- this sub-body is directly linked to the main body;
- reservoir properties are not as good as in the main body, but the values are matchable. Also, this sub-body is by far the one with the best reservoir quality among the three unconventionally developed sub-compartments;
- production data and net reservoir maps confirm the fair quality of the reservoir.

Seen in core, the sands look tighter than the main body ones. As index of that, bedding or any other kind of stratification is barely visible due to the high cementation and compaction of the reservoir rock. This most likely explains the differences in fluid production between the main body and this area.
100/15-15-038-08W5/00 is the Cardium horizontal closest to the type well for this sub-body. This well is considered the type horizontal producing from the Cardium in the southern body. The well has been spudded in mid-2013, and so far it produced around 76,000 bbls of oil and 790,000 Mcf of gas.
Production rate ranges from 6,500 bbls a month at the beginning of production to 600 at the present day. This testifies the excellent economic profitability of horizontal drilling in the Cardium, and more specifically in this sub-body.
With the current development setting, 100/15-15-038-08W5/00 is interpreted to have a EUR of 95,000 bbls of oil and 1,100,000 Mcf of gas. This horizontal is expected to produce oil until 2017.
As previously explained, the method used consists in comparing routine core analysis data with production data of the horizontal producing closest to the core itself. This is favoured by the extreme down-spacing of the horizontals, whose density is around 4 per section, therefore it's not hard to find a Cardium cored well nearby.
This method provides geologists with a petrophysical modeling of the reservoir interval drilled by a horizontal well. That is useful to compare unconventionally developed bodies as well, as they obviously don't have detailed well log data along their trajectory.
Cored well 100/16-15-038-08W5/00 is close to two Cardium producing horizontals: 100/15-15-038-08W5/00 and 100/01-15-038-08W5/00. Both can be considered producing in the stratigraphic section shown in the cored well, therefore both have been considered for the GOR comparison.

100/16-15-038-08W5/00

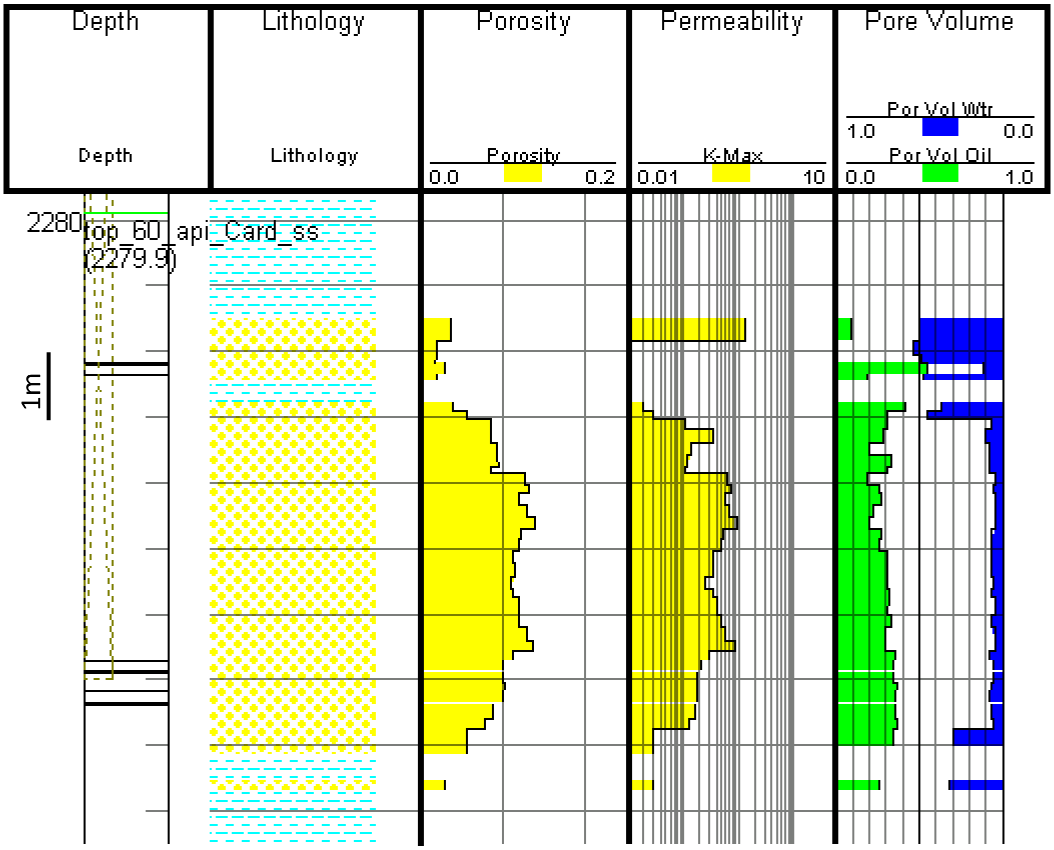


Fig.56: petrophysical model of Cardium core taken in well 100/16-15-038-08W5/00. Max porosity and permeability are found in the middle-top reservoir; oil saturation generally increases going deeper in the core.

The core plot shown above summarizes the petrophysical characteristics of the Cardium reservoir in the southern sub-body. As it has been described in the second chapter, the lower and the top intervals of the reservoir are the least permeable due to the high degree of cementation, respectively mainly made up of silica and siderite. These tighter portions of the reservoir cause the good quality sandstones to be around 3-4 m thick.

Also, there is a difference between the top of the sandstones seen in core and the ones seen in well logs. Part of it is due to the not perfect matching between core and well log depths, but also to the presence of facies 2c on top of the reservoir interval.

5 metres of sands have been directly observed in core. The basal meter of the sands show core porosity ranging from 6% to 10%, with porosity increasing going stratigraphically upwards in the core. Permeability shows the same trend, with values ranging from 0.05 to 0.2mD. After this interval there are 3 metres of better-quality sandstones, that form the main reservoir. Sand-sized sediments have porosity ranging from 10 to 14% and permeability from 0.2 to 1mD. Then, another meter of tight sand is present at the top of the interval. In terms

of petrophysical properties, the top sands are similar to the base of the sand package. Porosity and permeability range respectively from 6 to 10% and 0.1 to 0.15mD.
The top of facies 3 marks the beginning of facies 2C, that is around 75 cm thick according to core logging and core plot as well.
Oil saturation is around 20% at core top and increases to around 35% in the deeper portion of the cored interval.
Once established the petrophysical model for the Cardium reservoir, now production data have been compared to the defined reservoir properties.
This process can be applied to every horizontal producer having a Cardium core nearby. In this sub-body of the Ferrier 22 wells have a core in the Cardium reservoir interval, and 11 of those have an HZ producer closer than 500 meters from the vertical well trajectory. Each one of these wells has been taken into account for this method, and production data have been matched with reservoir quality seen in cores.
This process has been used to characterize the sub-body, as well as to compare the three different sub-bodies and unravel what may cause differences in production, in order to find the most economically profitable areas to target in the halo portion of the Ferrier.
This comparison has been standardized for each Cardium horizontal with cores nearby. Cumulative production, GOR and OGR (oil vs gas) values from the 4th to the 6th month of production have been considered to compute average values. Production data of the first three months have been dropped because they are still affected by fracking operations, and data from the 7th month to the present day haven't been taken into account as data tend to standardize along time, so early production data are better to detect fluid differences.
In this area, Cardium cores have been taken from the '60s to nowadays, and horizontals can't obviously be drilled too close to other wells because of security issues, that means there's not a perfect match between the petrophysical characteristics seen in cores and the ones of the reservoir drilled by the horizontal. The assumption that this method implies is that this difference can be considered negligible if the core is closer than 500m to the producing horizontal.
To test the model, production data of two Cardium HZ closer than 500m to the Cardium Core previously described (100/16-15-038-08W5/00). The two wells, 100/01-15-038-8W5/00 and 100/15-15-038-8W5/00, are roughly 400m far from each other, and the Cardium core is located in between.

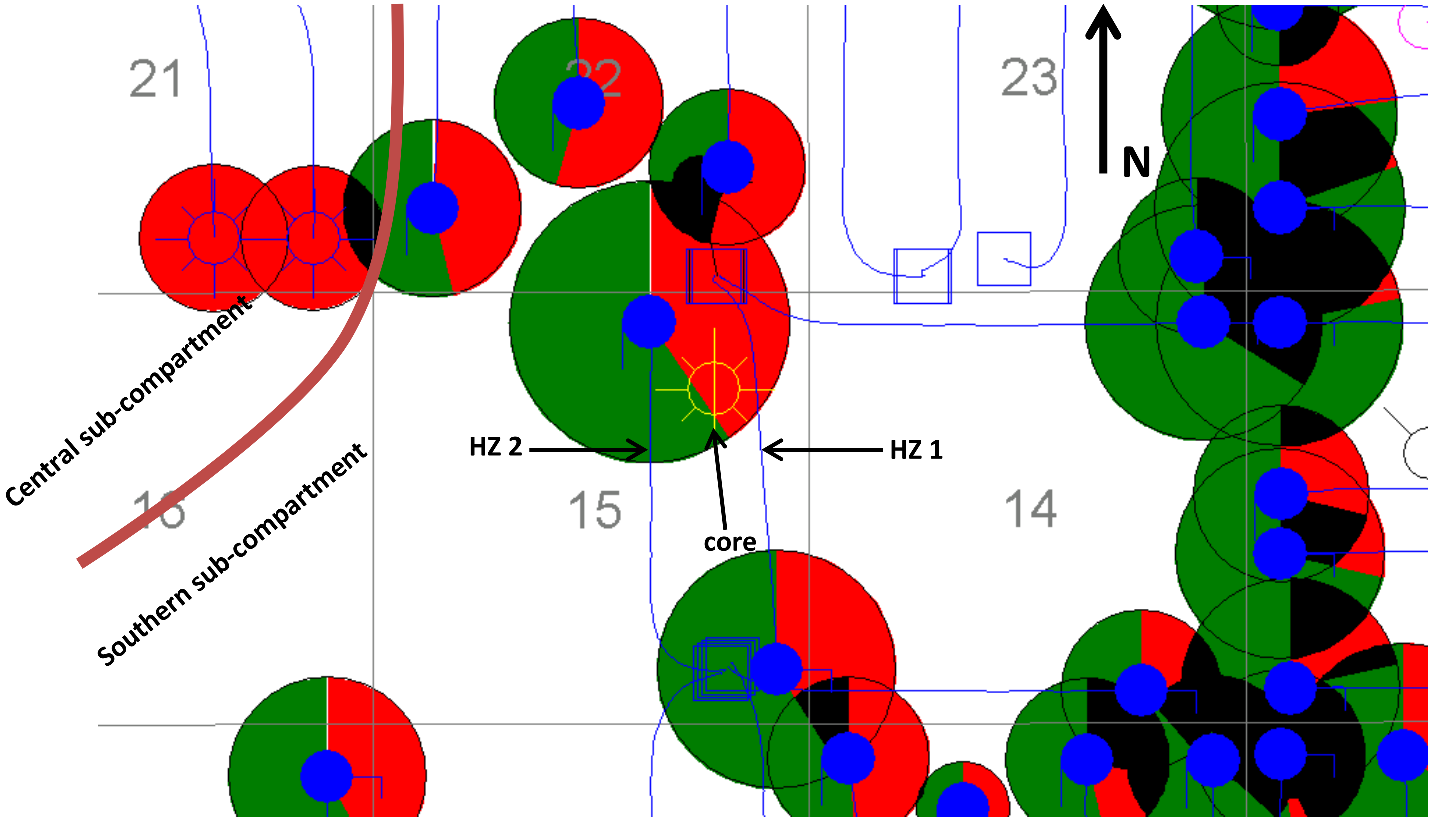


Fig.57: Cardium cored well 100/16-15-038-08W6/00 is shown in yellow in the picture, as well as the trajectories of the two horizontal wells used to test the model. The two producers are displaced by around 400m, and the core was taken in between. In the NW sector part of the gas producing sub-compartment (central sub-compartment) is visible.

Now, production data have been plotted versus standardized producing time, as the wells weren't spudded in the same month. The graph is shown below.

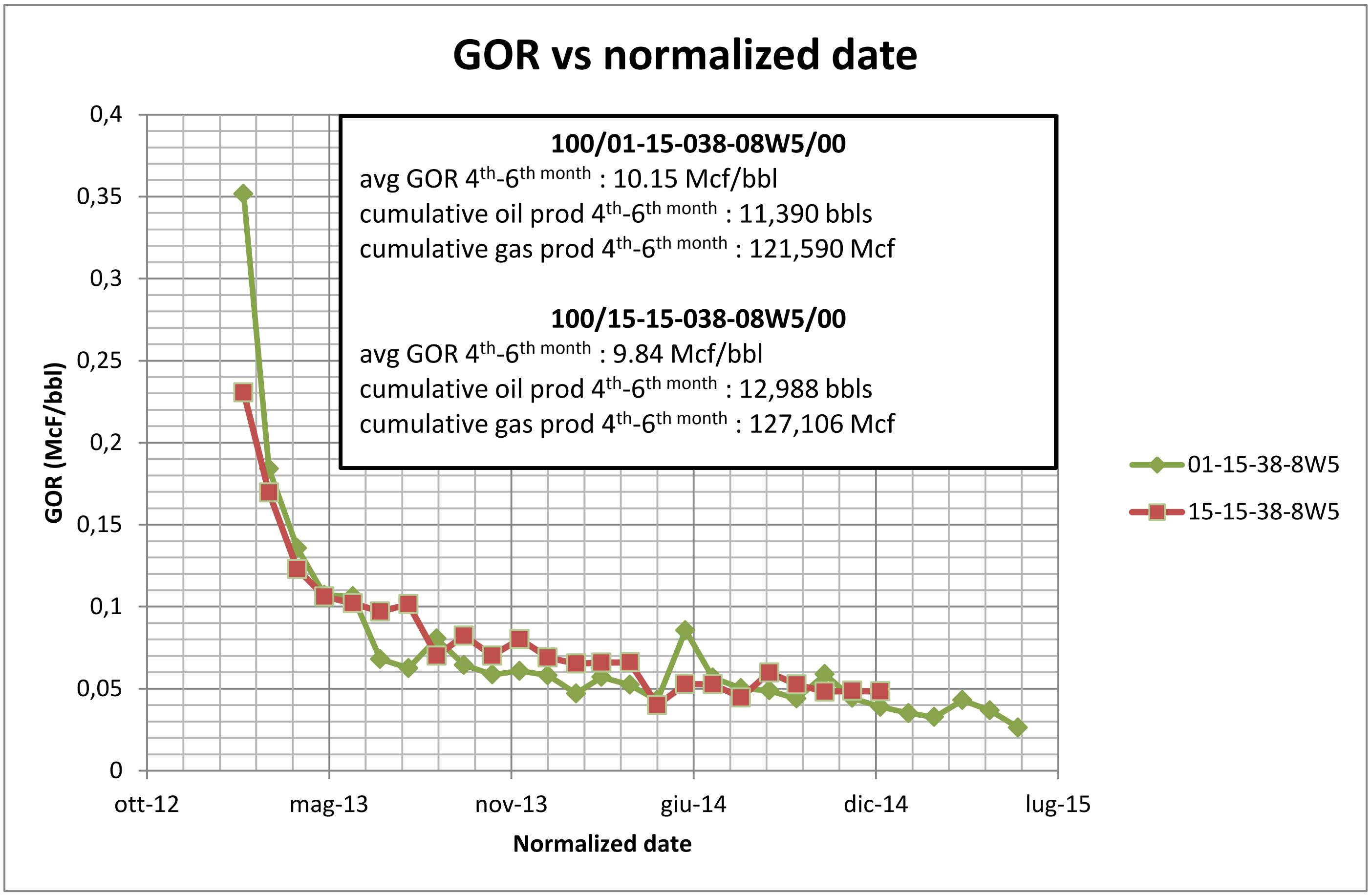


Fig.58: Normalized date vs GOR of wells 100/01-15-038-08W5/00 and 15-15-038-08W5/00. Great match is observed between the two trends. This testifies that similar reservoir properties, in this body, correlates with similar production behaviour. This means there is very few to no influence of external factors like differential migration or fracturing.

The graph shows that production values along time are extremely similar between the two horizontals. That testifies the reliability of the assumption that had to be made to make this method be geologically significant. The EUR of these two horizontals ranges from 65,000 to 95,000 bbls of oil (2 bbls/day cut-off) and from 920,000 to 1,100,000 Mcf of gas (200 Mcf/day cut-off). Cardium horizontals have a cost of approximately 2 million CAD per well, so this body is extremely economically profitable.

To further characterize this body, the same process was applied to each horizontal with core nearby. The provided table shows the results of these study in the southern sub-body. In the table, the permeability of the reservoir has been taken into account, as well as the production data of the horizontal. The net reservoir portion of the core has been estimated through core analyses using 0.1 and 0.3mD as permeability cut-offs.

The following table summarizes the results:

Cored well UWI	>0.3 mD and >0.1 mD net reservoir (m)	Oil saturation in cores (%)	Nearby producer UWI	4^{th}-6^{th} month average GOR (Mcf/bbl)	4^{th}-6^{th} month cum oil prod (bbls)	4^{th}-6^{th} month cum gas prod (Mcf)	Estimated P_{50} EUR (oil)	Estimated P_{50} EUR (gas)
16-15-38-8W5	3.3 – 4.6	29.95	01-15-38-8W5	10.15	11,390	121,590	65,000	920,000
16-15-38-8W5	3.3 – 4.6	29.95	15-15-38-8W5	9.84	12,988	127,106	95,000	1,000,000
06-18-38-8W5	1.6 – 4.4	34.78	03-18-38-8W5	22.28	5,464	121,161	35,000	840,000
10-36-37-8W5	1.0 – 2.3	No data	09-36-37-8W5	7.04	8,970	37,980	38,000	320,000
01-03-39-8W5	4.0 – 5.5	No data	14-34-38-8W5	35.44	4,101	141,254	40,000	1,800,000
01-03-39-8W5	4.0 – 5.5	No data	15-34-38-8W5	40.75	3,801	150,444	38,000	1,900,000

Table 1: comparison between petrophysical values observed in core and horizontal well productivity. Producing wells having the same core at roughly the same distance from each other always show similar production behaviour.

The production behaviour of the horizontals is shown in the multi-well production analyses shown in picture 59. Around 70 horizontals are targeting the Cardium in this sub-compartment.

Generally oil is exploited faster than gas, and therefore oil production decline is faster with respect to the gas one. Today, current monthly group production is around 25,000 oil barrels and 900,000 Mcf.

This “current cumulative high GOR” is caused by the rapid oil production decline with respect to the gas one, as previously described.

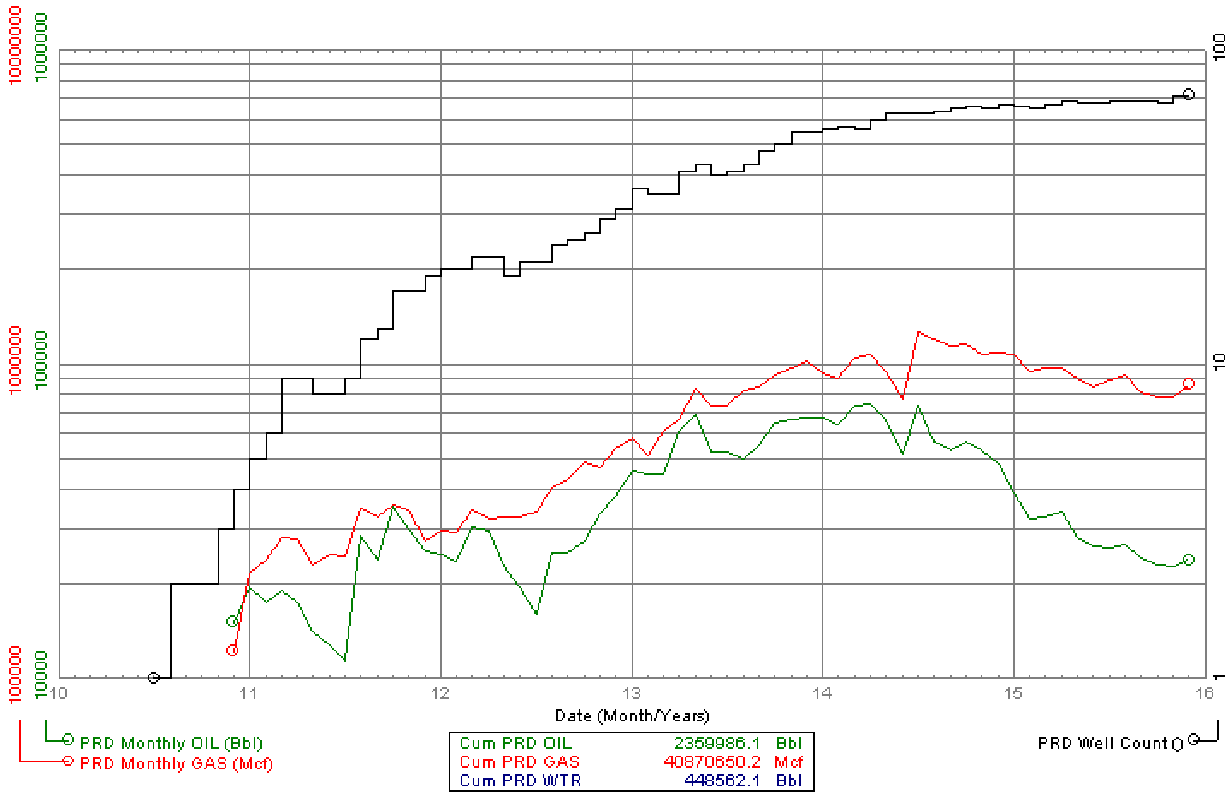


Fig.59: group production of the southern sub-body Cardium horizontals. The graph shows monthly oil and gas production, as well as the producers well count.

In conclusion, the southern sub-compartment shows fair reservoir characteristics and looks the area of unconventionally developed portion of the Ferrier with the best reservoir quality.
The main reservoir interval is 3 to 4m thick in average, showing porosity ranging from 10 to 14% and permeability from 0.3 to 0.8mD.
The sands have been targeted since 2010 with horizontal wells and multi-stage fracking techniques, and this sub-compartment proved to be economically profitable as light oil and gas halo play.
Comparison between reservoir properties and production behaviour was positive, therefore production rates and GOR strongly depend on reservoir properties.

3.3.2.3: Northern sub-body

This reservoir compartment is located between the central body and the conventionally gas producing area of the Ferrier, from whom it's separated by a belt with relatively low gross and net reservoir thickness values (see fig.51).
A porosity vs permeability cross-plot has been built for the body using routine core analyses. The graph shows that reservoir characteristics are slightly better than the central body. Average permeability and oil saturation are around 0.23mD and 24.9% respectively. Most of values seem to fall in the 0.2mD range, and some fractured samples with high permeability are present.

