Palacky University Olomouc

Faculty of Science

Department of Geology

Assessment of a carbonate reservoir characterization (CARP)

Bachelor Thesis

Zhokar Tareq Hwayyiz

Petroleum Engineering (B0724A330002)

Full Time study

Supervisor: Prof. Dr Howri Mansurbeg

Advisors: Rebar Mahmmud M.Sc.

Salahedin Shahrokhi

Olomouc 2023

Assessment of a carbonate reservoir characterization (CARP)

Anotace: (in Czech)

Tato studie se ponoří do různých aplikací nového softwaru CARP v ropném průmyslu s primárním zaměřením na získání cenných informací o jeho funkcích, výhodách a výzvách. Cílem výzkumu je osvětlit klíčové aplikace tohoto softwaru, počínaje důkladným prozkoumáním jeho schopností. K tomuto účelu byly použity tři mikroskopické vzorky tenkého řezu z khurmalského souvrství (pozdní paleocén-začátek eocénu) v oblasti Kurdistánu v Iráku. Tyto vzorky měly svou pórovitost a propustnost předem stanoveny v laboratoři. V této studii byl software použit k výpočtu poréznosti těchto vzorků a bylo provedeno komplexní srovnání mezi daty softwaru CARP a laboratorními daty.

Zjištění tohoto výzkumu zdůrazňují software CARP jako užitečný a nákladově efektivní nástroj pro provádění základních studií nádrží. K efektivnímu fungování však vyžaduje vysokou úroveň odborných znalostí. Je zřejmé, že pro získání přesných a komplexních výsledků je nezbytné doplnit data softwaru laboratorními daty. Kombinace těchto datových souborů zvyšuje spolehlivost a přesnost nálezů a poskytuje výzkumníkům ucelenější pochopení vlastností nádrží.

Tato studie podtrhuje význam softwaru CARP v ropném průmyslu pro provádění základních analýz nádrží. I když nabízí nákladově efektivní výhody, odbornost v jeho používání je zásadní. Využití duálního přístupu, který kombinuje jak softwarová data CARP, tak laboratorní data, zajišťuje spolehlivější výsledky a umožňuje výzkumníkům činit informovaná rozhodnutí při charakterizaci nádrží a jejich průzkumu. Studie zdůrazňuje význam využití jak technologického pokroku, tak tradičních laboratorních technik pro maximalizaci užitečnosti softwaru CARP a optimalizaci jeho potenciálního dopadu v ropném průmyslu.

Klíčová slova: Software CARP, pórovitost, propustnost, formace Khurmala, tenký řez

Assessment of a carbonate reservoir characterization (CARP)

Anotation: (in English)

This study delves into the diverse applications of the new CARP software in the oil industry, with a primary focus on obtaining valuable insights into its functionalities, benefits, and challenges. The research aims to shed light on the crucial applications of this software, starting with a thorough examination of its capabilities. For this purpose, three microscopic thin section samples from the Khurmala Formation (Late Paleocene-Early Eocene) in the Kurdistan Region of Iraq were utilized. These samples had their porosity and permeability previously determined in the laboratory. In this study, the software was employed to calculate the porosity of these samples, and a comprehensive comparison between CARP software data and laboratory data was carried out.

The findings of this research highlight CARP software as a useful and cost-effective tool for conducting fundamental reservoir studies. However, it necessitates a high level of expertise to operate effectively. It is evident that to obtain accurate and comprehensive results, it is essential to complement the software's data with laboratory data. The combination of these datasets enhances the reliability and precision of the findings, providing researchers with a more holistic understanding of reservoir properties.

This study underscores the significance of CARP software in the oil industry for conducting basic reservoir analyses. While it offers cost-effective benefits, proficiency in its usage is crucial. Employing a dual approach, combining both CARP software data and laboratory data, ensures more reliable results and enables researchers to make informed decisions in reservoir characterization and exploration endeavors. The study emphasizes the importance of leveraging both technological advancements and traditional laboratory techniques to maximize the utility of CARP software and optimize its potential impact in the oil industry.

Keywords: CARP software, Porosity, Permeability, Khurmala Formation, Thin Section

I declare that I have prepared the bachelor's thesis myself and that I have stated all the used information resources in the thesis.

In Olomouc, July, 2023

…………………………………………
Zhokar Tareq Hwayyiz

Acknowledgment

First and foremost, I would like to thank God, the compassionate and the merciful, for giving me His showers of blessings throughout my bachelor thesis to be able to proceed successfully. A number of wonderful people have greatly supported me to complete my study. To only some of them, it is possible to give a mention here.

This thesis owes its completion to the invaluable cooperation and support of Mr. Arvi Lønøy. His guidance and assistance in data analysis, along with his generous provision of the Carp software free of charge, deserve our deepest gratitude.

I would like to express my deepest appreciation to my supervisor Professor Howri Mansurbeg who has shown the attitude and the substance of a genius: he continually and persuasively guided me in all times of research and throughout the course of my dissertation. Without his supervision and constant help, this project would not have been possible.

I am also thankful to the members of my thesis committee for their valuable insights and constructive feedback.

Lastly, I would like to express my heartfelt gratitude to my family. Their unwavering support, understanding, and love have been my constant source of strength throughout this journey. Their belief in my abilities and their encouragement during both challenging and rewarding times have been invaluable.

Table of contents:

List of figures:

List of tables:

Chapter 1: Introduction

Carbonate deposits represent the major kind of hydrocarbon reservoirs (Kargarpour, 2020). According to Akbar et al. (2000), carbonate reservoirs contain around 60% of the globe's oil deposits. Carbonate reservoirs are tremendously heterogeneous due to their diverse settings of porosity and permeability (Jardine & Wilshart, 1982). Such heterogeneities are created by the vast range of conditions during which carbonates are deposited, as well as the later diagenetic transformation of the parent rocks fabric (Jardine & Wilshart, 1982). After the discovery of oil in carbonate rocks in the world, studying and investigating the most important features of this type of sedimentary rocks in world became an attractive topic for scientists (Magoon and Dow, 1994). Carbonate rocks have complex reservoir properties, that's why oil companies and scientists focus on methods that can easily check the reservoir properties of this type of rock (Garland et al., 2012). In these ways, various methods and programs were created, each of which achieved success (Garland et al., 2012). The fundamental reason for the unsuitable classifications of carbonate rocks is their diverse characteristics, which have become even more apparent when one seeks to define the petro-physical features at different scales (Garland et al., 2012; Janjuhah et al., 2019).

CARP is one of the new software that has been released by Arve Lonoy in recent years. The main purpose of this thesis is to examine the most important features of this software in the oil industry and its applications.

This study will be on the new pore-type-based methodology for reservoir characterization and modeling of carbonate reservoirs CARP, which has been developed by Arve Lonoy. This new methodology is based on the global empirical relationships between pore types and reservoir parameters and it can be integrated into a geological framework with sedimentological and diagenetic controls on carbonate reservoirs quality distribution. The method can be applied in the exploration, and production development phases of wells and it produces detailed input parameters for reservoir modeling and volume estimation. Nevertheless, sensitivity testing can be carried out on all input parameters in a very short time.

The methodology of the original dataset of CARP software has been successfully applied in several producing reservoirs, including one Russian field, four Iranian fields, and four Iraqi fields. The method has also been applied in the exploration phase including the 22nd round, Barents Sea, and Prospect evaluation in the Norwegian Sea.

The basic elements in the methodology of CARP software are pore types, porosity, and height above FWL (for saturation predictions). Essentially if such key elements are known, all reservoir parameters can be predicted, which normally go into static reservoir models and also many other parameters that go into dynamic models.

The pioneering pore-type classification system, introduced by Lonoy in 2006, holds a central role within the cutting-edge CARP software. Comprising a comprehensive set of 21 distinct pore types (as outlined in Table 1), this classification serves as the primary framework for characterizing porosity variations.

At the heart of this classification lies the amalgamation of essential elements: pore geometry, pore size, and porosity distribution. By encapsulating these critical factors, the model achieves a profound understanding of the complex nature of different pore types. It is worth noting that these pore types are intricately influenced by sedimentological and diagenetic processes, making them an indispensable part of geological models.

The seamless integration of this classification system into the CARP software empowers geologists and researchers to gain invaluable insights into the dynamic relationships between pore characteristics and geological phenomena. As we continually refine and advance the software, we strive to maintain the highest level of accuracy and utility, ensuring it remains a robust and indispensable tool in the realm of reservoir characterization and petrophysical analysis.

Table 1 New porosity classification of carbonate rocks proposed by Lønøy. (2006)

Pore Type	**Pore Size**	**Pore Distribution**	**Pore Fabric**	**R2**
Interparticle	Micropores (10-50 um)	Uniform	Interparticle, uniform micropores	0.88
		Patchy	Interparticle, patchy micropores	0.79
	Mesopores (50-100 um)	Uniform	Interparticle, uniform mesopores	0.86
		Patchy	Interparticle, patchy mesopores	0.85
	Macropores (> 100 um)	Uniform	Interparticle, uniform macropores	0.88
		Patchy	Interparticle, patchy macropores	0.87
Intercrystalline	Micropores (10-20 um)	Uniform	Intercrystalline, uniform micropores	0.92
		Patchy	Intercrystalline, patchy micropores	0.79
	Mesopores (20-60 um)	Uniform	Intercrystalline, uniform mesopores	0.94
		Patchy	Intercrystalline, patchy mesopores	0.92
	Macropores (>60 um)	Uniform	Intercrystalline, uniform macropores	0.80
		Patchy	Intercrystalline, patchy macropores	
Intraparticle			Intraparticle	0.86
Moldic	Micropores (<10-20 um)		Moldic micropores	0.86
	Macropores (>20-30 um)		Moldic macropores	0.90
Vuggy			Vuggy	0.50
Mudstone microporosity	Micropores (<10 um)		Tertiary chalk	0.80
			Cretaceous chalk	0.81
		Uniform	Chalky micropores, uniform	0.96
		Patchy	Chalky micropores, patchy	

1.1 Geographic distribution

The database comprises approximately 10,000 samples sourced from diverse geological time periods, formations, and global depositional settings. The data range varies from samples that only have defined pore types to samples that include a wide range of measured petrophysical properties. The CARP tool visually displays the global distribution of the complete CARP database, presenting information on geological age, formation, depositional setting, and the distribution of dominant pore types. Regular updates are made to the database to ensure its currency. Understanding the composition of dominant pore types is crucial for statistically predicting pore types in carbonates across different geological time periods and depositional settings, both locally and globally. The video illustrates how this database can be utilized to estimate pore types in various depositional settings based on local statistical distributions. Such applications are particularly valuable when limited local data is available, such as during exploration, and can significantly impact predictions of flow properties and volume estimates. In fact, incorrect pore-type assignments can lead to differences of several hundred percent in volume estimates, as demonstrated in Lonoy's publication in 2006. The statistical distributions of dominant pore types can be employed to spatially assign pore types and associated reservoir properties, such as within the grid cells of a reservoir model.

Within this section of CARP, an interactive globe faces us where we can choose the countries that have a specified dataset to their respective formations and can be chosen for required purposes. The interactive globe can be zoomed in and out, can be dragged and turned around and reveals the countries that have a saved dataset with red and dark red colors depending on the quality of the samples. Nevertheless, for each chosen country with a dataset, the age, formation and depositional settings can also be chosen. This process leads to creating a pie chart where it covers all the percentages of the pore types which the respective data set of chosen country holds.

