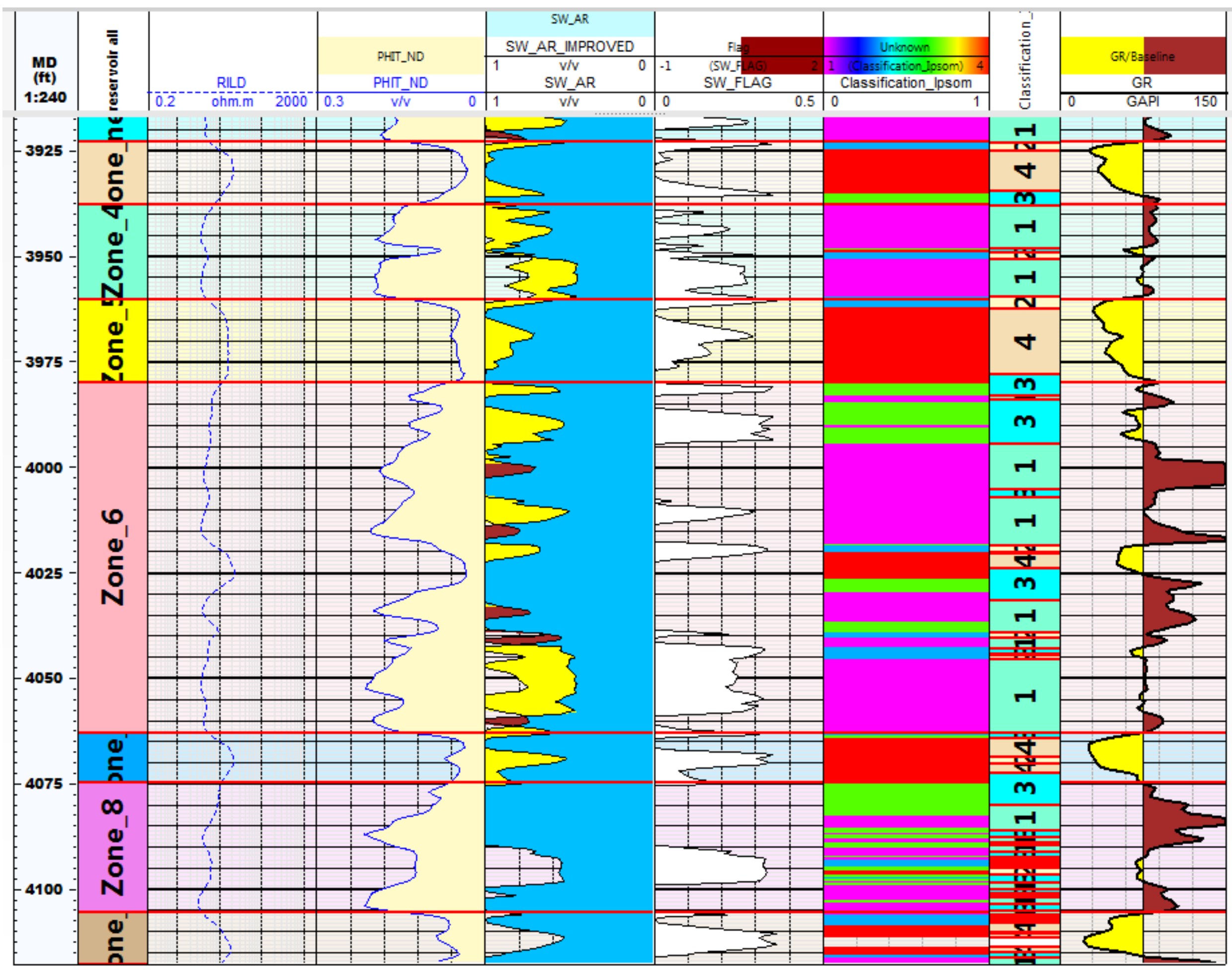
IMPROVED RESERVOIR CHARACTERIZATION BY A FACIE BASED ON ROCK MECHANICAL PROPERTIES



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Improved Reservoir Characterization by a Facie Based Rock Mechanical Properties

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Abstract

This study analyzed 10 wells from Lansing Formation in Rawlins County, Kansas for improved reservoir characterization. The approaches used include petrophysical evaluation, rock mechanical facies and prediction of hydraulic flow units using well logs from 9 wells and core data from a single well. Initial well correlation exercise was used to identify 9 different zones that form the basis of the interpretation. The average thickness of the zones identified within the Lansing Formation was about 281ft. Lithology computation showed three main lithology types limestone, quartz and shales across the zones with carbonate fraction accounting for 20 to 90%. Petrophysical analysis revealed that Lansing carbonate reservoirs have a wide range of porosity and permeability due to different rock types mixed within different zones and that water saturation calculation parameters can be dependent on rock quality. Using mechanical rock facies, 4 different rock types were identified with quality in decreasing order of 4, 3, 2 and 1. Integration of the rock classification types into water saturation calculation in one well showed an error of 0-30%. If translated across the 206 wells in Rawlins County the increase in oil production per annum can be up to 5.6 million barrels. Furthermore, hydraulic unit was defined by the flow zone indicator (FZI) concept using Amafuele equation based on integration of data regarding the distribution of rock quality index (RQI) and petrophysical properties. Prediction of the hydraulic from both the histogram plot of log FZI, and the normal probability plot of the same log FZI revealed 6 different units with a reasonable link to RQI. This information can be used in further reservoir performance estimation during the flow simulation.

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Preface

This project has been put together as a Master Thesis, in order to complete the Oil and Gas Technology MSc. Program at Aalborg University Esbjerg in the department of Chemical Engineering. The main objective of this study is to identify and map individual hydraulic flow units and rock facies to aid determination of the potential for continued development.

The report will present you methods of reservoir improvement based on mechanical rock facies derived from wireline logs and identification of hydraulic units. The analysis was done using the Schlumberger Oilfield Services wellbore platform Techlog ©.

The methodology that has been used in this work include definition of rock types based on mechanical facies, and the use of permeability-porosity relationship for reservoir quality index , flow zone indicator and subsequent prediction of hydraulic units that can be available for reservoir engineers during field wide simulation.

In all, 9 wells with basic wireline logs (gamma ray, density, neutron porosity, sonic and resistivity) and one well with core data were employed to fulfill the objectives of this study.

The work has been grouped into chapters and each chapter has sections and sub-sections and the summary of organization of this thesis is presented. References are labelled as [X]; figures, tables and equations are numbered according to the chapters. Result and discussion are presented after each analysis (plot of figure and table) for the entire work.

In this project all of the references to literature, articles and websites are cited in the references section at the end of the project report.

Duration of this work spans from October 2014 to January 2016, and has been written in a very simple English for every reader, be it engineers, geoscientists, technicians or even non-professionals in the oil and gas industry.

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1 Introduction

Reservoir characterization approaches are valuable as they provide a better description of the storage and flow capacities of a petroleum reservoir. Carbonate reservoirs are always very challenging to characterize because of their tendency to be tight and generally heterogeneous due to depositional and diagenetic processes. The common petrophysical heterogeneity found in carbonate reservoirs are normally seen through the wide variability observed especially in porosity-permeability relationships of core data analysis. To overcome some of these challenges, the characterization of carbonate reservoirs into hydraulic flow units is a practical way of partitioning the reservoir into different units. The presence of distinct units with particular petrophysical characteristics such as porosity, permeability, water saturation, pore throat radius, storage and flow capacities help geoscientists and reservoir engineers to establish a strong reservoir characterization. Hydraulic flow units in general represent a reservoir zone that is continuous laterally and vertically and has similar flow and bedding characteristics (Ebanks et al., 1984). If these units are determined early as part of the reservoir characterization, it will give a better understanding of the future reservoir performance during production activities.

In addition, using the rock mechanical properties, the reservoir characterization tool can be further enhanced. The basis for these relationships is the fact that many of the same factors that affect rock mechanics also affect the other physical properties such as velocity, elastic moduli and porosity (Chang et al., 2006). In many wells, samples from the cores do not cover the whole interval of the well and also can be very expensive. If there are no core samples available for direct measurements, empirical relationships that are based on measurable physical properties are routinely used. For these reasons, prediction of rock mechanical properties from wireline logs using empirical relationships and correlations was also incorporated into this study.

This study therefore focuses on using available conventional wireline logs from 9 wells and core data from 1 well to attempt to improve the reservoir characterization of a carbonate formation from Rawlins County, Kansas USA. The main objective of this study is to identify and map individual hydraulic flow units and rock facies to aid determination of the potential for continued development of the fields. The distribution of discrete reservoir parameters such as porosity and permeability are taken into consideration for such flow units mapping. Other objectives of this study include demonstration of advanced reservoir characterization tools using Techlog© software of Schlumberger, that can result in a significant increase of reserves.

The characterization was based on the old data set and new data derived from the empirical relationships between the available logs.

Starting with the well correlation, 9 zones were identified in the section of the Lansing formation and correlated along the 9 different wells. For all the wells, individual well log analysis and calculations of the petrophysical parameters such as volume of shale, porosity, permeability and fluid saturation have been made. Furthermore, to improve the reservoir characterization, rock types using rock mechanical facies and rock quality based on permeability-porosity relationships were predicted, as well as the identification of hydraulic flow units across different wells which can enable adequate stimulation for production purposes.

1.2 Problem statement

The exploration for economic accumulations of oil and gas starts with the recognition of likely geological structures, progressions to seismic data acquisition, and the drilling of one or more wild-cat wells. If one is lucky, these wells may encounter oil, and if that is the case, measurements made down the hole with wireline tools are used to assess whether sufficient oil is present, and whether it can be produced.

At the moment, oil production from the study area has yielded cumulative amount of oil (10 million barrels) to date. However the old reservoir characterization were based on porosity and

saturation determined from wireline logs, which do not accurately reflect reservoir quality and performance that needs to be factored into simulation for production behavior.
In addition, carbonate reservoirs usually have low recovery efficiency due to the fact that they are highly heterogeneous in both vertical and lateral continuity. In addition, they usually exhibit relatively low permeability and low porosity. In order to achieve a reliable production profile, mapping of reservoir quality and hydraulic units within the formation is important (to avoid any units being bypassed). Such information is very useful in constructing static and dynamic reservoir models that can identify better way of fluid recovery and aid determination of the potential for continued development of the fields for additional recovery.

1.3 Data and method

The data used in this project was taken from the Kansas Geological Survey, University of Kansas website which is part of the public available datasets for research purposes. The wells selected from the database have included a set of wireline logs (gamma ray, density, neutron porosity, sonic and resistivity) and one well with core data, belonging to oil fields in Rawlins County.
The techniques used for reservoir description must meet basic requirements to be of value in a mature, heterogeneous field such as Lansing Formation. In this study the methodologies employed include:

1. Mapping of reservoir parameters (water saturation (S_w), net to gross ratio (*N/G*), porosity and permeability) for each reservoir zones.
2. Well correlation of different reservoir zones across the multi wells.
3. Rock type extension based on rock mechanical facies that can be correlated to the flow parameter (permeability).
4. Identification of flow units using the available wireline logs because only one well has core data. Thus, the fundamental reservoir description must be log based. However, because values of porosity and saturation derived from routine log analysis do not accurately identify productive rock units in the Lansing Formation, it is necessary to

develop a log model that will allow for the prediction of another producibility parameter, in this case hydraulic units.

5. All the analyses were done using the Schlumberger Oilfield Services wellbore platform Techlog ©.

The main benefit of the techniques employed is that we use only the existing database - no new wells will be drilled to aid reservoir description which will save a lot of money that will be spent on acquiring new data. The existing database consists of conventional cores from one well and 9 wells with a relatively complete log suite (gamma ray, density, resistivity, and neutron logs).

1.4 Area of the investigation

The study area is the Rawlins County, Kansas situated in the northwestern part of Kansas and the southwestern part of Nebraska, Figure 1. The total area of the County is about 2,771 km2. The main geological formation in this area belongs to Lansing-Kansas City Group [24]. The Lansing-Kansas City Group accounts for a significant amount of 'Kansas' oil production, and a combination of new ideas and use of latest technology have helped to reinvigorate this area.

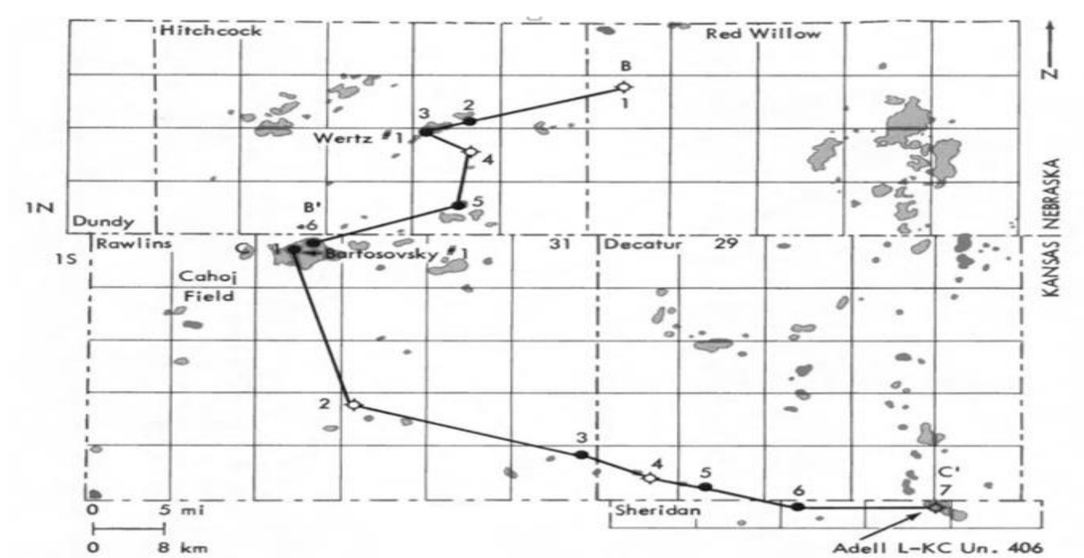


Figure 1: Location of the study area [18]

1.5 Hydrocarbon production in Rawlins County

The field doesn't present a major interest for the big companies since the reserves found in the field there are not big enough. But the smaller companies are taking advantage of this. The oil and gas production fields in the Rawlins County, which is the location of the wells used in this study, is shown in Figure 2. About 90% of these wells are located in the northern part of Rawlins County.

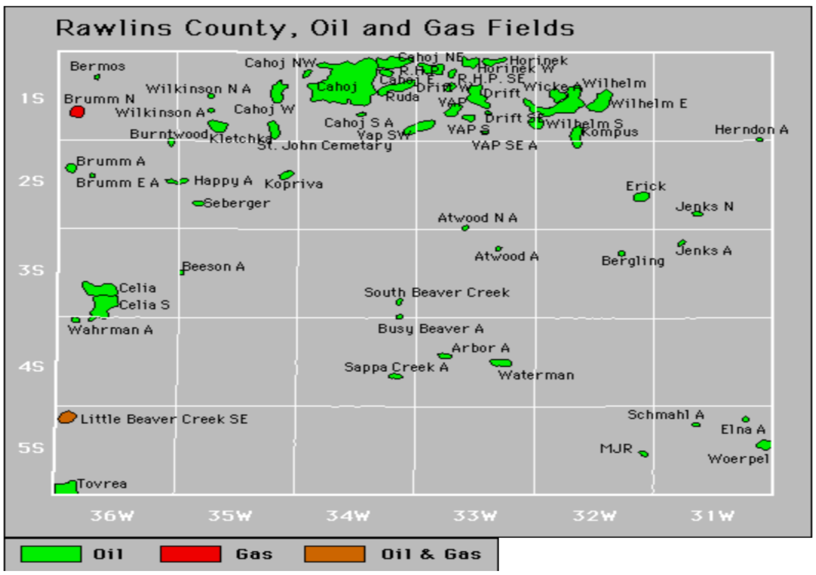


Figure 2: Oil and gas fields Rawlins [6]

Since the formation was divided in zones, the two most productive ones are J and G Zone. The summary of the total production from this County over the last 20 years is shown in Table 1. It should be mentioned that the methods of recovery are primary and secondary, depending on the quality of the reservoir and the number of productive zones from it. The average production per well is about 40-50 thousand barrels. This translates into about 10 million barrels for the entire wells (J.E.Rakaskas 1979].