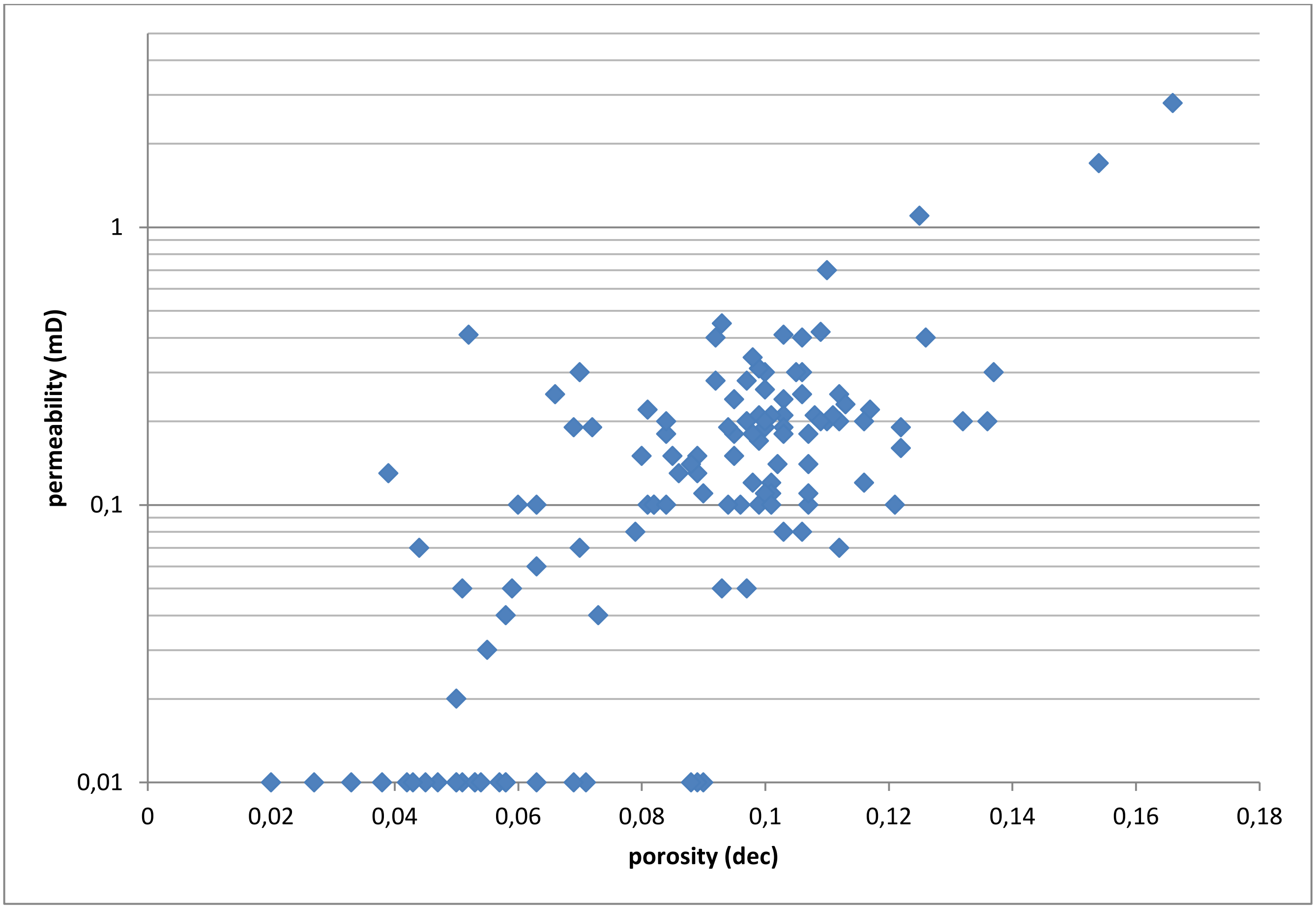
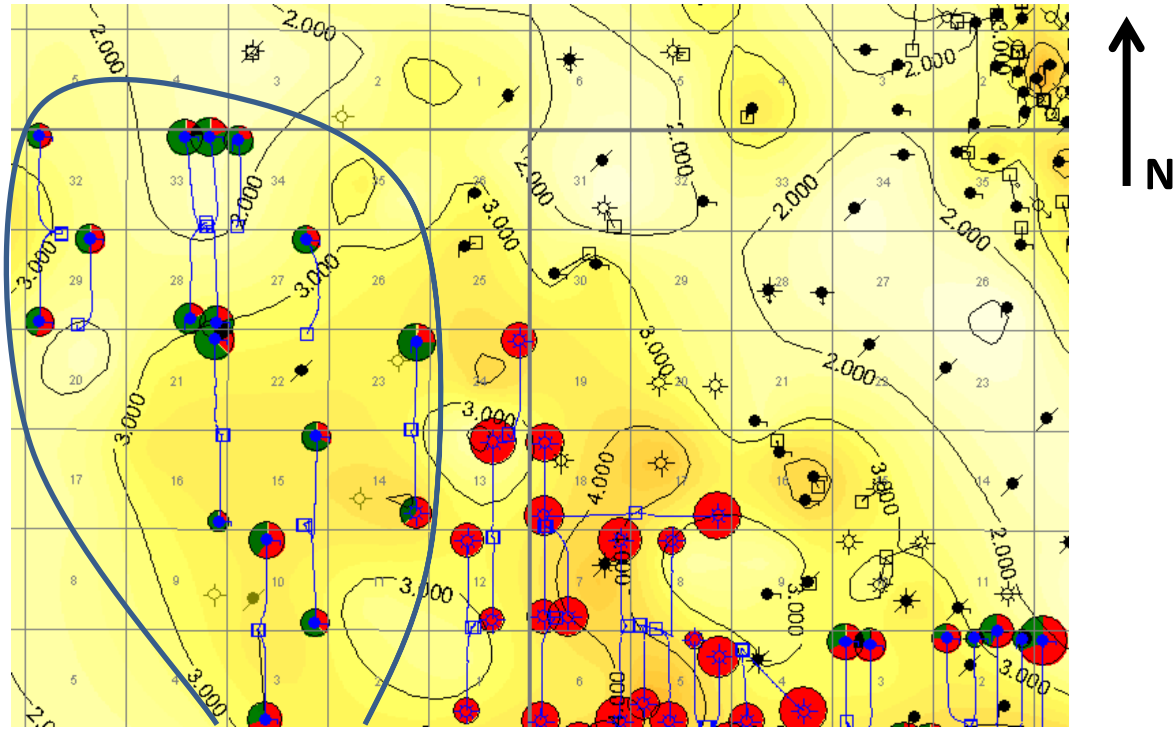


Fig.60: porosity vs permeability cross-plot of the northern sub-compartment of the unconventionally developed area of the Ferrier.



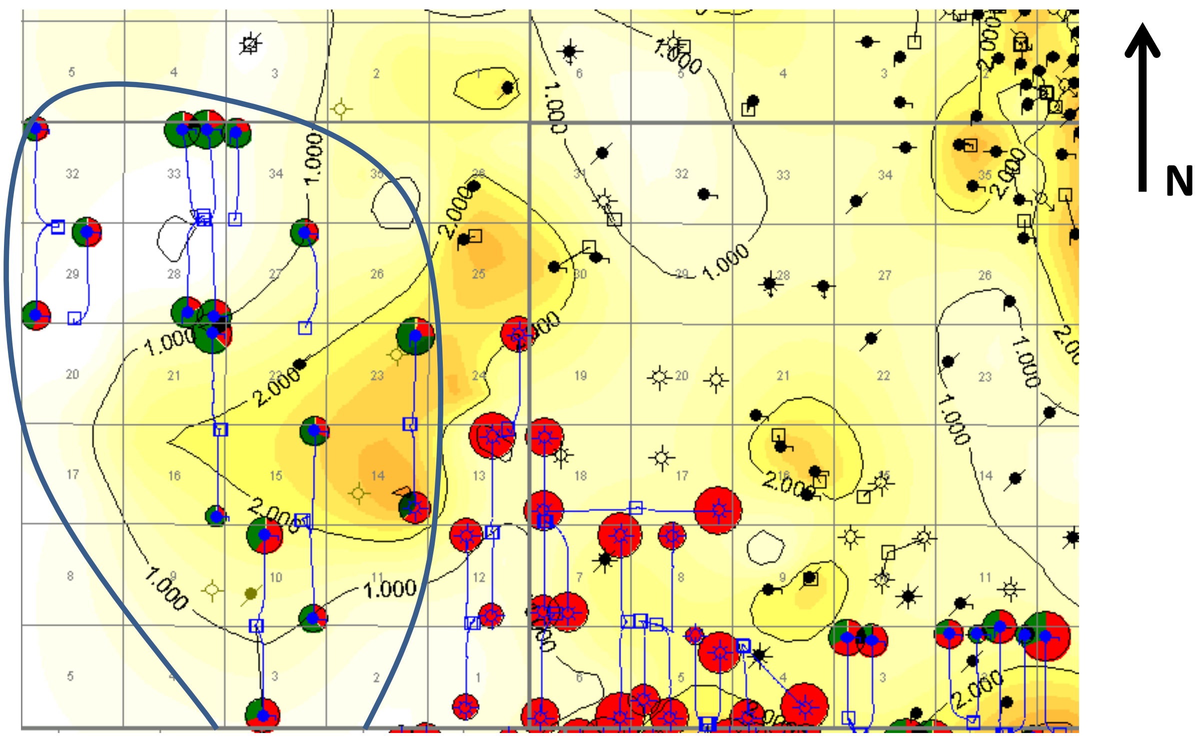


Fig.61: 6% (61a) and 12% (61b) net reservoir maps of the northern sub-compartment of the unconventionally developed area of the Ferrier. The gas producing, central body is visible in the SE area.

Net reservoir mapping shows that this sub-compartment is located in an area where 6% and 12% net reservoir values are lower than the surrounding regions of the map. 6% net reservoir thickness is 2-3m in average, whereas average 12% net reservoir thickness is around 1-2m. Based on the general porosity vs permeability cross-plot and net reservoir mapping, 100/06-10-039-09W5/00 has been chosen as type well for this reservoir compartment. The core plot of this well is shown below.

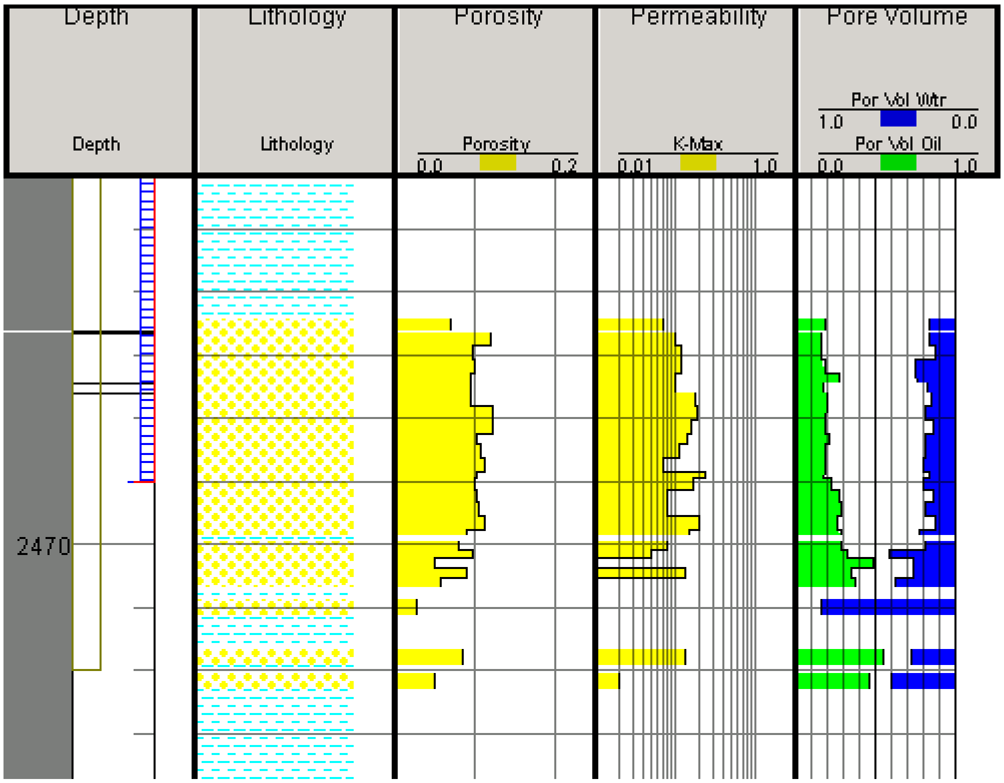


Fig.62: core plot of the Cardium core taken in well 100/06-10-039-09W5/00.

Core analyses, as well as net reservoir mapping, show that 6% net reservoir thickness is around 3m, and 12% thickness is around 1m. Core oil saturation ranges between 20% in the shallower area to 40% deeper in the core, with a general good relation between depth and core oil saturation.
Only two horizontal wells have cores taken closer to 500m in this sub-compartment of the Ferrier. The same process applied for the southern body is described in the table below.

Cored well UWI	>-0.3 mD and >0.1 mD net reservoir (m)	Oil saturation in cores (%)	Nearby producer UWI	4^{th}-6^{th} month average GOR (Mcf/bbl)	4^{th}-6^{th} month cum oil prod (bbls)	4^{th}-6^{th} month cum gas prod (Mcf)	Estimated P_{50} EUR (oil)	Estimated P_{50} EUR (gas)
06-10-039-09	0.00-2.45	26.8	14-10-039-09	18.97	7,570	138,930	50,000	1,400,000
10-23-039-09	0.40-3.00	No data	16-23-039-09	4.56	9,186	39,877	105,000	900,000

Table 2: comparison between petrophysical values observed in core and horizontal well productivity.

It's hard to see whether or not there is a correlation between reservoir values and production data due to the lack of cores with available core analyses in the considered area. What can be seen is that producer wells closer to the boundary with the central body generally have greater GOR and produced gas values rather than wells farther from that edge. The northern sub-compartment counts the smallest number of Cardium HZ producers, and this makes interpretation harder. In the near future, when more Cardium horizontals will be drilled, additional information will be gained.

15 Cardium horizontals are currently producing oil and gas in the northern sub-body, and the group production chart is shown below.

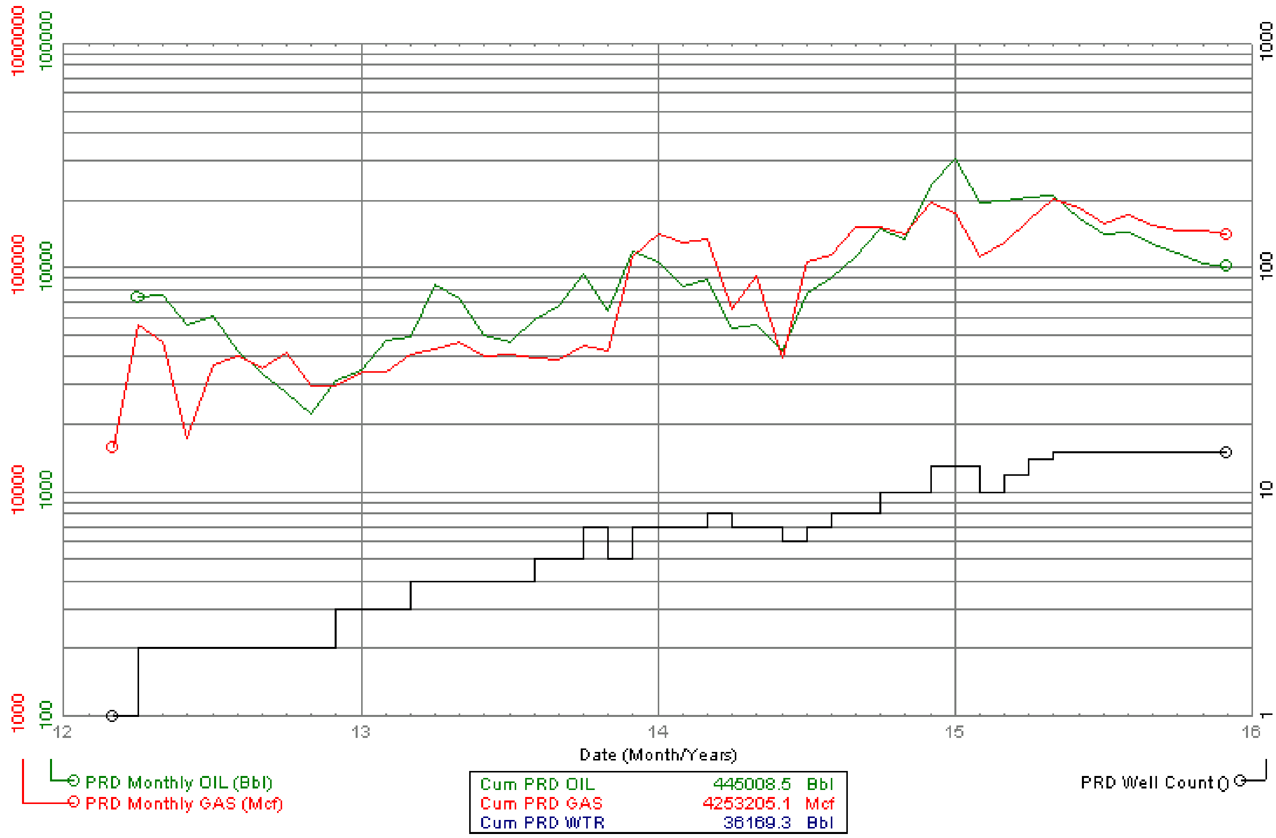


Fig.63: group production of the northern sub-body Cardium horizontals. The graph shows monthly oil and gas production, as well as the producers well count.

In the chart shown above it's important to notice that both oil and gas production increased until 2015, then the two are both slowly decreasing. This is due to the relative recent exploitation of this body, so that the rapid increase in Cardium producing well count led to an equal increase in cumulative fluid production.

This means this body has still a lot of upside potential, even if reservoir properties are worse than the southern body.

In conclusion, the northern sub-compartment shows poor reservoir characteristics and looks the area of unconventionally developed portion of the Ferrier with the lowest reservoir quality.

The main reservoir interval is around 3m thick in average, showing average porosity ranging from 10 to 12% and permeability from 0.1 to 0.3mD.

The sands have been targeted since 2012 with horizontal wells and multi-stage fracking techniques, and this sub-compartment proved to be fairly economically profitable as light oil and gas halo play.

Due to the lack of data, it's not exactly understood what controls the GOR of the horizontal producing wells. In general GOR increases going towards the central body, that is 100% gas producer, but this is not verified everywhere in the pool, that's why additional studies are required to shed light on this topic.

3.3.2.4: Central sub-body

This reservoir compartment is located between the northern and the southern sub-bodies (see fig.51). It shows up in the production map because no oil is produced in this area of the Cardium. Therefore, there is 100% gas production, and the contact with the adjacent producing bodies is very sharp. Understanding the geologic controls over this production issue is one of the main aims this project has been carried out for.

8 wells have cored the Cardium in this area, and a porosity vs permeability cross-plot has been built from routine core analyses.

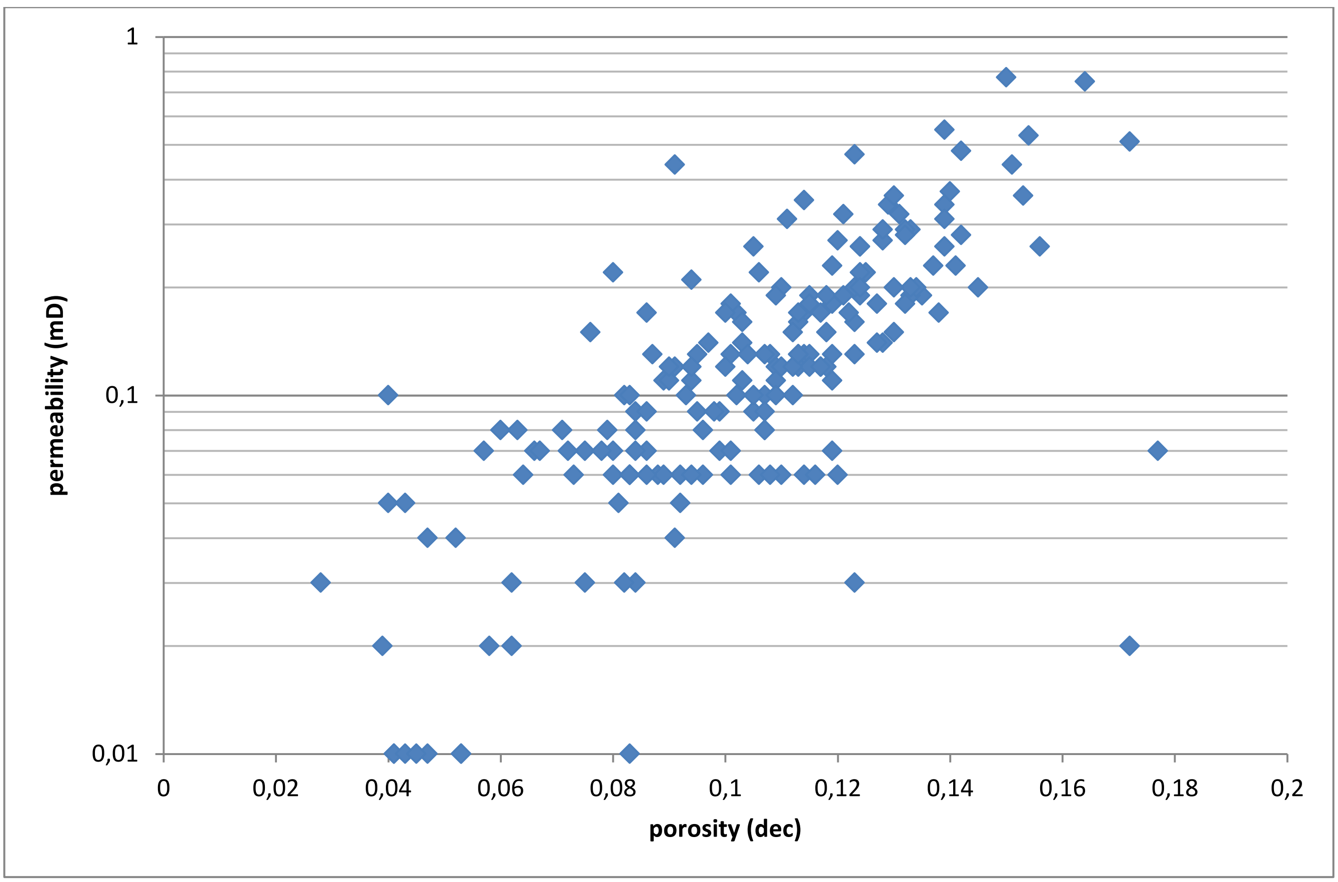


Fig.64: porosity vs permeability cross-plot of the central sub-compartment of the unconventionally developed area of the Ferrier.

The distribution of the data in the cross-plot shows lower reservoir characteristics than the other two reservoir sub-compartments. Porosity vs permeability numeric relation is the same as all bodies (around 12-13% porosity to have 0.3mD of permeability), but in this area most of the data fall in the 0.1-0.15mD range. Very few data show values over 0.3 mD. Estimated permeability average in the body is around 0.11mD, and oil saturation values have an average of roughly 26.4%.

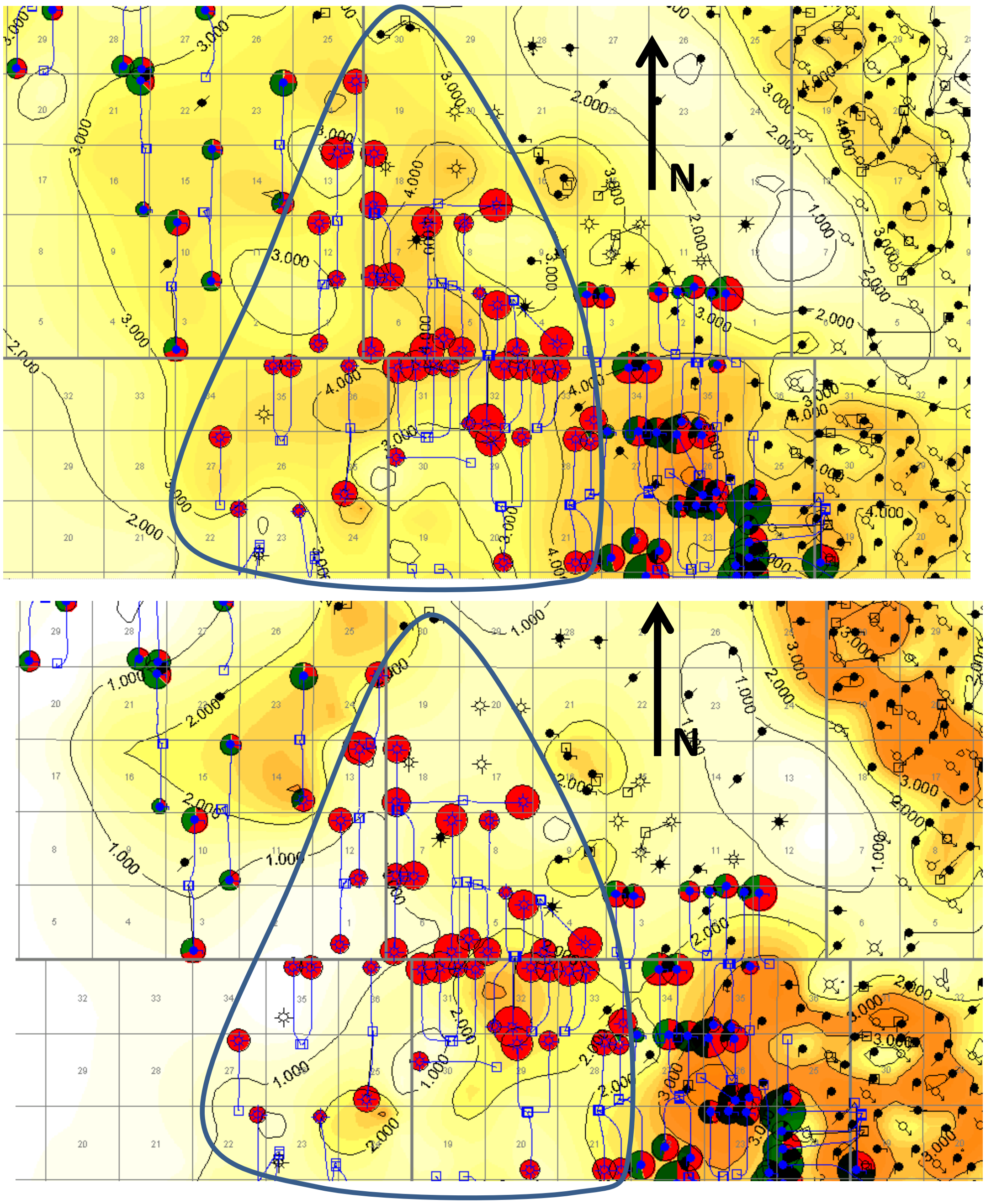


Fig.65: 6% (65a) and 12% (65b) net reservoir maps of the central sub-compartment of the unconventionally developed area of the Ferrier. Northern and southern sub-compartments are visible in the NW and SE areas of the maps respectively.