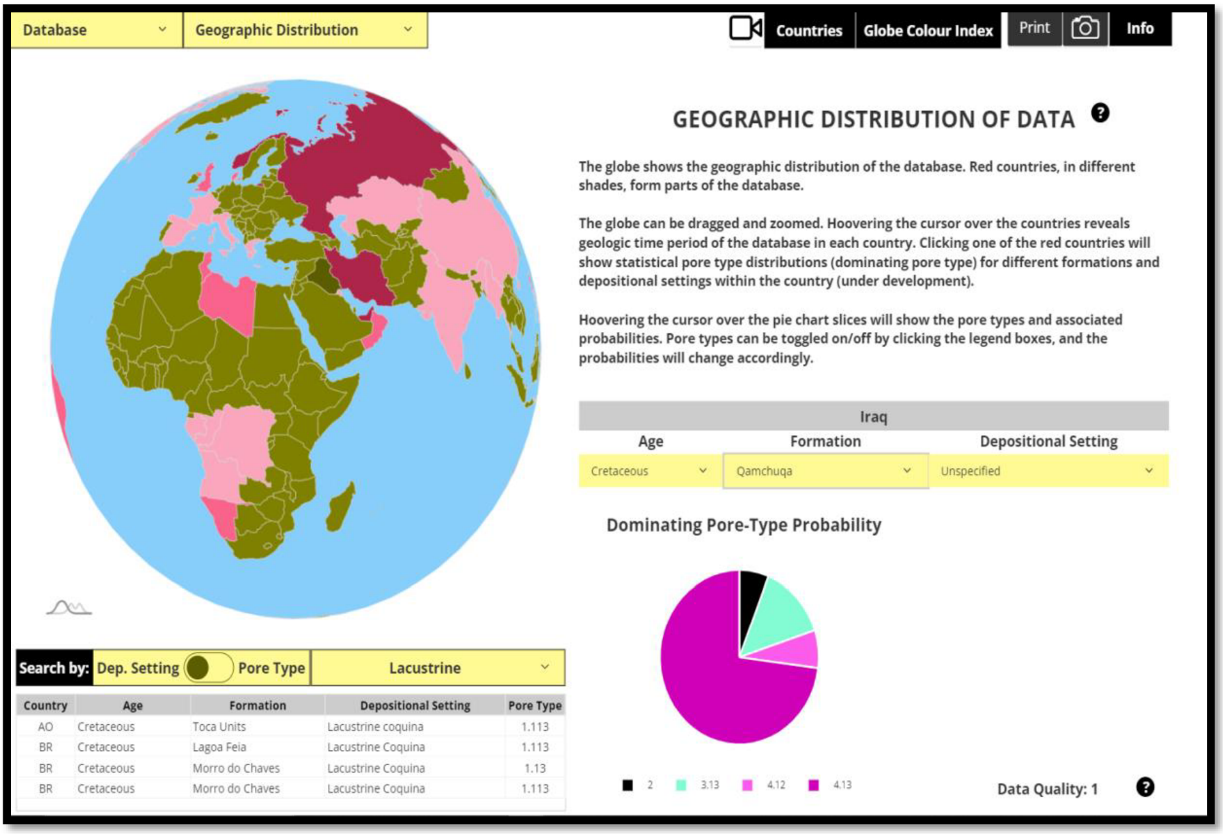

Figure 1 Global dispersion of data collected from different parts of the world (CARP Software).

1.2 Pore types

Pore type is the basic element of CARP. Combined with porosity and few other parameters, pore types can be used for the prediction of several different reservoir parameters. CARP applies the pore classification of Lonoy (2006), with one additional pore type. The classification system is based on empirical optimization of global porosity-permeability relationships, and uses elements from Choquette & pray (1970) and Lucia (1983, 1995, and 1999) pore-type classification systems, but also introduces many new elements. The pore system includes 21 pore-type classes that show a predictable relation between porosity and permeability. The classification system consists of six main pore-type categories, labelled 1-6, four of which are subdivided in up to six subclasses. The pore types and assigned number codes are given in the table below (Figure 2).

Pore structures are the primary determinants of permeability and elastic characteristics. Different rocks of identical depth and porosity could possess various permeabilities and acoustic velocities (Baechle et al., 2008).

All thin-section micrographs included inside the prediction tool are taken under plane-polarized light and porosity is stained blue or green. Pore types are normally defined from thin sections and predicted wire-line logs in non-cored intervals using an artificial neural network (ANN). In limited data sets, they can also be predicted with lower accuracy from porosity-permeability relationships. In exploration, pore types are based on regional experience and sedimentological/diagenetic models. Figures 3, 4, 5, and 6 demonstrate how pore types are viewed inside the geological model and examples of thin sections derived from the dataset of the model.

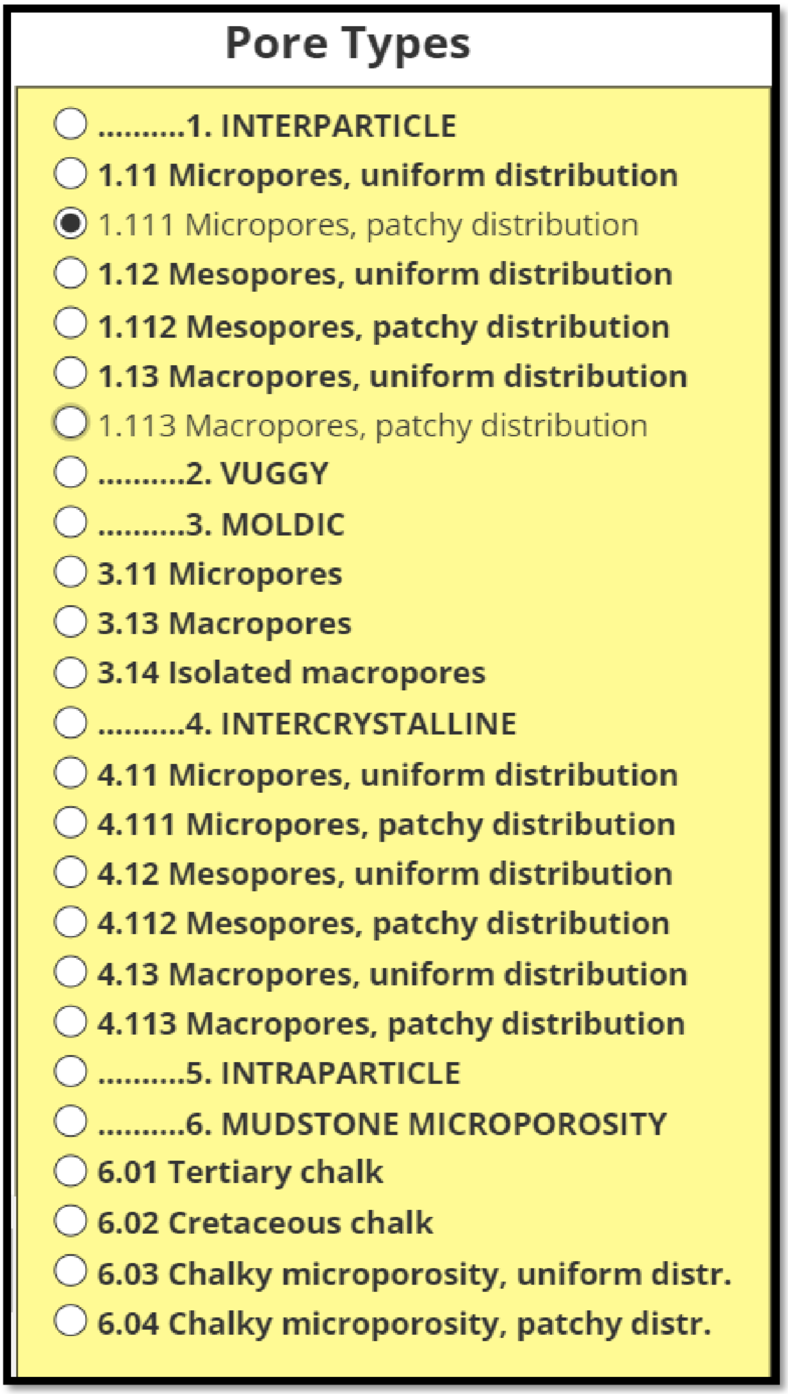

Figure 2 pore type classification of CARP model based on Lonoy. 2006 classification (CARP Software).

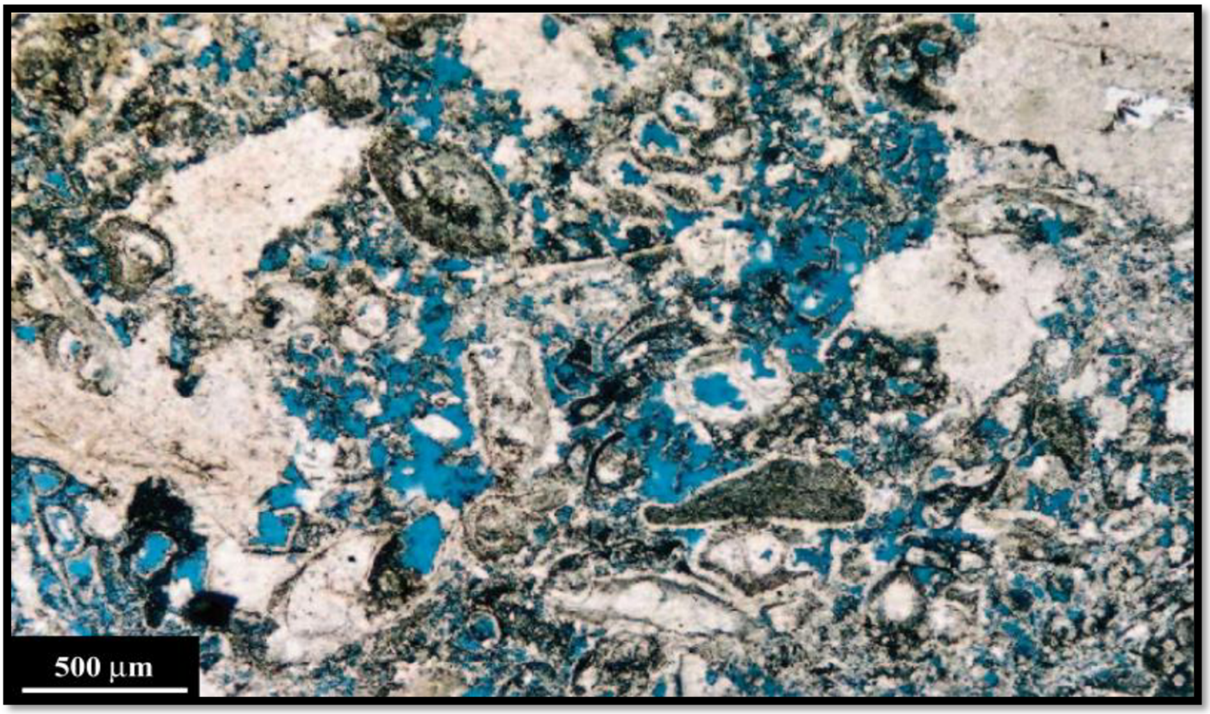

Figure 3 Mesoporosity (50–100 mm pore diameter) with uniform porosity distribution, f = 19.3%, k = 9.47 md (CARP Software).