Table 1: Oil and gas production in Rawlins [6]

Year	Production (bbls)	Wells	Cumulative (bbls)
1995	300,989	213	19,735,844
1996	300,989	167	19,998,839
1997	300,989	163	20,241,072
1998	300,989	152	20,450,108
1999	300,989	139	20,640,511
2000	300,989	135	20,815,628
2001	300,989	136	20,997,981
2002	300,989	143	21,178,500
2003	300,989	133	21,423,881
2004	300,989	164	21,708,655
2005	300,989	166	21,995,356
2006	300,989	166	22,195,338
2007	300,989	166	22,405,918
2008	300,989	155	22,612,887
2009	300,989	134	22,827,499
2010	300,989	134	23,012,400
2011	300,989	120	23,169,688
2012	300,989	123	23,348,200
2013	300,989	149	24,085,999
2014	300,989	187	25,541,459
2015	300,989	206	26,247,012

1.6 Project Outline

Chapter 1 - will introduce you to the project, showing the problem statement, data and method of investigation, area of investigation and the hydrocarbon production from the Rawlings County.

Chapter 2 - The characterization of a reservoir requires basic understanding of reservoir properties that can be measured and quantified. The correctness of such parameters is significant to the total evaluation of a petroleum reservoir. In this chapter the reservoir rock and their properties are briefly described.

Chapter 3 - This chapter gives a general background and stratigraphy of the area of study. For a better understanding of the area, a lithofacies framework is interpreted in terms of the depositional facies of the original sedimentation. In the process was added well-log data and samples description that were used to interpret these facies or zones of geologic cross section.

Chapter 4 - The investigation of the quantity of fluid saturation is one of the important things in every reservoir characterization/petrophysical study. The correctness of the petrophysical parameters, namely porosity, permeability, saturation and net to gross ratio are very significant to the total evaluation of an oil and gas reservoir. This chapter seeks to apply some of the models or equations earlier described for computations and evaluation of petrophysical parameters in the given wells.

Chapter 5 - In this chapter an attempt will be made to do a rock classification using rock mechanical facies.

Chapter 6 - In this chapter we have attempted a delineation of the hydraulic flow units in the uncored-wells having well logs by considering the relationships between petrophysical parameters of permeability and porosity already calculated in the previous chapters.

Chapter 7 - findings and discussion will conclude with the facts of improvement brought by this project.

1.7 Project limitations

Project limitations include lack of core data and information for majority of the wells. The information from core can be used to confirm some of the results derived from the study.

2.0 Reservoir Characterization

The characterization of a reservoir requires basic understanding of reservoir properties that can be measured and quantified. The correctness of such parameters is significant to the total evaluation of a petroleum reservoir. In this chapter the reservoir rock and their properties are briefly described.

2.1 Reservoir rocks and their properties

The main reservoir rocks are sandstones and/or carbonates (99%), but there are reservoirs which are made up of metamorphic or highly fractured igneous rocks. Sandstone and carbonates are sedimentary rocks formed by chemical precipitation or debris (animal, vegetal or mineral compound).

Sandstone reservoirs: they are clastic sedimentary rocks. Sandstone forms the most common type of the reservoir, 80% of the worldwide reservoirs and 60% of all the oil reserves. Oil production from sandstone reservoirs take account for about 37% of world total reservoirs, comes second after carbonate formations. Sandstone has in composition cemented grains of Quartz (SiO_2) and Feldspar $(KAlSi_3O_{8,}NaAlSi_3O_8, CaAl_2Si_3O_8)$. Usually, the sandstone can be found in combination with other rocks such as shale or clay - it is very rare to find 100% sandstone. When sandstone is mixed with shale, it is generally called a shaly-sand formation. Such reservoirs are sometimes difficult to characterize because of the complex properties coming from addition of clay minerals.

The environment of deposition of sandstones can vary and usually include deserts, stream valleys, and coastal/transitional environments such as beach sands, barrier islands and deltas. Example of well-known petroleum resources in sandstone formations include Niger delta, Sallyards and Lamont oil field southern Kansas, USA.

Carbonate reservoirs: they are formed due to a biological activity resulting in calcite formation. The calcite can be changed chemically to dolomite. Therefore carbonate reservoirs usually exist either as limestone$(CaCO_3)$ or dolomite$(CaMg(Co_3)2)$. Limestone can be further divided into mudstones, wackestones, packstones, grainstones etc. The usual mix of these types of rocks is with shale. In case that the shale quantity in the mix is higher than 35%, the permeability of the rock decreases and this rock can't be a reservoir rock anymore. In carbonate rocks, we can find both types of porosity; inter-and intergranular porosity.

The origin of formation of many carbonate reservoir rocks are shallow marine depositional environments (i.e. lagoons, atoll etc.). They form slowly from accumulation of remains of calcareous shelly marine organisms that settle to the bottom of the ocean. Over large geological time scales these accumulations grow to hundreds of feet thick. Carbonate reservoirs produce the world's largest petroleum resources (about 62%) and are formed only 21% out of major sedimentary rocks that include shale and sandstone.

Understanding reservoir rock properties and their characteristics is crucial to the development of petroleum resources and hence attempts to characterize reservoirs during the stage of petroleum exploration. The most important reservoir rock properties are highlighted below.

2.3 Reservoir Rock Properties

The existence of reservoirs indicates the presence of a trap capable to stop the hydrocarbon to migrate. It is an area bounded with barriers which will be sealed with a layer of impermeable rocks (cap rocks) the hydrocarbons. Rocks that form a trap don't usually contain hydrocarbons, but all hydrocarbons are caught in some kind of a trap.

2.3.1 Porosity

Formation porosity is determined from two main sources mainly: laboratory measurements and from well logs. The laboratory method is done by taking plugs from core samples from the well of interest and performing any of the available methodologies such as injection of mercury and compressible inert gas such as helium.

In general, porosity refers to the apparent volume, or total volumeV_t, consisting of a solid volume $V_S$and a pore volume which is noted withV_P. In this situation the porosity Ø in:

$$\emptyset = \frac{V_{pores}}{V_{total}} \qquad \text{EQ.2.1}$$

The result will be expressed in percentages.

The fact that the reservoir rocks were formed in time by deposition of sediments means they can have different types of porosity; some of the void spaces are interconnected with other void spaces and create a network; other ones are connected between them while in the other type the void spaces are completely isolated or without any connection with the other void spaces. Due to this, we have different types of porosity; the absolute porosity of the rock is comprised of ineffective and effective porosity.

Effective porosity - The porosity of interest in our situation is the one that allows the hydrocarbons to circulate between grains, it is called effective porosity $\emptyset_u$ this corresponds to the pores connected with each other and possible with different formations. This can be defined as ratio of dead-end pores and interconnected pores to the total volume:

Ineffective porosity - However the ineffective porosity is defined as a ratio between volumes of isolated or completely disconnected pores to the total volume:

$$\emptyset = \frac{Vol.of\ isolated\ pores}{total\ volume} \qquad \text{EQ.2.2}$$

Absolute porosity - is the ratio between the total void spaces in the rock and the total volume of the reservoir rock:

$$\emptyset = \frac{total\ pore\ volume}{total\ volume} \qquad \text{EQ.2.3}$$

All in all a reservoir rock with high total porosity but without a good conductivity of the fluids between grains (lack of interconnectivity) makes the fluid to stay trapped inside of the pores, due to this phenomenon the hydrocarbons will be immobile ore unrecoverable.

Table 2 below shows the general classification of porosity based on [80]

Classification	Porosity range %
Low	0-5
Mediocre	5-10
Average	10-20
Good	20-30
Excellent	>30%

As a rule, it is known that the porosity decreases with the increasing of the depth. In a given situation the porosity is described within the main types of rocks found in the reservoir.

2.3.2 Permeability

One of the most important criteria in defining the reservoir production is permeability, unlike the porosity which is a static property of the porous environment, permeability is a dynamic property based on the flow properties. In order to properly define the permeability of a reservoir rock, a series of important properties should be used:

a. Permeability measures the fluid conductivity properties of a pores environment

b. The permeability stays as the measurement of its specific flow capacity.

Permeability is a property of the medium and is a way to measure the capacity to transmit fluids. Permeability together with porosity are the reservoir parameters that ensure the type of fluids, amount rate of fluid flow and fluid recovery estimation [*30]*. The permeability of a rock depends on the effective porosity of the rock which is consequently affected by the rock grain size, grain shape, grain distribution (sorting) grain packing and the degree of consolidation and cementation. Permeability is also affected by type of clay or cementing material between the sand grains, especially where fresh water is present. Certain clay materials such as bentonites and montmorillonites swell in fresh water either partially or completely.

2.3.2.1 Determination of permeability

It can be determined by Darcy's Law. This stands like:

$$Q = \frac{kA}{\mu} * \left(\frac{\partial_p}{\partial_x}\right) \qquad \text{EQ2.4}$$

Where:

Q= flow rate

A= cross section

K= permeability coefficient

μ= dynamic viscosity

∂_p= downstream pressure

∂_x= length

In order to use the formula above it necessary to fulfill conditions such as; a laminar flow, steady state, homogeneous formation and incompressible fluids.

2.3.2.2 Types of permeability

Effective Permeability – comes with K_g, K_o, K_w of the gas, oil and water permeability. All the effective permeability values are less than the absolute permeability, it can be written as a fraction where the absolute permeability of a rock has any of the present fluids on 100% saturation. It is known in real life that in a reservoir there are two different fluids (water and hydrocarbons), Darcy's law helps determine an effective permeability for both of them;

$$Q_1 = \frac{K_1 * A}{\mu_1} * \frac{\partial_{p1}}{\partial_x} \qquad \text{EQ.2.5}$$

And

$$Q_2 = \frac{K_2 * A}{\mu_2} * (\frac{\partial_{p2}}{\partial_x}) \qquad \text{EQ.2.6}$$

Relative Permeability - this depends on the rock sample concerned and the proportions of the fluids present inside. Due to the fact that in fluids 1 and 2 there is a different pressure mainly because of the capillary mechanism, the concept of relative permeability will look like:

$$Relative\ permeability\ oil = \frac{Effective\ permeability\ of\ oil}{Permeability\ of\ the\ rock} \qquad \text{EQ.2.7}$$

Absolute permeability - This is the permeability of porous rocks, where the rock is saturated by 100% of a particular formation fluid (single phase).

2.4 Fluid saturation

It's about how that pore volume, pore space or storage capacity is distributed or portioned among the reservoir fluids such as gas, oil and water. Fluid saturation is a ratio of the volume of a fluid phase in a given reservoir rock sample to the pore volume of the sample;

$$Fluid\ saturation = \frac{Total\ volume\ of\ fluid\ phase}{Pore\ volume}$$ EQ 2.8

It should be noted that the fluid saturation is generally reported as a fraction of the effective pore volume rather than the total pore volume, it makes more sense since the fluids which are presented in the isolated pore spaces can't be produced.

Fluid saturation can be expressed as a fraction for each fluid in particular;

$$S_g = \frac{Volume\ of\ Gas}{Pore\ Volume}$$ EQ.2.9

$$S_w = \frac{Volume\ of\ Water}{Pore\ Volume}$$ EQ.2.10

$$S_o = \frac{Volume\ of\ oil}{Pore\ Volume}$$ EQ.2.11

All the above equations can be expressed as one single equation. The result of the equation will be in percentage and it will indicate that the saturation can range from 0-100% or 0-1 and since all the saturation is scaled down to the pore volume their summation should be always 1 or 100%:

$$S_g + S_o + S_w = 1$$ EQ.2.12

Although hydrocarbon saturation is the quantity of interest in petroleum reservoir evaluation, water saturation is usually used because of its direct calculation in Archie's saturation equation. Evaluation of the amount of hydrocarbon present in a reservoir is based on the estimating the volume of water present in the pore spaces in the reservoir rock.

2.4.1 Evaluation of Water Saturation.

Archie equation is the keystone of log analysis and for the calculation of water saturation in a potential oil and gas reservoir. This is because it is simple and acceptable all over the world. Water saturation is estimated from electrical resistivity logs which are based on the resistivity of water, resistivity of oil and the true resistivity of the formation. The most general expression used to represent Archie's equation is:

$$S_w = \left(\frac{a}{\emptyset^m} * \frac{R_W}{R_t}\right)^{\frac{1}{n}} \quad \text{EQ.2.13}$$

EQ.13 is developing as two different equations; the first one will describe the ratio of:

$$\frac{R_o}{R_W} = \frac{a}{\emptyset^m} \quad \text{EQ.2.14}$$

Where:

R_o= resistivity of a water saturated Rock

R_w= formation water resistivity

$\emptyset$= fractional porosity

m=cementation factor

a = tortuosity factor in the zone of interest

The second one will focus on:

$$\frac{R_t}{R_o} = \frac{1}{S_W^n} \quad \text{EQ.2.15}$$

Where:

R_t = formation resistivity

R_o= expected resistivity

S_w= fractional water saturation

n= saturation exponent which value typically varies from 1.8 to 2.5 but most often assumed to be 2.

All the above equations are universally applied. But in order to make the application possible a set of parameters must be known or at least have a good estimation of them. Some are evaluated from well logs while others from other studies/accepted research. Parameters like R_w, R_t, and $\emptyset$ are determined from well logs either directly or indirectly whilst a, n, and m are from accepted research on similar rock characteristics.

The saturation of hydrocarbons S_h which is of paramount importance is evaluated by using a simple equation as stated below.

$$S_h = 1 - S_w \qquad \text{EQ.2.16}$$

2.4.2 Residual oil saturation

Residual oil saturation is oil saturation that cannot be produced from an oil reservoir from gas or water displacement. It is usually considered the immobile oil saturation after conventional primary and secondary recovery [30].

Usually the determination of residual oil saturation is based on result from a laboratory test on core sample. The idea behind this process is when you inject gas or water in a 100% saturated core plug. In this phenomenon we can see how the fluid from the core will be replaced with the one injected. However it doesn't matter how much force is applied through fluid injection, there will not be a 100% recovery of the oil from that core plug since a lot of oil droplets will still be trapped inside the pores, this oil trapped inside it is called residual oil. The above facts will give a huge importance in the oil industry since residual oil calculation gives us the data about how much oil can be recovered and how much will be left behind.

2.4.3 Irreducible water saturation

It is represented by the minimum water saturation that is present in a porous medium. In order to understand this concept, it is needed to consider a perfect reservoir where everything is ideal, all the fluids reached a state of equilibrium and they are separated by densities, in this way there will be oil on top of the water and below a gas cap [1]. In order to reach this perfect equilibrium small pores are saturated with water, where the hydrocarbons can migrate from the source rock. However, due to this physical force that acts (capillary and gravity) during this migration process, the complete gravity segregation will not happen - the fact that makes the connate water to be distributed through the oil and gas zones. All in all the water from these zones is reduced to the irreducible minimum (irreducible water saturation). A particularity of these phenomena is that they can be created as an artificially created saturation, irreducible water saturation in the reservoir and in nature-driven process; they can be influenced only by the competition between capillary and gravity forces.

2.5 Volume of Clay Content

Volume of shale usually defined as (*Vsh*) is one of the most critical parameters to be determined in petrophysical analysis. Yet in many areas it is very difficult to determine the volume of clay accurately. An overestimation of clay volume can result in effective water saturations (S_{we}) that are too low, thus making the reservoir look productive. Under-estimation of clay volume can result in effective water saturations that are too high, which can result in the bypassing of a productive zone [30]. The volume of clay is usually estimated from gamma ray logs using different models even though it can be established from other logs such as neutron-density logs, SP, neutron-sonic among other logs.

In general the equation for calculation of volume of shale from gamma ray is given by:

$$Vsh = (GR - GRo)/(GR100 - GRo) \qquad \text{EQ.2.17}$$

Where:

GR = gamma ray log reading in zone of interest corrected for borehole size (API units)

GRo=gamma ray log reading in l00% clean zone (API units)

GRl00 = gamma ray log reading in l00% shale (API units)

Vsh = shale volume from gamma ray log (fractional)

3.0 Geological Background

This chapter gives a general background and stratigraphy of the area of study. For a better understanding of the area, a lithofacies framework is interpreted in terms of the depositional facies of the original sedimentation. In the process was added well-log data and samples description that were used to interpret these facies or zones of geologic cross section.