Net reservoir mapping points out that the reservoir in this sub-compartment shows fair thickness characteristics, much closer to the southern area than the norther body. However, as seen in the cross-plot, reservoir properties are even lower than the ones of the northern body.
100/10-12-039-09W5/00 has been picked as type well of this compartment. Gross reservoir thickness is around 5m, but petrophysical properties of the producing formation are much worse than the ones of the other bodies. Just 1.44 m of the reservoir have permeability values over 0.1mD, and no values over 0.3mD are visible in core analyses. Also, the best portion of the reservoir is not a single, 1.44m thick package of sediment, but the best sand spots are 40-50 cm thick and occur in between tighter sand. Maximum permeability values are lower than 0.2 mD. The petrophysical characteristics of the reservoir are summarized in the petrophysical model proposed below, together with core pictures.

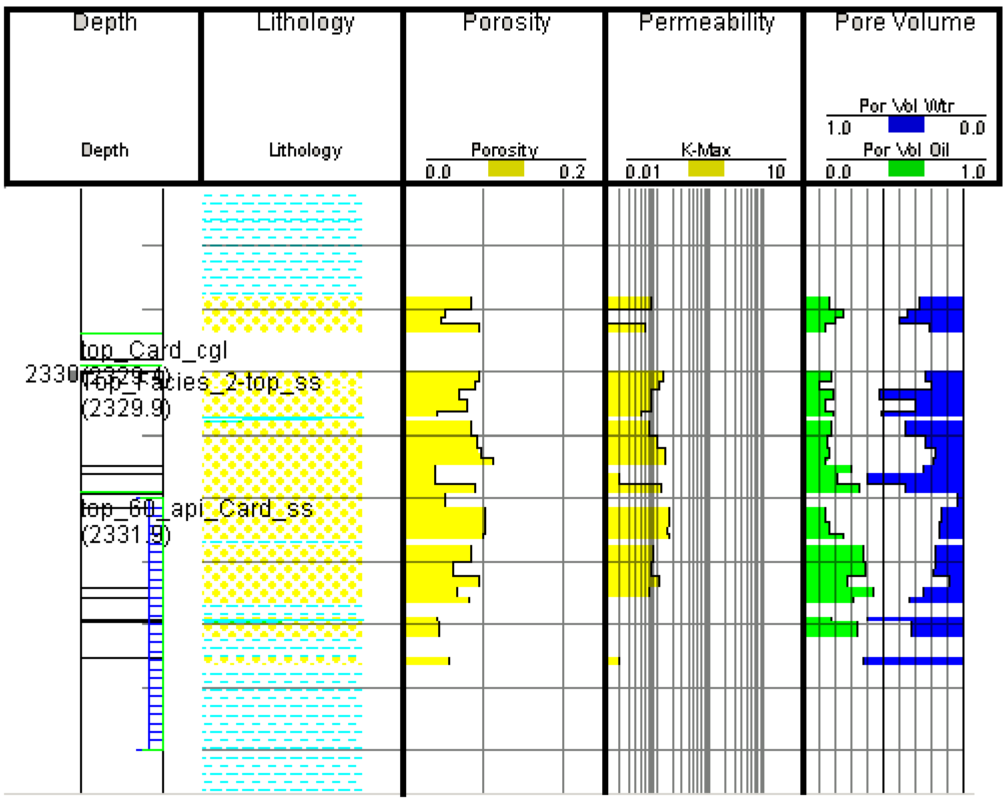


Fig.66: core plot of Cardium cored well 100/10-12-039-09W5/00.

Fig.67: full core of Cardium cored well 100/10-12-039-09W5/00. Details are provided in additional pictures.

Ichnofacies characterization was used to estimate eventual additional permeability given by bioturbation.

ROS: *Rosalia sp.*; TH: *Thalassinoides sp.*; OPH: *Ophiomorpha sp.*

As there is not any oil producing well in this compartment, the GOR in each well can be considered as + ∞.

Looking at core data, oil is present in core in the same amount encountered in the northern and southern bodies as well (fig.68), so a major point of this study will be to develop a theory able to geologically explain this odd production behaviour. This will be mainly treated in the "discussion" sub-chapter (chapter 3.3.2.5).

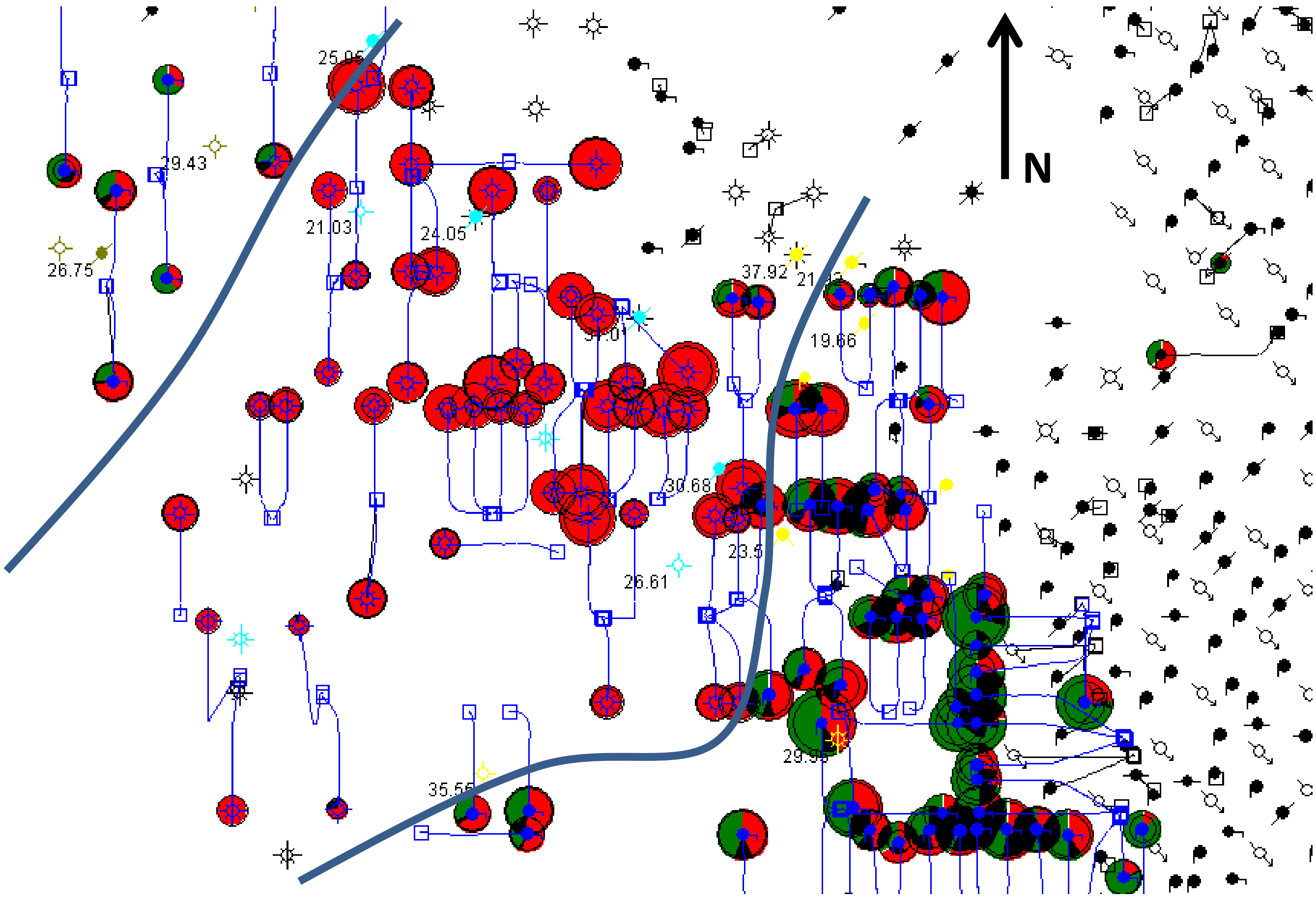


Fig.68: core oil saturation (percentage) data for each Cardium cored well having this data available. Overall, average core oil saturation doesn't radically change among the three sub-compartments. Different fluid saturation therefore is not the main cause for the absence of oil production in the central body.

The process of matching core properties with horizontal producers nearby has not been applied In this sub-compartment. The reason for that is that something odd is happening within the reservoir, as no oil is produced in the area although been as present in core as in the southern and northern compartments. In this work, specifically for this compartment, it has been preferred first to understand the reason(s) behind the observed odd production behaviour of the reservoir. This will be discussed in detail in chapter 4.

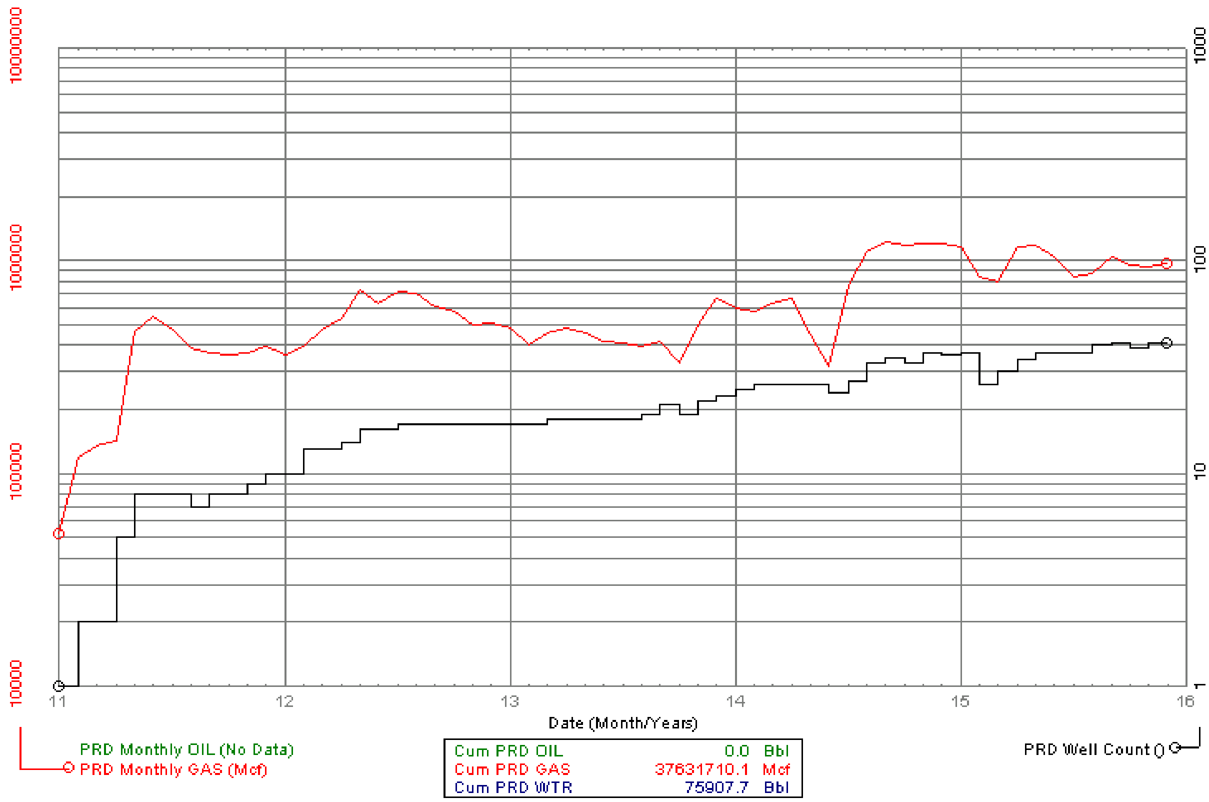


Fig.69: group production of the central sub-body Cardium horizontals. The graph shows monthly oil and gas production, as well as the producers well count. No oil is produced in the Cardium in this area.

41 horizontal wells are currently producing gas from the Cardium with variable success. So far almost 38Bcf of gas gave been produced in this sub-compartment, and monthly gas production rates are still increasing.

In conclusion, the central sub-compartment shows good net reservoir thickness, but very poor reservoir properties, even worse than the northern sub-compartment.

The main reservoir interval is around 4m thick in average, showing average porosity ranging from 10 to 12% and permeability from 0.1 to 0.2mD.

The sands have been targeted since 2011 with horizontal wells and multi-stage fracking techniques, and this sub-compartment proved to be economically profitable as gas halo play.

What controls the GOR of the Cardium horizontals in this area does not depend on reservoir thickness, as the latter is generally greater than the northern body one. Also, core oil saturation data show that oil is present in core in the same amounts of the other two sub-compartments. This means that something is going on in the reservoir at smaller-scale, and this is confirmed by the lack of permeability in several cored wells of the central sub-body. To shed light on this important geological and production issue, additional data have been acquired and considered. These data and analyses are shown in chapter 4.

3.3.3: Conventionally developed, gas charged body

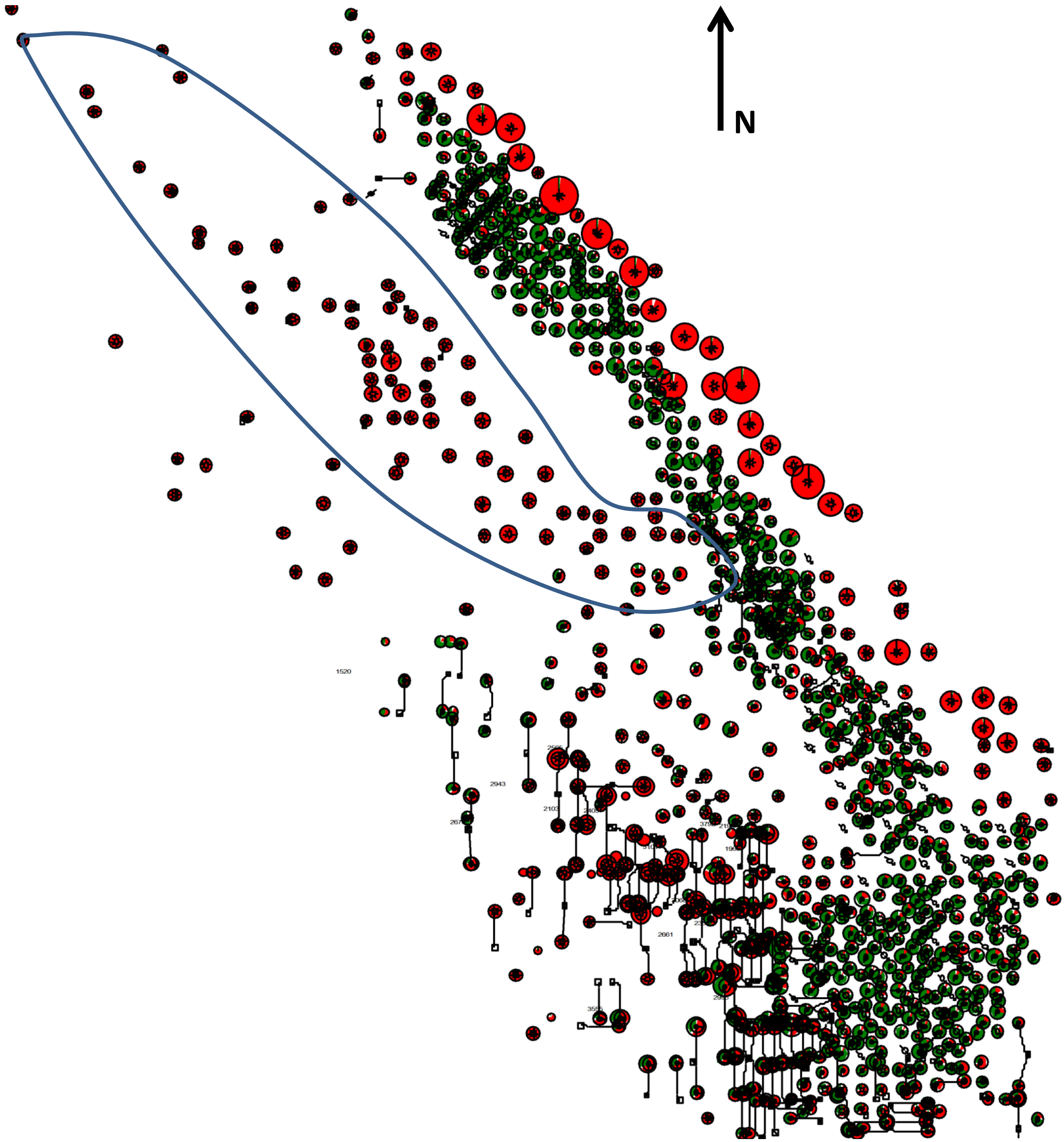


Fig.69: geographic location of the conventionally developed, gas producing area of the Ferrier. The bubble map represent cumulative oil and gas production for each Cardium producer. No oil is exploited in this compartment.

This body is located W-NW from the main Ferrier oil body. A 0m sand belt parallel to the general sand trend separates this body from the main one, but a perpendicular sand body joins the two (see fig.30).
The base maps below provide the location of this geologic body, and a bubble map has been computed to show production data from Cardium producing vertical and deviated wells. Gas production values are shown in BOE (Barrels of oil equivalent), with a standard gas : oil ratio of 10 Mcf: 1 bbl.
In this compartment, gas is produced from more than one Cardium horizon. More specifically, a deeper sand body is present and often completed. Therefore in this compartment a lot of Cardium commingled wells are present, and there are even cases where Cardium production only occurs from this deeper body.
The lower sandstone package occurs roughly 30-40m beneath the main producing interval. This clastic body extends towards the SE as far as the unconventionally developed compartment.
Reservoir properties are not high-class, but the interval has been completed in a few tens of wells together with the main interval or by itself with good production results.
The thickness of the interval can range from 2m to around 5-6m using a Gamma Ray cut-off of 75 API.

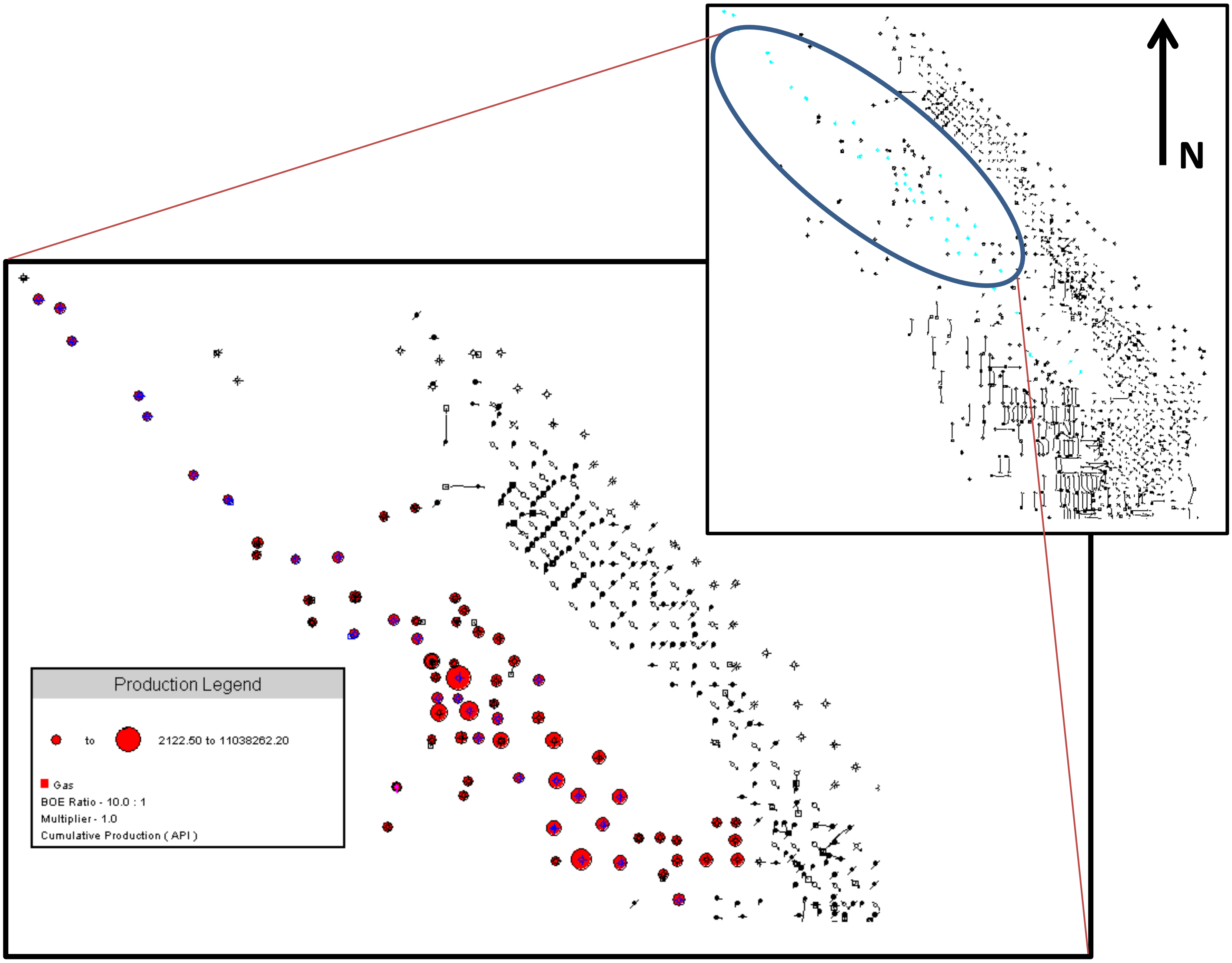


Fig.70: geographic location of the conventionally developed, gas producing area of the Ferrier. The bubble map represent cumulative oil and gas production for each Cardium producer. Blue wells represent where the lower sand sequence is producing gas too.

As visible in the base map, this clastic body extends from the deep NW to the SE, reaching the unconventionally developed portion of the Ferrier. Depositional trend looks roughly the same of the Ferrier body and the overall Cardium framework. It's important to notice that the map only shows Cardium wells with producing lower sands, but in the areas in between the lower sand sequence is equally present although not completed due to poor reservoir characteristics.

The deeper sand body generally shows worse reservoir properties than the main producer one, but fairly good gas production is observed in the producing wells.

Fig.77 shows how the Cardium typically looks like in well logs when the lower sequence is observed too.