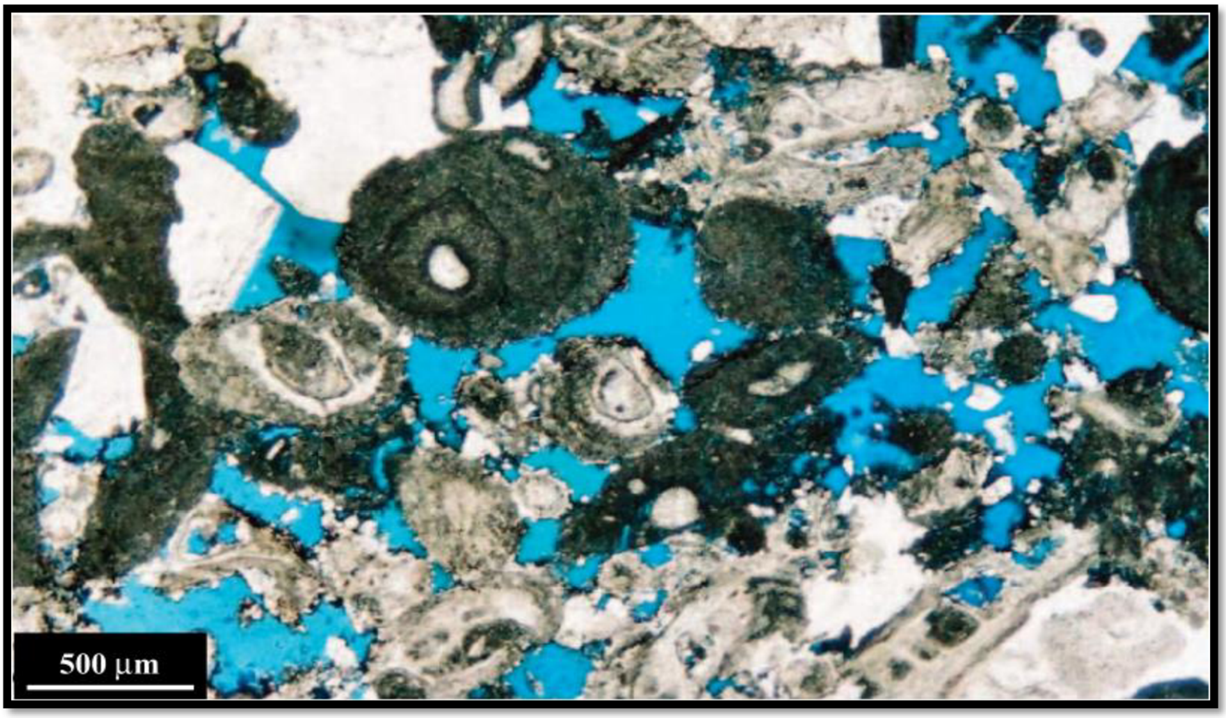

Figure 4 Macroporosity (>100 mm pore diameter) with uniform porosity distribution, f = 15.3%, k = 132 md (CARP Software).

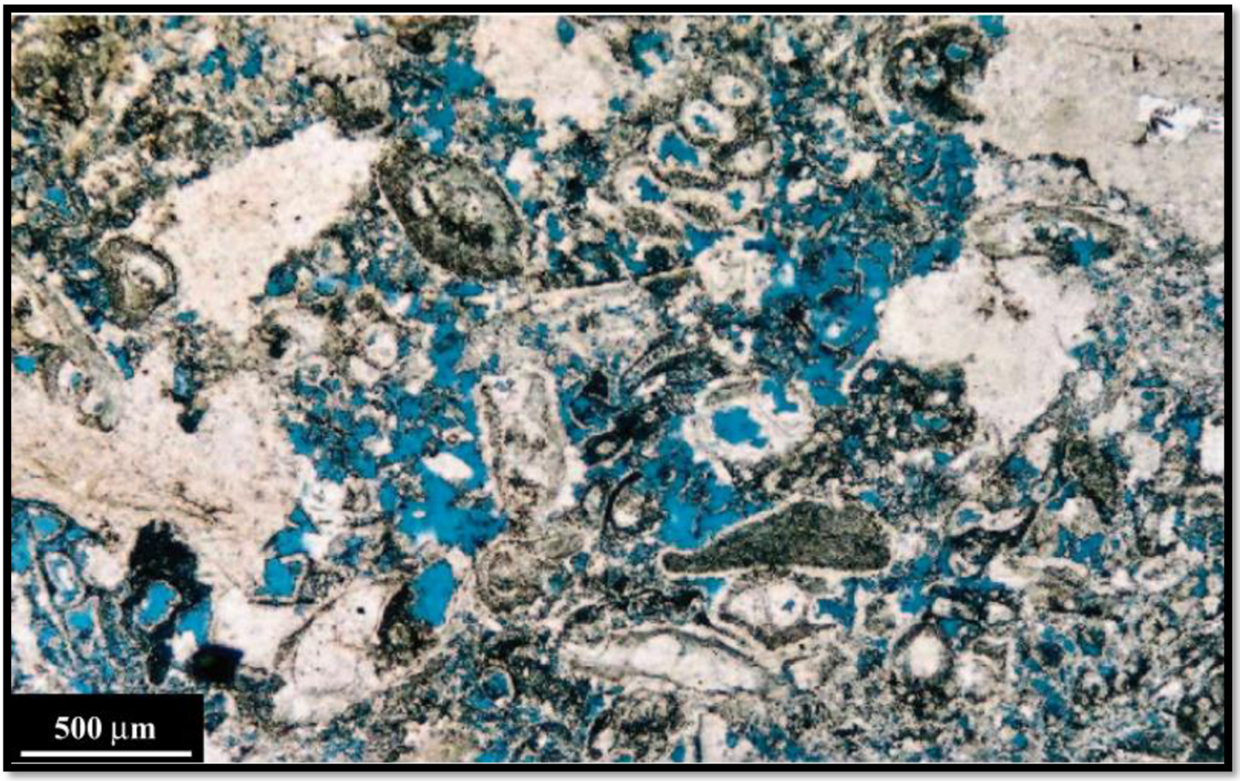

Figure 5 Macroporosity (>100 mm pore diameter) with uniform po rosity distribution and pore-lining calcite cement, f = 9.7%, k = 0.465 md (CARP Software).

1.3 Permeability

Permeability is an important parameter for understanding the flow of water and hydrocarbons in the subsurface (Lucia, 1995). When rock samples are unavailable for direct measurement, permeability is usually predicted from porosity-permeability cross-plots derived from the core plugs (Lonoy, 2006). Such cross-plots show a poor coefficient of determination unless plots are made for individual pore types. Permeability prediction is based on the empirical global relationship between pore types, porosity, and permeability. Expected and P10 to P90 permeabilities are predicted and are based on a revision of Lonoy. (2006). the permeability prediction tool can handle up to two important pore types which include dominant and subordinate. Nevertheless, plug-measured permeabilities in a given reservoir are always applied to test the validity of the global equations. Figures 6 and 7 demonstrate the predicted permeability plots and the options of inserting dominant and subordinate pore types within the CARP tool.

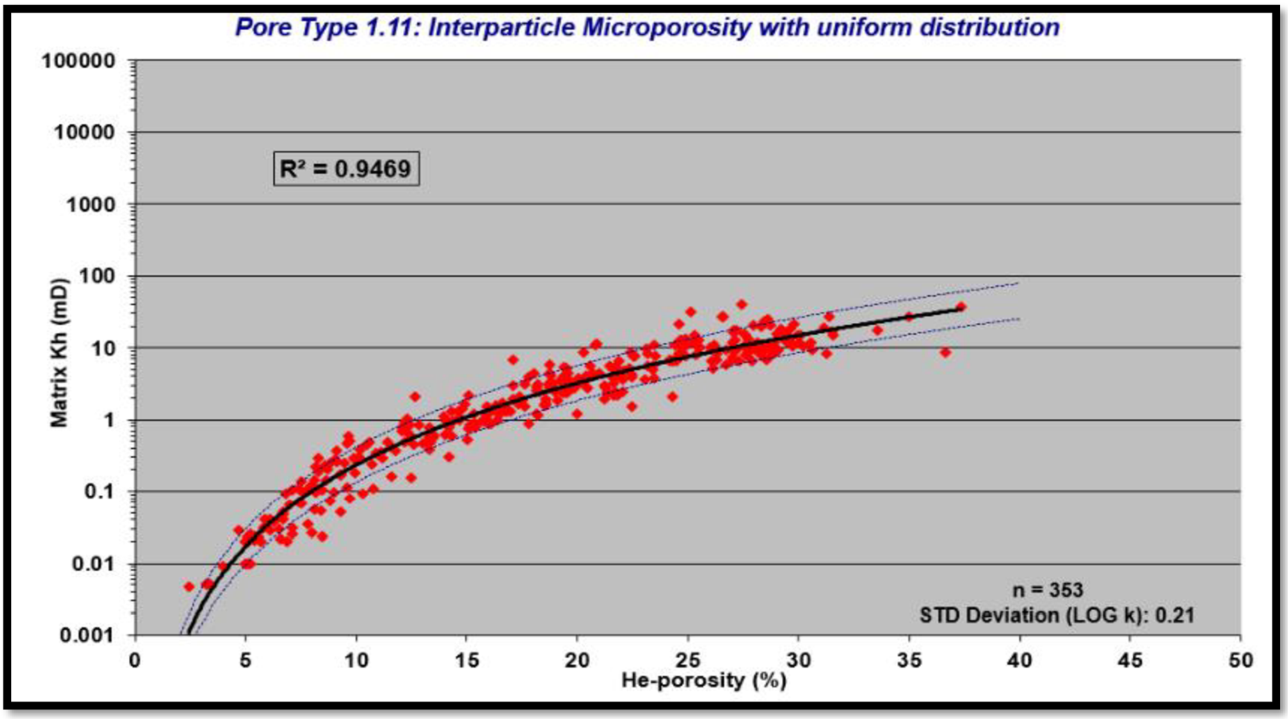

Figure 6 Permeability prediction plot for interparticle microporosity with uniform distribution (CARP Software).