3.1 General geology of the study area

As was mentioned earlier, the study area is located on the south-west flank of the southeast-northwest extended on the Cambridge Arch (Figure 3). From the structural point of view, this feature is an anti-form separated from the Central Kansas Uplift to the southeast by a small depression. The important periods of the structure movements are taking during the pre-Mississippian and in Middle Pennsylvanian time. The surrounding movement also occurred during the Mesozoic period. It was spotted in certain areas that the Precambrian rocks are directly overlain by layers of Pennsylvanian time. [20]

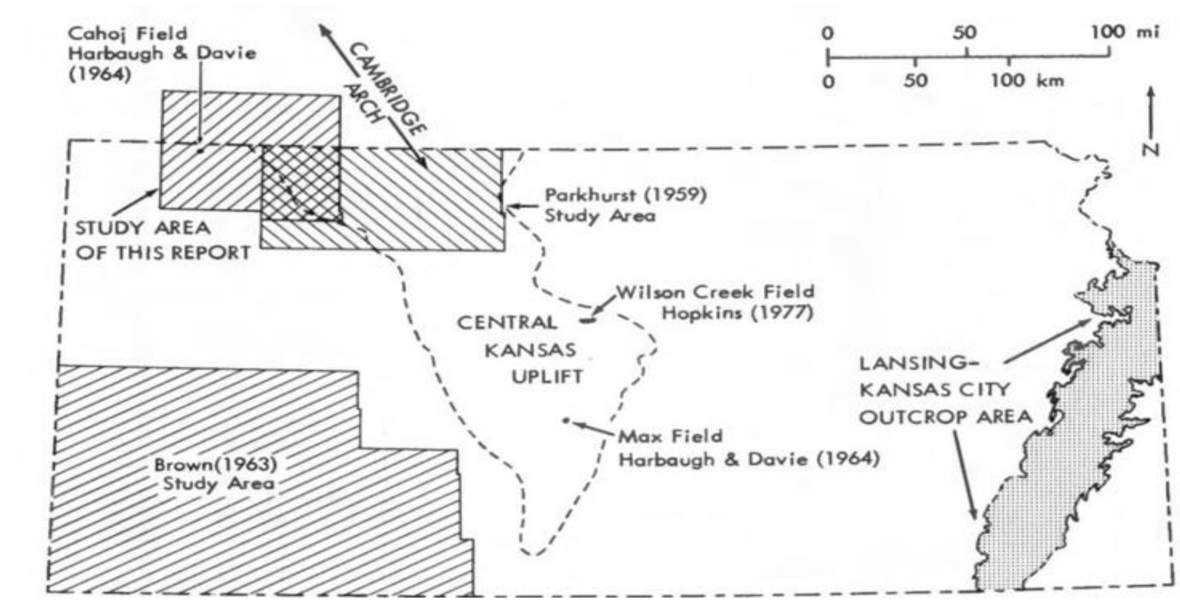


Figure 3: Map showing the geology of the study area [20]

The most mature and productive well-developed areas of oil and gas are located on the Central Kansas Uplift (Lansing-Kansas City), more particular is our point of interest Rawlins County, which according to the investigators, is still in the middle stages of development. Even though, no further information says that the area is not as prolific as that on the Uplift. Within the future explorations, there can be made a better comparison. However, till now the Graham County which is located in the Kansas Uplift has produced more than 136.000.000 barrels of oil with the help of 1400 wells [11]

3.2 Lansing-Kansas City Groups Formation

Figure 4 shows that the Lansing-Kansas City Groups are part of the Missourian stage of the Upper Pennsylvanian Series. They were formed by shales and interbedded carbonates and trails of sandstone and coal. Heckel and Mossler's (1973) explorations show us that the outcrop belt of the Lansing-Kansas City which are composed of carbonate units, displays a big variety of different depositional environments such as phylloid-algae-bearing or lime-mud banks to oolite shoals. On the opposite side in the Northwestern Kansas carbonate facies are a high variable in the Lansing-Kansas, this can be observed as an interbedded terrigenous clastic, ranging from red-brown very silty shales to black claystone. A bit to the southwest from the mentioned zone, the Missourian sequence is not a carbonate shelf anymore; becomes basin facies composed by thin limestone, dark grey shales, and a lot of sands.

Group	Stage	Series
WABAUNSEE	VIRGILIAN	UPPER PENNSYLVANIAN
SHAWNEE		
DOUGLAS		
LANSING	MISSOURIAN	
KANSAS CITY		
PLEASANTON		
MARMATON	DESMOINESIAN	MIDDLE PENN.
CHEROKEE		

Figure 4: Stratigraphic position of rocks.[5]

In 1953 Morgan [26] uses the Gamma Ray logs to create a subsurface correlation scheme, to provide a better formation view. These Gamma ray logs are the most common log in this study. Further way it can be notes that the geologist of the time create a nomenclature in order to describe the zones better, this sets a particular name such as ‘J’ Zone (Figure 5) which corresponds with an 180 feet zone, which has a consistence interlayer of carbonate and some shale formations.

An extra attention was given to the thickness of the carbonate layers, since they are a key factor in providing information about the oil production. Morgan (1952) comes with this idea, since he notes that the highest elevation of the carbonate bed doesn’t coincide with the structure from the top of the Lansing formation. [26] The explanation of this key formation becomes an important factor in predicting and locating the oil and gas. Getting all the information about each carbonate member was necessary in order to create a conclusive evaluation of a drilled well. Knowing the zones with the prolific properties such as high porosity and permeability, and treat them with acid helped getting a good completion of the well. A general knowledge about the carbonate facies of the areas can help in improving the drilling program. An example of the correlation schemes which describe the carbonates zone can be observed in the log of Conoco Adell L-KC Unit 406 which is a part of Lansing-Kansas Group (Figure 5).

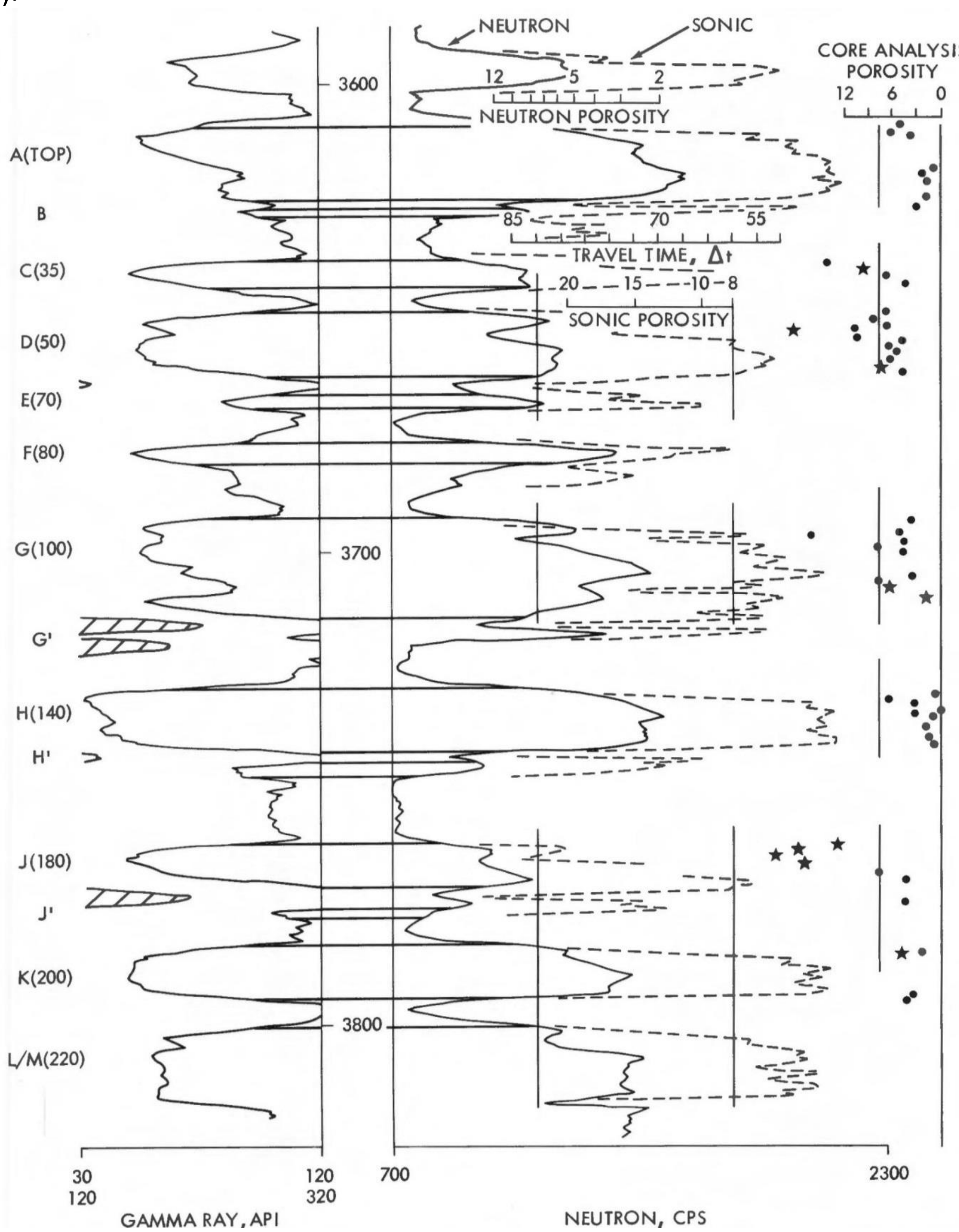


Figure 5: Letter system of correlation of carbonate zones. Numbers describes the correlation system based on the depth below the top of Lansing formation [26]

In the example below (Figure 6) we can observe the structural and stratigraphic well-log cross section which uses the same letter-designated correlation, showing the most important aspects of the Lansing-Kansas Group, more precise the Lansing formation.

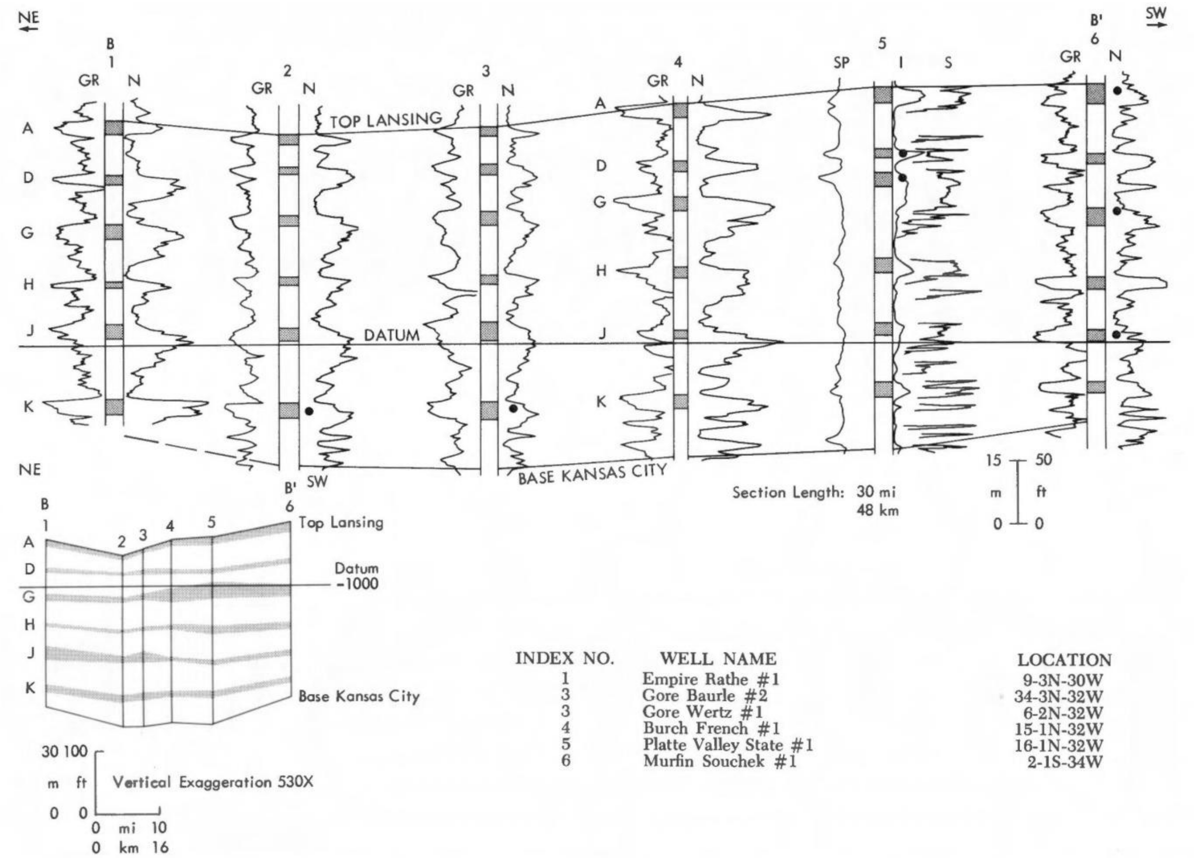


Figure 6: The B-B' section of the Lansing-Kansas Group can be found in Figure 4 as well.

The datum describes the mentioned J-zone. Black dots are a mark of the production zone which can be seen in the upper and lower correlation, this is the top of Lansing and the base of the Lansing-Kansas Group. The logs mentioned on this picture are GR=Gamma ray and SP=Spontaneous Potential [26].

The description above can help with the interpretation of the cyclic events that resulted in the layered stratigraphy of study area. More information about the stratigraphy of the area has been described in many articles. [26]

3.3 Core sample description and lithology

There are around 14 wells which provided 160 samples that have been closely examined with a petrographic microscope. This was made in order to determine detailed written and graphic lithologic logs of the core sections which were constructed. This helped in the interpretation of the environments of deposition. In order to distinguish the dolomite from the calcite Alizarin Red-S was used to stain the samples.

During the study of the area several cores are been described in the following table (Table 3). In the core evaluation it has been found that there are sedimentological characterizations which is common for all cores, a 25-60 foot-thick sequence of certain types of carbonates and shales can be spotted in a Missourian section which comprise a cycle of sedimentation.

Table 3: Core description from the study area [26]

Well Name	Spot Location	Cored Interval (feet)	Carbonate Zones Found in Core
	— KANSAS —		
Empire Palmer #10	NENESE 6-1S-33W	4055-73	J
Murfin Souchek #1	CSENE 2-1S-34W	3959-65 °4004-4037 4100-09 4121-25 4140-54	A D, E H H′ J
Skelly Bartosovsky #1	SESWSW 9-1S-34W	3960-4250	A through M
Skelly Kisling #7	CNWNW 10-1S-34W	3994-4030 4171-74	A J
Cities Service Miller #2-1	SENESE 31-2S-27W	°3680-3762	A through H
Murfin Prentice # 1	CNENE 30-2S-35W	4238-4278 4297-4323	D, E G
Cities Service Holmdahl A-1	NESWSW 29-3S-31W	3955-3991.5	C through E
Conoco Adell Un. 406	SESESW 2-6S-27W	3583-3808	A through M
	— NEBRASKA —		
Farmer Nicholson #1	CSWSW 12-1N-27W	3160-74	D
Farmer Nicholson #3	CNENE 14-1N-27W	3153-68	D
Farmer Nicholson #5	CSWNE 14-1N-27W	°3154-70.5	D
Gore Wertz #1	CSESW 6-2N-32W	3640-67 3688-3717 3738-53 3769-3814 3836-56	D, E G H J K
Empire Rathe # 1	CNWSW 9-3N-30W	3618-42 3653-74 3742-70	D G J

° Incomplete interval

More specifically, below is a sample of the core taking from Lansing formation that was observed from Soucheck, (the only well in this study that has core information). The core indicates that the sedimentary structures include high angles cross–stratification, in coarse mixed-skeletal packstone, organically beds of packstone and weckstone, algal stramolite and lime mudstone interclast conglomerate. Detail lithology description of the core sample is highlighted below.