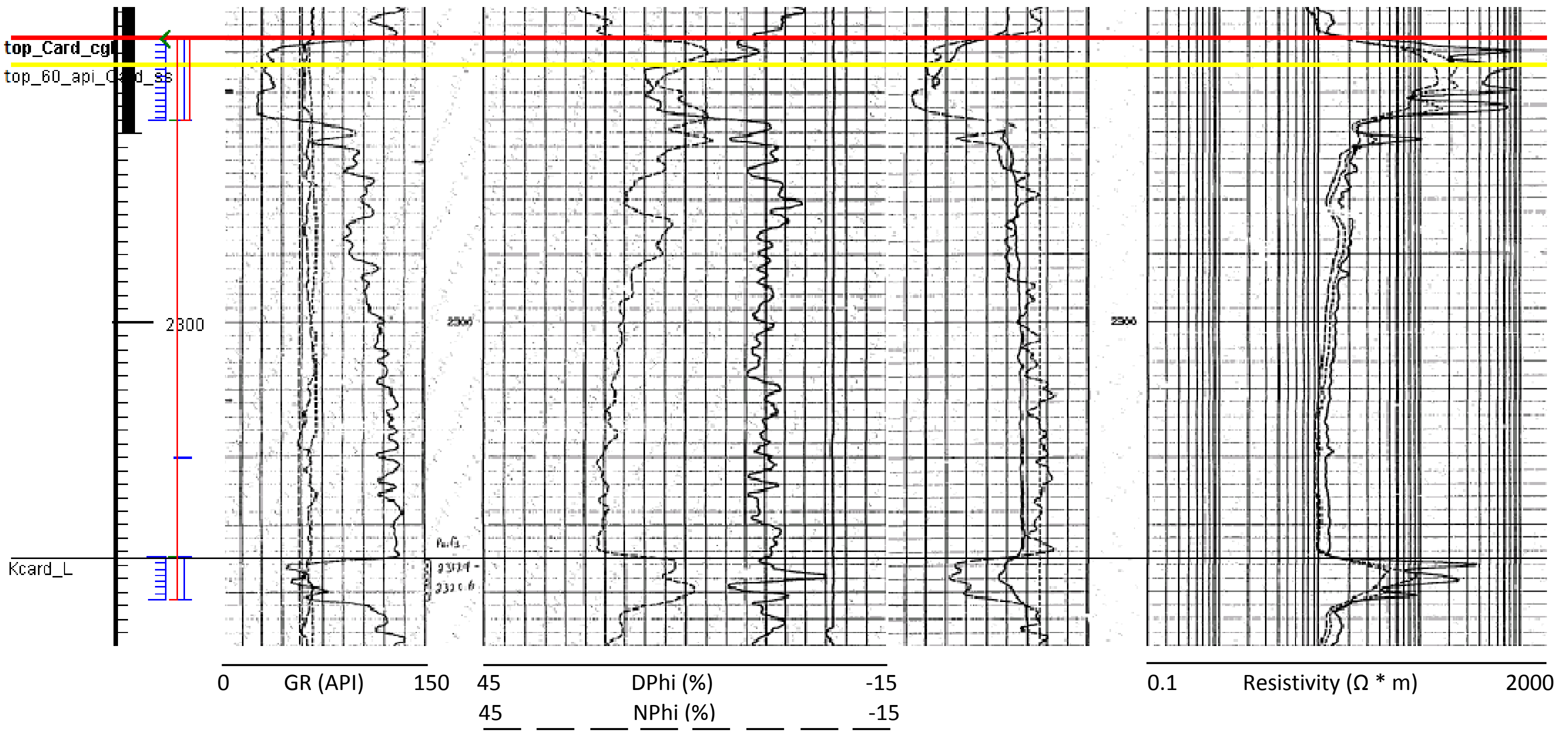


Fig.71: Type well logs of the Cardium where the lower sand sequence is present and completed (well 06-08-041-09W5/00). Density log points out that conglomerates could be present at the top of the interval (low density porosity reading). The lower clastic sequence is marked at its top by the Cardium_L surface.

This study has been only focused on the upper clastic sequence, but it's important to describe the lower sand body as well because it might have played a major role in the hydrocarbon distribution within the Ferrier.

This hypothesis will be described in chapter 4, whereas the study shown in this chapter refers to the upper sand sequence only.

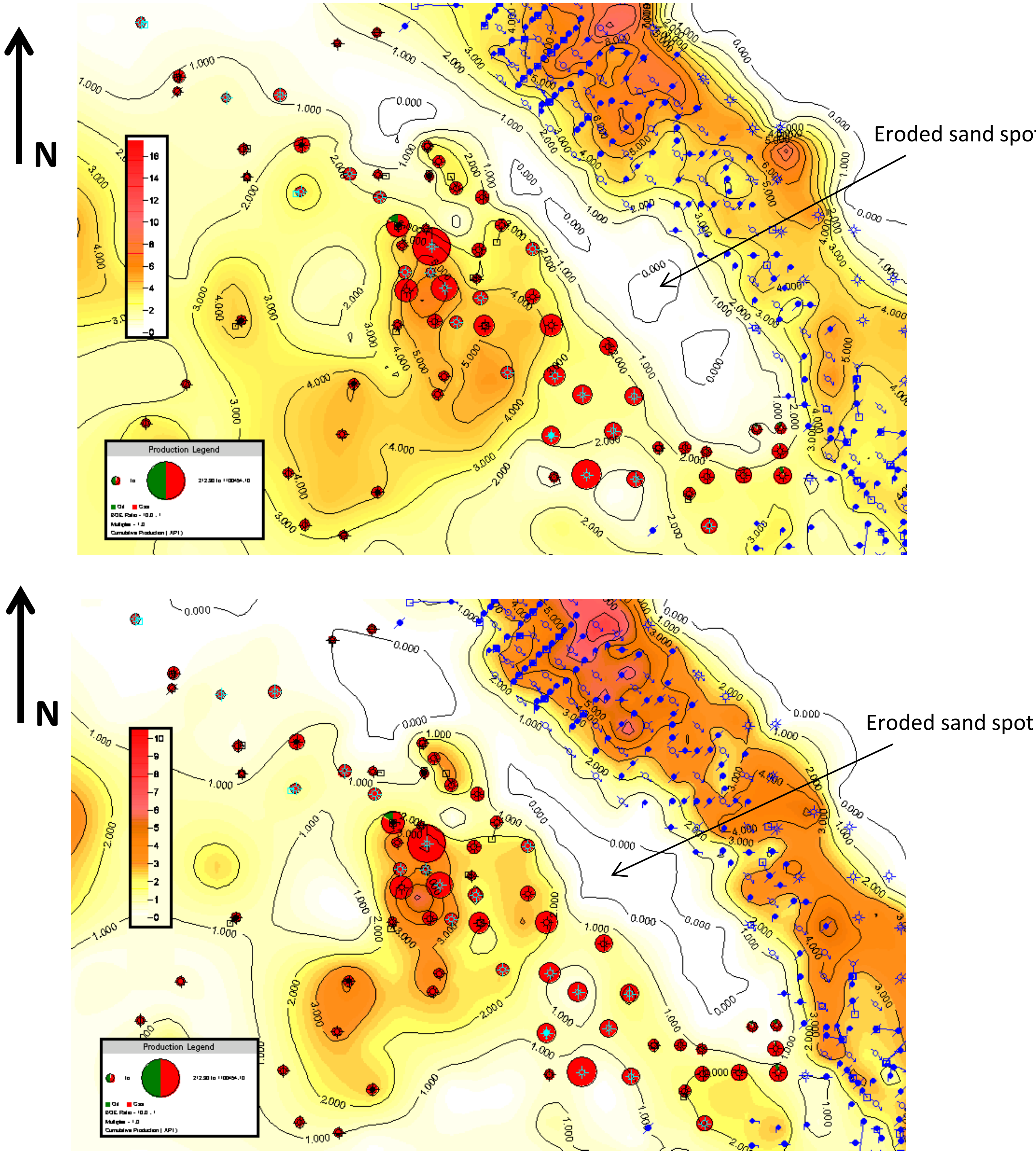


Fig.72: 6% (81a) and 12% (81b) net reservoir map of the conventionally developed, gas producing body of the Ferrier area. Light blue wells represent Cardium producers where the lower sand sequence has been completed together with the structurally shallower one.

The E5 surface top map and 3-D visualization show the presence of a topographic bulge (fig.73). Previous works of the researchers of the University of Calgary (e.g. Foyer, 2011) detected the presence of SW dipping, NW-SE oriented thrusts in the area. This bulge can't be a depositional feature, and must have formed after the Cardium deposition. This because, if there had been a paleo-topographic bulge already present at the moment of deposition of the sandstones, few to no sediment would have preserved on a topographic high. Instead, as visible in the projection of gross reservoir thickness map on top of the E5 surface map, sand thickness is high in the bulge (fig.74).

That bulge is therefore a post-depositional structural feature, and most likely it represents a thrust fault-fold system. This is also supported by direct observations on logged cores. 100/06-08-041-09W5/00, for example, shows extensive fracturing, and several fault mirror surfaces (slickensides) have been logged in other cores nearby.

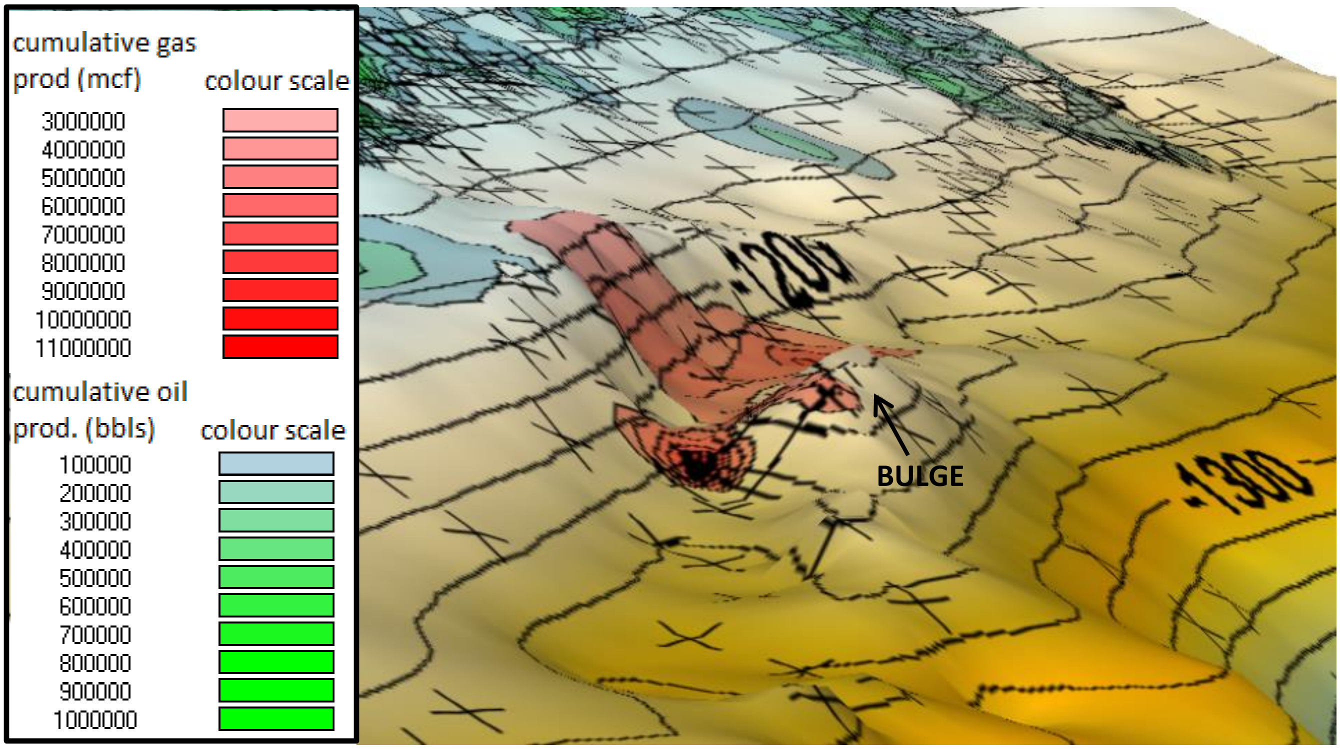


Fig.73: structure map of the top of the Cardium upper sand sequence.

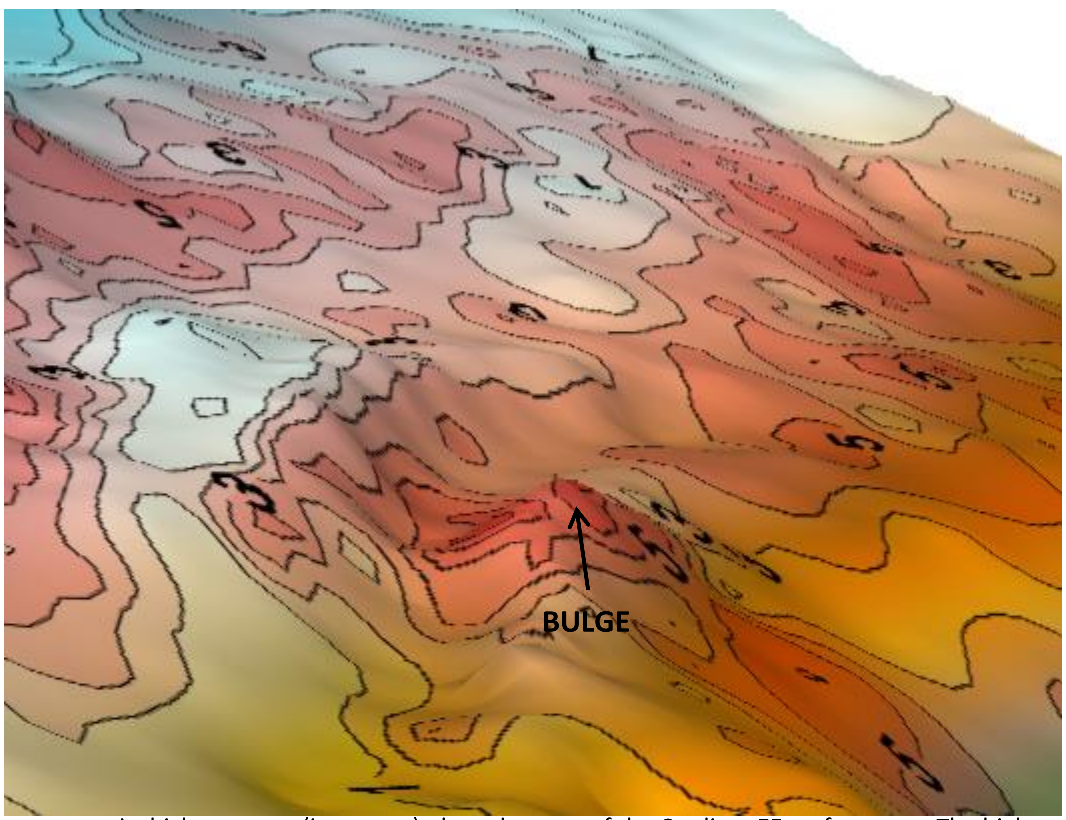


Fig.74: gross reservoir thickness map (in metres) plotted on top of the Cardium E5 surface map. The highest amount of facies 3 and 4 thickness is observed on top of the bulge. This means the bulge formed after sediment deposition.

To further evaluate reservoir properties of this area, a porosity vs permeability cross-plot was built based on 6 cored wells. These wells have been picked in the most structurally up-dip portion, to prevent greater depth from causing bias in comparing these analysis with structurally shallower bodies.

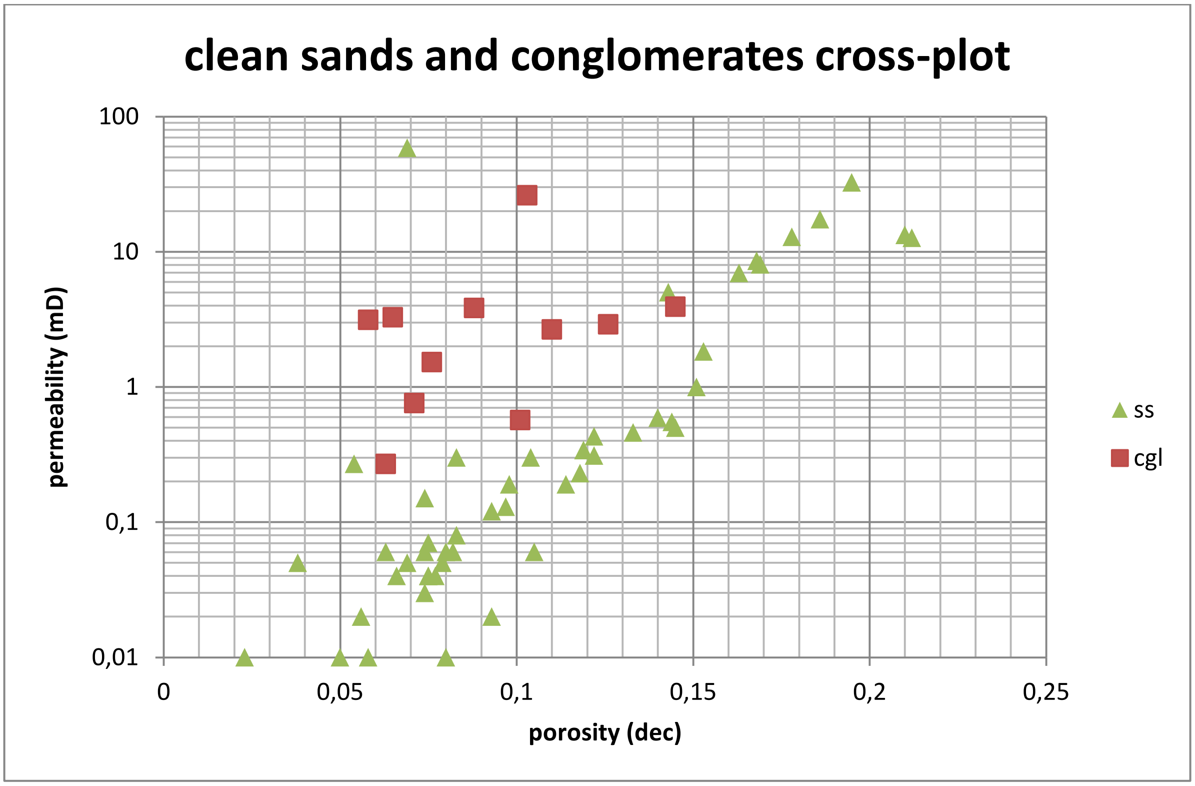


Fig.75: porosity vs permeability cross-plot of the gas producing, conventionally developed portion of the Ferrier.

Each conglomerate sample has been considered, whereas only the clean sand samples (no fractures or

extensive cementation) have been counted.

The first cross-plot has been built using clean sand data only. This has been made because potential structural features have been observed in the area, and this would cause bias in the process to find the right porosity vs permeability trend.

The cross-plot shows that, as for the sandstones of the main oil body, 0.3mD matches fairly well with 12% porosity. However, very high porosity and permeability values are not that frequent among the clean sandstones, even if a few samples show good reservoir quality.

Another cross-plot has been computed for each sand sample, both clean and not. This because, if a structural component is present in the area, as claimed in this study, fracturing evidence should be visible in cross-plots.

As it was expected, part of the samples reaches the same permeability of clean sands at lower porosity, and other samples have lower permeability in spite of having the same porosity.
The latter case can be attributed to the cementation effect, that decreases porosity, but not as much as permeability. The first case is actually the fracturing effect, that doesn't significantly increase porosity, but has a great impact on permeability. Fracturing effects have directly been observed in the cored well 100/06-08-041-09W5/00, shown in the next pages.

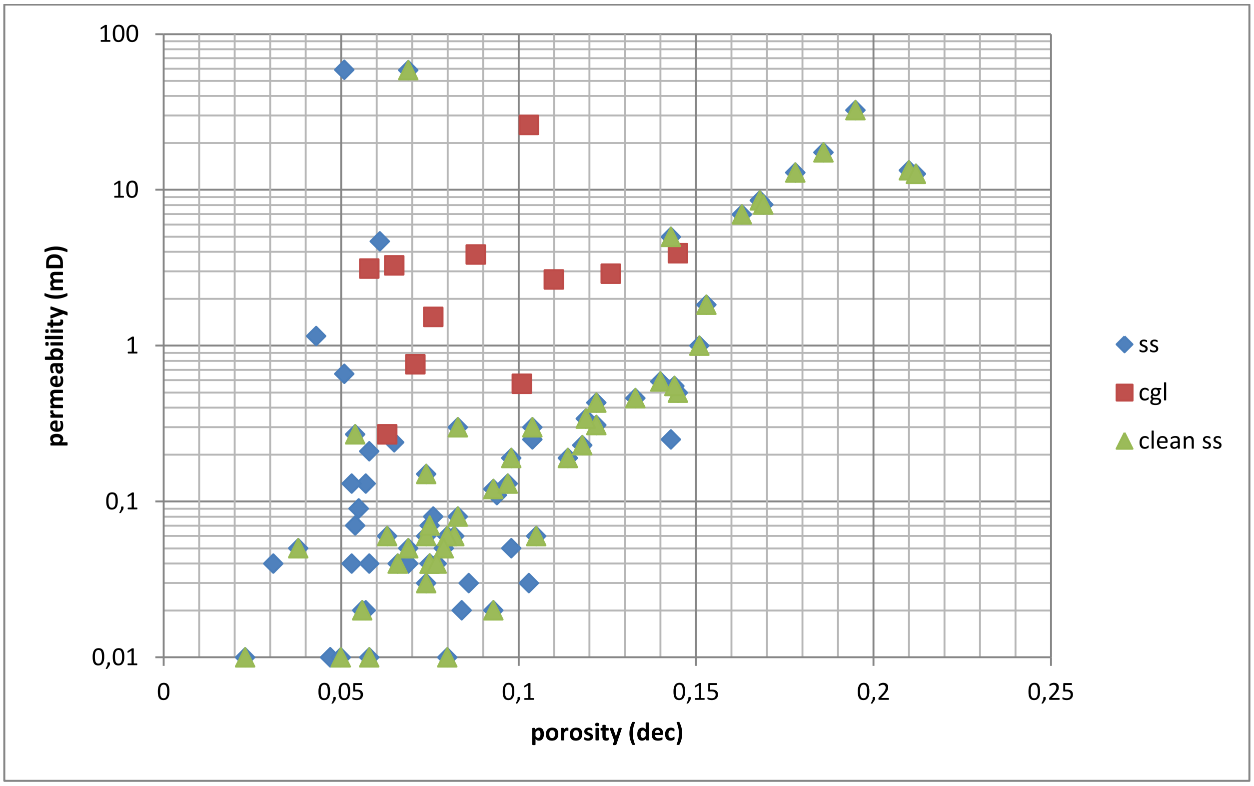


Fig.76: porosity vs permeability cross-plot of the gas producing, conventionally developed portion of the Ferrier.

Each sample has been considered. A few fractured samples are present.

6% and 12% DPhi net reservoir maps, as well as core analyses, show that the best reservoir characteristics in the area are located in the portion closer to the sand bulge. Maps also show that the belt that links this body with the main one has decent reservoir thickness and fair petrophysical characteristics.
100/06-08-041-09W5/00 has been picked as type producer for this gas charged body. The core has been logged in detail at the AER research centre, and the pictures are shown below.