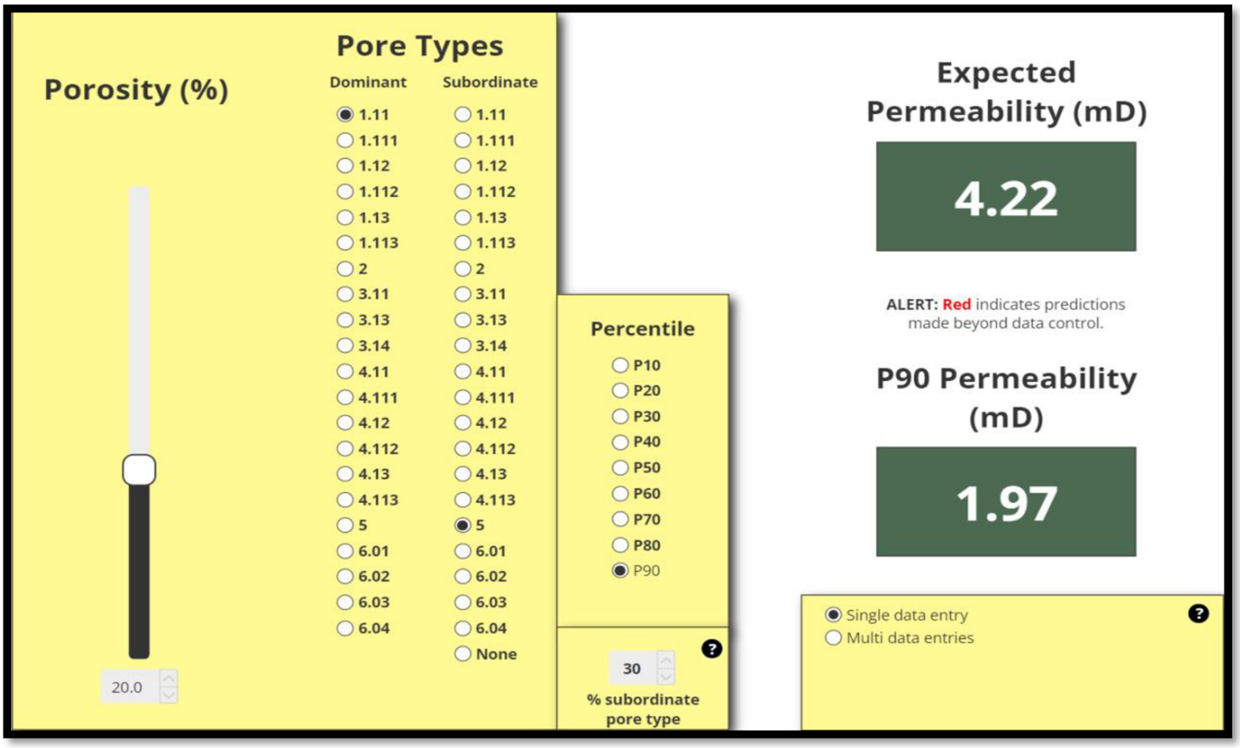

Figure 7 Example of pore type within the CARP software with dominant pore type of 1.11, subordinate pore type of 5 (30% coverage) and P90 percentile (CARP Software).

1.4 Effective porosity

Total porosity is composed of effective and ineffective porosity (PHItotal = PHIeffective + PHIineffective). Ineffective porosity is believed to have insufficient permeability to contribute to the flow. The effective porosity is controlled by pore-throat diameter, where porosity enclosed by pore-throat diameters less than a specific limit is considered ineffective. Essentially, a cut-off on pore throat diameter is applied. Nevertheless, there are several other factors that will have an effect on porosity (e.g. viscosity, oil composition, pressures, wetting, and tortuosity).

Pore-throat diameters and effective porosity are dependent on pore type and porosity and can be determined from mercury-injected capillary pressure (MICP) curves. Based on a large global database, the relation between effective and total porosity for different pore types has been defined. The effective porosity is defined as the total Hg-injected pore volume minus the pore volume constrained by a specific pore throat diameter.

The effective porosity tool in this software can handle up to two important pore types which are dominant and subordinate and predicts the expected and P10 to P90 effective porosities at two different pore-throat cut-offs.

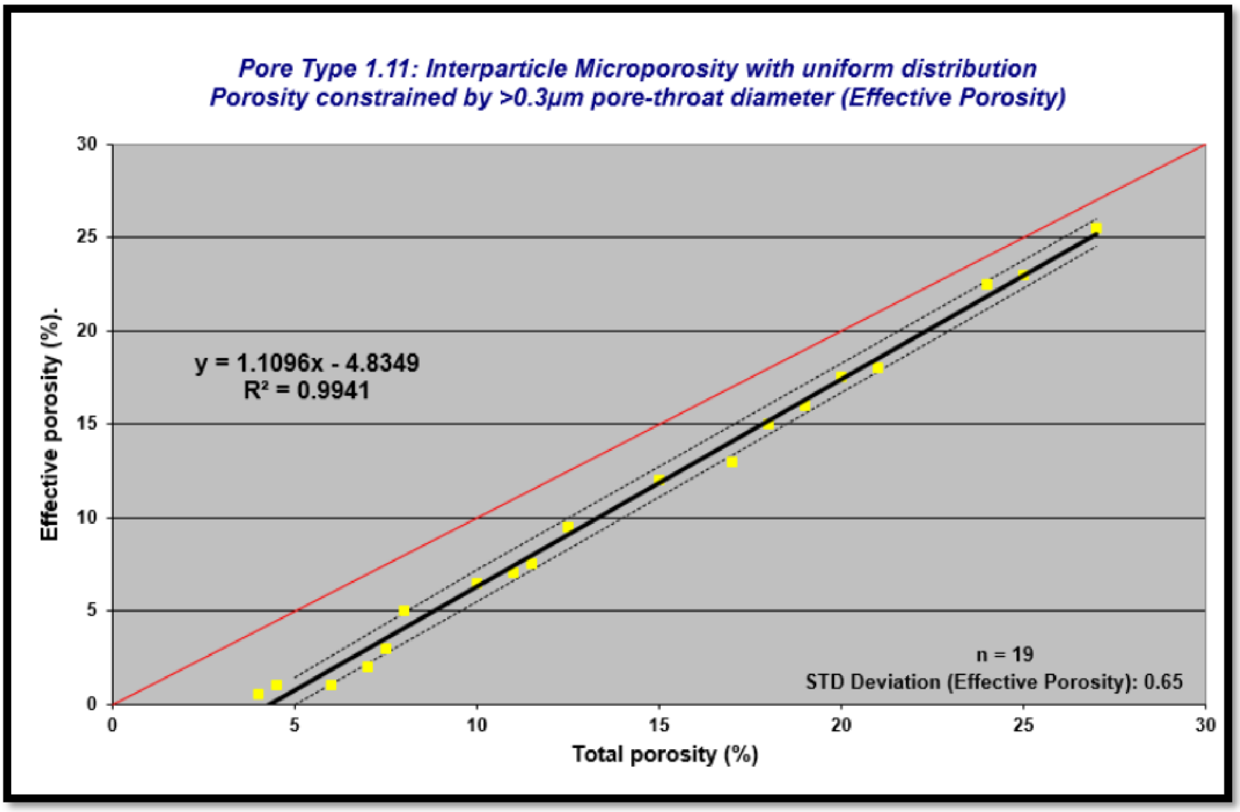

Figure 8 effective porosity plot showing pore type 1.11: interparticle microporosity with uniform distribution (CARP Software).

1.5 Saturation

Saturation is based on MICP-based saturation heights. Several methods can be applied in averaging the measured capillary pressure curves, e.g. Leverett j-function and Thomeer (Clerke et al., 2008). The Lonoy method is based on empirical relations between pore types, porosity, and MICP curves, and applies a large, global, carbonate data set. Best fit equations for MICP curves and irreducible water saturation (Swirr) have been optimized for porosities up to 30%. The advantage of this method is that permeability is not required as input and that the MICP curve can be predicted from porosity and pore type (both dominant and subordinate pore types can be handled. Figure 9 shows the overview of the water saturation prediction tool inside the CARP software.

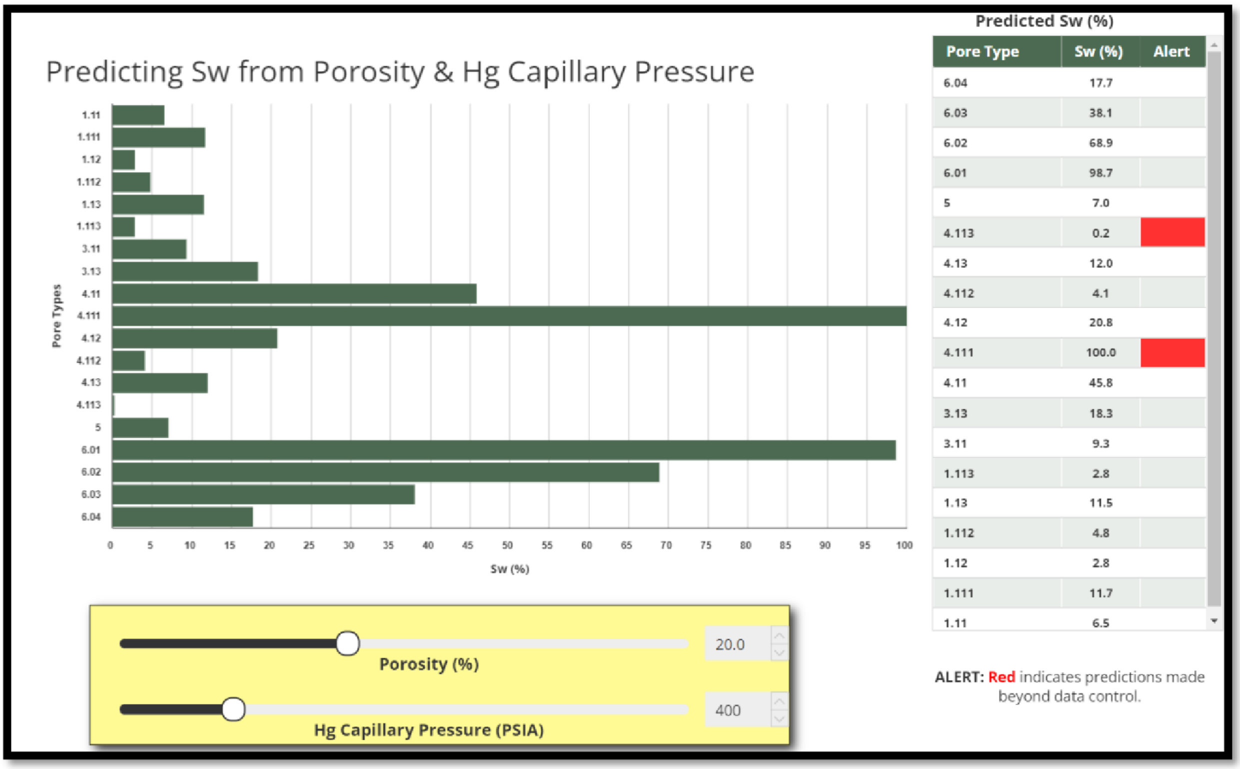

Figure 9 Saturation prediction window within CARP software (CARP Software).

1.6 Capillary entry pressure

Capillary entry pressure is a measure of the Oil-Water contact, Gas-Water contact, and Gas-Oil contact in a reservoir (Longeron et al., 1994). The capillary entry pressure depends on porosity, pore type, and hydrocarbon type, more specifically their contact angle and surface tension (Longeron et al., 1994). Porosity and pore types varies throughout the reservoir, giving variable contacts within the reservoir and in some cases multiple contacts (Longeron et al., 1994).

Several interactive prediction tools for capillary entry pressure are available in CARP. Three tools predict the capillary entry pressure for mercury, oil, and gas at different porosities, pore groups, and pore types. Capillary entry pressures can also be predicted from sedimentary facies based on the empirical or expected pore-type probability within each facies, where pore types are assigned randomly according to the pore-type probability. The required input parameters in order to measure the capillary pressure are porosity, pore types, pore groups, surface tension, and contact angles. Figure 10 shows the overview of the capillary entry pressure window inside CARP software.

Figure 10 Capillary entry pressure prediction window inside CARP tool (CARP Software).

1.7 Relationships between Porosity and Permeability

The relationships between porosity and permeability play a crucial role in predicting permeability based on porosity values and determining porosity cut-offs (Kristensen et al., 2016). Wireline borehole tools typically cannot directly measure permeability, so in uncored wells, permeability is commonly estimated using porosity-permeability relationships derived from cored wells (Kristensen et al., 2016). Porosity cut-offs are commonly applied in exploration and are often defined based on an assumed flow-critical permeability of 1 millidarcy (mD) for oil reservoirs (Kristensen et al., 2016).