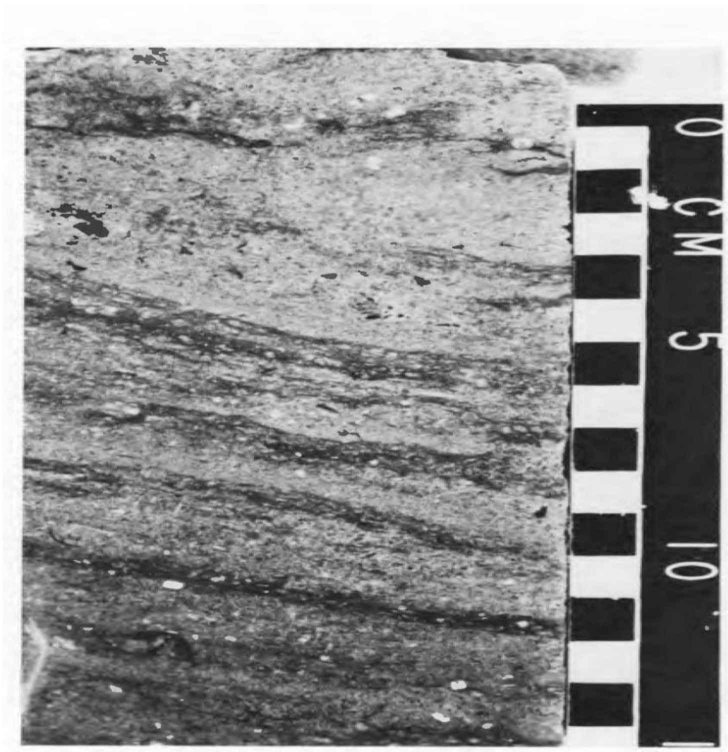


Figure 7: Soucheck core sample coming from an upper carbonate interval [7]

The Souchek well is located in the Cahoj Field from Rawlings county, field that was presented above. The field was discovered in 1959 and produces about 70% of the Rawlings County oil. Describing the lithology by zone; it is recognized as follows:

Zone A 3959-4100 ft:

- On the top part of the zone (3959-3965 ft) we have found fossiliferous, wackestone with autoclastic brecciation and infilling by green shale. Mold-filling cements are ferroan calcite.
- 3965-3972 ft; coated bioclasts, wackestone to pakestone, fossiliferous, crinoid, olive clay, calcite cemented silt, autoclastic brecciation and infilling by very–fine sandstone.
- 3972-4004 ft; Brown to red very fine sandstone with oil stains, concreation formed with non-ferroan cacite , non ferroan dolomite, ferroan calcite and baroque dolomite. Tracks of silt are present. Red-brown silty shale with mycrocrystaline-calcite nodules and green mottling.

- 4005-4100 ft; red-brown silty shale with green mottling, fossiliferous, wackestone with a autoclastic brecciation and inffiling by green shale, peloidal packstone with infilling by green shale, fossiliferous grainstone with oil staining and porosity estimated to less than 8%.

Zone I - 4100-4121 ft.

- The interval presented in this zone is not complete, from 4110 till 4129 is not presented.
- 4100-05 ft; red-brown silty shale with microcrystalline-calcite nodules.
- 4105-10 ft; Fossiliferous wackestone with microcrystalline-oolites, fossiliferous grainstone, fossiliferous packstone.

Zone H-4121-4140 ft.

- Gray Shale with fossils, fossiliferous packstone with excellent porosity, nonferroan calcite, baroque dolomite and fissiliferous wackestone with microcrystalline.

Zone J- 4140-4155 ft.

- Red brown silty shale with microcrystalline calcite nodules, lime mudstone with autoclastic brecciation and infilling by red-brown shale, lime mudstone with autoclastic brecciation and infilling by dark-grey shale,fossiliferous grainstone, fossiliferous wackestone with microstyloites and mottling by grainstone zones that are oil stained.

Collecting core samples of the zones can bring additional rock properties information of the area, which can help in many areas of reservoir characterization by providing data about the bottom-hole pressure which could be insufficient to allow significant in-flow of formation fluid, reservoir grain sizes, and fluid saturation among others. In this study we have used the permeability –porosity relationships from the core sample to transform core to log permeability in the un-cored wells. This will be described in the later chapter of this thesis.

4.0 Petrophysical evaluation

The investigation of the quantity of fluid saturation is one of the important things in every reservoir characterization/petrophysical study. The correctness of the petrophysical parameters, namely porosity, permeability, saturation and net to gross ratio are much significant to the total evaluation of an oil and gas reservoir. This chapter seeks to apply some of the models or equations earlier described for computations and evaluation of petrophysical parameters in the given wells.

4.1 Data analysis

Data analysis started by compiling all the wells that have the basic logs that can be used in the formation evaluation/petrophysical analysis. Most of the wells in the study area have differentiable log suites recorded, although the stratigraphic relationships are very complex. Some of the log characters are constant, some are very variable, and some have not been identified in this study and will possibly be resolved by core-log integration. At the end we arrived at a number of 10 wells with only one having core data. All the wells are located in the same county, and shared the same geological formation. The available wireline data consists of certain number of logs, but the basic logs which are common to all the wells and used in the project are shown in Table 4. *GR* is the gamma ray, *SP* is spontaneous log, *RILD* is the deep induction resistivity log, *RHOB* is the bulk density and *CNLS* is the compensated neutron log. Details about the description and logging methods can be found in the appendices. It should be mentioned that only one well is cored out of the 10 wells, this well is named Murfin Souchek which can be spotted in Table 4.

Table 4: Well logs summaries

No	Well Name	Well Logs	Core Data
1	B_ Horinek #4-1	GR. SP, RILD, CNLS, RHOB,	NO
2	Burk Trust _A_ No_ 2-23	GR. SP, RILD, CNLS, RHOB,	NO
3	Cooper #1-11	GR. SP, RILD, CNLS, PHIE, RHOB,	NO
4	Drake No_1-22	GR. SP, RILD, CNLS, RHOB,	NO
5	Emma No_ 1-18	GR. SP, RILD, CNLS, RHOB,	NO
6	Erickson #1-21	GR. SP, RILD, CNLS, RHOB,	NO
7	Hartner #1-10	GR. SP, RILD, CNLS, RHOB,	NO
8	Sattler No_1-19	GR. SP, RILD, CNLS, RHOB,	NO
9	Souchek 1	-	YES
10	Walter No_ 10-5	GR. SP, RILD, CNLS,, RHOB,	NO

4.2 Well correlation study

Marker bed correlation is the most widely used and reliable correlation technique even if the lithology or origins of the beds are not known. In this study, we have used the gamma ray response that indicates different marker beds within the Lansing formation found in every well without exception. The gamma ray log is also used as a reference log for correlation because of its readily identified log character, and also because it present in all the wells except Soucheck that makes it applicability generic. Figure 8 shows the location of the wells based on their longitude and latitude as displayed in the field-map using Techlog ©. From the field-map it can be observed that about 66% of the wells are concentrated in the northern part of the study area while about 33% was located in the southern part of the study area. The vertical distance between the wells (N-S) is about 50 km maximum and horizontal distance (W-E) is about 50 km as well. It can be concluded that the wells are within an area of 50 x 50 km.sq.

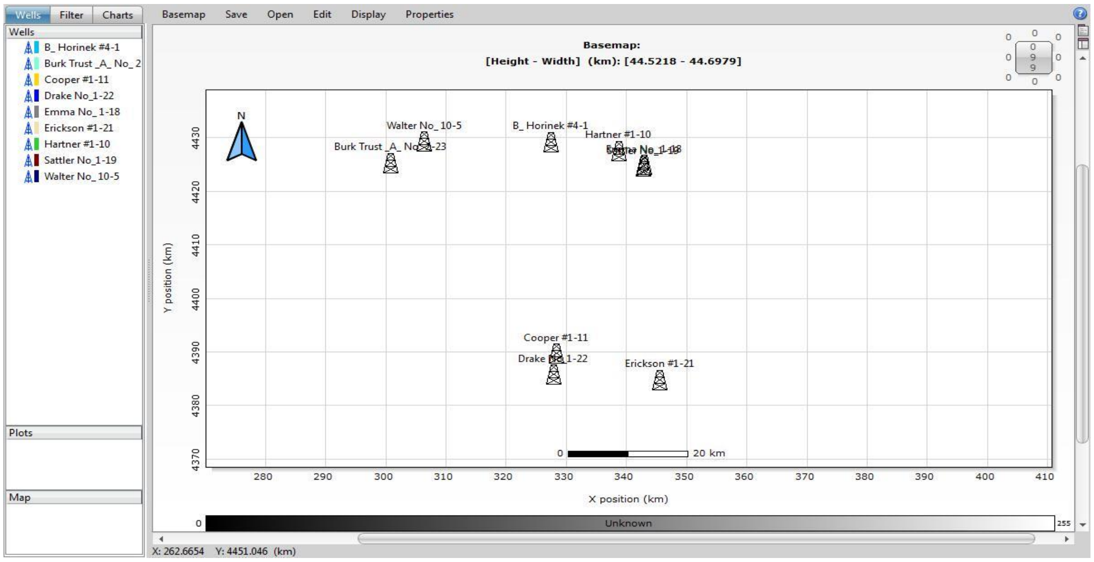


Figure 8: Location map of the wells showing the distance in N-S and W-E direction.

Turning the depth into a 2-D kriging map we can see the structural height of the wells (Figure 9). The wells on the structural tops are Cooper and Drake in the south, Hartner, Walter in the north, while the other well mostly lies on the flanks.

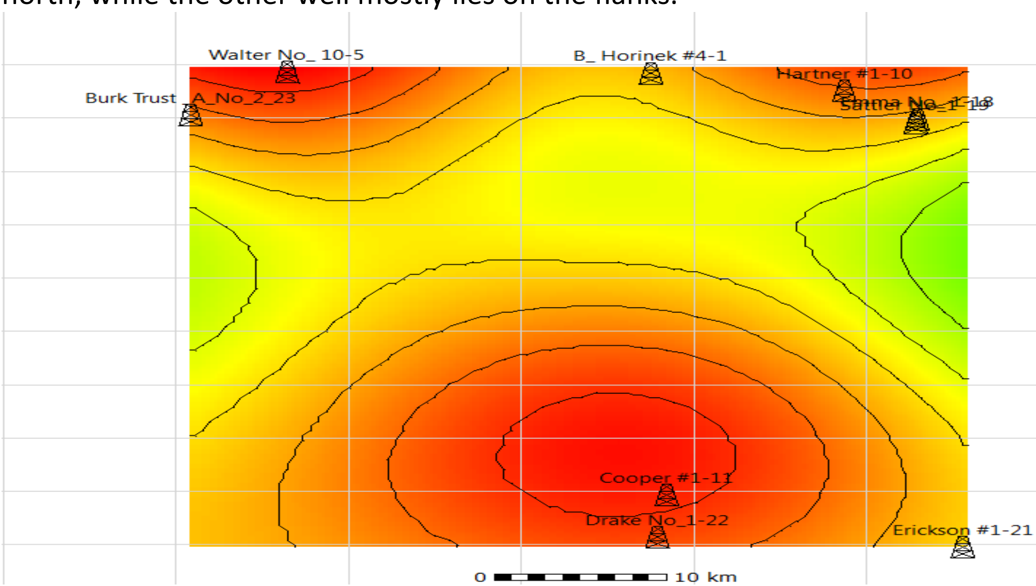


Figure 9: Structural map of the wells based on 2-D kriging of depth data.

Figure 10 shows the result of well correlation using the gamma ray across the wells along W-E direction. Nine different units were recognized in the wells, and labelled as zone 1-9. It can be observed that the cross-well data clearly provide detailed information on the lateral extent of the zones.

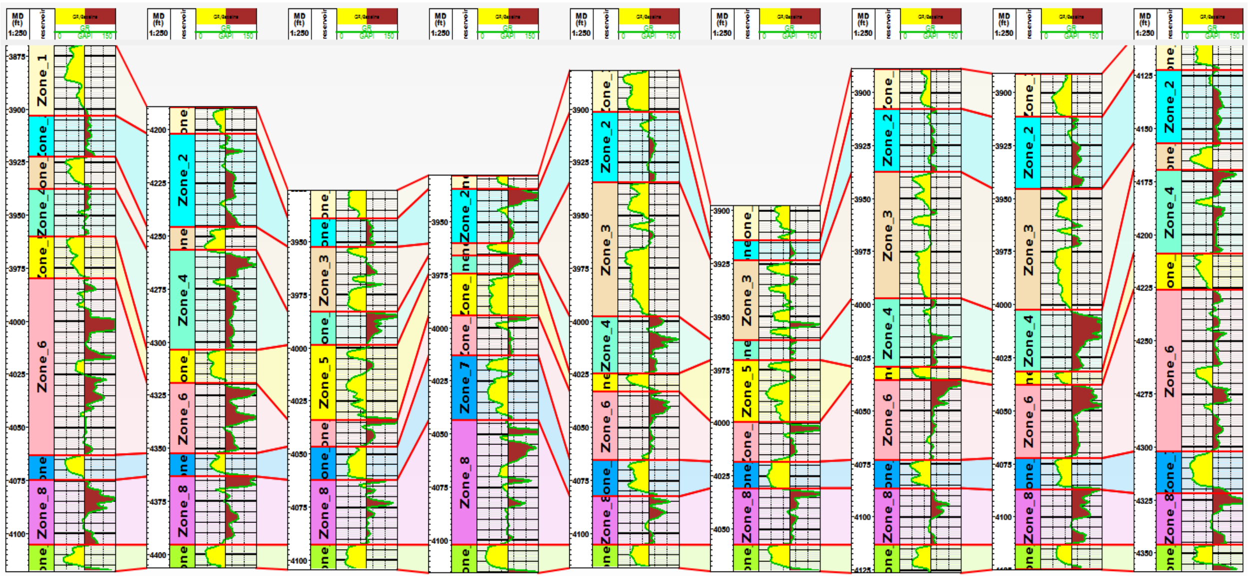


Figure 10: Well correlation panel between the wells (W-E direction)

The identified zones will be significant in providing stratigraphic framework that will be used throughout this study, in terms of petrophysical evaluation (using the zonation it will be easy to assign parameters along zonation to accommodate the difference in reservoir properties) and the zones could also be incorporated into reservoir simulations. Table 4 gives the summary of the thickness of the zones each well. The zonal average in the last column of Table 6 showed that the zone 6 has the largest thickness among all the zones, while the zone 9 has the lowest thickness. Termination of zones cannot be readily identified in this particular cross section, suggesting that the zones continued laterally into other parts of the field.

When compared to the zones described in the core data from Soucheck well (Table 5) from the same Lansing Formation traced across all the wells, the delineated zones from wireline log has 9 reservoir intervals, while the core sample showed 7 limestone units. There are two uncored zones the core information, which might represent the remaining two reservoir units delineated. The depth interval for the zones varies expectedly because of the structural position of the wells. Similarity between the number of reservoir units delineated by wireline log and description from core data, suggest initial reservoir zones identified can be are suitable for further evaluation of the petrophysical parameters.

Table 5: Reservoir units described from core data for Soucheck well.

MD (ft)	Zone Name	Description
3960	Limestone A	Reservoir
3968	Eq. of Limestone B	Reservoir
3972	Silty Shale + Calcite	Reservoir
4005	Limestone D	Reservoir
4009	Uncored 1	Unknown
4029	Limestone E	Reservoir
4035.869	Uncored 2	Unknown
4100	Silty Shale	Shale
4099.998	Limestone H	Reservoir
4120	Grey Shale	Shale
4117.144	Limesone HH	Reservoir
4140	Silty Shale 2	Shale
4136.45	Limestone J	Reservoir

Table 6: Summary of zone thickness across each well in ft.

Zone/Unit	B_ Horinek (ft)	Burk Trust_A_ (ft)	Cooper #1-11 (ft)	Drake No_1-22 (ft)	Emma No_1-18 (ft)	Erickson #1-21 (ft)	Hartner #1-10 (ft)	Sattler No_1-19 (ft)	Walter No_10-5 (ft)	**Zonal Average** (ft)
Zone 1	33.723	12.548	13.333	6.274	19.607	16.469	18.822	20.39	15.685	17.427
Zone 2	19.606	43.918	13.332	25.88	32.938	9.411	29.801	33.723	34.507	27.012
Zone 3	14.901	10.98	30.586	5.490	63.524	37.644	59.603	57.25	12.547	32.502
Zone 4	22.743	47.054	15.685	8.627	26.665	9.411	32.155	29.017	39.213	25.618
Zone 5	19.607	15.685	35.291	19.606	8.627	29.017	6.274	6.274	17.254	17.515
Zone 6	83.131	32.939	12.548	18.822	32.154	18.822	37.644	34.507	76.072	38.515
Zone 7	11.763	10.980	15.685	30.586	17.254	12.548	13.332	14.901	19.606	16.295
Zone 8	30.586	32.154	30.586	58.819	22.743	26.665	26.665	25.881	24.312	30.934
Zone 9	12.548	10.980	11.764	13.332	10.979	12.548	13.332	11.763	12.548	12.1993

4.2 Petrophysical analysis

The interpretation of well log data must be done in several steps and it is not recommended to analyze them randomly because, the result might be a total error. In order to build a petrophysical model, a probabilistic approach was applied for obtaining the volumes of rock and fluid. The final product of this process was the generation of a volumetric mineralogical model in terms of volume of lithology and shale volume, and finally, the porosity and fluid saturation. Each of the steps in the petrophysical analysis will be describe below. The input data were obtained from log curves (complete suite of conventional log curves already described in Table 5).