TOP CORE

BOTTOM CORE

Fig.77: full core of cored well 100/06-08-041-09W5/00. Additional detailed core pictures are shown in the right side of the page

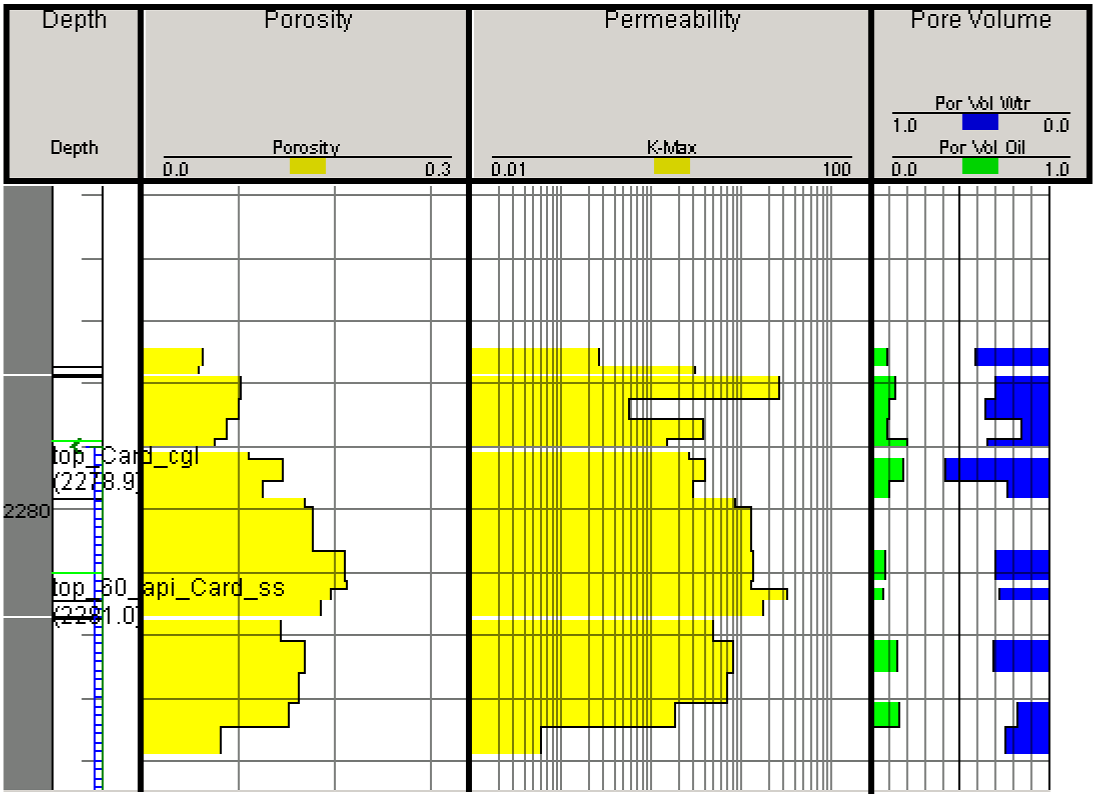


Fig.78: core plot of the top sand sequence of cored Cardium well 100/06-08-041-09W5/00.

First of all it's important to write a disclaimer. 100/06-08-041-09W5/00 shouldn't be a type well, as it's the well showing the highest reservoir quality and produced hydrocarbon volume of the analyzed body. Therefore it is not representative of the entire compartment, but just of the area with highest net reservoir thickness.

The main reason this well has been picked as type producer is that it is located at the base of the topographic bulge, therefore it was very useful to demonstrate the presence of structural features within the body. The other reason is that this well shows specific sedimentary facies that could shed light on conglomerate deposition, as it shows facies more typical of a channel rather than a shoreface.

As conglomerates are claimed to have come from the raising mountains, they have most likely been transported by channels roughly perpendicular to the shoreline trend. This core shows fining-upwards sequences, as well as conglomeratic facies looking more like fluvial gravel bars than a pebble lag. This facies and characteristics are typical of fluvial environments, and could shed light on conglomerate deposition.

Talking about reservoir properties, core plot, as well as detailed core logging, shows around 6m of gross reservoir thickness. Sand accounts for roughly 4.5m and shows porosity and permeability values of around 15-18% and 1-15mD respectively.

Conglomerates are around 1.5m thick and show permeability values ranging from 1 to 35mD. Overall, average core oil saturation is around 15%, with no values above 20%. This can explain why oil is not produced in this compartment in spite of the good reservoir quality of the Cardium sandstones and conglomerates. With these low core S_o values, oil can be considered not present in the system, as gas saturation is too high to let the oil move.
Whereas in the main oil and gas body the average S_o was around 25-30%, in this body more than 50% of the wells has $S_o < 10\%$, and another 20% of the wells has $10\% < S_o < 20\%$.
Therefore, oil is present in cores, but gas is the only produced fluid most likely because of the low relative permeability of oil due to high gas saturation.
Production data are shown in the group production chart shown in fig. 79. This chart collects the production data of each of the 81 Cardium producing wells in this compartment of the Ferrier play.
It's important to notice that almost 150,000 barrels of oil have been produced in this compartment, that first was claimed to be gas producing only. Actually, in the area where this body is connected to the main oil and gas body, the producers close to the main body start exploiting a few oil from the Cardium sands and conglomerates. Oil percentage increases approaching to the main oil and gas body, but the final transition between the two compartments is very sharp.
The reason for this odd production beaviour of the Ferrier will be discussed in chapter 4, that will deal with the relationship between geology, reservoir properties and hydrocarbon distribution.

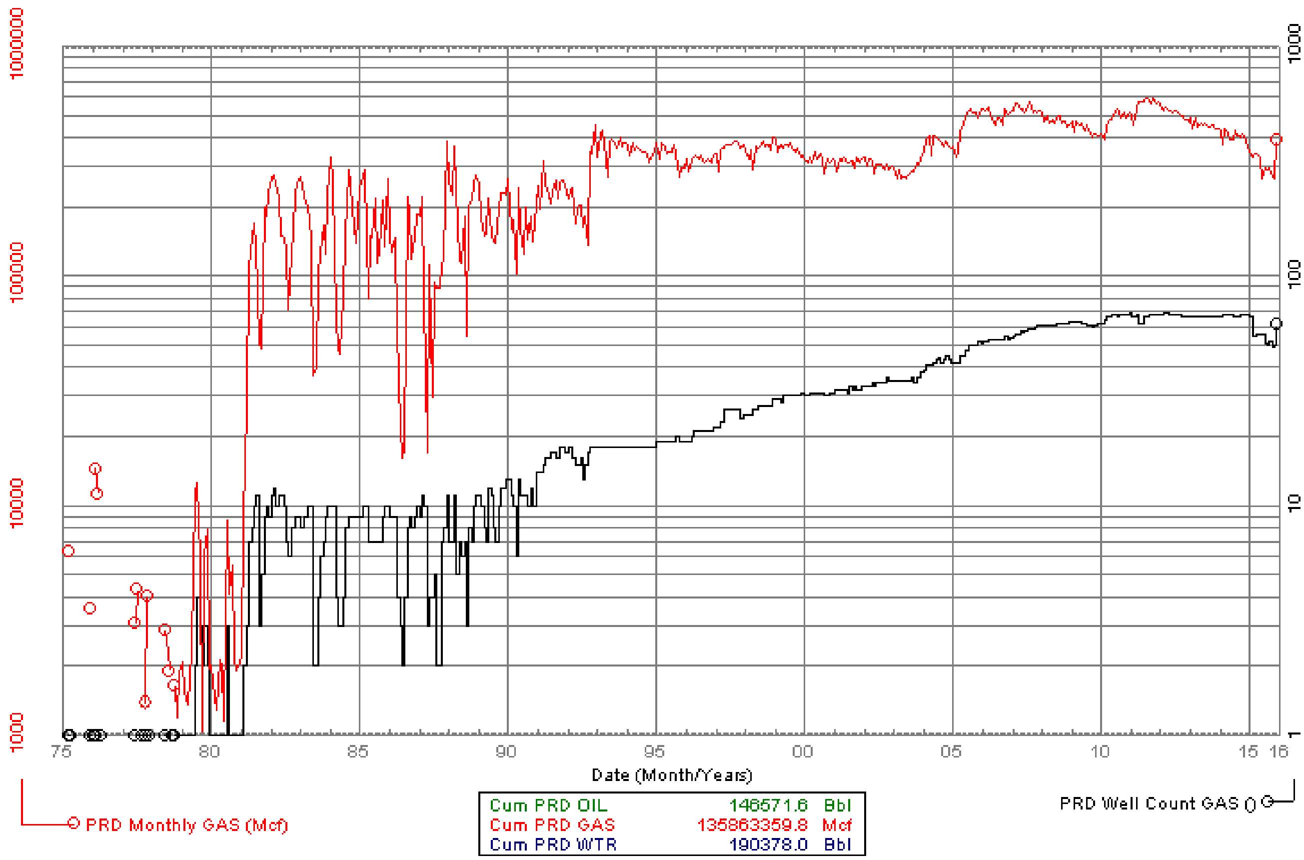


Fig.79: group production of the conventionally developed, gas producing area of the Ferrier. The graph shows monthly oil and gas production, as well as the gas producers well count.

The group production chart posted above shows the production behaviour of this compartment of the Ferrier play. To the present day, 81 wells are producing hydrocarbons, and cumulative gas production reached values of 135.8 Bcf.

EUR estimation of the play is not meaningful, as wells are still being drilled in the compartment.

3.3.3.1: Conclusions

The conventionally developed, gas charged body is a gas producing body located western of the Ferrier Oilfield.
In the eastern side it's separated from the main oil and gas body by an area with no evidence of sandstone preservation. A sand belt perpendicular to the customary depositional trend of the Cardium links these two different reservoir compartments in the southern area of the body analyzed in this chapter.
Sandstones and conglomerates are similar to the main oil and gas body sediments. The main difference between the two is that in the considered body porosity and permeability aren't as high as the main body ones. However some samples showed high permeability values because of extensive fracturing due to structural features. Faults have been identified in reservoir maps and slickensides have been observed in cores.
Almost 100% gas is exploited from the reservoir, and gas production abruptly terminates in the sand belt linking this compartment to the main oil and gas body.
This is not a matter of poor reservoir petrophysical properties, as the reservoir characteristics of the Cardium are almost as good as the main body ones.
As confirmed by routine core analyses, oil is present in cores, even if in a lower saturation than each of the several Ferrier bodies. Core oil saturation values have an average of around 15%. Therefore, they are very similar to the ones shown in the gas cap of the main oil and gas body, where the average core oil saturation is around 18%.
As no oil is produced in this area, this is most likely caused by higher gas saturation that abruptly decreases the relative permeability of the oil and, therefore, its mobility. This is claimed to happen in the gas cap of the main oil body as well.
The conventionally developed, gas producing body most likely plays a major role in hydrocarbon migration towards the main oil and gas reservoir.
Cross-sections show that there are two spots where the sand is not preserved or just the lower quality sand (the lower one) has been preserved. The sand belt located in between these two spots is included in the gas producing, conventionally develop body. This belt can be considered the carrier belt for the hydrocarbons, flowing from the deep basin to the main Cardium reservoir. Gas migration is most likely still active towards the structurally shallowest portion of the Ferrier, and this is testified by the production data of the wells that produce from the Cardium in that sand belt. These data show that 100% gas production occurs as far as the area immediately west of the main oil and gas body, than the oil proportion gradually increases (decrease in GOR).
If the migration had already ended, the gas would have probably completely flown towards the gas cap of the main oil and gas body, instead producing wells still get 100% gas in the preserved sand belt. This can be interpreted as an index of active gas migration towards structurally higher portions of the Cardium.
This gas could come from another area of the primary source rock or from another source (thermogenic gas), although gas isotope analyses are required to shed light on the source area and migration mechanism.

Hydrocarbon distribution in the Ferrier will be discussed in chapter 4, and the reason behind gas presence in the sand belt will be unraveled.
In the study area evidence of an additional sand body 30-40m deeper than the top of the Cardium sandstones was found. The sands and conglomerates are 2 to 6m thick, and they hold gas only, with the same gas composition as the gas produced in the upper sequence, as well as every other well in the Ferrier area.
The deeper sand sequence begins in this compartment and goes all the way down to the unconventionally developed portion of the Cardium. Petrophysical values are usually low because of high degree of cementation, and they seem to decrease going southward. This explains why this interval is generally not completed in the SW Ferrier area, although being present and fairly thick.

4: Geology and hydrocarbon distribution of the Cardium Formation in the Ferrier Oilfield

4.1: Introduction

This chapter represents the link between the depositional architecture and post-depositional modifications described in chapter 2 and the small-scale geological and petrophysical features of the reservoir sub-compartments described in chapter 3.
One of the main aim of this research was to understand the geologic controls over fluid production in this hydrocarbon play.
In the main oil and gas body it turned out conglomerate thickness plays a major role in hydrocarbon exploitation. In the other two compartments of the Ferrier, where conglomerates rarely are present and thick, net reservoir thickness is generally proportional to the volume of produced fluid.
The main production issues in the Ferrier don't concern the volume of produced hydrocarbons, but rather the oil vs gas ratio. Both in the conventionally- and in the unconventionally developed areas of the Ferrier, sharp changes in GOR occur at extremely small scale, and for "small scale" we talk about 200-300 meters dividing oil producers from gas ones.
This production heterogeneity in the Cardium has been well observed in the Ferrier, but so far there is not any updated paperwork or presentation trying to explain the reasons behind the odd production behaviour of the pool.
In this chapter the research made to shed light on this topic will be presented, and a new theory will be proposed based on the available dataset.

4.2: Geological introduction to the areas showing odd production behaviour

Detailed production analysis detected two main areas with evident odd production behaviour. One of the two is located in the gas producing, conventionally developed portion of the W Ferrier, whereas the other one is situated in the middle of the unconventionally developed body.
Both the cases are characterized by the abruptly showing up of gas presence beneath or within an oil zone, and these occurrences are displaced by around 15km. Each one of the two situations will be described in a single chapter.

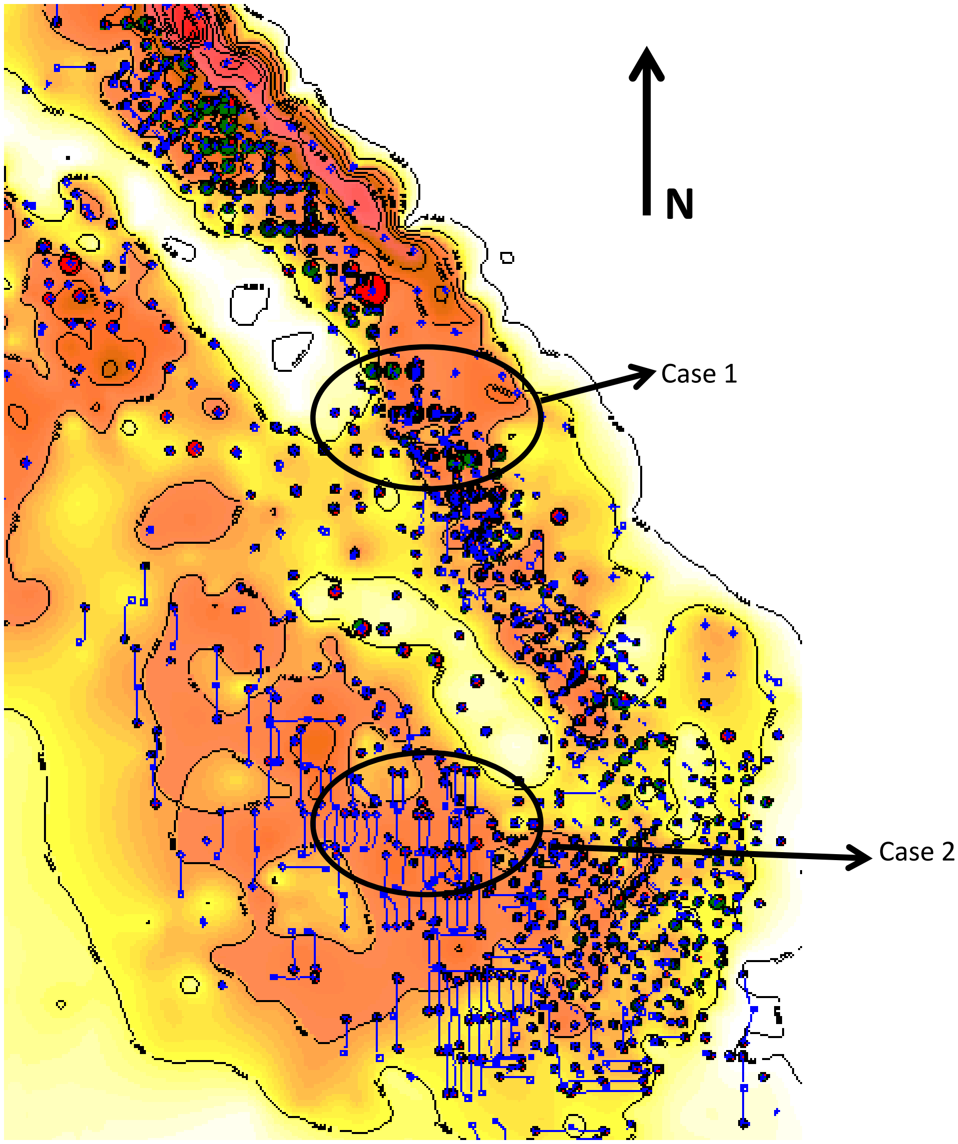


Fig.80: gross reservoir base map with production data of the Cardium wells. The two situations with odd production behaviour of the Cardium are shown. Case 1 occurs in the preserved sand belt between the two spots where sand is eroded; case 2 occurs in the middle of the unconventionally developed compartment.

4.2.1: Case 1 – conventionally developed, gas producing body

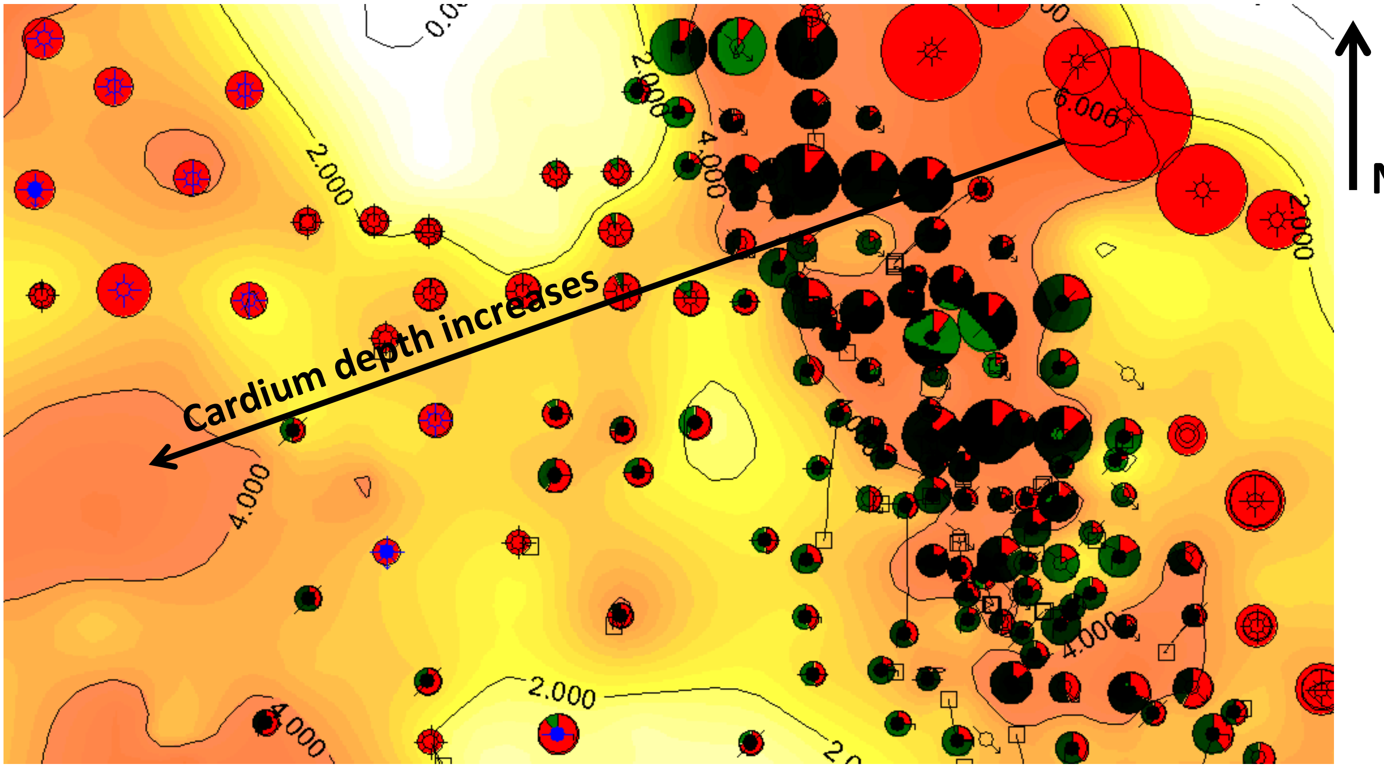


Fig.81: gross reservoir base map focused on case 1. Gas production is shown structurally deeper than oil production. This is not the customary fluid layering in a reservoir, and therefore it has been studied in detail.

Case 1 occurs in the sand belt that links the main oil and gas producing body to the preserved sand belt of the western Ferrier compartment (see section C-C', chapter 2 fig. 34 and gross-reservoir map in fig.80).

What can be observed looking at production data is the presence of gas structurally beneath the oil zone of the main body. This is odd because the customary fluid distribution in a trap sees gas above oil, as the latter is more dense.

C-C' cross-section crosses this sand belt and cross-sections, as well as cross-plots and well log data prove that the petrophysical characteristics of the sands are fair. That means oil is not present in the sediment or not moveable due to high gas saturation, because otherwise it would be exploited as well.

Petrophysical characteristics of the sand belt are shown in several cores, including 100/10-16-040-08W5/00. Routine core analyses show porosity and permeability values up to 15% and 1.5mD. These values are a bit lower than the main oil body, but still pretty good in average. Values are even higher in the structural bulge area, just NW of the sand belt.

Once stated that petrophysical characteristics would allow oil, if present, to flow, another factor must have great control over fluid production.
In the cross-sections description it was proposed that the sand body that can be found in the main oil zone and in the western Ferrier is the same unit. Parasequences correlation in sections B-B’, C-C’ and D-D’ showed that before the major erosional event there was just one sand body, but erosion removed the sands in sections B-B’ and D-D’. This means C-C’ is the only section where researchers can actually understand if the sand body is unique and laterally continuous or if it’s composed by two or more discrete areas.
Parasequences correlation in C-C’ section shows that the wells within the preserved sand belt can be correlated both to the sand body in the western Ferrier and to the main oil and gas body in the eastern portion of the oilfield. This is a proof of the presence of one single sand body that is in part eroded in its middle portion.

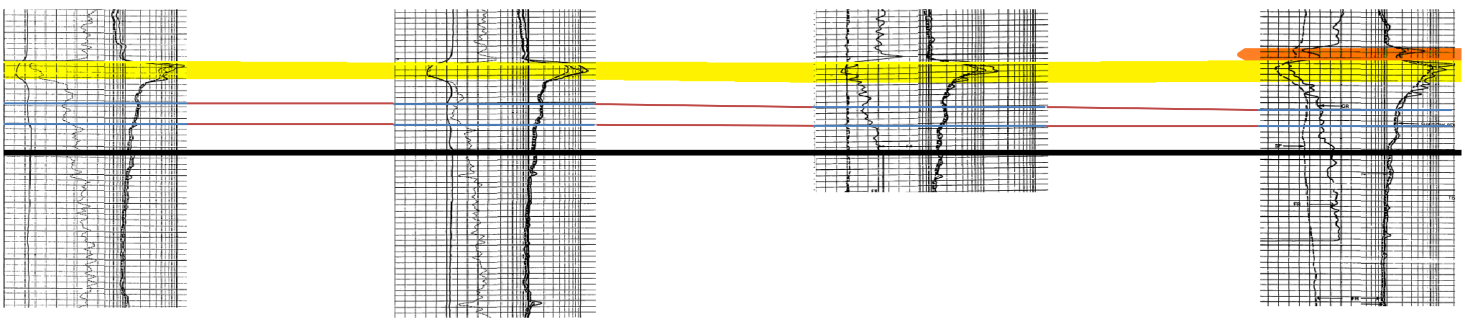


Fig.82: stratigraphical correlability between the preserved sand belt in the conventionally developed, gas producing area and the main oil and gas body of the Ferrier. Parasequences show it’s the same body, and therefore it’s claimed to offer fluidodynamic continuity. Datum is shown in black in the section.