In siliciclastic reservoirs, porosity-permeability relationships are usually well-established, and permeabilities and porosity cut-offs are well-defined (Jolley et al., 2007). However, in carbonate reservoirs, such relationships are often underdeveloped due to the complex nature of pore geometries in carbonate rocks (Jolley et al., 2007). To improve the definition of porosity-permeability relationships in carbonate reservoirs, it is necessary to evaluate different pore types (Jolley et al., 2007). The porosity-permeability database in CARP demonstrates how different pore types significantly influence these relationships. Equation-based trend lines for various pore types can be applied in reservoir models to predict permeability (and porosity cut-offs) for each cell in the grid. This is achieved by combining sedimentary facies maps and porosity distributions in the model and assigning pore types based on statistical global or local distributions within different facies. The control of sedimentologic and diagenetic processes on pore types allows for this approach.

Sensitivity testing of the reservoir model can be performed by utilizing CARP's equation-based probability curves, allowing users to define P10 to P90 values in 10% increments. In Figure 7, the P10 and P90 trend lines are represented as dashed lines, while the expected trend line is shown as a solid line. Porosity cut-offs vary significantly for different pore types, and this can have a significant impact on estimating hydrocarbon reserves in a field. Practical examples based on data from various fields (Lønøy, 2006) demonstrate that the original oil in place (STOOIP) can vary by several hundred percent solely based on pore type and associated changes in porosity cut-off. Pore types also influence water saturation, leading to additional variations of several hundred percent in STOOIP.

1.8 Permeability Prediction for Dual Pore-Type Systems

Permeability prediction in dual pore-type systems involves evaluating samples that contain a mixture of multiple pore types (Anselmetti et al., 1999). The two most significant pore types in terms of volume are categorized as dominant and subordinate (Anselmetti et al., 1999). The subordinate pore type should only be defined if it accounts for at least 25% of the total pore volume, while the dominant pore type typically constitutes more than 50% of the pore volume (Ehrenberg et al., 2006). Empirical data indicate that the dominant and subordinate pore types provide the most crucial reservoir quality information, and additional pore types are often unnecessary (Ehrenberg et al., 2006). Volumetric assessments of pore types are performed through visual estimation (Ehrenberg et al., 2006).

When the dominant and subordinate pore types have nearly identical pore volumes, the more permeable pore type should be designated as the dominant, while the less permeable one should be designated as the subordinate (Lønøy, 2006). However, the pore-volume percentages should only serve as a guideline because pore connectivity is what truly matters (Lønøy, 2006). An experienced geological evaluation of the sample is necessary to determine this connectivity (Lønøy, 2006). Occasionally, a pore type may be classified as dominant even if it is not the most volumetrically significant (Lønøy, 2006). This can occur when a higher-quality (more permeable) pore type forms a continuous network throughout the sample, despite not being the dominant pore type in terms of volume. Fractured plugs provide an extreme example of this scenario, where fractures may not be volumetrically important but can control permeability (Ehrenberg et al., 2006).

In general, most samples typically require only the definition of a dominant pore type, while the need to define a subordinate pore type arises less frequently. Implementing both a dominant and a subordinate pore type in reservoir models can be challenging. In cases where the dominant and subordinate pore types have similar flow properties, the choice between using the dominant or subordinate pore type in the model may not significantly affect the results. CARP offers a tool that can predict the expected permeability and percentile permeability of dual pore-type systems.

Figure 11 Permeability Prediction for Dual Pore-Type Systems in CARP software (CARP Software).

1.9 Permeability prediction from sedimentary facies

CARP enables the prediction of permeability based on sedimentary facies using global poro-perm trendline curves for individual pore types. By utilizing this tool, dominant pore types and their corresponding permeabilities can be predicted from sedimentary facies and porosity. The predictions can be performed on pre-defined facies and associated pore-type probabilities, as well as on user-defined facies and their associated pore-type probabilities.

Pre-defined facies and pore-type probabilities are derived from a comprehensive global database that establishes the empirical relationship between sedimentary facies, pore-type probabilities, porosity, and permeability. On the other hand, user-defined sedimentary facies control on pore-type distribution is based on local expertise and can be inputted into the prediction tool.

The tool predicts dominant pore types for sedimentary facies by considering their respective global and/or local pore-type probabilities. For instance, if a sedimentary facies has dominant pore-type probabilities of 20% (pore type 1.11), 30% (pore type 1.12), and 50% (pore type 1.13), the tool will randomly assign one of these pore types according to their probabilities. Both expected permeabilities and probability ranges (from P10 to P90 in 10% increments) are predicted for each pore type.

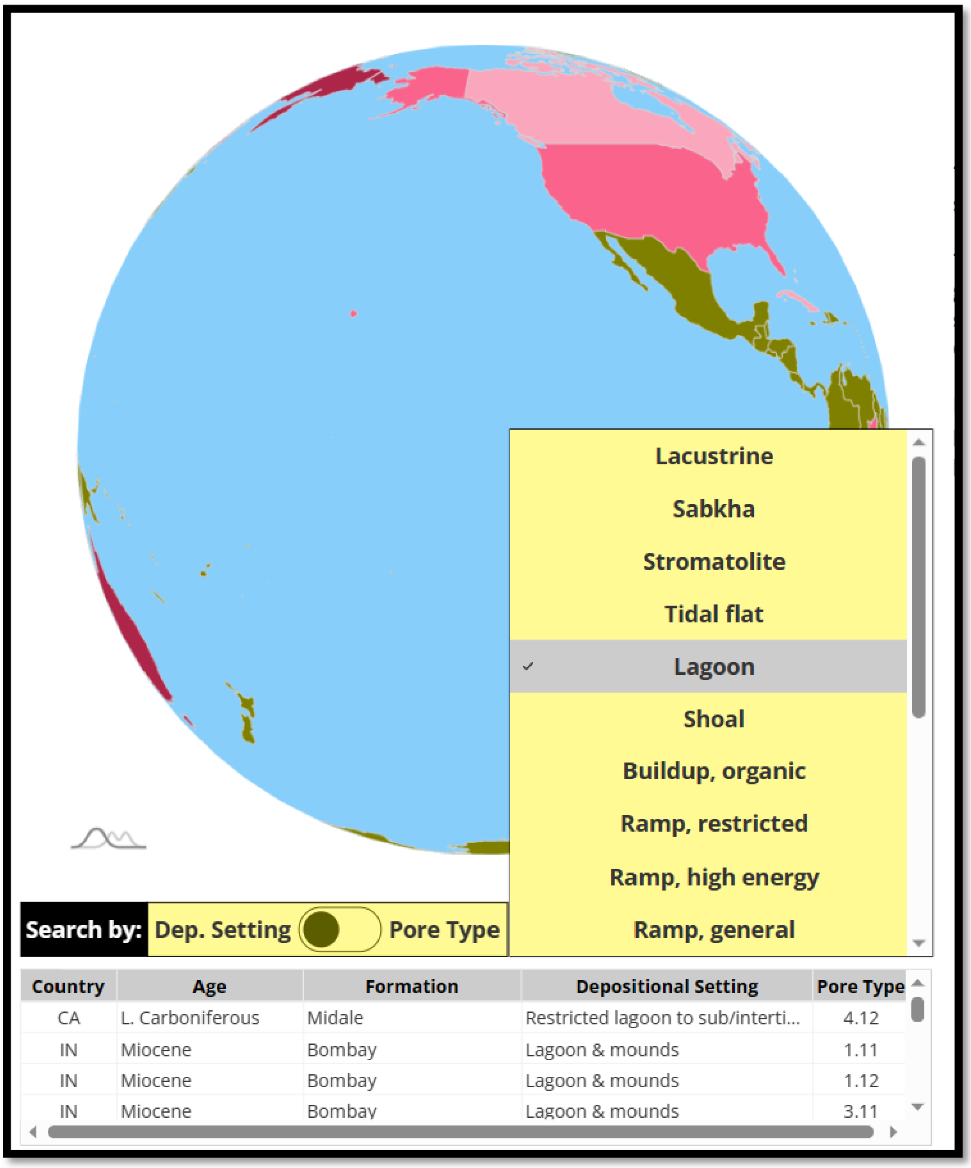

Figure 12 Permeability prediction from sedimentary facies in the CARP software (CARP Software).

Chapter 2: Methodology

In this thesis, by using the integration of different methods, various applications of CARP software have been tried in the oil industry.

At first, a general study was done about Carp software, and information about the most important features of this software was prepared. The main source of information and study about this software was the videos that the creator of this software has placed in the software for learning and use by its users. Also, in order to understand more about these videos, a general discussion has been held with the main developer of Arvi Lønøy software.

In this study, carbonate samples from Khurmala Formation (Late Paleocene-Early Eocene) were used. Four samples from different layers of this Formation were selected to perform porosity and permeability tests. In order to calculate the porosity and permeability of the rocks in question, real samples should be prepared from reservoir rocks in appropriate dimensions (Hartikainen, 1996). Then the samples with a certain total volume (diameter and height) are placed inside the machine. In the next step, helium gas is used to saturate the accessible pores of the sample, and the volume of the grains and the volume of the pores are calculated directly in a chamber using Boyle's law for the expansion of helium gas at the same temperature (Hartikainen, 1996). It should be noted that this method is only able to calculate the effective porosity of the rock due to gas penetration into accessible pores (Hartikainen, 1996). The device includes a pressure control panel and a cylinder with a predetermined volume. Gas supply with the desired pressure is done by an external helium gas capsule. Usually, gases are used instead of liquids to measure the absolute permeability of core samples (Hartikainen, 1996). Dry gases such as nitrogen, helium, or air are used as fluids in measuring the absolute permeability of core samples. The use of gases is practical and suitable because gas, in addition to being clean and ineffective, does not change the empty spaces of the network (Hartikainen, 1996). In other words, absolute permeability measurement is not affected by rock-fluid interactions. In the following, thin sections have been prepared from the existing samples also, in order to determine pores types and their properties, epoxy resin was injected into the samples (Dullien, 2012).

A preliminary study and photography of microscopic thin sections were done. In the next step, the thin sections have been sent to Geoconsult Company in Norway for detailed analysis. And detailed studies have been done on them and the results of these processes are presented in detail in the next chapter.

Chapter 3: Results

In this chapter, the results obtained from two separate methods that have been used to measure the porosity and permeability of the Khurmala Formation samples are presented. The results of the porosity and permeability measurements that were carried out in the laboratory on the plug samples show that in sample number 1, the porosity is 17.80% and the permeability in this sample is 0.54 mD. On the other hand, the microscopic studies that have been done using CARP software have measured the porosity of this sample to be 1.1%. By using Lønøy classification in CARP software, visible pores in this thin section are mainly type 3.3 (small isolated molds; possibly after dissolution). But it is most likely that most of the pores of this sample are of type 6.03 (Chalky microporosity, uniform distribution), considering that there is an excellent fit between the porosity and permeability data of this sample with type 6.3.