4.2.1 Lithology estimation

The identification of a bed's lithology is fundamental to all reservoir characterization because the physical and chemical properties of the rock that hold hydrocarbons and/or water affect the response of every tool used to measure formation properties. Understanding reservoir lithology is the foundation from which all other petrophysical calculations are made. To make accurate petrophysical calculations of porosity, water saturation (*Sw*), and permeability, the various lithologies of the reservoir interval must be identified and their implications understood. In this study the lithology computation was done based on the basic input logs we have for the wells. The result is shown in Figure 11. Limestone and quartz as the dominant lithology types, however, the limestone fractions are dominant in the formation. The fraction of the cumulative volume remaining is those that will be occupied by shale volume and porosity, which hold the fluid content. Calculation of shale volume and porosity will be described in later sections. This lithology calculated is essentially based on log responses to simultaneously determine lithology. In reality the limestone fraction consists of different types as indicated in the core description in chapter 3, and therefore rock typing will be much more involved. Such rock typing that can be used to refine petrophysical and fluid flow properties.

Figure 11: Lithology computation. Second column shows quartz in yellow and limestone in blue. The remaining fractions represent the space for volume of shale and porosity

4.2.2 Volume of shale

Shale volume calculation is an important thing to do because, it can be useful to calculate the water saturation, if the reservoir has shale within its body (shaly) that reservoir may have higher water saturation because, shale has the ability to bound together with water which will increase the water saturation. Shale volume could also be used as an indicator of zone of interest or not, typically it is not common to classify a formation with high shale volume as a reservoir because of its low permeability. The volume of clay calculation is based on *equation 2.17* and it is implemented through the use of the software Techlog©. The process involved setting the parameters per zone using the zones in each well (Zone1-9). The parameters setting correspond to the *GR_Matrix* (cut off for clean gamma ray from log) and *GR_Shale* (cut off for shale line from log). Figure 12 shows an example of how the cut off for matrix line and shale line is done using the software for well B Horineck and the output *Vsh* calculated in the last column. The linear method of GR was used in the computation.

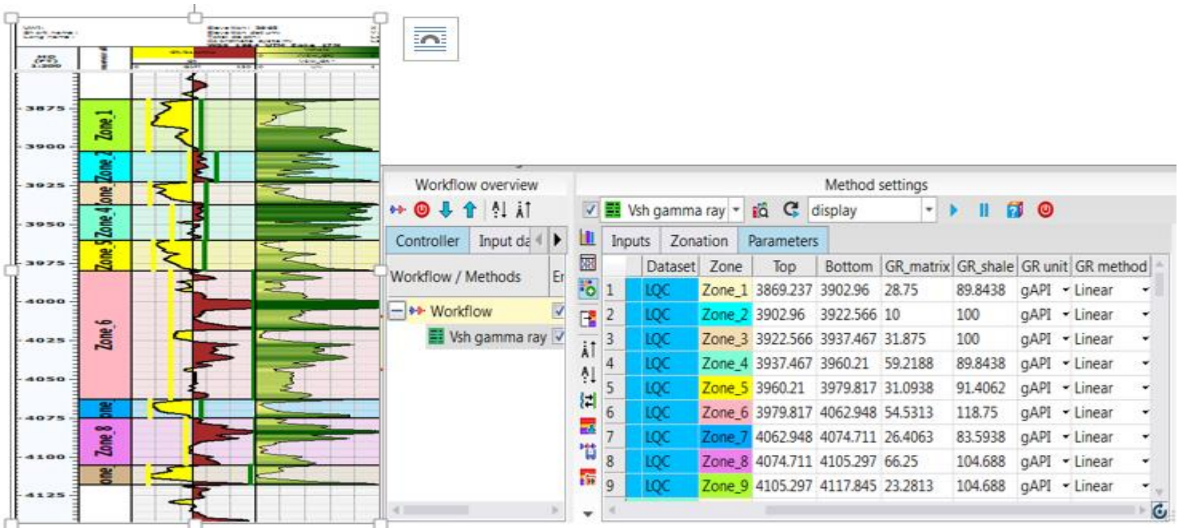


Figure 12: Computation of Vsh using the linear GR method and the parameters

Similar procedure was repeated for all the other wells. The variation in the shale volume is also graphically presented in Figure 13 while the summary of the average shale volume per zone is given in Table 6.

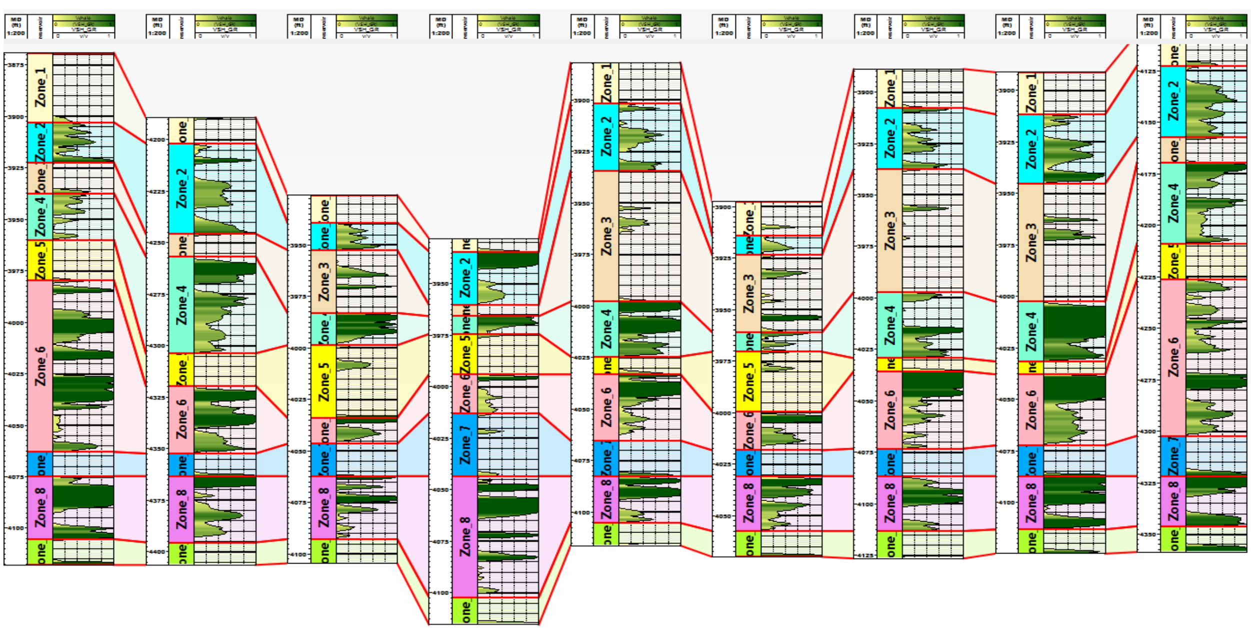


Figure 13: Shale volume across the wells used in the study

For the different zones delineated in the Lansing Formation, shale contents show values between 3 – 51 %. Zone 4 in general appears to be a high shale section, as the values observed in each well for this zone range between 24-80 %. The zone with lower value of shale less than 10% probably consist of more limestone and quartz matrix, an indication of better quality reservoir zones. The shale contents range 0-10 % for these intervals as shown in Table 7.

Table 7: Result of calculated Vsh per per zone in wells used in the study

Zone	B_Horinek #4-1	Burk Trust _A_ No_ 2-23	Cooper #1-11	Drake No_1-22	Emma No_ 1-18	Erickson #1-21	Hartner #1-10	Sattler No_1-19	Walter No_ 10-5	Zonal Average
Zone 1	0.02	0.02	0.01	0.09	0.01	0.04	0.02	0.02	0.05	0.03
Zone 2	0.43	0.30	0.36	0.43	0.27	0.22	0.27	0.41	0.39	0.34
Zone 3	0.05	0.03	0.14	0.07	0.04	0.15	0.03	0.07	0.05	0.07
Zone 4	0.24	0.49	0.66	0.62	0.67	0.30	0.33	0.80	0.45	0.51
Zone 5	0.01	0.01	0.09	0.03	0.13	0.05	0.07	0.01	0.01	0.05
Zone 6	0.45	0.59	0.48	0.25	0.44	0.40	0.48	0.64	0.37	0.46
Zone 7	0.01	0.09	0.02	0.05	0.07	0.01	0.02	0.08	0.12	0.05
Zone 8	0.60	0.40	0.31	0.32	0.46	0.47	0.45	0.70	0.54	0.47
Zone 9	0.14	0.01	0.12	0.09	0.02	0.10	0.01	0.11	0.25	0.10

4.2.3 Porosity calculation

Porosity is the void or space inside the rock, they are very useful to store fluids such as oil, gas, and water, and they are also able to transmit those fluids to a place with lower pressure (probably surface) if they are permeable. Porosity calculation is the third step of the petrophysical analysis done in this study and it could only be done correctly if the second step (shale volume calculation is correct). Volume of shale is taken into account in the calculation of effective porosity. There are many methods that can be used to calculate the porosity - in this thesis we have used the neutron and density logs to calculate the total and effective porosity. The neutron-density logs are available in all the wells used in this study.

The method of calculation of the porosity was an interactive interpretation workflow with explicit consideration of neutron matrix scale and shale content. The method is more reliable than traditional method of overlay technique (overlain of neutron–density logs) in the presence of arbitrary lithology and fluid effects. In hydrocarbon-bearing formations, ϕt can be directly calculated from density logs if and only if matrix density ρm and fluid density ρf are known precisely. The workflow was implemented in Techlog©, and the basic algorithm is based on the equation below.

$$\emptyset d = \frac{\rho b - \rho m}{\rho f - \rho m} = \emptyset t + \Delta \emptyset d \qquad \text{EQ. 4.1}$$

Where ρb is bulk density measurement, ρm and ρf are assumed matrix and fluid densities, respectively, e.g., limestone matrix of 2.71 g⁄cm3 and freshwater of 1 g⁄cm^3. The result of the porosity calculation for all the wells is shown in figure 14. The column with white shade is effective porosity while the column with yellow shade is total porosity. It can be observed that the yellow shade is greater than the white shade across the wells. The reason for this is because effective porosity is typically less than total porosity at any given depth due to the fact that the effective porosity excludes isolated pores and pore volume occupied by water adsorbed on clay minerals or other grains. Effective porosity is usually the point of interest in reservoir characterization and it is the one taken into consideration in this study.

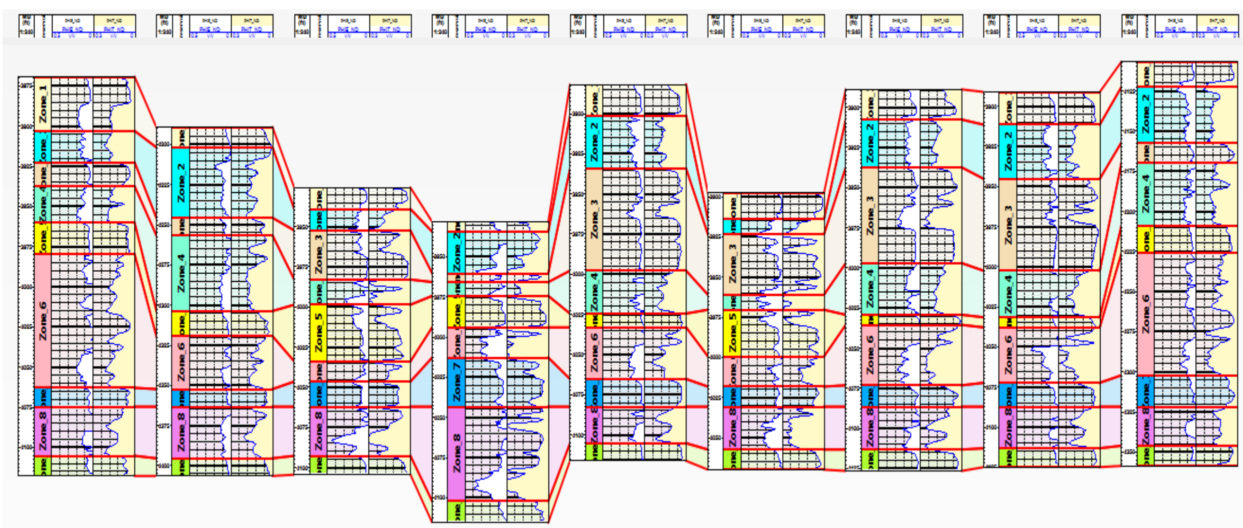


Figure 14: Effective and total porosity for all the wells

In order to see the distribution of the effective porosity more clearly across the wells, a matrix histogram plot with cumulative frequency line is shown below (Fig. 14). The value range between 0-0.5 v/v, with the distribution more symmetrical in Emma well and Drake.

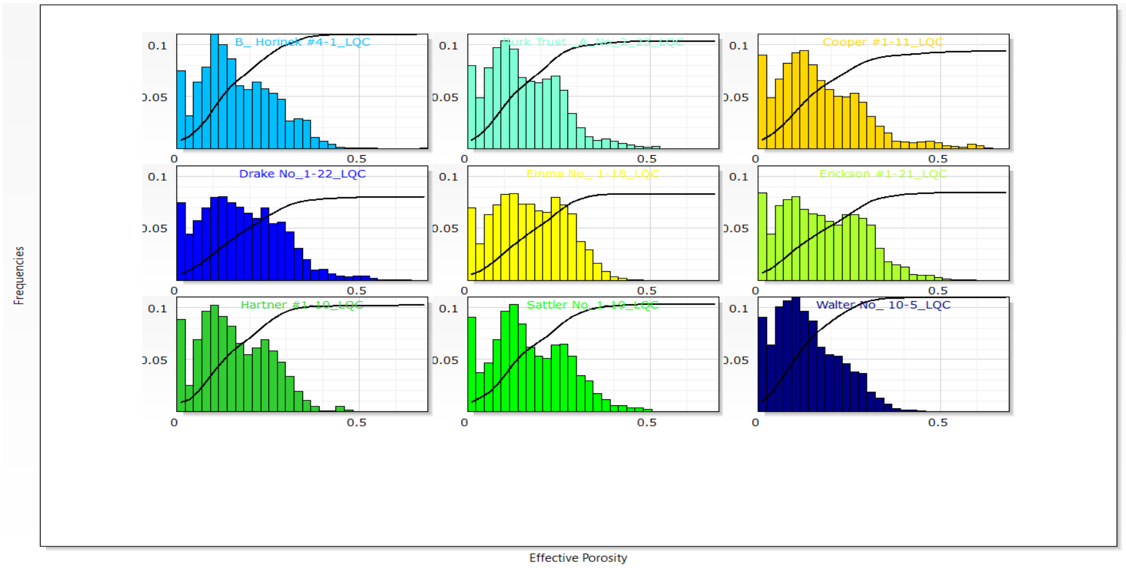


Figure 15: Matrix histogram plot for effective porosity distribution

Along zonal partitioning, the average effective porosity is showing in table 8. The porosity value is higher in zone 2 (0.13 v/v) and least in zone 9 (0.05 v/v). The average porosity value in general indicates low-average based on the porosity classification of Cosse, 1993. [21]

Table 8: Average effective porosity for different zones in each well

Zone	B_Horinek #4-1	Burk Trust _A_ No_ 2-23	Cooper #1-11	Drake No_1-22	Emma No_ 1-18	Erickson #1-21	Hartner #1-10	Sattler No_1-19	Walter No_ 10-5	Zonal Average
	(v/v)	(v/v)	(v/v)	(v/v)	(v/v)	(v/v)	(v/v)	(v/v)	(v/v)	(v/v)
Zone 1	0.10	0.04	0.06	0.13	0.07	0.03	0.10	0.06	0.07	0.07
Zone 2	0.12	0.08	0.15	0.11	0.14	0.16	0.15	0.13	0.12	0.13
Zone 3	0.05	0.08	0.07	0.13	0.07	0.11	0.11	0.06	0.06	0.08
Zone 4	0.14	0.07	0.13	0.11	0.06	0.24	0.12	0.03	0.09	0.11
Zone 5	0.05	0.05	0.11	0.07	0.03	0.10	0.03	0.05	0.06	0.06
Zone 6	0.07	0.05	0.08	0.23	0.09	0.08	0.13	0.11	0.08	0.10
Zone 7	0.058	0.04	0.11	0.09	0.04	0.06	0.06	0.06	0.05	0.06
Zone 8	0.05	0.08	0.16	0.12	0.08	0.14	0.09	0.04	0.05	0.09
Zone 9	0.06	0.04	0.06	0.06	0.04	0.04	0.05	0.03	0.04	0.05

4.2.4 Permeability estimation

Out of the 10 available wells for this study, only one well has core data and therefore, the main task in this section is to predict the permeability for the un-cored wells, (9 wells in total). As for every petrophysical study, the main driving starting point to do the prediction is to construct a relationship between core plug porosity and permeability.