This depositional architecture can’t explain the occurrence of gas production in the W Ferrier that abruptly switches to oil production going structurally shallower.
Looking at production data, it is visible that the sand belt where gas is produced is linked to a portion of the field where gas is produced only (i.e. the conventionally developed, gas producing body in the W Ferrier). The greatest producing wells of this compartment are located near the structural bulge described in chapter 2 and 3.
Now the most important question is how can gas be exploited in the upper sand sequence if going towards the southeast (i.e. in the portion of the unconventionally developed body with the same depth values) there is oil instead. Similar depth values between the two different compartments point out that it’s not a matter of reservoir temperature or oil maturity.
The interpretation for the gas presence in the conventionally developed, gas producing body is that gas most likely comes from another source rock or another area of the same source rock, and it has been generated after oil generation and migration.

This is claimed to be possible because of the presence of a deeper sand body (around 30-40m below the E5) in the W portion of the Ferrier that shows a depositional trend analogous to the upper sand body of the play. This deeper sand sequence, 2 to 6m thick, extends from the deep NW towards the SE all the way down to the unconventionally developed portion of the Ferrier (see fig.83).
The deeper sand body is gas charged, and several wells have been completed in the lower Cardium interval to target the gas play.
Looking at the chemical composition of the gas, it's analogous to the one produced in the top sand sequence of the Cardium in the gas producing, conventionally developed portion of the Ferrier, as well as everywhere else in the Ferrier play. Gas contains around 80-85% C1 (methane), 8% C2 (ethane), 4% C3(propane), 2% C4 (butane) and minor heavier gas molecules.
Gas composition classifies this gas as wet gas, and it's probably a thermogenic gas coming from cracking of kerogen, and not from oil cracking in the main body. This is assumed because reservoir temperature reaches max values of around 80°C, and around 150°C are required to generate gas from oil cracking. This may also be scientifically verified acquiring carbon isotopic data of the Cardium gas.
The proposed model claims that gas was generated from some source rock (2WS or other) after oil generation and migration, i.e. when the source rock was deep enough to reach the gas window and start generating thermogenic gas.
The interpretation is that the oil which generated during early maturity was able to fill the upper sand sequence, either passing through the deeper sand body or migrating through a lateral way. Thermogenic gas, whose generation and migration occurred after oil accumulation, filled the deeper sand body first, as it is the structurally deepest Cardium sand body in Ferrier area.

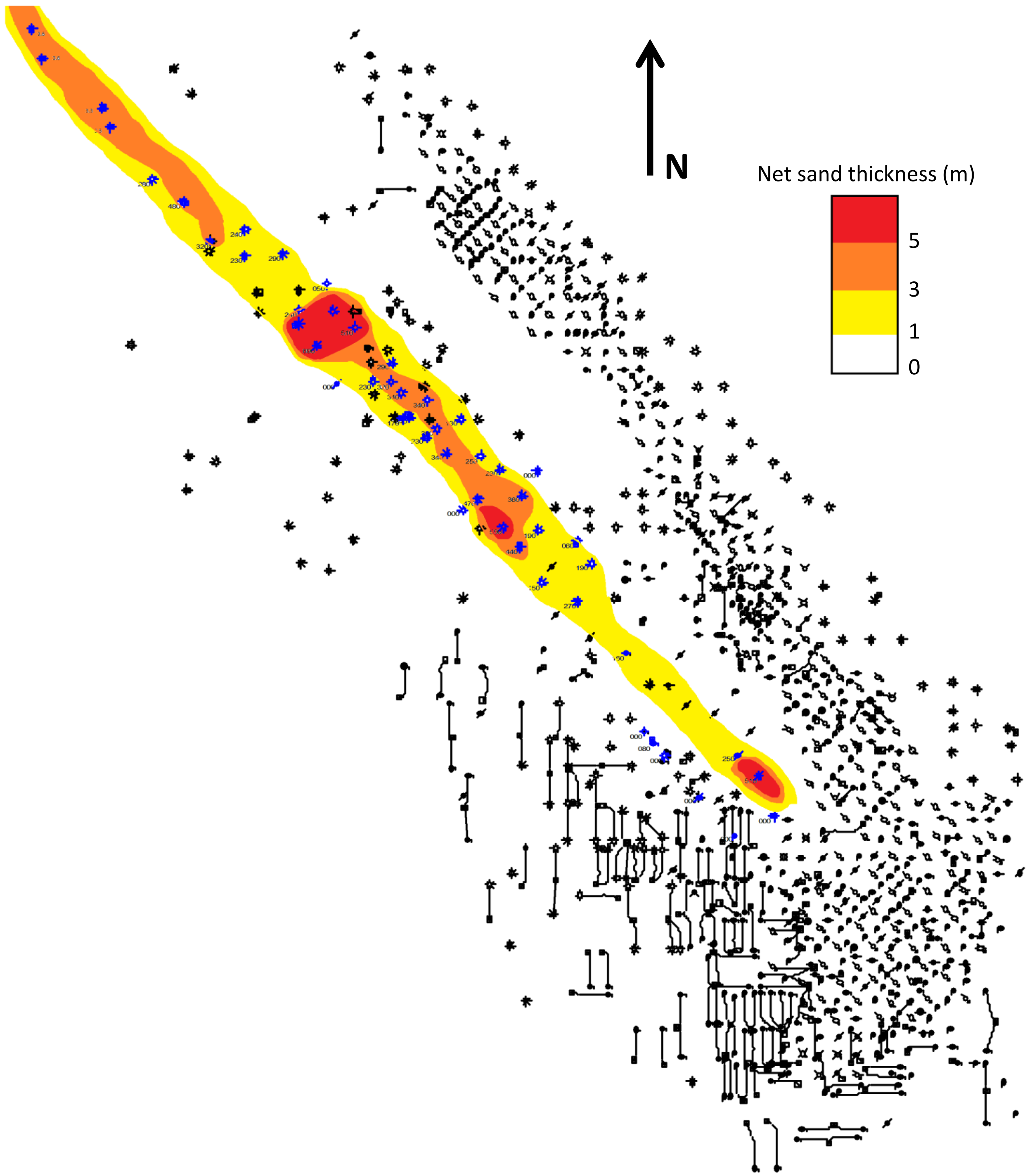


Fig.83: net sand (75 API) map of the Cardium deeper sand sequence. The body stretches NW-SE from the deep NW all the way down to the unconventionally developed area.

The interpretation for the gas presence in the preserved sand belt is that hydrocarbons, going through the deeper sand body, arrived beneath the structural bulge area, that is characterized by the presence of a thrust fault with fracturing evidence. This fault affects the deeper sand body as well, as running a structure map of the top of the deeper sand body (i.e. the Cardium_L surface) a bulge shape is observed in the map, just in the area where also the E5 surface showed a bulge. This means the same fault affects both the upper and the deeper body.

Following faults and fractures connecting the upper to the deeper sand body, gas was able to go from the deeper sand body all the way up to the upper sand sequence and finally spread into the Ferrier main oil and gas body. Evidence of faulting and fracturing has been clearly seen in reservoir mapping and core logging. Thrust faults have also been mapped in the Ferrier area by Foyer (2011) using seismic sections and 3-D seismic data. This study pointed out that the trace of the thrust faults was NW-SE oriented, i.e. parallel to the Rocky Mountains deformation front.

The proposed model assumes that at least part of the fault(s) or fractures connecting the two formerly discrete sand pools are permeable enough to let gas pass through.

Fault sealing analysis requires 4-D seismic data and microseismic, but other data like well testing and well logging can be suitable to the analysis, but only if they are taken as repeated monitoring.

The absence of these data makes this assumption not verifiable, and then detailed studies are required to test the proposed model.

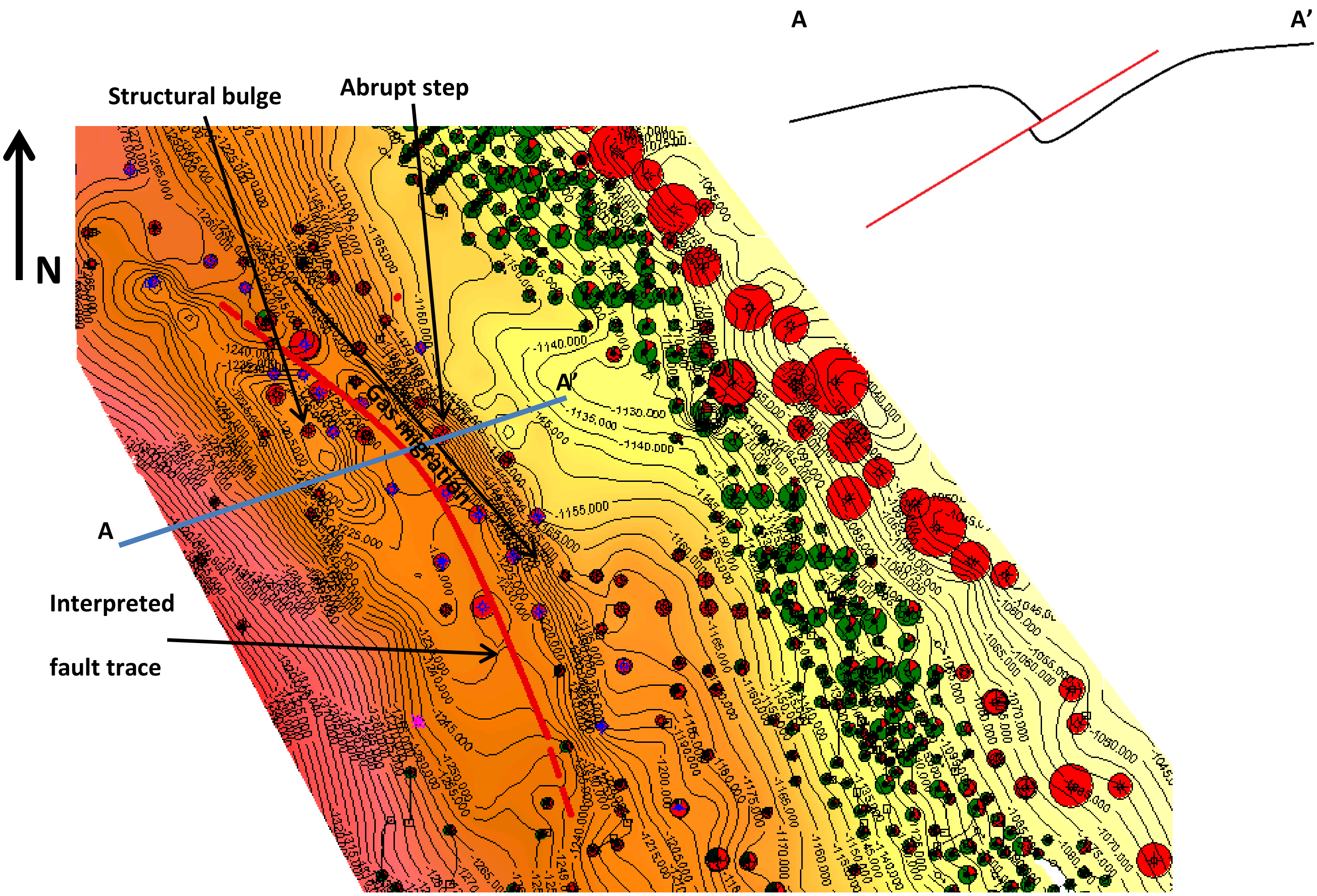


Fig.84: Structure map of the Cardium E5 surface. A an important structural bulge is observed, as well as an associated abrupt topographic step. Section A-A' shows the topography of the E5 along the line. According to the observed geometry a thrust fault trace has been interpreted and posted in the map. Fault respects the thrust geometry identified by Foyer et al. (2011). This fault is claimed to play a major role in the gas flow from the deeper sand body to the upper one. Wells with both upper and deeper producing sand are marked in blue in the map.

Once gas got in the upper sand body, as lighter than oil it goes towards the structurally up-dip portion of the reservoir. The structurally shallowest portion of the Ferrier is towards the NE, therefore gas tends to flow towards that direction (i.e. towards the gas cap of the main body).

The gas migration towards the NE is obstacled by the absence of sand in the two eroded spots identified in reservoir and facies mapping. In this case, the northern spot where the sand has been eroded acts as flow barrier (see fig.85).

The two areas where the sand has been eroded post-deposition constitute a strong flow barrier. In these spots, sand in not present at all or, if present, only the basal 1-1.5m are preserved. Core logging and core analyses pointed out that the base of each sand sequence showed the most poor reservoir properties. That means hydrocarbons can't go straight towards the NE, and therefore gas goes on flowing towards the SE.
Considering this pathway, now the most comfortable way for gas to go structurally up-dip is to pass through the preserved sand belt in between the two eroded spots, as it's the one with greater thickness and best reservoir quality in the area. This is most likely the reason behind the gas presence in the sand belt.
According to the proposed model, the gas exploited in the sand belt is not steady in the reservoir, but it's flowing towards the northeast (i.e. towards structurally up-dip areas). This explains the sharp change from gas to mainly oil production going east, as oil shows up abruptly when the main oil body begins, whereas gas is produced deeper in the basin during its active flow towards structurally up-dip areas.
In the gas producing, conventionally developed body, oil saturation is in average around 15%, and massive gas saturation explains why oil is not produced even if slightly present in core, as the result of very low oil relative permeability in a mainly gas saturated system.
This also happens in the gas cap of the main oil and gas body, where no oil is produced in spite of an average oil saturation of around 18%.
A transitional zone around 4 km long is present where oil and gas production coexist. Oil vs gas ratio increases going towards the main oil and gas body.
As the deeper sand body goes all the way SE as far as the unconventionally developed portion of the Ferrier, gas could come from either/both the NW side or/and from the SE side of the body, and then go up through the fault and spread in the main body.
The interpretation is that gas flows just or in main part from the NW side of the lower sand body. This has been interpreted from the hydrocarbon distribution in the sand belt, shown in picture 85.

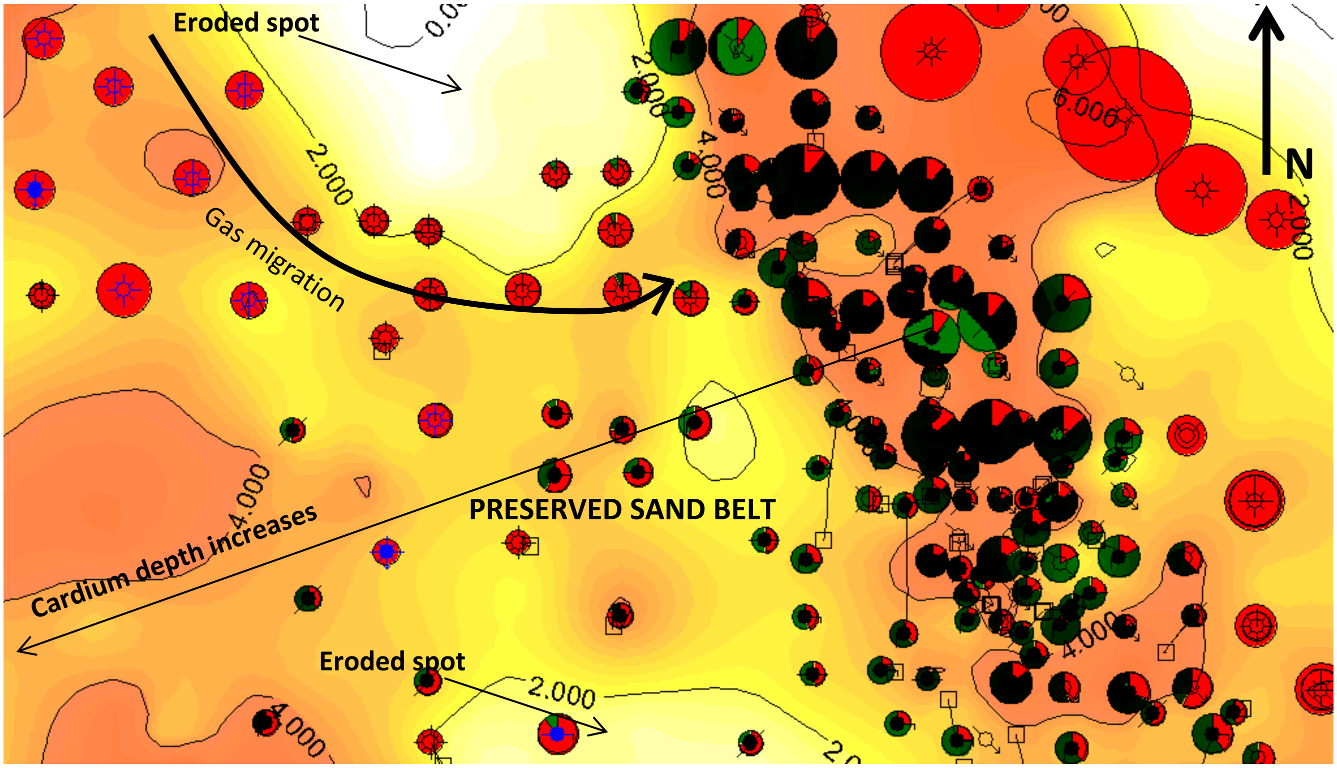


Fig.85: hydrocarbon distribution in the preserved sand belt. 100% gas production occurs in the northern area of the belt, therefore gas is claimed to come from the NW. Black arrow shows the interpreted direction of gas migration from the W Ferrier towards the structurally shallower E-NE.

As visible in the picture, 100% gas production only occurs in the northern area of the sand belt, whereas the southern portion of the sand belt is characterized by oil and gas production, with values similar to the ones in the main oil and gas body.

Gas is claimed to come from the NW because the gas charged portion of the sand belt is located in its northern portion, and therefore it's in fluidodynamic connectivity with the conventionally developed, gas producing body of the Ferrier.

The migration model states that gas starts going towards the SE along the border between the eroded spots and the W Ferrier sands (see the thick black arrow in fig.85). When it encounters the preserved sand belt, gas finds a reservoir with much better petrophysical properties and greater thickness that is also going structurally up-dip, so it quickly deviates towards the east. This makes the northern portion of the sand belt be filled with gas, whereas in the southern area gas doesn't flow, as it abruptly deviates its path as soon as it encounters the best reservoir, i.e. more north.

In conclusion, case 1 is an excellent example of how sedimentology, petrophysical characteristics and post-depositional modifications (i.e. structural features and sediment

erosion) can interact with each other, strongly affecting hydrocarbon migration and, consequently, hydrocarbon production.
In this specific case, gas presence beneath the main oil charged zone has been interpreted as the result of active gas migration from the Cardium deeper sand body towards the main oil and gas body, that is structurally up-dip.
Detailed analysis of sedimentology, petrophysics and structural features in the Ferrier area, as well as post-depositional modifications (i.e. sand erosion) led to the proposal of a new model able to scientifically resolve the reason behind this odd production behaviour of the Cardium Formation in the Ferrier Oilfield.

4.2.2: Case 2 – unconventionally developed body

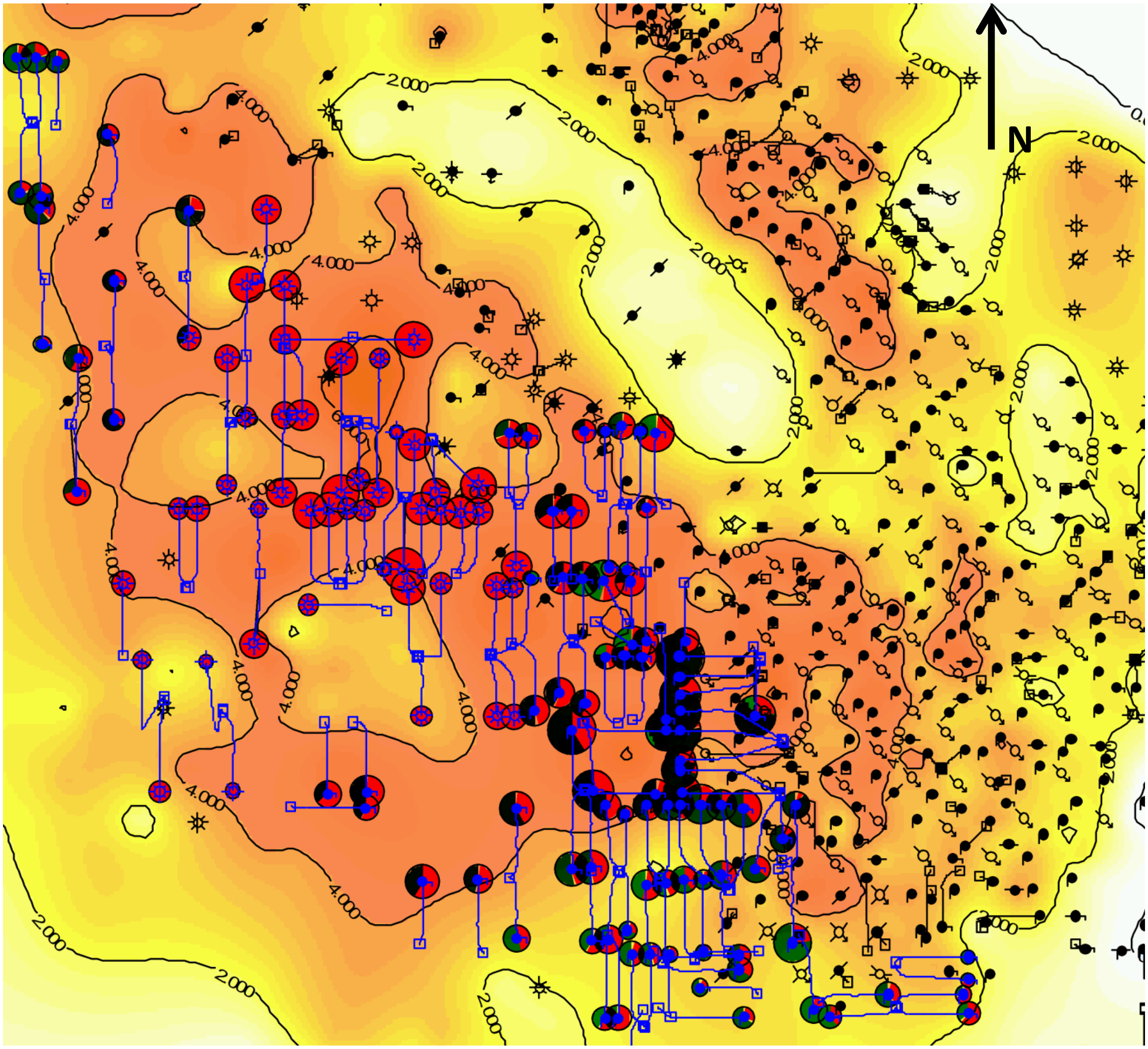


Fig.86: gross reservoir map with HZ Cardium production. Red bubbles represent gas producing wells; green bubbles represent oil producing wells. The central compartment does not produce any oil.

Case 2 has been observed in the central sub-compartment of the unconventionally developed portion of the Ferrier.
Routine core analyses mark that oil is present in each of the three sub-compartments with similar values, but in spite of that oil is produced just in the northern and southern portions, whereas in the central sub-body no oil is produced at all.
As core oil saturation data indicate that oil is present in the area even if it's not produced, it means that most likely it is not moveable. This can happen because of several reasons, and this study aims to find what may cause this production issue in this specific case.
To understand the reason behind the non-mobility of oil, detailed petrophysical analysis of the unconventionally developed Cardium reservoir has been performed discriminating between 100% gas producing areas and oil and gas producing zones.
In chapter 3 porosity vs permeability cross-plots of each unconventionally developed compartment were built and analyzed. It was visible that the central, 100% gas producing body was the one with the poorest reservoir characteristics. Despite approximately the same amount of sand than the adjacent compartments (even higher than the northern sub-body), the central body shows low (<0.2mD) permeability values in around 80% of the reservoir, with a few tens of centimetres of slightly better sand (0.2-0.3mD) located between tighter areas.
If the porosity vs permeability plots of the northern and central compartment, that are the ones showing the poorest reservoir characteristics, are overlapped, it is clearly visible that the central sub-body values are moved to the right in the plot (fig. 87). That means more porosity is required to have the same permeability in that compartment.
With statistic tools it is possible to find the percentage of samples for each set range of permeability, and these graphs also confirm that the gas bearing zone is much less permeable than the one where oil is produced.
Looking at the cumulative percentages it's noticeable that 73% of the gas zone samples have a permeability value lower than 0.2mD, and 85% have a value lower than 0.3mD.
Conversely, the oil zone shows 49% of the samples being less permeable than 0.2mD, and 62% of the samples less permeable than 0.3mD. That means in the oil zone 38% of the samples has a permeability value above 0.3mD, whereas the same threshold is achieved by just 15% of the gas zone samples.
The northern body was the most similar to the central compartment, but the gas producing body has lower quality than the oil and gas producing one. This is visible by comparing the cross-plots of the two. It is evident that in the central compartment higher porosity is required to reach the same permeability than the northern body.