Table 2 the results of porosity and permeability calculated in the laboratory for 3 samples of the Khurmala Formation

Core ID	**Porosity (%)**	**Permeability (mD)**
Sample 1	17.80342	0.54
Sample 2	21.57039	0.94
Sample 3	13.25671	0.52

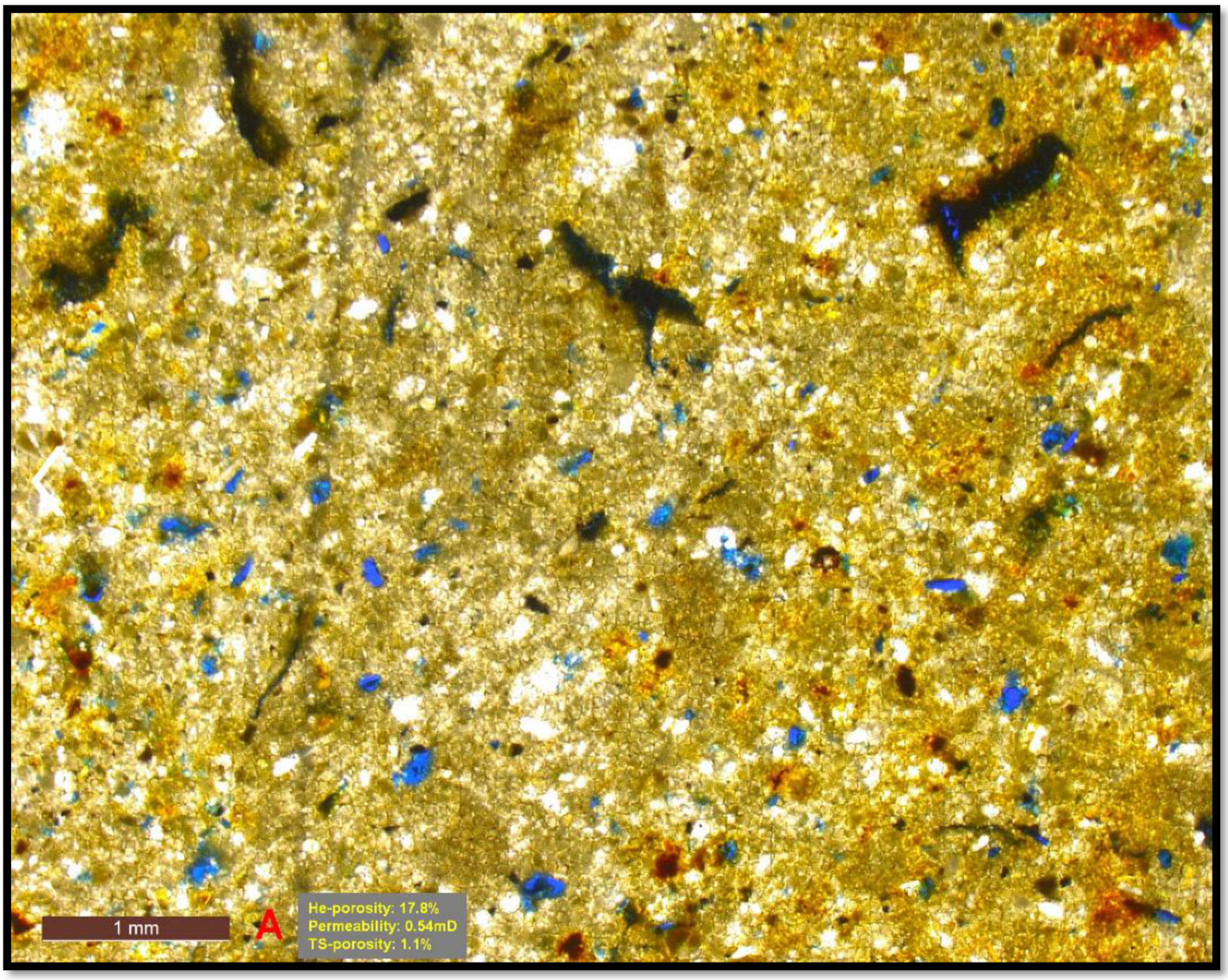

Figure 13 Sample No. 1 prepared from Khurmala Formation.

In sample number 2, the porosity and permeability data calculated in the laboratory are 21.6% and 0.94 mD, respectively. But the porosity calculated through the thin section and Carp software is 2.3%. According to Lønøy classification dominant observable pore type 3.13 (small isolated molds; possibly after dissolution). The probable dominant pore type is 6.03 (Chalky microporosity, uniform distribution). If 21.6% measured porosity is correct, there must be 19% microporosity (pore type 6.03 or 6.04) below visual resolution. Based on the texture, this may be the case. The poro-perm for the sample has an excellent fit to pore type 6.03. Pore type 6.03 is thus believed to be dominant.

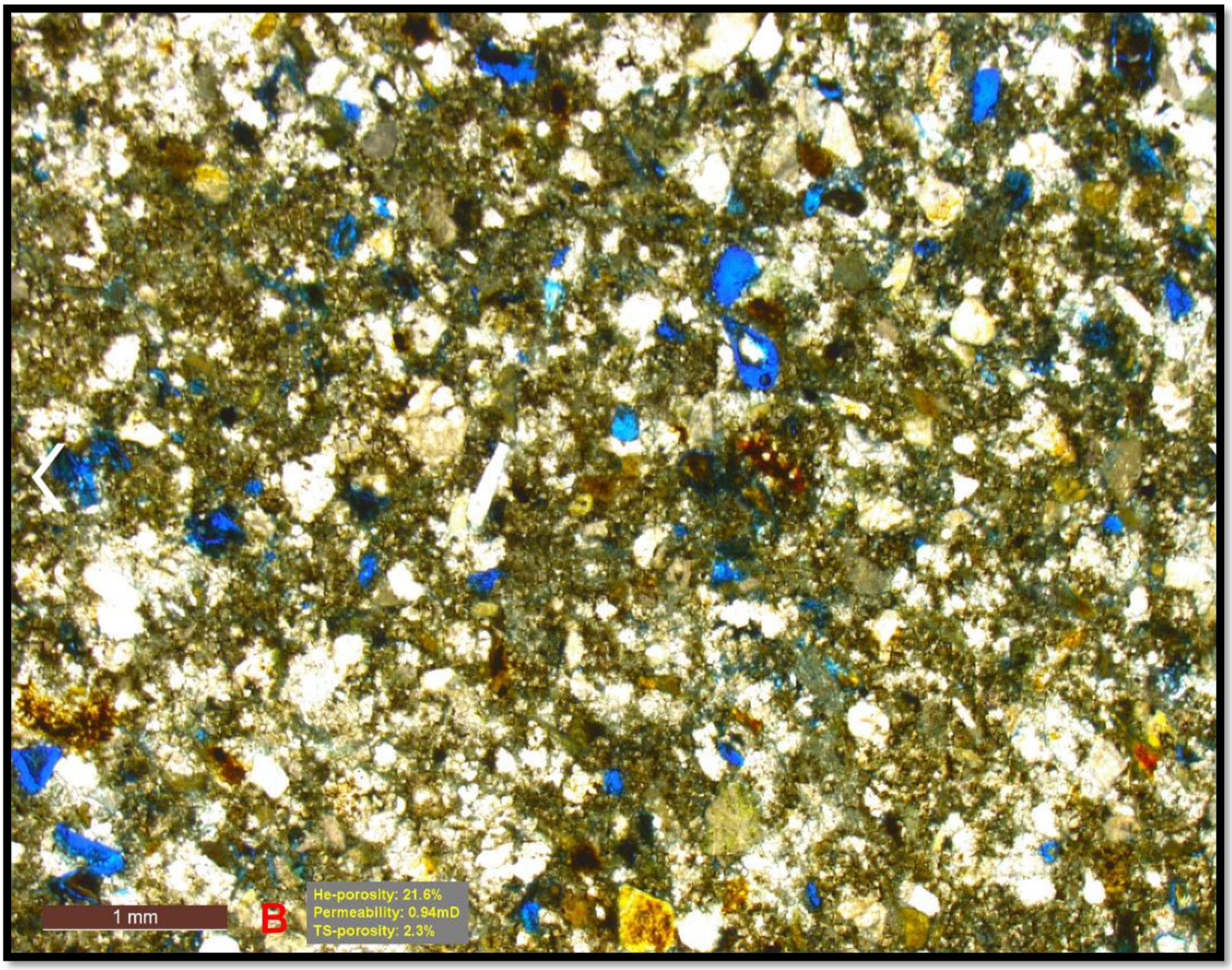

Figure 14 Sample No. 2 prepared from Khurmala Formation

The porosity and permeability calculated for sample number 3 from Khurmala Formation in the laboratory were 13.3% and 0.52 mD, respectively. Moreover, microscopic studies carried out through the Carp software show that the primary type of pore observed is 3.13, which consists of small isolated molds. However, the most likely dominant pore type is 6.03, as indicated below. Image analysis of the thin section reveals a porosity of 0.4%. If the measured porosity of 13.3% is accurate, it suggests the presence of 13% microporosity (pore type 6.03 or 6.04) that cannot be visually resolved. The texture supports this possibility. The porosity-permeability relationship for the sample strongly aligns with pore type 6.03 and reasonably aligns with pore type 6.04. Therefore, it is believed that pore type 6.03 is the prevailing pore type.