In literature, most of the researchers [30] agreed on that the most successful models can be characterized by a linear relationship between log permeability and porosity coordinate system, with the following equation;

$$log(K) = a .* \emptyset + b \quad \text{EQ.4.2}$$

Where *a* and *b* are the calibration parameters.

This equation works properly for the sandstone reservoirs, but it can be a big problem in carbonate reservoirs. The equation can fails with increasing heterogeneity and non-uniformity that usually characterize the carbonate rocks (Altunbay, et.al., 1997). In this study, the first step was to make an evaluation of the data provided by core sample of Soucheck. The data provided was introduce in to an excel spreadsheet as shown in (Appendix 1). The core plug porosity measurements are plotted against logarithm of core permeability. The plot is given in figure 15. A linear regression analysis was run between the two data. The resulting regression equation is given in equation 4.3 with R^2 value of 0.60 which is an acceptable value to progress to core-log transformation.

$$log(K) = 0.0046 * \emptyset + 0.052 \quad \text{EQ.4.3}$$

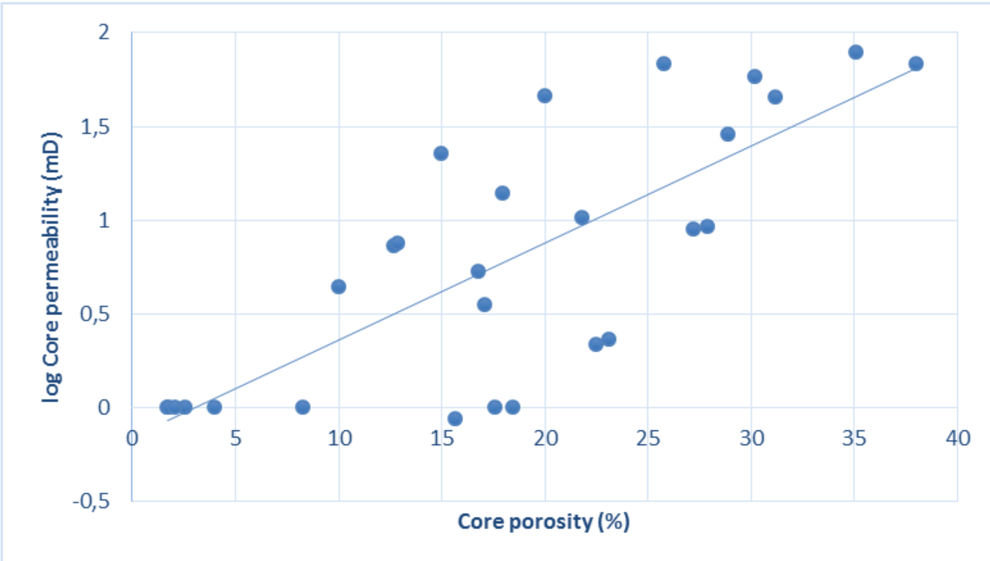


Figure 16: Core permeability and porosity relationship.

The result of core-to log transformation is shown in figure 17 below. The permeability derived for each well showed different characteristic across the zones. Permeability is important for the fluid flow, hence its importance in reservoir characterization.

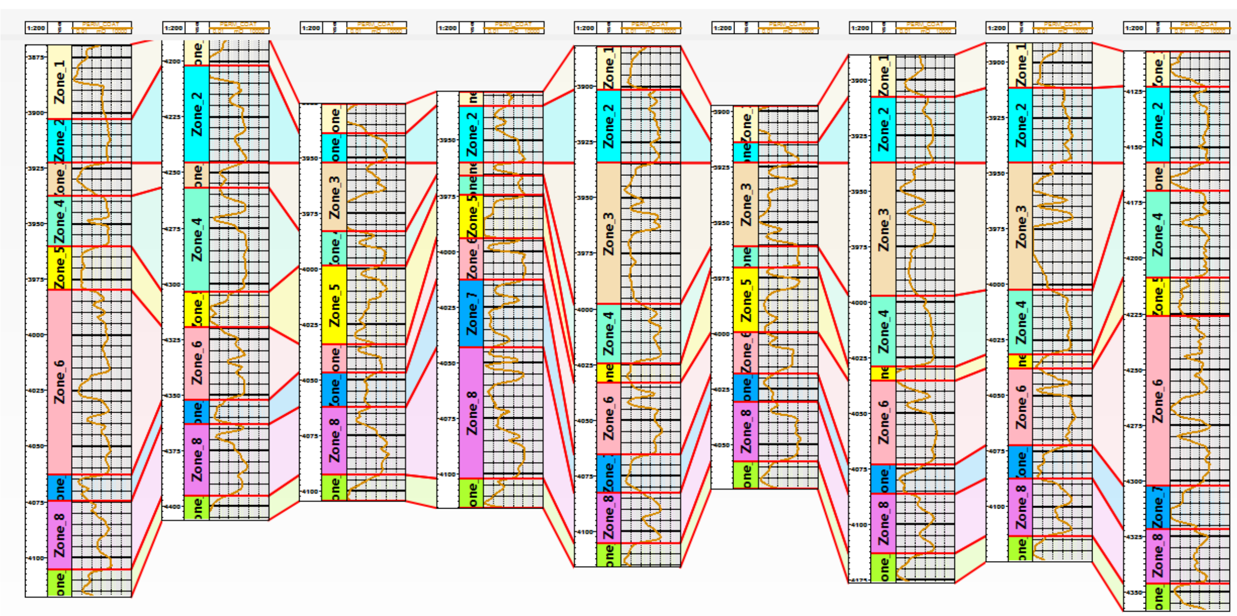


Figure 17: Permeability derived from core permeability and core porosity relationship wells where core data is absent.

Table 9: Average permeability per zone

Zone	B_Horinek #4-1	Burk Trust _A_ No_ 2-23	Cooper #1-11	Drake No_1-22	Emma No_ 1-18	Erickson #1-21	Hartner #1-10	Sattler No_1-19	Walter No_ 10-5	Zonal Average
	(mD)	(mD)	(mD)	(mD)	(mD)	(mD)	(mD)	(mD)	(mD)	(mD)
Zone 1	10.30	0.23	0.23	4.72	0.51	0.04	2.33	1.31	22.04	4.63
Zone 2	36.82	21.97	51.00	39.58	30.43	43.76	30.35	28.84	37.13	35.54
Zone 3	0.72	1.56	27.42	21.49	37.15	35.07	40.67	35.43	1.21	22.30
Zone 4	33.61	35.29	42.17	43.66	37.55	65.88	33.54	35.88	33.00	40.06
Zone 5	0.248	0.322	38.04	46.99	0.077	48.42	0.042	0.09	0.26	14.94
Zone 6	26.75	23.50	28.73	62.76	35.01	24.74	49.62	47.81	29.66	36.50
Zone 7	0.76	0.23	1.984	26.34	0.50	0.18	0.80	19.24	0.67	5.63
Zone 8	34.59	23.15	41.85	44.18	39.15	54.36	31.45	34.24	29.76	36.97
Zone 9	1.46	0.06	1.34	0.40	0.08	0.18	0.34	0.06	27.46	3.48

We also checked the permeability calculation with a different method that is based on log using Coates method that is based on the equation 4.4 [2]. The inputs are irreducible water saturation and calculated effective porosity and calculated total porosity (both were earlier calculated for each well). The value of irreducible water saturation was taken as 0.15, this amount represent the water saturation that will always remain in the rock pore no matter how much force is applied, as earlier defined in chapter 2. The plot of the correlation between the two methods of permeability is shown in figure 18. With the high correlation observed as indicated by the R^2 value (0.989), that indicated that both values honor each other, it is taken that the propagated permeability derived from the core permeability/porosity relationship is sufficient to be used in the other wells.

$$PERM = kc * PHLe4 * \left(\frac{PHLt - PHLe * Swirr}{PHLe * Swirr}\right) \qquad \text{EQ4.4}$$

Kc =constant

PHLe = calculated effective porosity

PHLt = calculated total porosity

Swirr = irreducible water saturation

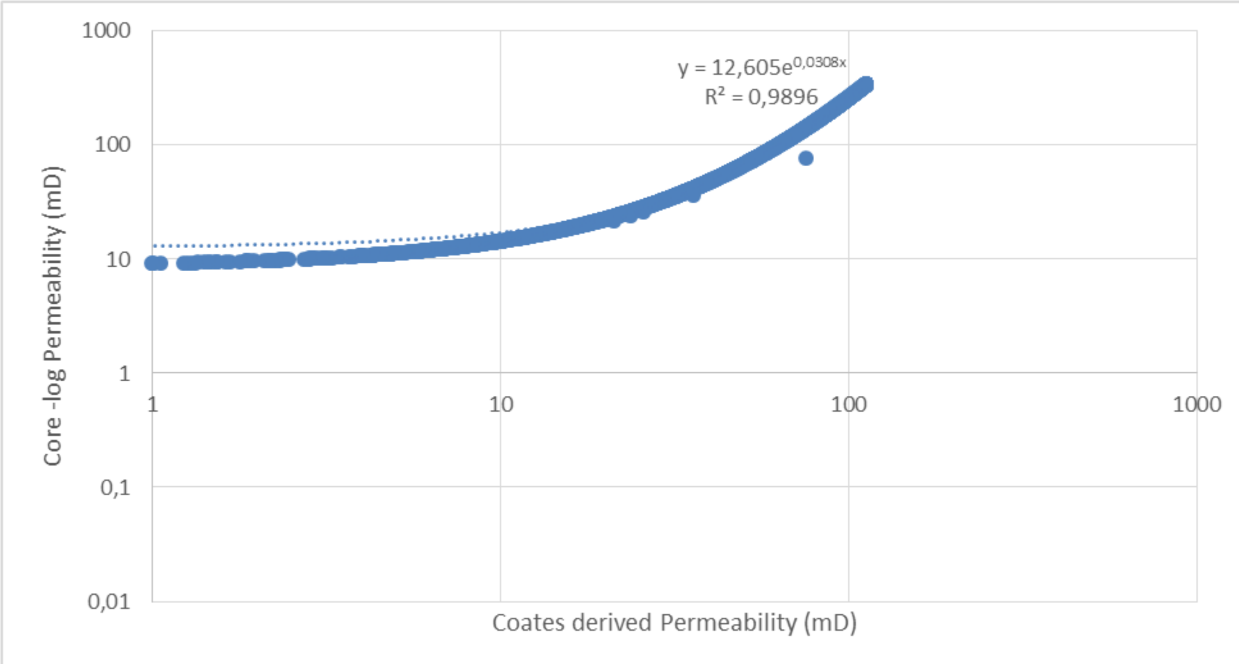


Figure 18: Correlation between two permeability methods.

4.2.5 Fluid Saturation

In order to determine the saturations of hydrocarbons within the formations, first saturations of water should be calculated.

To calculate the water saturation, Archie equation algorithm embedded in TechLog© software based on equations 2.13 and 2.16 earlier described in chapter 2. The equations are shown below ($S_w = (\frac{a * R_W}{R_t * \emptyset_t^m})^{\frac{1}{n}}$, $S_H = 1 - S_W$). The water saturation (S_w) is first calculated, with water saturation known, volume of hydrocarbon (S_H) can be derived. The values of cementation factor (m) and saturation exponent (n) were assumed for the calculations.

However another input that is needed is Rw which is the resistivity of water in the uninvaded zone. However because there is no information provided for R_w, we have calculated R_w based on porosity and resistivity input. The algorithm is based on equation 2.14 as shown ($\frac{R_o}{R_w} = \frac{a}{\emptyset^m}$). This is possible because of the relationship between R_o and R_w typically called formation factor.

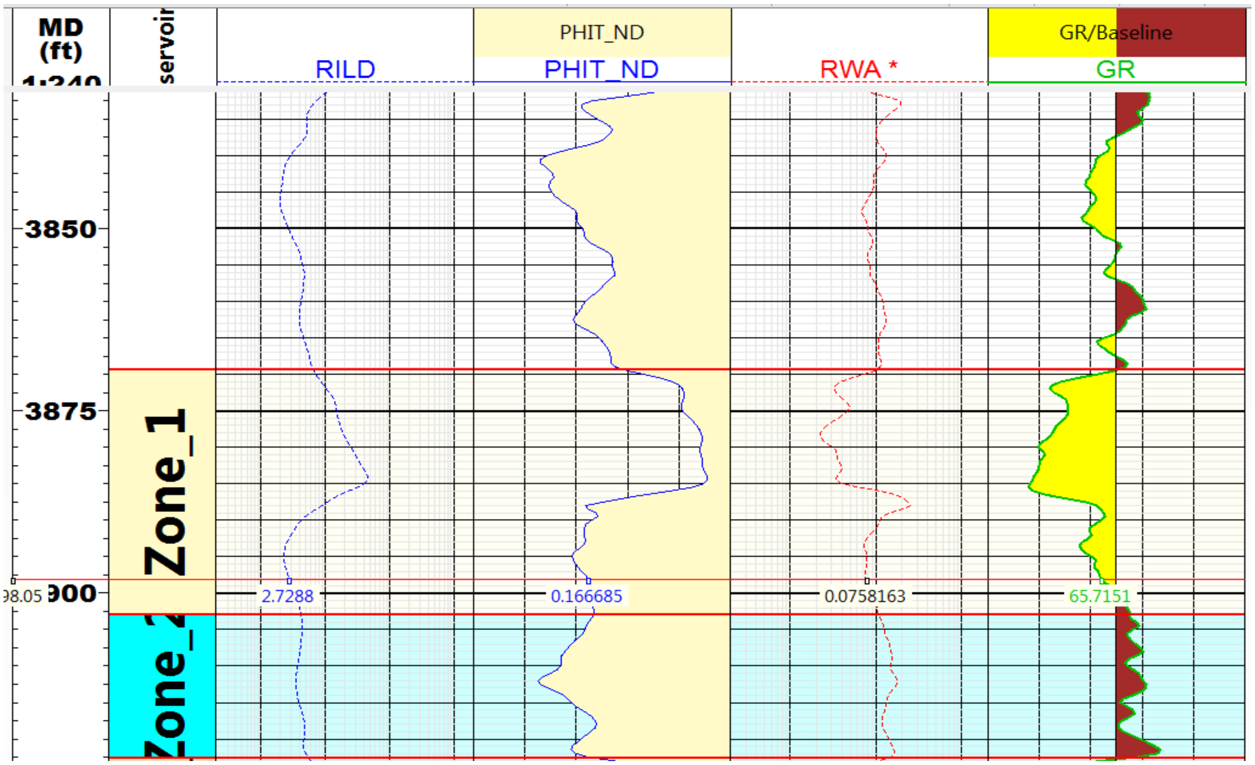


Figure 19: Example of Rw determination as seen for Well B. Horineck

An example of R_w determination is seen for Well B. Horineck, the value of R_w in a clean water saturated zone is 0.0758 ohm-m (Fig. 19). The same procedure was repeated for all the wells to derive R_w used in water saturation equation. The final calculation of water saturation for each well is shown in figure 20. The distribution of water saturation varies across the zone, based on the input parameters of Rw, a, m and n.