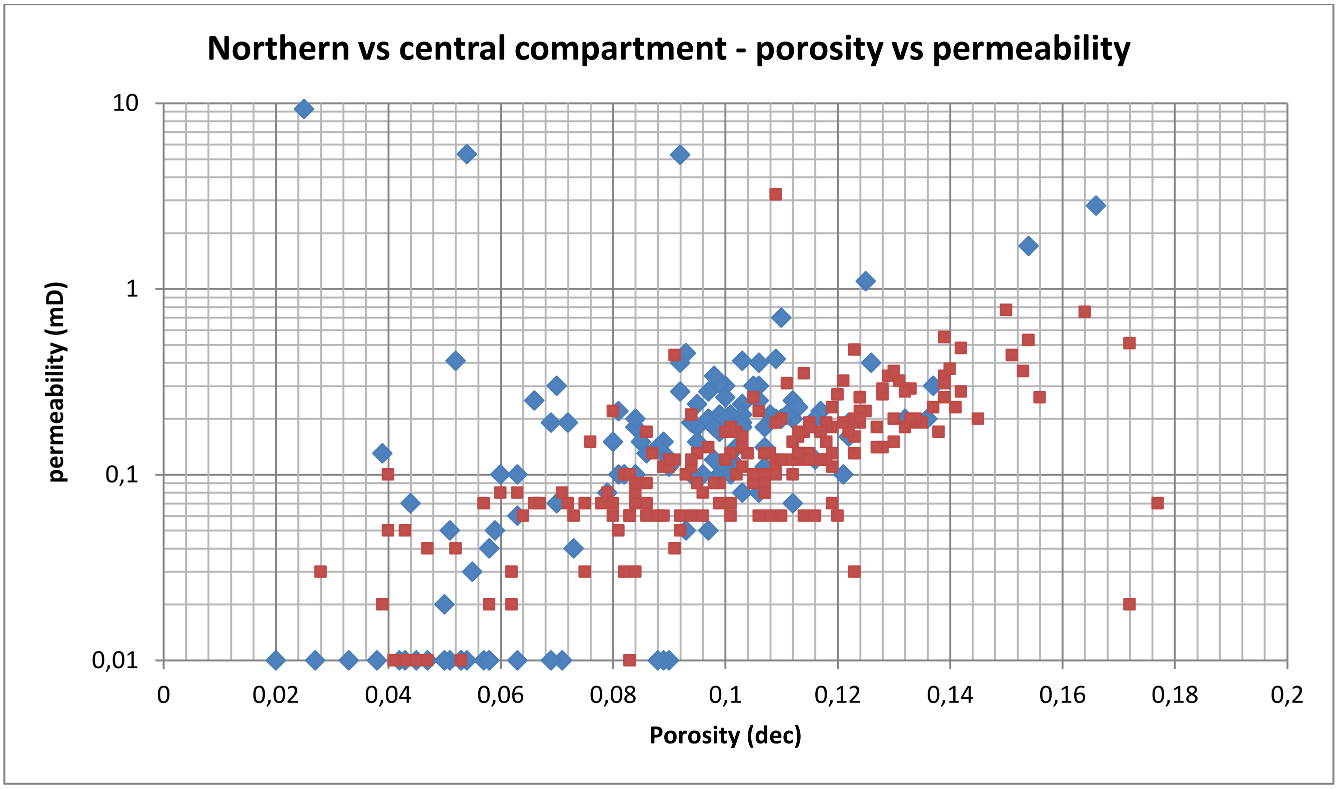
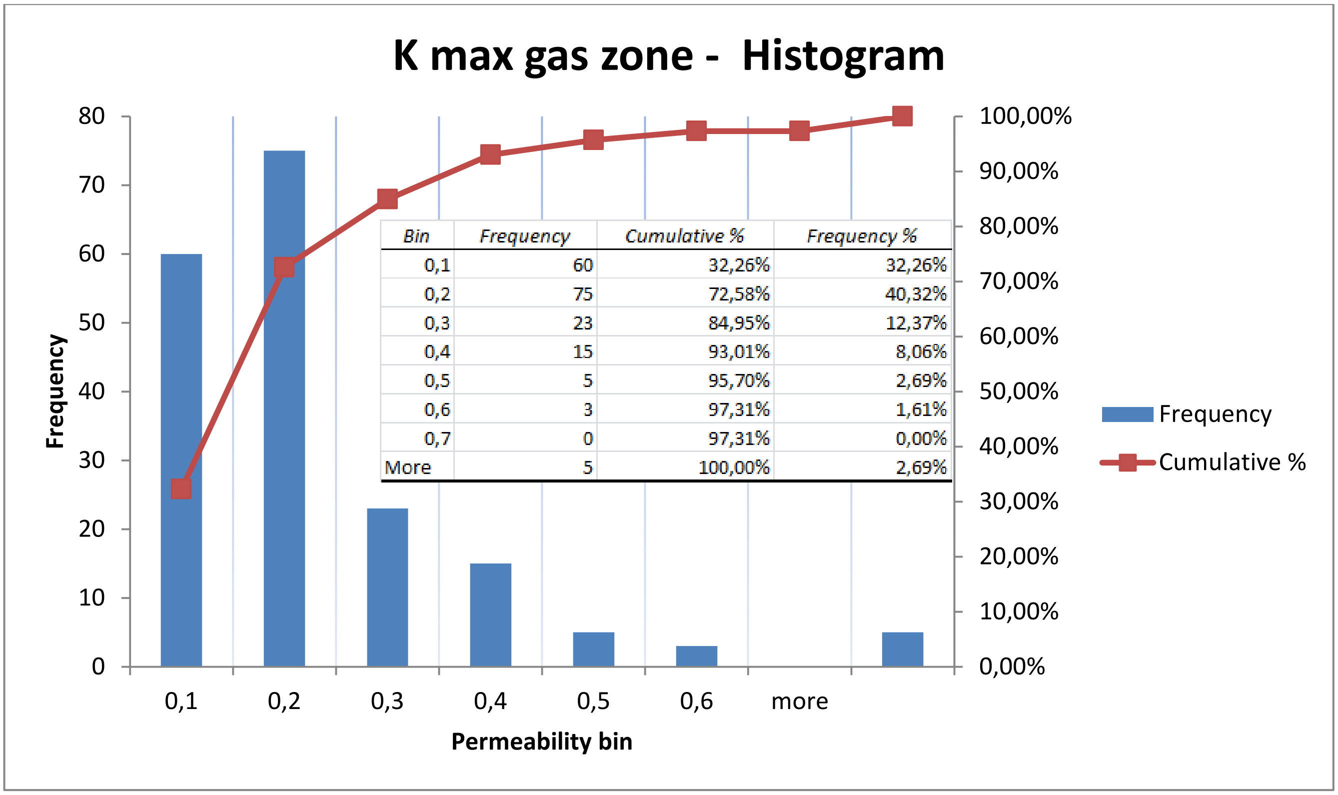
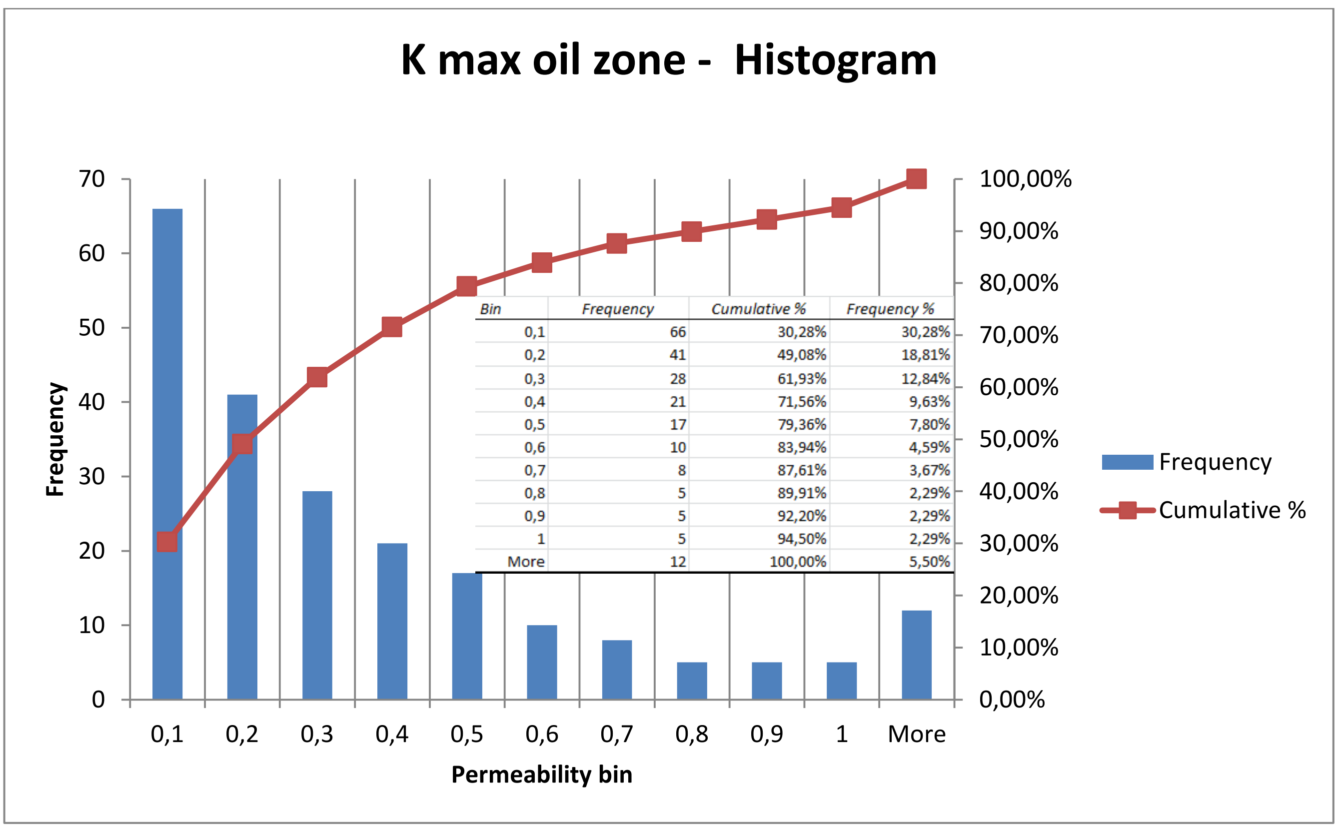


Fig.87: porosity vs permeability cross-plot of the northern (blue diamonds) and the central (red squares) sub-compartments.



Bin	Frequency	Cumulative %	Frequency %
0,1	60	32,26%	32,26%
0,2	75	72,58%	40,32%
0,3	23	84,95%	12,37%
0,4	15	93,01%	8,06%
0,5	5	95,70%	2,69%
0,6	3	97,31%	1,61%
0,7	0	97,31%	0,00%
More	5	100,00%	2,69%



Bin	Frequency	Cumulative %	Frequency %
0,1	66	30,28%	30,28%
0,2	41	49,08%	18,81%
0,3	28	61,93%	12,84%
0,4	21	71,56%	9,63%
0,5	17	79,36%	7,80%
0,6	10	83,94%	4,59%
0,7	8	87,61%	3,67%
0,8	5	89,91%	2,29%
0,9	5	92,20%	2,29%
1	5	94,50%	2,29%
More	12	100,00%	5,50%

Fig.88: sample classification of the oil zone and the gas zone according to permeability bins. Oil zone samples are more permeable than gas zone ones.

Once stated that the gas producing compartment has worse reservoir characteristics than the adjacent oil producing body, now the point is to find the reason behind this drop in reservoir properties along depositional strike.
Detailed core logging didn't detect any major difference between the two different compartments, as well as thin sections description. The geologic cause for the low permeability of the body must therefore occur at a smaller scale, therefore SEM and CL analyses were performed on the samples.
This small-scale pore characterization has been considered necessary because the porosity of the Cardium in this area is not great (10-12% max), so cementation would exert much more effect in this area rather than the main oil and gas body, where porosity reaches values up to 26%.
The pore characterization involved 6 wells (see base map in fig.40): 3 in the main oil and gas body and 3 in the unconventionally developed portion of the Ferrier, i.e. one for each sub-compartment. More specifically, 100/10-12-039-09W5/00 was picked for the central sub-body to detect any major micro-scale differences from what observed in every other well.
For each considered sample thin sections, EDX mapping, SEM and cathodoluminescence analyses were performed to understand what controls the lower reservoir quality of the central body, and the study was mainly focused on everything that was inside the Cardium pores of the unconventionally developed gas zone.

100/10-12-039-09W5/00 – sample 2B (2326.58m)

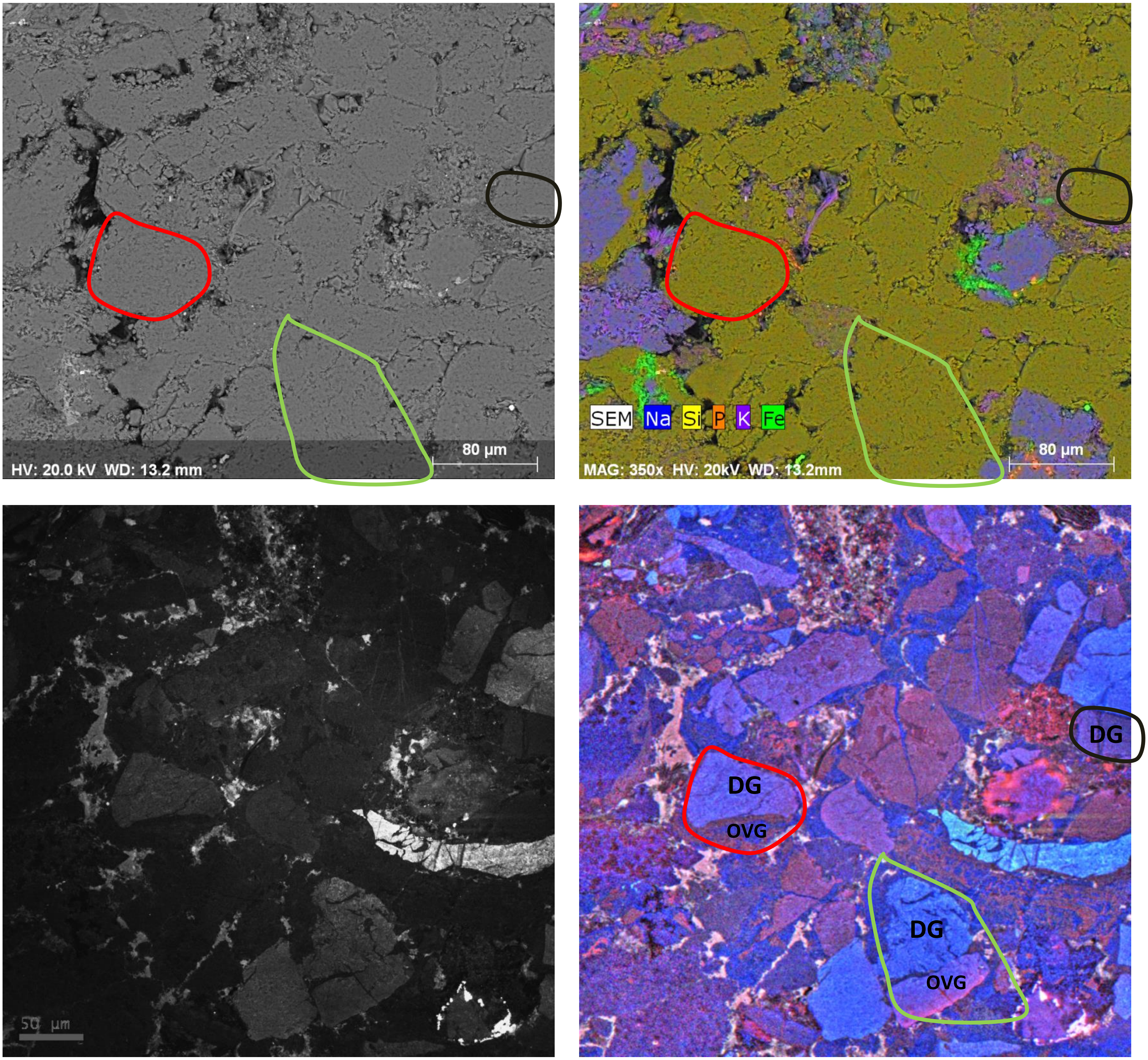


Fig.89: EDX mapping (89a, 89b) and CL analysis (89c, 89d) of a sample taken in the Cardium reservoir of the central sub-compartment. Quartz is still the most common mineral, CL shows the diagenetic fabric of the sands. DG: detrital quartz grain; OVG: quartz overgrowth.

100/10-12-039-09W5/00

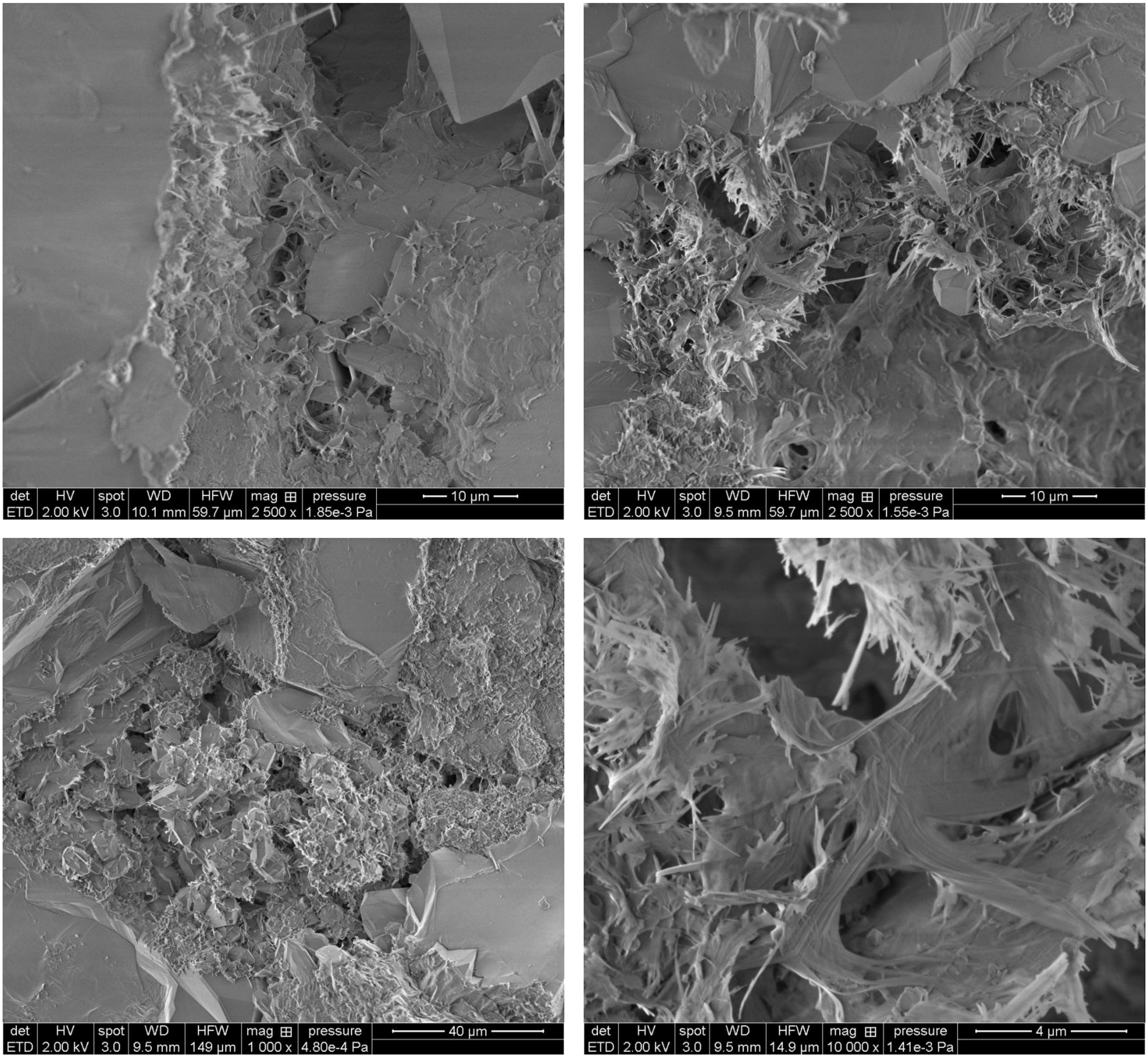


Fig.90: SEM pictures of Cardium pores in cored well 100/10-12-039-09W5/00. The sample shows massive Illite cementation. Clay cement occurs in the highest observed amount among every other well observed. Picture 90c shows a spectacular example of micro-crystalline quartz coated by Illite partially occluding a Cardium pore. Picture 90d shows how Illite fibres can connect to each other and create an even more effective permeability barrier.

Mineralogy and pore characterization of the gas zone shed light on the smallest-scale geologic features of the Cardium reservoir in the area. EDX mapping confirms that silica still accounts for the major portion of the minerals. Other minerals present are weathered relict minerals such as plagioclases (Na- and K-rich) and authigenic minerals like Chlorite and pyrite (Fe-rich). Cathodoluminescence shows that silica wasn't deposited in one single phase, as grains have different tonalities of violet, blue and red (fig.89). Also, CL is able to differentiate between quartz and chert grains, as the latter don't show quartz cement overgrowth.
SEM analysis mainly aims to characterize and quantify the degree of cementation of the sample, as well as the type of cement, as each cement affects permeability in a different way. Throughout all this Ferrier research, several types of cement have been found: quartz, chert, calcite, siderite and clay cement (illite, kaolinite, chlorite).
The SEM tool can give an idea of the possible effects of each cement over fluid flow, just looking at the texture of the cement itself and the width and visual aspect of any pore in the cemented area.
Siderite cement occurs massively in the top portion of the Cardium sandstones. It has the effect of dropping porosity and permeability values, and therefore hydrocarbons can't even get in the cemented interval. That means siderite is not a major issue to production, as few to no hydrocarbons are able to get in there.
Calcite cement has been detected in extremely small amounts in very few samples, and therefore it's not a big issue in the Cardium Formation in the Ferrier area.
Quartz cement is largely present in the Cardium, and its effect can be seen in thin sections, SEM and CL. The effect over permeability is high, as prisms are braided and therefore pore space is slow in quartz cementation areas. This is even worse when clay cement is associated with micro-crystalline quartz (fig.91) or chert cement, that shows micro-crystals generally smaller than the quartz ones.