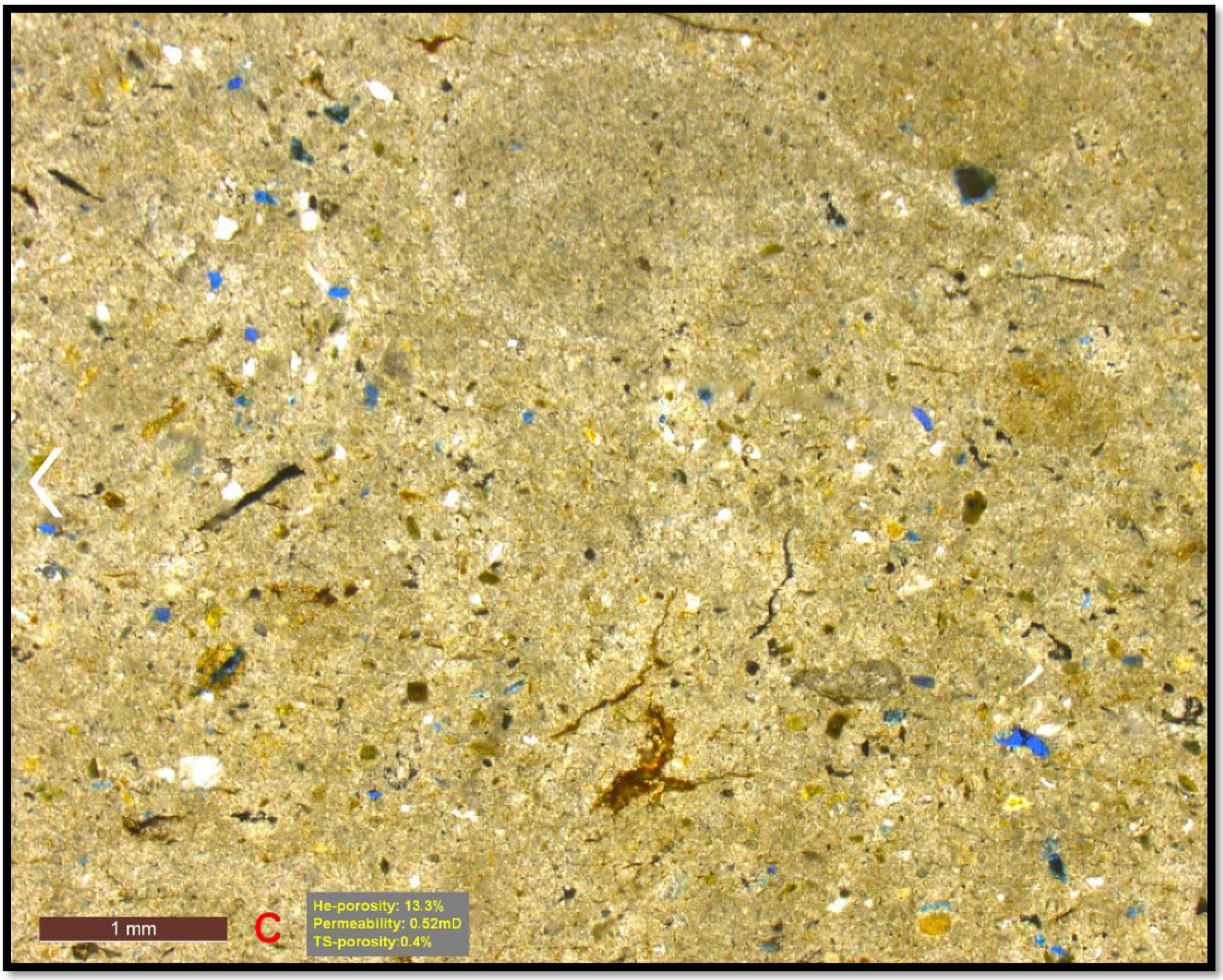

Figure 15 Sample No. 3 prepared from Khurmala Formation

Within the CARP software, each of the introduced porosity types is thoughtfully accompanied by an illustrative example in the form of a corresponding thin section image. As part of this visual representation, Figures 17 and 18 vividly showcase the images of Porosity type 3.13, depicting small isolated molds, and Porosity type 6.03, displaying Chalky microporosity with a uniform distribution. These carefully selected thin section images offer valuable insights into the distinct characteristics of each porosity type, aiding researchers and industry professionals in understanding the visual cues associated with specific porosity features. By integrating such visual elements, the CARP software facilitates a more immersive and comprehensive exploration of the diverse porosity variations found in the geological samples from the Khurmala Formation. The utilization of these illustrative examples further enhances the user's ability to identify and differentiate between various porosity types, contributing to more accurate reservoir analysis and decision-making in the oil industry.

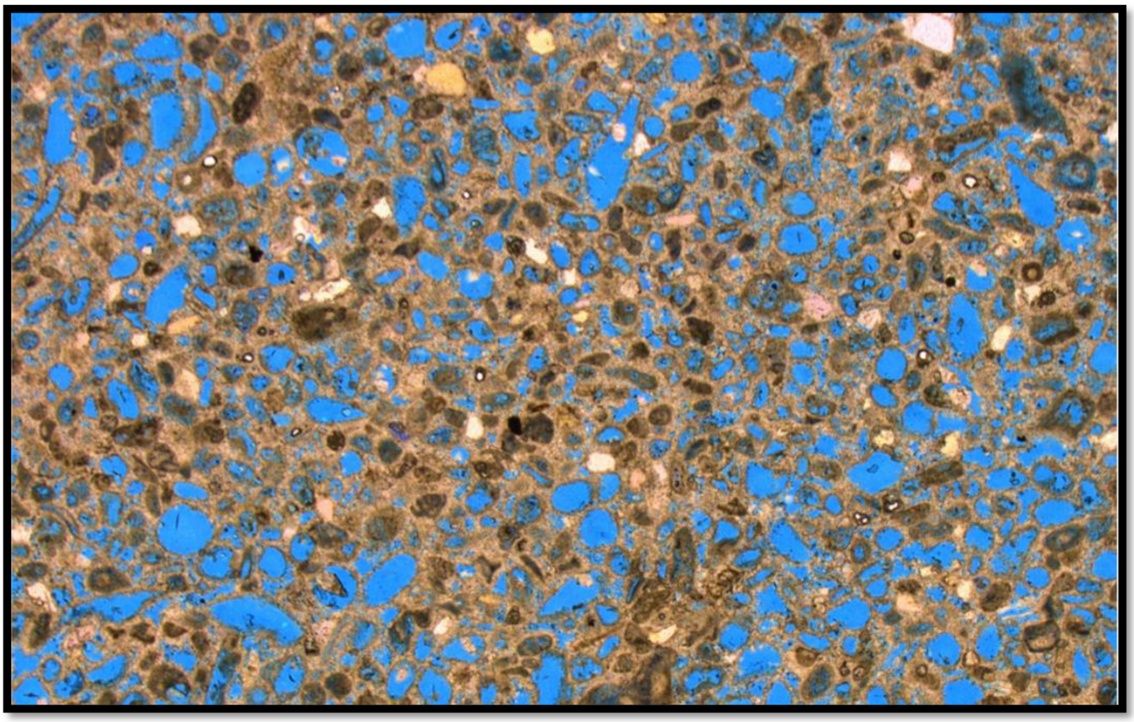

Figure 16 Porosity type 3.13 (small isolated molds) introduced in CARP software (CARP Software).

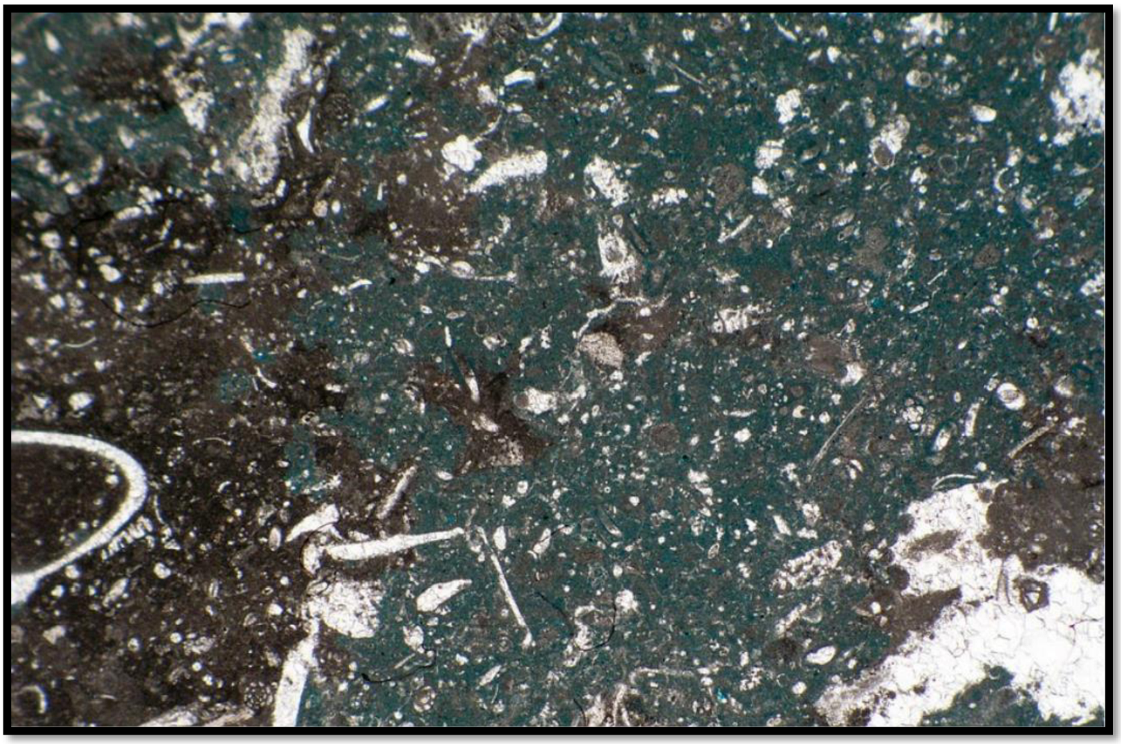

Figure 17 Porosity type 6.03 (Chalky microporosity, uniform distribution) introduced in CARP software (CARP Software).

Chapter 4: Discussion

Fascinating and insightful findings have emerged through the examination and comparison of data obtained from both laboratory testing and microscopic studies using CARP software. These results have revealed a notable disparity between the two datasets, prompting further investigation into the reasons behind these variations. Two primary factors that might contribute to the discrepancies are: a) the heterogeneous nature of core plugs, and b) the thin section staining technique.

In the case of heterogeneous core samples, the observations made from thin sections may not accurately represent the entirety of the plug. This can lead to potential misinterpretations, especially when standard porosity staining techniques fail to capture microporosity, rendering it invisible in the thin sections. Consequently, the dominant pore type (PT) may be inaccurately identified based on observable porosity, resulting in poro-perm data that deviates from the global trendline due to the incorrect definition of PT. Nevertheless, an alternative staining technique capable of capturing microporosity exists, which can offer a more accurate representation of the core plug's porosity.

When a significant difference is observed between the measured porosity and the porosity observed in thin sections, it serves as an indication that the thin section observation might not be representative of the core plug. Seasoned geologists can intuitively recognize such discrepancies, but quantifying the porosity difference can be achieved through image analysis. This analytical approach further enhances the ability to identify potential discrepancies and ensures a more robust interpretation of the core plug's porosity and permeability characteristics.

By acknowledging and understanding the implications of these factors, researchers can enhance the reliability of their analyses and interpretations, leading to more accurate reservoir characterization and informed decision-making in the oil industry. The integration of alternative staining techniques and image analysis alongside traditional observations from thin sections contributes to a more comprehensive and reliable assessment of the core plug's poro-perm properties, offering valuable insights for oil industry applications.

CARP includes a section that covers various techniques used for reservoir description and characterization. One technique discussed here is the staining of micro-porosity.

Standard staining techniques used for thin sections often fail to stain micro-porosity due to its low permeability. Consequently, this porosity remains invisible, potentially leading to an incorrect definition of the dominant pore type and deviations in the porosity-permeability relationship compared to the overall trendline curves. To address this issue, an alternative technique is presented in CARP that enables the staining of microporosity, making it visible. The provided thin-section micrograph illustrates a sample that has been stained using this alternative technique. Chalky microporosity is depicted as faint blue-stained areas. Since the pore sizes are smaller than the thin section's thickness, individual pores are challenging to discern. Nevertheless, the staining clearly reveals the presence and distribution of micro-porosity.

If traditional staining techniques were employed, the micro-porosity in the sample would likely remain invisible because the low permeability hinders epoxy from penetrating deep into the pores. Consequently, the visible porosity would be significantly lower than the measured porosity. Therefore, a substantial disparity between the measured and observed porosity could suggest the abundance of micro-porosity.

To illustrate the concepts discussed, we will examine samples from the Paleocene-Eocene Khurmala Formation in Northern Iraq. Three supplied thin section micrographs (Figures 13-15) display a silty limestone with small moldic pores (blue, PT 3.13). However, a slight deviation from the global trendline for PT 3.13 is observed in the measured poro-perm data (shown in Figure 18, with red data points representing Khurmala samples). Strikingly, the thin section-derived porosities (provided in Figures 13-15; obtained through image analysis) exhibit notably lower values than the measured porosities (Table 2), suggesting that the thin section observations might be unrepresentative. This discrepancy may be linked to unstained microporosity, leading us to consider the possibility of chalky microporosity (PT 6.03) as the dominant pore type. Remarkably, the poro-perm data align almost perfectly with PT 6.03 (as seen in Figure 19), indicating that this pore type is indeed dominant rather than the observed PT 3.13.

In light of these findings, it is strongly recommended to consistently compare measured porosity with visual thin section porosity. Significant differences between the two may indicate that the visual porosity in the thin section is not representative, potentially leading to the misidentification of the dominant pore type. Therefore, meticulous examination of the thin section observations and comparison with measured data play a crucial role in ensuring the accuracy and reliability of poro-perm analyses.

By adopting this approach, researchers can avoid potential misinterpretations and make informed decisions when characterizing reservoirs in the oil industry. Additionally, the exploration of unstained microporosity and its impact on porosity measurements underscores the importance of employing comprehensive methodologies to capture the full range of pore types present in geological samples, ultimately enhancing our understanding of reservoir properties and their implications for oil exploration and production.