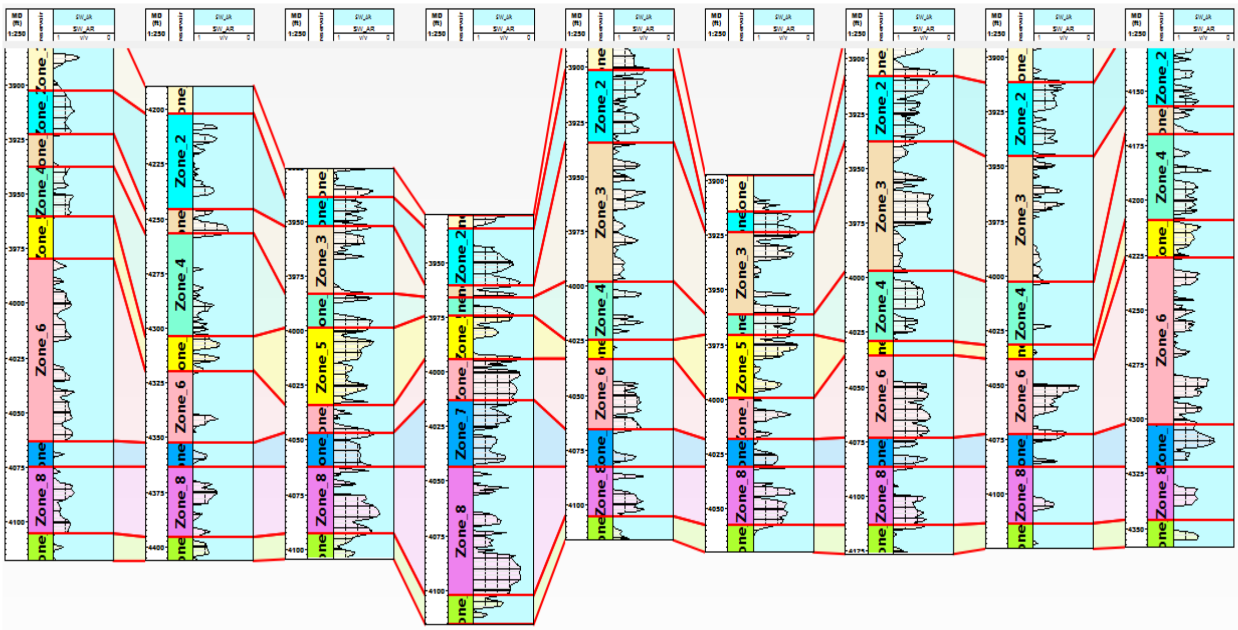


Figure 20: Distribution of water saturation per zone across the wells

Table 10: Average water saturation calculated for each zones per well

Zone	B_ Horinek #4-1	Burk Trust _A_ No_ 2-23	Cooper #1-11	Drake No_1-22	Emma No_ 1-18	Erickson #1-21	Hartner #1-10	Sattler No_1-19	Walter No_ 10-5	Zonal Average
	(v/v)	(v/v)	(v/v)	(v/v)	(v/v)	(v/v)	(v/v)	(v/v)	(v/v)	(v/v)
Zone 1	0.74	0.99	0.64	0.66	0.67	0.91	0.54	0.85	0.13	0.68
Zone 2	0.65	0.59	0.57	0.52	0.45	0.44	0.57	0.73	0.75	0.58
Zone 3	0.83	0.42	0.73	0.43	0.44	0.56	0.65	0.87	0.83	0.64
Zone 4	0.66	0.50	0.54	0.60	0.51	0.38	0.68	0.96	0.78	0.62
Zone 5	0.97	0.53	0.50	0.63	0.93	0.60	1	0.98	0.72	0.76
Zone 6	0.63	0.62	0.59	0.31	0.51	0.78	0.57	0.67	0.76	0.60
Zone 7	0.81	0.75	0.51	0.55	0.59	0.74	0.66	0.79	0.57	0.66
Zone 8	0.63	0.60	0.48	0.67	0.48	0.53	0.66	0.92	0.83	0.64
Zone 9	0.83	0.72	0.41	0.74	0.79	0.94	0.84	0.99	0.83	0.78

The calculated water saturation on zonal average shows a value of 0.58-0.78 v/v (Table 10). The lowest average value of 0.58 v/v is observed in zone 2 while the highest of 0.78 v/v is observed in zone 9.

The reason for the high values could be as result of low quality rock that are part of the zonation used in the computation, this low quality rocks can introduce erroneous volume of water that are part of the shale intervals within the zones, and also the average method added some intervals with high water saturation values.

If a vertical baseline is set at 50% as shown in column 4 in the figure below (Fig. 21) we can see more clearly how the water saturation varies clearly in a well. Those values below 50% can be seen to be oil saturated (i.e. S_h= 1-Sw).

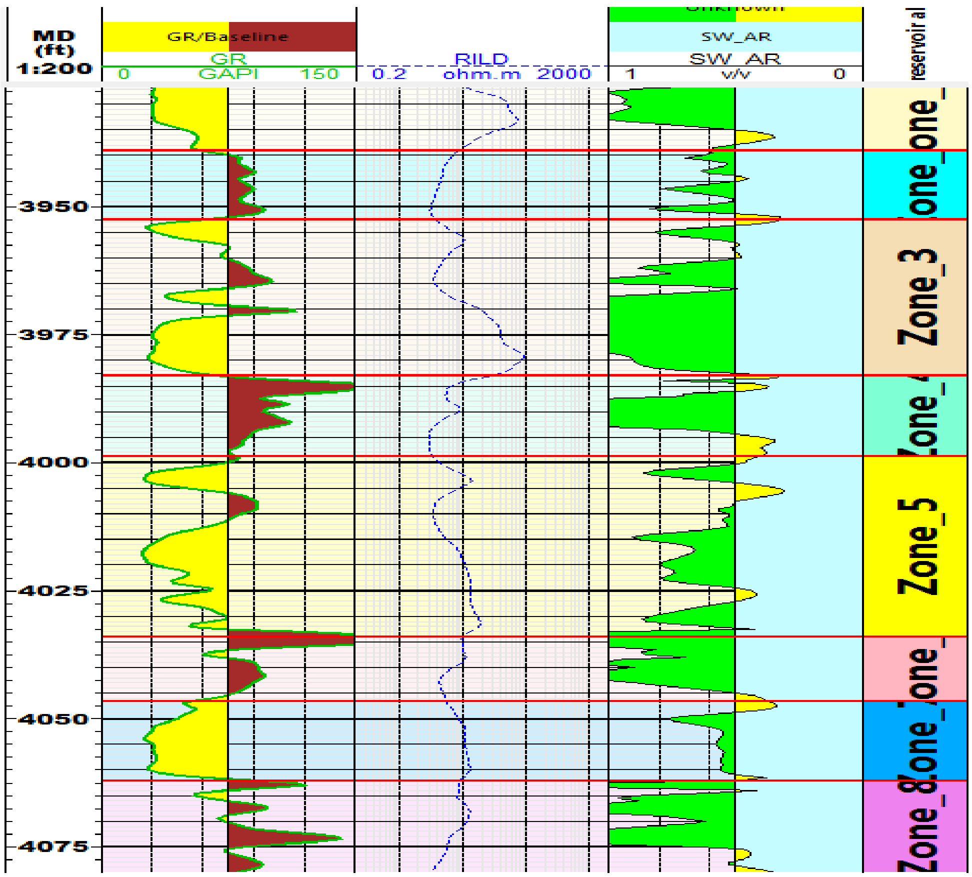


Figure 21: Vertical baseline for water saturation display

5.0 Rock typing and facies classification

Rock typing or classification is an emerging reservoir description tool that elicits broad research interests in the oil and gas industry. It has become increasingly important in modern reservoir characterization to invoke close integration of multi-discipline, multi-physics, and multi-scale subsurface data, including pore imaging, core measurements, well logs, seismic amplitude data, well testing, and production surveillance [25].As mentioned in the preceding chapter, there is an effect of variation of the rock composition on the calculated fluids saturation due to rock qualities that were not uniform.

In this chapter an attempt will be made to do a rock classification using rock mechanical facies. The rock classification or rock type derived will then be converted to a new zonation set that will be applied to re-define the parameters used in water saturation computation to compensate for the difference in rock quality. Therefore, developing new rock classification schemes and workflows that serve multiple characterization purposes from different disciplines remains a challenging but important task in this study.

5.1 Rock mechanical properties prediction

Rock mechanics as a definition is the theoretical and applied science of the mechanical behavior of rocks. It is that branch of mechanics concerned with the stability of the force fields of its physical environment. In other words, it can be said that rock mechanics characterize the mechanical properties, strength and geometry of the natural fractures existing in the rock mass. The method of rock mechanical properties was used for rock classification. The basis for this method is the fact that many of the same factors that affect rock mechanics also affect the other rock properties such as velocity, elastic moduli, permeability and porosity (Chang et al., 2006).

The proposed method is shown to simply and rapidly provide an estimate of the rock mechanical properties with a satisfactory range of uncertainty. The rock mechanical properties predicted based on the available logs in this study are frictional angle (FANG), unconfined compressive strength (UCS) and Poisson's ratio.

5.1.1 Unconfined compressive strength

Since in the present study we have Carbonates, more specific Limestone and Dolomites, it will be suitable to talk about the UCS in this case. In the present there are several empirical equations that can be used Table 11, but in our case since overall we have low porosity, in the given study the most appropriate one will be Rzhevsky and Novick (1971) which will state like:

$$UCS = 276(1 - 3\emptyset)^2 \qquad \text{EQ 5.1}$$

Where $\emptyset = calculated\ porosity$

Table 11: Empirical equations of UCS and other physical properties in carbonates [81]

Eq. no.	UCS (MPa)	Region where developed	General comments	Reference
(22)	$(7682/\Delta t)^{1.82}/145$	–	–	Militzer and Stoll (1973)
(23)	$10^{(2.44+109.14/\Delta t)}/145$	–	–	Golubev and Rabinovich (1976)
(24)	$13.8E^{0.51}$	–	Limestone with 10<UCS<300 MPa	
(25)	$25.1E^{0.34}$	–	Dolomite with 60<UCS<100 MPa	
(26)	$276\,(1-3\phi)^2$	Korobcheyev deposit, Russia	–	Rzhevsky and Novick (1971)
(27)	$143.8\exp(-6.95\phi)$	Middle East	Representing low to moderate porosity ($0.05<\phi<0.2$) and high UCS (30<UCS<150 MPa)	
(28)	$135.9\exp(-4.8\phi)$	–	Representing low to moderate porosity ($0<\phi<0.2$) and high UCS (10<UCS<300 MPa)	

In this study for the calculation of Unconfined Compressive Strength have been used Techlog ©. The EQ.5.1 was introduced in the system among the porosity values for each depth. For each individual value where is the case was calculate the equivalent of the UCS. Therefore the UCS was analyzed against the porosity in a Log Plot in order to have a better interpretation on the possible reservoirs.

5.1.2 Poisson's ratio

Poisson's ration (PR) is the ratio of expansion in one direction of a rock caused by a contraction at right angles. The PR of the common materials in usual measures from 0.0 to 0.5, 0 in case the material shows no Poisson contraction as a response to the extension. On the other side a material which will have perfectly compression which deforms elastically at small strains will have the values close or 0.5. In case of rocks, Poisson effect will take place under stress and strain.

Poisson's Ratio can be calculated using a set of logging data, such as Deep Resistivity, Fluid Saturation or P and S wave elastic wave velocities. This method can be very useful in rock mechanical calculation such as, UCS, angle of internal friction or cohesive shear strength. PR can be used in other purposes such as; borehole stress, modelling seismic response or acoustic response of the selected formation. The method depends on two factors, pore fluid characteristics and the shaliness of the formation (Craig, 2000). In the present study the following equation have been used:

$$\vartheta = 0.125 * q + 0.27 \qquad \text{EQ 5.2}$$

Where: q= shaliness index

To realize the PR calculation, at first the shaliness index was calculated. For this to be done an equation that is suitable for unconsolidated ground water aquifer will be needed in order to fulfil our formation requirements. Therefore the definition of dispersed-shale index was chosen (Anderson et al.,1973).

$$q = \frac{\emptyset_S - \emptyset_D}{\emptyset_S} \qquad \text{EQ 5.3}$$

Where:

$\emptyset_S$= porosity from the sonic log

$\emptyset_D$= porosity from density log

5.1.3 Frictional angle

We utilized gamma ray (GR) log for the estimation of friction angle (FANG). This method maps gamma ray to friction angle with a linear correlation. A cutoff is applied to friction angle. With default parameters, GR 120 gAPI is mapped to FANG 20 dega and GR 40 gAPI is mapped to FANG 35 dega.

5.2 Computation of rock mechanical facies model

The rock mechanical facies (RMF) were defined from the three predicted rock mechanical properties derived from above equations using the index and probability generating a self-organizing map (IPSOM). IPSOM components provide automatic classification solutions with both supervised and unsupervised methods. These methods are based on the neural network technology (The Kohonen algorithm (2013 Schlumberger)). All the methods were implemented using the Techlog ® wellbore platform. This approach is applied to all the wells where the Lansing units are encountered. Fig. 1 shows the typical facies workflow using IPSOM. The major steps involved in building the RMF classification groups are;

a. Neural analysis -clustering of the inputs in order to get a down sampled but a representative set of nodes.

b. Indexation + model refinement-regroup nodes with similar properties or assign facies to each node based on the indexation inputs. Model refinement is optional but can be used to define optimal number of classification groups.

c. Model application-apply the model on wells in order to create classification groups.

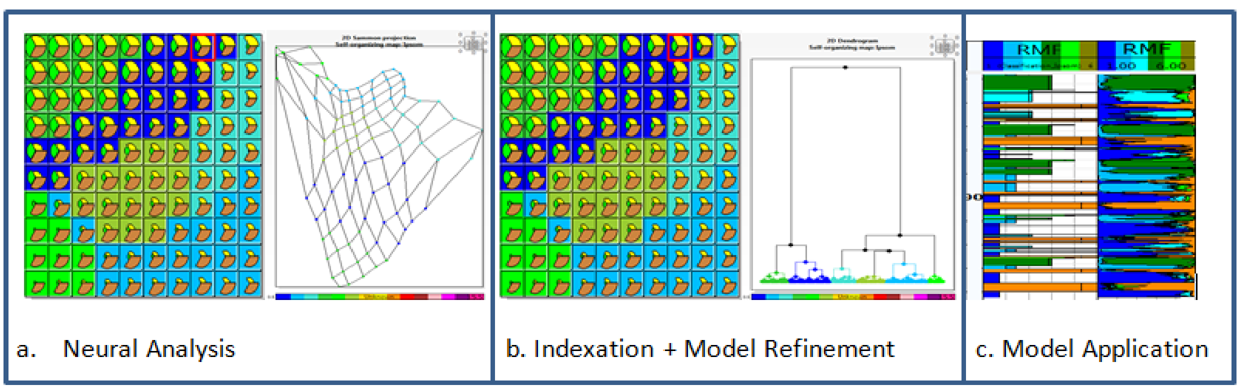


Figure 22: Example of the typical workflow using IPSOM. The steps involved include a. neural analysis, b. indexation + model refinement (model refinement is optional), and c. model application.

Rock Mechanical Facies Interpretation

Rock mechanical facies (RMF) classification obtained from the 3 predicted mechanical properties using the IPSOM method that is based on a neural network. Table 1 and Table 2 show the key information of the RMF classification groups.

Table 12: Variable correlation and contribution of each variable in the classification

Variable	Correlation	Information
Unconfined Compressive Strength	0.8986425	0.4240372
Friction Angle	0.8441257	0.3983127
Poisson's ratio	0.3764854	0.17765

Table 12 shows the correlation of the input variables with RMF model and the contribution of each variable in the classification. Statistical results are displayed in Table 13 that shows the mean and variance of the each input variable within each modality.

Table 13: The mean and variance of each input variable within each modality

Name	**Friction Angle**		**Unconfined Compressive Strength**		**Poisson's Ratio**	
RMF	Mean	Variance	Mean	Variance	Mean	Variance
1	32.6282	8.9346	157.8909	905.972	0.2909	0.0017
2	25.5071	3.5084	40.6275	605.578	0.3121	0.0008
3	31.0373	4.2147	53.0164	399.7909	0.2287	0.0067
4	35.2572	2.6856	226.9136	386.4886	0.3203	0.0012
5	18.3952	4.5489	55.19833	96.8206	0.2986	0.0015
6	27.0357	1.5116	95.3997	360.2865	0.3358	0.0001

6.0 Hydraulic flow units

A hydraulic flow unit is a volume of total reservoir rock within which geological and petrophysical properties that affect fluid flow are internally consistent and different from properties of other rock volumes and it provides a basis for many other reservoir characterization efforts such as saturation-height analysis and dynamic reservoir modeling (Rushing et al., 2008). Different hydraulic rock typing methods were advanced in the past; some of them use core measurements, such as Leverett's reservoir quality index (RQI) and flow zone indicator etc. [4]

The flow unit by definition is a reservoir zone which has lateral continuity, where the geological properties which are controlling the fluid flow are internally constant, and there are different from all the other adjacent flow units. The flow units can be identifying in the capillary pressure curves measured from the core samples extracted from the reservoir or by recognition of the pore throat radius from the core porosity and core permeability measurements or from well log data. Ability to define hydraulic flow units allowed a better petrophysical characterization and description of the field and can be used as inputs for construction of a reservoir model.