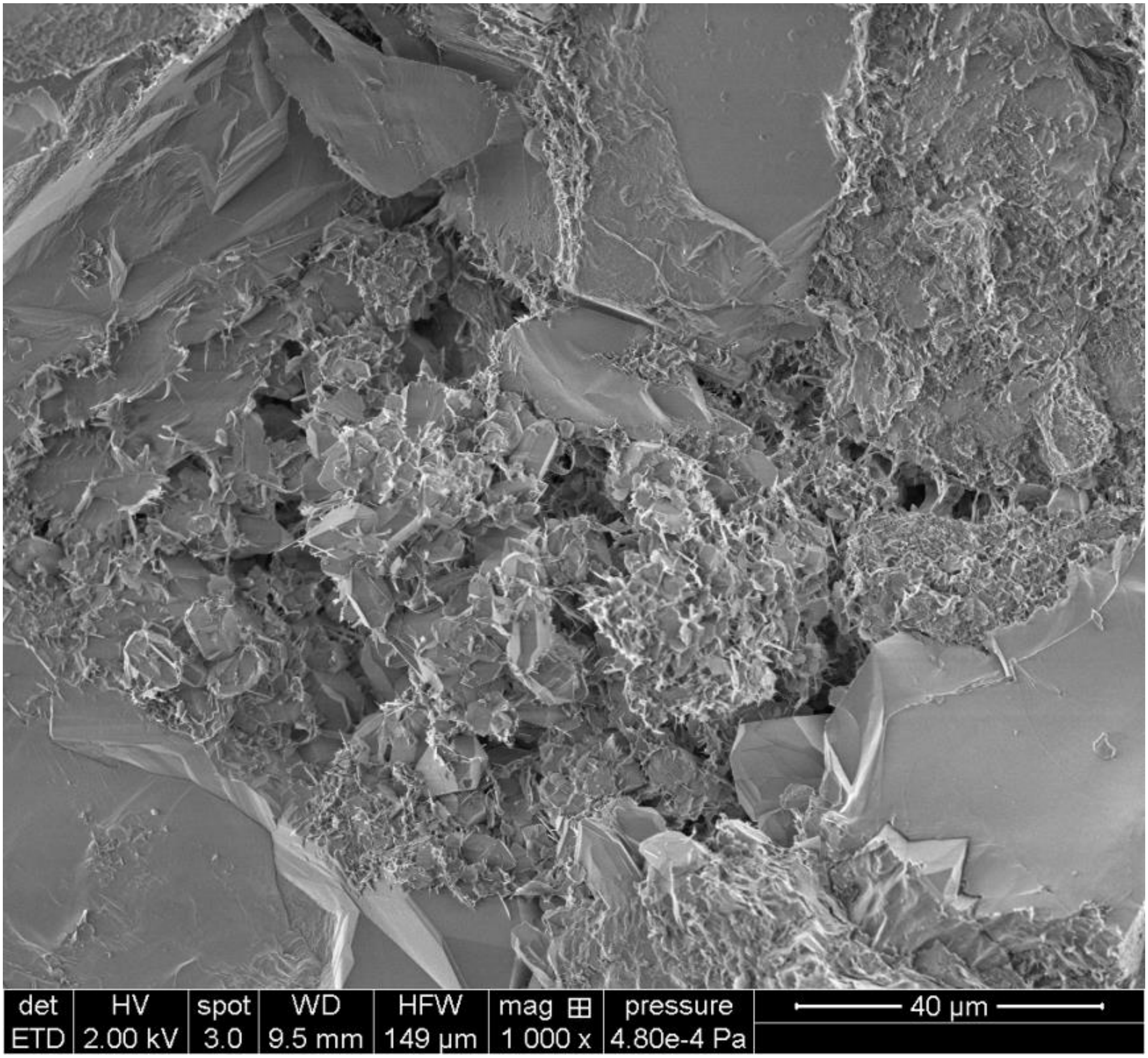
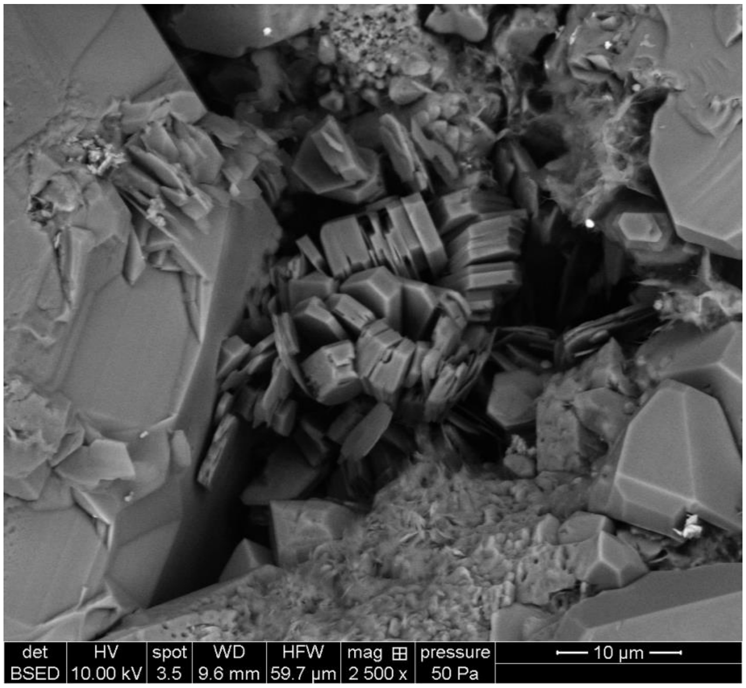


Fig.91: micro-crystalline quartz cement coated by Illite fibres in well 100/10-12-039-09W5/00. This combination of cements heavily affects permeability values due to pore occlusion.

Clay cement is not visible in core and thin section. To classify and quantify clay cement SEM analyses at great magnitude are required. Illite, kaolinite and chlorite have been detected in the Ferrier.
Unless present in massive amounts, kaolinite and chlorite are interpreted not to have great effects over permeability because of their texture. Chlorite plates usually coat sand grains without dropping permeability and kaolinite grows as a piling up of prisms (fig.92).



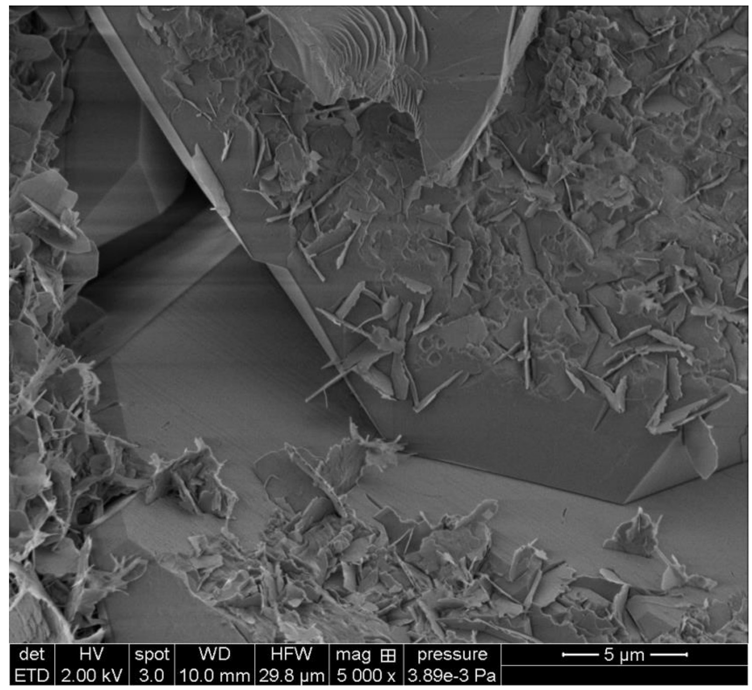


Fig. 92: SEM pictures of kaolinite (92a) in well 100/10-25-039-08W5/00 and chlorite plates (92b) in well 100/06-17-038-07W5/00. Kaolinite partially occludes the pore, but has not a lot of effect on permeability; chlorite plates can coat the sand grain, but they usually are not found in the pore space.

Illite has without any doubt the greatest effect over permeability among each observed clay type. If the same volume of kaolinite or chlorite and Illite is observed, the latter covers a much wider area, as it grows in large and spaced fibres. These fibres are extremely braided and can link to other Illite fibres creating areas where pores are extremely small, and this is a serious obstacle to fluid flow (see fig.90).
Pore characterization in the central compartment showed that Illite is present in this sub-body in much larger amounts than everywhere else in the Ferrier, and that explains the relative lower permeability of this portion of the unconventionally developed Ferrier with respect to the adjacent areas.

Also, significant amounts of microcrystalline quartz cement have been detected, usually together with Illite (fig.91), and that further contributes to drop the reservoir quality of the Cardium.
The presence of this large network of Illite fibres is most likely one of the main reasons oil is not moveable into the reservoir, although being present.
Looking at the production map of the unconventionally developed portion of the Ferrier, focus has been put on the contacts between the three sub-bodies. The gas body has very sharp contacts both with the southern and the northern body. Differences in fluid production rates and/or GOR occur at a scale of 300-400m, and the wells in the two different sides of the contact show completely different production behaviours.
Of course the lack of permeability is compensated by the induction of fractures through multi-stage fracking, but hydrocarbons still must flow from the matrix to the fractures. Therefore, fracking helps in giving additional permeability to the Cardium reservoir, but this permeability gain is ineffective if oil can't flow from the matrix to the induced fractures.
As the changes occur at such a small scale, clay cement growth may account for a significant part of the causes, as cement starts growing in spots and then expands in the adjacent pores. This can be considered an internal sealing of the reservoir, that acts as a ceramic filter and lets just gas move, as it's much less viscous than oil, that means it can flow in smaller pores than liquid and heavier hydrocarbons.
The scale at which production behaviour can change can be seen by comparing a southern body and a central body HZ next to the contact between the two different compartments.
More specifically, this analysis compares Cardium producing horizontals 100/01-21-038-08W5/00 and 100/04-22-038-08W5/00. These wells are spaced by roughly 450m and the spud dates of the two differ by just 13 days, that means the two HZs are comparable in each of their production values.
The central sub-body producing horizontal, 100/01-21-038-08W5/00, shows 100% gas production, with gas flow rate of 20,000 Mcf/month at the 6^{th} month of production, after the initial peak at 80,000 Mcf/month.
Starting from the 6^{th} month of production, production decline rate is estimated to be -32% after 1 year, -28.5% after 2 years and -25% after 3 years.
The southern body well, 100/04-22-038-08W5/00 shows both oil and gas production. Gas production, after the first 6 months starting from 50,000 Mcf/month and then rapidly decreasing, occurs at a flow rate of roughly 17,000 Mcf/month. Production decline rate is estimated to be -38% from the 6^{th} to the 18^{th} month of production, then -24% and -12.5% after another one and two years.
This well is producing oil too, starting from 5,000 barrels a month at the beginning of the well life to 1,300 bbls/month after 6 months. Oil production decline is faster than the gas one and typical of a horizontal well, but it still tends to decrease along time. Starting from the 6^{th} month of production, estimated decline rate sets at 46%, 28.5% and 36%.
If the two production graphs of the close horizontals are compared, they show a very good match in initial production and production declines. The fact that the two gas curves are really similar to each other but in one well there is oil production and in the other there is not, that can be an index that oil is present everywhere, but for some reasons it can't be

exploited in the central body. This is coherent with the potential interpretation of an internal sealing in the central compartment, which prevents oil from flowing.

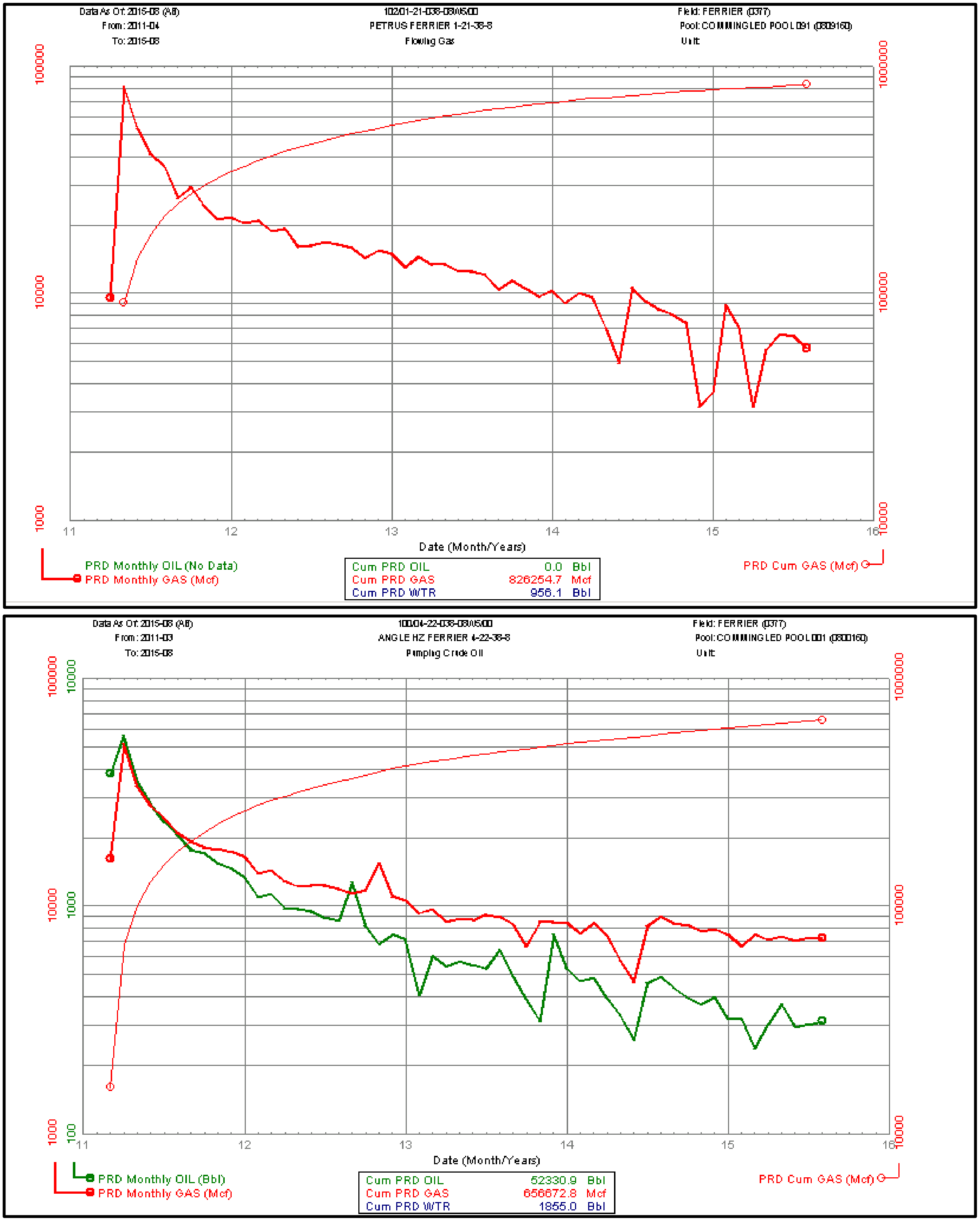


Fig.93: monthly oil and gas production in well 100/01-21-038-08W5/00 (93a) and well 100/04-22-038-08W5/00 (93b).

The gas production curve shows similarity between the two horizontal producers.

The most important question at this point then is the following: can clay cementation and the subsequent decrease in reservoir permeability fully scientifically explain the 100% gas production in the central body? Or there is another mechanism that drives this production behaviour?

The general impression is that the internal sealing model scientifically works in this pool for all of the above mentioned points, but most likely something else is going on in the pool itself. The internal sealing model actually works for the majority of the producing wells with available core nearby, but there are some cases that put this model into discussion.

If massive clay cementation is estimated to be present in that portion of the reservoir, if it's claimed that each 100% gas producing horizontal doesn't exploit oil because of poor reservoir characteristics, then each core taken close to a Cardium HZ in the central compartment should show poor permeability values.

As above mentioned, this works properly with most of the cores, but there are some exceptions that it's important to mark, as they may suggest that internal sealing is not the only cause for fluid discrimination.

In the next pages, each core plot of the central body will be shown, and cores coherent with the model will be differentiated by the ones that don't match the internal sealing theory.

The petrophysical model of cores taken in the gas producing area confirms that the internal sealing model doesn't work everywhere. This model indeed can't admit any high permeability area where oil is not produced either, instead some cores don't confirm the proposed model (fig.94).

There must be another factor that contributes to govern fluid distribution within the play together with the degree of clay cementation. The dataset available for this study didn't include any seismic, but in the area it has been demonstrated the presence of thrust faults and strike-slip faults (Lyatsky et al., 2005; Foyer, 2011).

Evidence of thrusts in the W Ferrier was detected as they created a topographic gradient, but this doesn't work for strike-slip faults. Thrusts are supposed to be NW-SE oriented, whereas strike-slip faults should have a perpendicular trend. The three sub-bodies are ideally separated by NE-SW oriented borders, so they could be related to this kind of faulting. Seismic could be an excellent way to identify any eventual fault trace and compare their location to the borders of the three sub-bodies, in order to understand reservoir compartmentalization.

The absence of seismic data doesn't offer the opportunity to completely unravel what controls the odd production behaviour of the central body.

Anyway, this study was useful as it first demonstrated that net reservoir thickness has nothing to do with this odd production occurrence, and second that massive clay cementation is observed in the area, preventing oil from flowing.

The internal sealing model apparently does not work everywhere in the central sub-compartment, as 2 cores show good permeability values, but gas only is produced in the horizontals nearby, with no oil occurrence. The internal sealing model can't explain why the horizontal close to these two cores don't produce oil.

Therefore the interpretation is that the internal sealing model is not the only reason that prevents oil from moving into the reservoir.

To test the possibility of SW-NE oriented strike-slip faults compartmentalizing the reservoir detailed 3-D seismic and microseismic has to be seen and interpreted.
Considering the very good match between the trend of borders dividing the compartments and the one of strike-slip faults identified in the Ferrier, the presence and influence of this kind of structures over reservoir compartmentalization seems to be very reasonable.

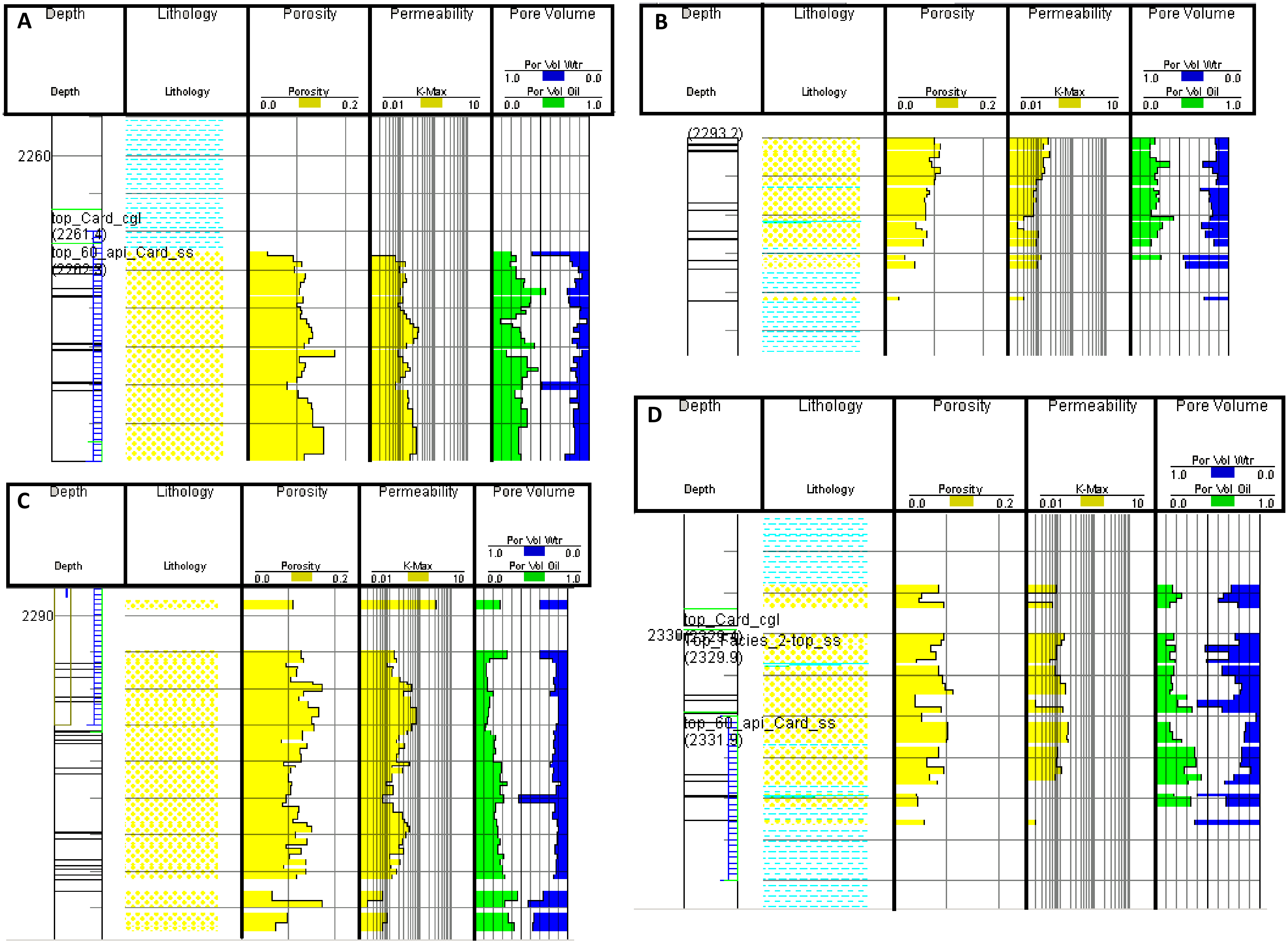


Fig.94: discrimination between central body cores matching the internal sealing model (A, B and D) and cores that don't (C)

In conclusion, the central sub-body has different petrophysical characteristics from the adjacent areas. It shows great amounts of clay cement, more specifically illite, that may strongly account for the non-mobility of the oil present in the reservoir. However, core data show that massive cementation doesn't occur everywhere in the compartment, so it can't be the only reason accounting for oil non-mobility.

Gas production could therefore be favoured by structural features. Strike-slip faults and basement faults have been observed in the Ferrier area. Strike-slip faults are SW-NE oriented, that is the same trend of the borders separating the three different compartments in the unconventionally developed area of the Ferrier. Gas presence could therefore be caused by these kind of structural features, that act as reservoir compartmentalisers.

The absence of seismic data makes really difficult to test the model, as strike-slip faults don't create as much topography as thrust faults, therefore this faulting type can't be seen in structure mapping. Additional data such as 3-D and 4-D seismic and microseismic are required to identify any presence of faulting and fracturing and to test if the structural discontinuities are permeable or not. Horizontal coring could also be a great asset, as strike-slip faults are usually high-angle, so it would be easier to find these structures coring horizontally rather than vertically.

Chapter 5 - Conclusions

5.1: Summary

This study focused on the depositional architecture, post-depositional modifications and reservoir characteristics of the Cardium Formation in the Ferrier oilfield area, and on how these three main features can interact with each other and generate odd production behaviour in the pool.

In the Ferrier area, the Cardium Formation is composed by a NE prograding clastic sequence generally coarsening upwards from offshore muds to shoreface sands and conglomerates. Tectonic activity of the Rocky Mountains is claimed to have provoked the deposition of pebbles on top of the sands, thickening the gross Cardium reservoir interval. Offshore muds seal the reservoir vertically and laterally, and that permitted oil and gas accumulation.

Facies and net reservoir mapping identified the thickest spots of the sands and conglomerates, and they also showed the presence of two areas where the Cardium reservoir has partially or totally been eroded.

Reservoir mapping and cross-sections detected the presence of a gas producing deeper sand sequence in the western portion of the study area, evidencing that the Cardium has more than one producing horizon in the Ferrier play.

Facies mapping matched with production data pointed out that, when present, conglomerates generally are the most permeable facies, even if they are often less thick than the underlying sandstones.

Great match is observed between conglomerate thickness and volume of produced hydrocarbons. In absence of conglomerates, net reservoir thickness rules hydrocarbon productivity.

Overall, the reservoir shows good quality and great oil and gas production. In some cases the production behaviour in the play does not follow the customary fluid layering in a reservoir (i.e. oil structurally beneath gas). These anomalies were identified at the beginning of the research, and detailed study was able to resolve the reason behind these occurrences.

The two most evident cases of abnormal production behaviour have been analyzed and resolved. This constitutes the major discovery of this thesis, together with the Cardium depositional architecture and post-depositional modifications in the Ferrier area.

Detailed analyses revealed that the observed odd production behaviour is due to the control exerted by structural features, reservoir thickness and reservoir quality over migration pathway in at least one case over two.

Diagenetic effects, and more specifically clay cementation, are interpreted to be one of the main causes for the non-mobility of oil in the other situation.

Future work includes acquisition, processing and interpretation of 3-D and 4-D seismic. This would be an excellent tool to detect the presence of thrust and strike-slip faults, claimed to have a major role in both the observed cases of odd production behaviour. Seismic can also be useful for fault sealing analysis, that is one of the tools able to test the proposed model.

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