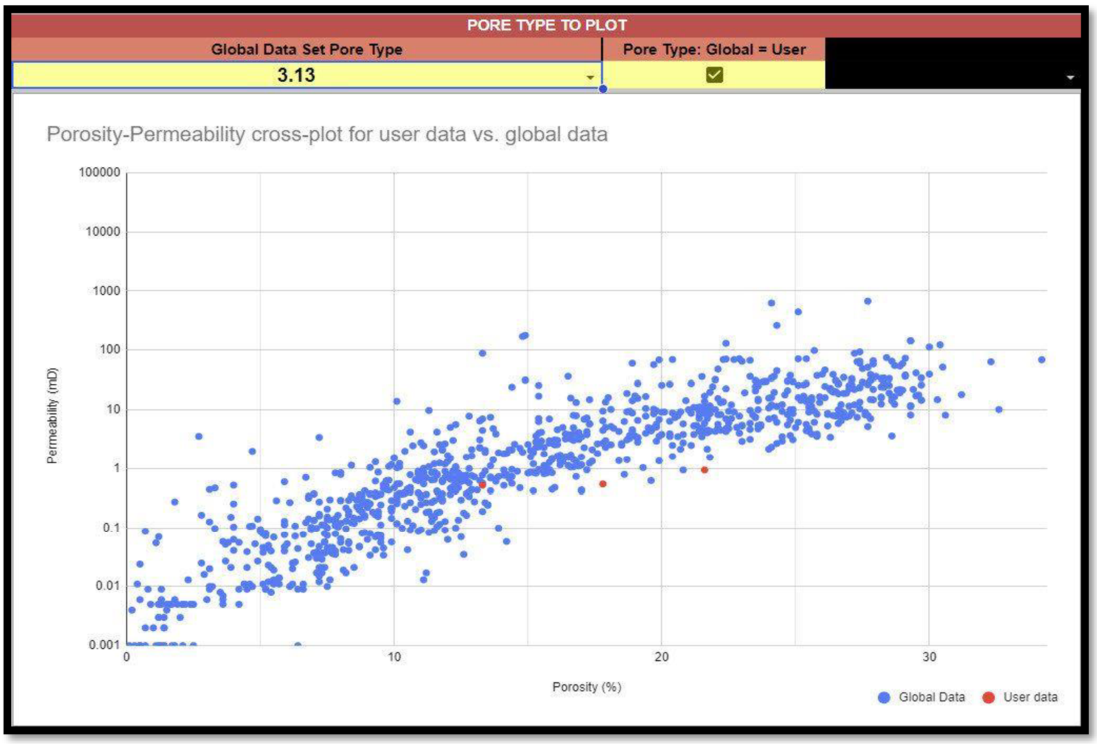

Figure 18 Porosity and permeability cross plot for user data and global data for porosity type 3.13. (CARP Software).

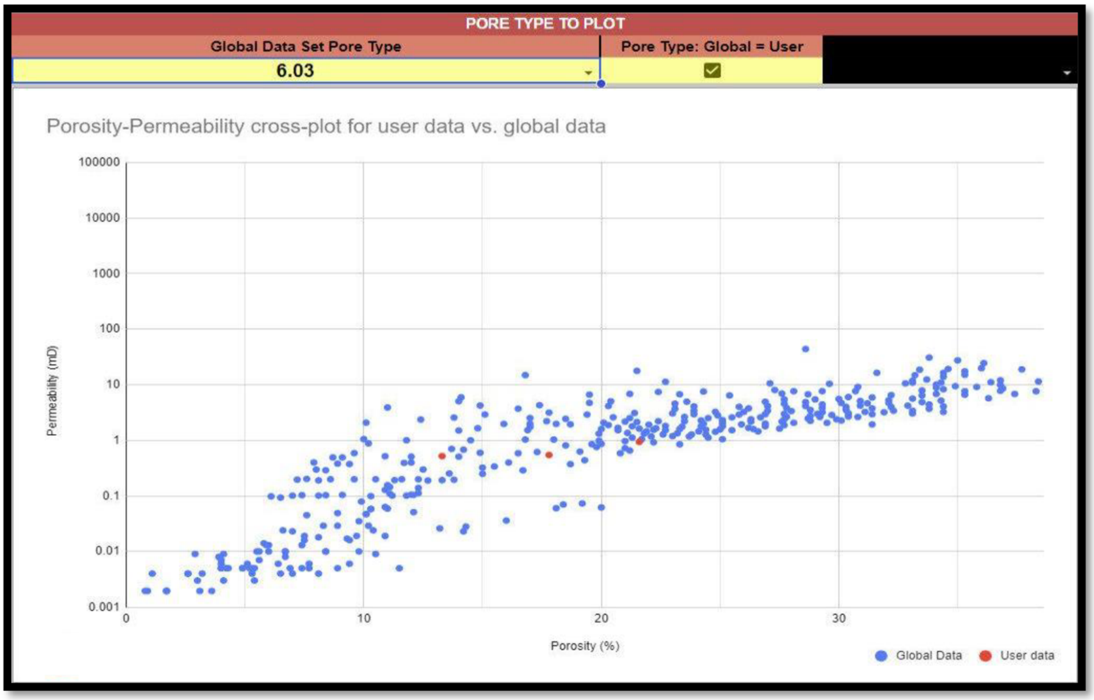

Figure 19 Porosity and permeability cross plot for user data and global data for porosity type 6.03. (CARP Software).

Chapter 5: Conclusion

This research offers a comprehensive exploration of the applications of CARP software in the oil industry, highlighting its potential benefits, as well as addressing certain limitations that must be considered. The study reveals that leveraging this tool can yield valuable insights, particularly in the preliminary prediction of porosity and permeability. The software's key strength lies in its vast and credible database, enabling it to deliver reliable estimations across various domains. Notably, CARP software serves as a crucial resource when access to well-equipped laboratories is restricted or unavailable, offering a cost-effective and rapid alternative.

However, some challenges associated with the software warrant attention. Foremost among these is the requirement for users to possess significant expertise in geology, particularly in identifying distinct porosity types accurately. Proficiency in this field is essential to ensure precise identification and avoid any errors that may compromise the trustworthiness of the generated data. Additionally, potential issues with coloring techniques and thin section quality could pose constraints on the software's smooth operation.

When examining the findings obtained from studying three samples extracted from the Khurmala Formation during this research, it becomes evident that complementing CARP software with laboratory data enhances the comprehensiveness and accuracy of the results. By employing a combined approach that harnesses the capabilities of both the software and standard laboratory techniques, researchers can achieve more robust and refined outcomes.

In summary, this study underscores the value of CARP software for early estimates of porosity and permeability, particularly in scenarios where access to fully equipped laboratories is limited. Nevertheless, it is imperative to consider the user's expertise and be aware of the potential limitations of the software to ensure the reliability and precision of the findings. Furthermore, the research emphasizes the importance of integrating laboratory data with software-based analyses to yield more comprehensive and precise results, ultimately advancing our understanding of reservoir properties and informing decision-making in the oil industry.

References:

Akbar, M., Vissapragada, B., Alghamdi, A.H., Allen, D., Herron, M., Carnegie, A., Dutta, D., Olesen, J.R., Chourasiya, R.D., Logan, D. and Stief, D., 2000. A snapshot of carbonate reservoir evaluation. Oilfield review, 12, 20-21.

Anselmetti, F.S. and Eberli, G.P., 1999. The velocity-deviation log: a tool to predict pore type and permeability trends in carbonate drill holes from sonic and porosity or density logs. AAPG bulletin, 83(3), pp.450-466.

Baechle, G.T., Colpaert, A., Eberli, G.P. and Weger, R.J., 2008. Effects of microporosity on sonic velocity in carbonate rocks. The leading edge, 27(8), pp.1012-1018.

Choquette, P.W. and Pray, L.C., 1970. Geologic nomenclature and classification of porosity in sedimentary carbonates. AAPG bulletin, 54(2), pp.207-250.

Clerke, E.A., Mueller III, H.W., Phillips, E.C., Eyvazzadeh, R.Y., Jones, D.H., Ramamoorthy, R. and Srivastava, A., 2008. Application of Thomeer Hyperbolas to decode the pore systems, facies and reservoir properties of the Upper Jurassic Arab D Limestone, Ghawar field, Saudi Arabia: A “Rosetta Stone” approach. GeoArabia, 13(4), pp.113-160.

Dullien, F.A., 2012. Porous media: fluid transport and pore structure. Academic press.

Ehrenberg, S.N., Eberli, G.P. and Baechle, G., 2006. Porosity–permeability relationships in Miocene carbonate platforms and slopes seaward of the Great Barrier Reef, Australia (ODP Leg 194, Marion Plateau). Sedimentology, 53(6), pp.1289-1318.

Garland, J., Neilson, J., Laubach, S.E. and Whidden, K.J., 2012. Advances in carbonate exploration and reservoir analysis. Geological Society, London, Special Publications, 370(1), pp.1-15.

Hartikainen, J., Hartikainen, K., Kuoppamäki, K., Timonen, J. and Hautojaervi, A., 1996. Helium gas method for rock characteristics and matrix diffusion (No. POSIVA--96-22). Posiva Oy.

Janjuhah, H.T., Sanjuan, J. and Salah, M.K., 2019. An Overview of the Porosity Classification in Carbonate Reservoirs and Their Challenges: An Example of Macro-Microporosity Classification from Offshore Miocene Carbonate in Central Luconia, Malaysia. International Journal of Geological and Environmental Engineering, 13(5), pp.302-310.

Jardine, D. and Wilshart, J.W., 1982, March. Carbonate reservoir description. In International Petroleum Exhibition and Technical Symposium. OnePetro. Bejing, China, 18– 26 March.

Jolley, S.J., Barr, D., Walsh, J.J. and Knipe, R.J., 2007. Structurally complex reservoirs: an introduction. Geological Society, London, Special Publications, 292(1), pp.1-24.

Kargarpour, M.A., 2020. Carbonate reservoir characterization: an integrated approach. Journal of Petroleum Exploration and Production Technology, 10, 2655-2667.

Kristensen, L., Hjuler, M.L., Frykman, P., Olivarius, M., Weibel, R., Nielsen, L.H. and Mathiesen, A., 2016. Pre-drilling assessments of average porosity and permeability in the geothermal reservoirs of the Danish area. Geothermal Energy, 4(1), pp.1-27.

Longeron, D.G., Kalaydjian, F. and Bardon, C., 1994, September. Gas/oil capillary pressure: measurements at reservoir conditions and effect on gas-gravity drainage. In SPE Annual Technical Conference and Exhibition? (pp. SPE-28612). SPE

Lønøy, A., 2006. Making sense of carbonate pore systems. AAPG bulletin, 90(9), pp.1381-1405.

Lucia, F. J., 1999, Carbonate reservoir characterization: Berlin, Springer-Verlag, 226 p.

Lucia, F.J., 1983. Petrophysical parameters estimated from visual descriptions of carbonate rocks: a field classification of carbonate pore space. Journal of petroleum technology, 35(03), pp.629-637.

Lucia, F.J., 1995. Rock-fabric/petrophysical classification of carbonate pore space for reservoir characterization. AAPG bulletin, 79(9), pp.1275-1300.

Magoon, L.B. and Dow, W.G., 1994. The petroleum system: chapter 1: Part I. Introduction.