6.1 Flow zone indicators

In this study we have attempted a delineation of the hydraulic flow units in the uncored-wells having well logs by considering the relationships between petrophysical parameters of permeability and porosity calculated. The method used to calculate the hydraulic units are statistical, and it recognized the similar fluid flow characteristics (flow zone indicator) that are independent of the lithofacies. The purpose of doing the flow zone indicator is with respect to reservoir performance.

By using the concept developed by Amafule, flow zone indicator can be calculated as shown below. [4]

$$0.0134\sqrt{\frac{k}{\emptyset_e}} = \left[\frac{\emptyset_e}{1-\emptyset_e}\right]\left[\frac{1}{\sqrt{F_s * TS_{gv}}}\right] \qquad \text{EQ: 6.1}$$

Where:

K= permeability (md)

$\emptyset_e$= effective porosity

F_s= shape factor

T= tortuosity

S_{gv}= surface area per unit grain volume (μm)

Flow zone indicator FZI is related to the rock quality index as shown in equation 7.4.

$$RQI = 0{,}0134\sqrt{\frac{k}{\emptyset_e}} \qquad \text{EQ: 7.2}$$

$$\emptyset_z = \frac{\emptyset_e}{1-\emptyset_e} \qquad \text{EQ: 7.3}$$

$$FZI = \frac{1}{\sqrt{F_s}\tau S_{gv}} = \frac{RQI}{\theta_z} \qquad \text{EQ: 7.4}$$

Equation 7.4 can be written as shown in equation 7.5 to do a computation for plotting a log-log based on equation 7.4 for RQI versus $\emptyset_z$. All points that have similar FZI will be on a straight line slope equal to 1 and the value of FZI is determined at the intercept of the slope at $\emptyset_z$= 1.

$$logRQI = log\emptyset_z + logFZI \qquad \text{EQ: 7.5}$$

Where:

RQI= reservoir quality index (μm)

$\emptyset_z$= pore volume-to-grain volume ratio

FZI= flow zone indicator (μm).

Using equation 7.4, FZI was calculated and transformed to log FZI. FZI distribution is a superposition of multiple log-normal distributions, a histogram of log FZI should therefore, show an *n* number of normal distributions for *n* number of hydraulic flow units. The histogram of log FZI is shown in figure 23. The result indicated that 6 numbers of hydraulic flow units were recognized based on histogram analysis.

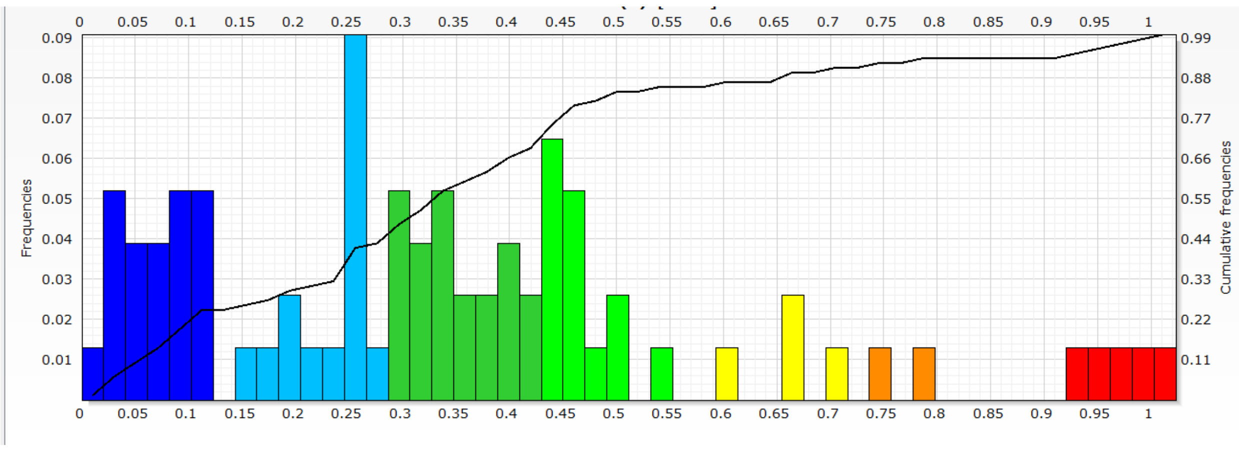


Figure 23: Numbers of hydraulic flow units recognized based on histogram analysis

In some cases, it is often difficult to separate the overlapped individual distributions from a histogram plot, a normal probability analysis was also done to check. Using a normal probability function to analyze the flow zone indicator n linear distributions can be obtained which show the number of hydraulic flow units. The probability plot (the cumulative distribution function) is the integral of the probability density function (histogram). A normal distribution forms a distinct straight line on a probability plot. Therefore, the number of straight lines in the probability plot may be used to indicate the number of hydraulic flow units in the reservoir. Figure 24 shows a probability plot of the logarithm of FZI for all the data for the 9 un-cored wells in the Lansing Formation. A total of 6 hydraulic flow units were distinguished for the reservoir zones in this study, numbered H1, H2, H3, H4, H5 and H6.

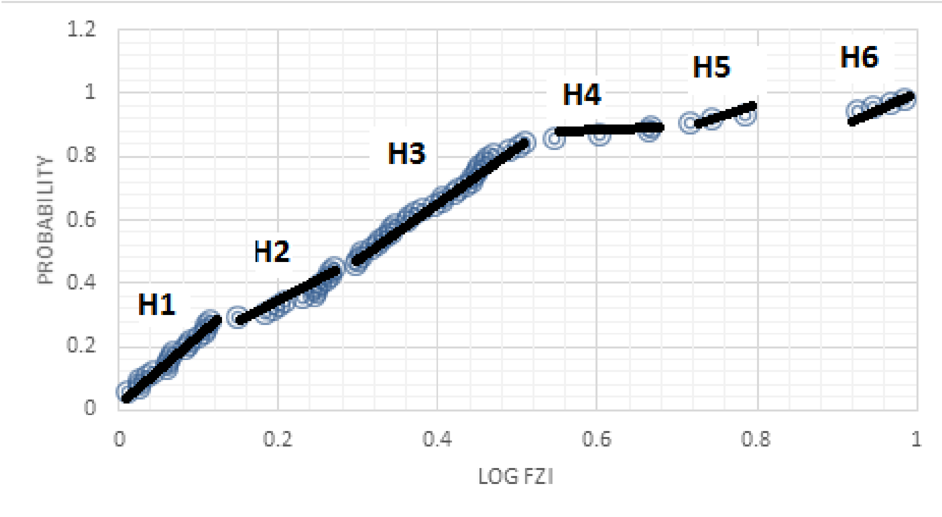


Figure 24: Probability plot of the logarithm of FZI

By loading the calculated FZI and log FZI into Techlog ©, the values can be displayed across the 9 wells (Figure 25). The hydraulic flow units have increasing value from blue to red as shown in the legend. Blue represents the lowest hydraulic flow unit while red correspond to the highest flow unit. The pattern suggest that the best flow units lies mostly at the top zones in about 6 of the wells (the wells in the middle), while two to three wells have best hydraulic flow units towards the bottom zone. This could be due to the structural position of the wells (at the flanks). In general each well has different numbers and distribution of hydraulic flow units.

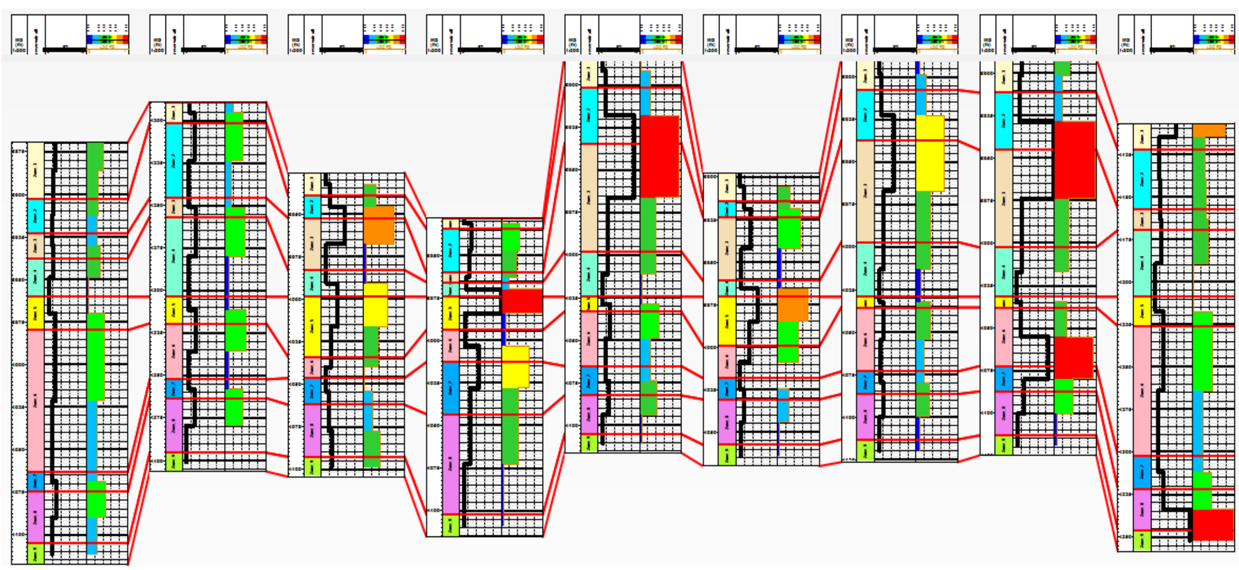


Figure 25: FZI and log FZI across the nine un-cored wells

The 2D model of the log FZI is displayed in figure 25 above, showing how the flow units are connected across the wells. It can be seen that the structural high wells have the best pattern of hydraulic flow paths. The 2D map allows for rapid identification of areas of the field dominated either by high flow zone or low flow zone, which is also linked to the rock quality index (RQI).

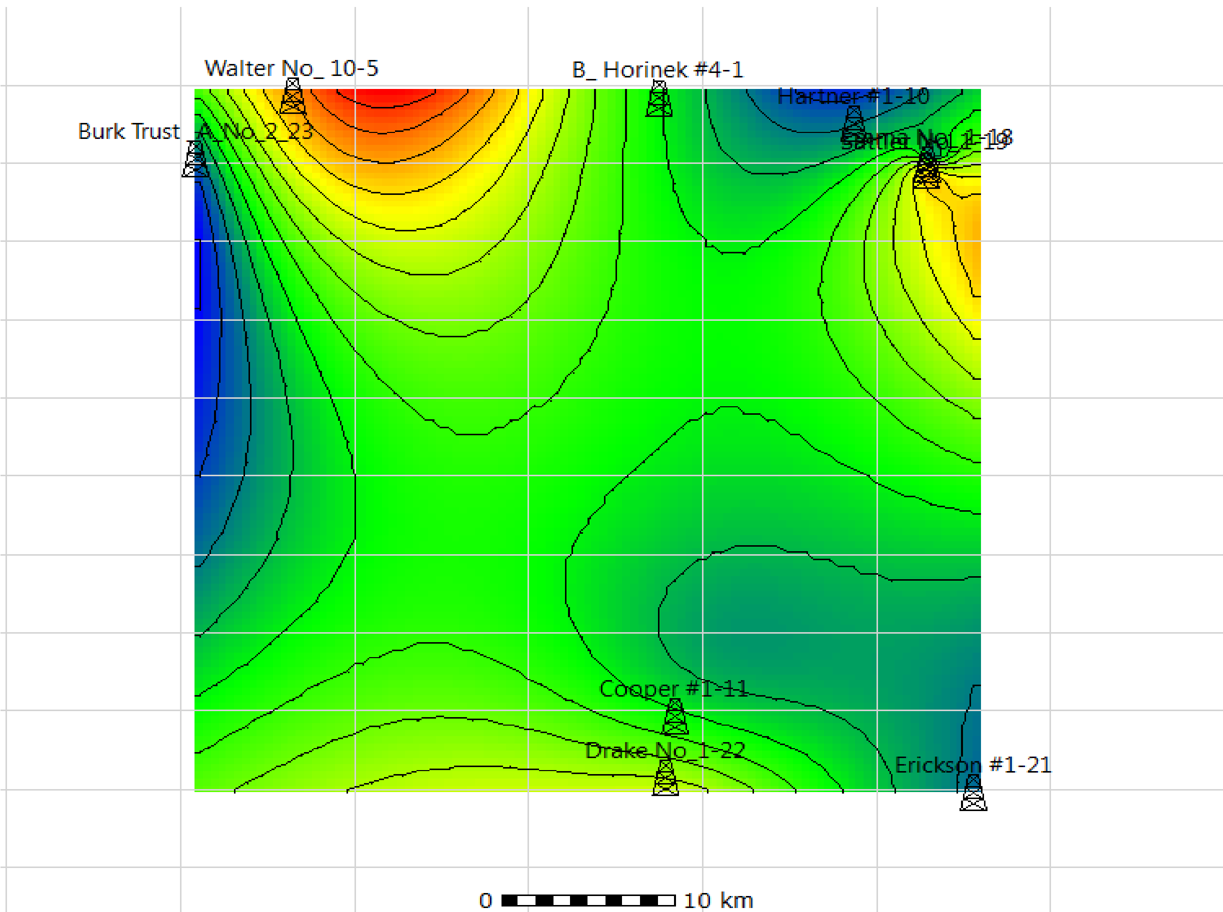


Figure 26: 2D map of the flow zone indicator (FZI) for all the wells used in the study.

7.0 Findings and Discussion

In this study, we have applied a new rock classification method to describe a challenging Lansing Formation of reservoirs comprising mixed clastic-carbonate sequences. The summary of the outputs for all the wells is shown in the Appendices (2-11).

7.1. Well correlation and lithology

From the well correlation, the thickness of the Lansing Formation in the wells study from Rawlins County ranges from about 172 to 251 feet. In terms of zonal classification used in the study, 9 zones were identified with thickness of between 12 to 38 feet (Table 7). When summed up, this give an average of 218 feet for Lansing Formation thickness for the 9 wells used in this study. This is consistent with the thickness of the Lansing Group in the subsurface of eastern Kansas ranges from about 20 to 250 feet [32].

Lithology interpretation of the Lansing Formation across the wells was done by the use of well log; gamma ray. Three main lithology types; - limestone, quartz and shales (determined from shale volume calculations) were recognized in the wells studied. The limestone and shale usually occur in alternations. From the analysis of the well logs, the limestone and quartz was recognized by low gamma ray count while the high gamma ray count indicated shale units. The carbonate ratio of the Lansing Formation ranges from about 20 to 90 percent but has no readily apparent correlation with thickness of the zones. The irregular high carbonate ratios may indicate marine limestone buildups. The presence of interbedded shales provided the top seals against vertical migration of hydrocarbon within the Lansing Formation.

7.2 Petrophysical parameters

Different petrophysical properties were determined as part of the reservoir characterization exercise. These include porosity, permeability and water saturation.

7.2.1 Porosity

Porosity calculation was done using the neutron-density method to allow for a mix of minerals that is consistent with carbonate formation such as Lansing Formation. Porosity values calculated across the 9 zones identified in the studied wells range from 5% to 13%. This porosity is assumed to be primary porosity. Main observation from the calculation of the porosity is that the porosity distribution in this formation is not uniform due to the nature of the Lansing statigraphy. The ranges of porosity, as shown by the calculated values (Table 8) indicate the necessity for accurately determining porosity. Irregular distribution of porosity could hamper oil production efforts if not properly accounted for, and it therefore necessary to identify area with good porosity distribution during reservoir characterization.

In addition, there is no availability of core data for majority of the wells used in this study, however the core porosity from the core samples available from well Soucheck showed a value of 2-30% porosity for 33 samples taken across a 185 feet interval of Lansing Formation, confirming the irregular nature of the porosity distribution in Lansing Formation. The average was calculated to be 9.5% porosity. This still falls between low to average porosity classification of Cosse, 1993. However, some limestone units within the Lansing formation have been reported to have additional secondary porosity [30].

7.2.2 Permeability

The matrix permeability of reservoirs is a key parameter that provides an understanding of the global flow hierarchy in the pore network and flow channels. The permeability hierarchy was conceived by transforming the core permeability–porosity relationship from cores to uncored wells. This was based on the fairly good correlation measured between the core permeability and core porosity. Average permeability calculated per zone across the wells range from 3 to 40 mD. This is within the range of permeability measured on core plugs that range from 0 to 77 mD. Though it can be observed that there is a difference of few order of magnitude, the samples have been taken at different depth in interval, while the value calculated were for zonal average. Zones 2, 4 and 6 appear to have higher magnitude of permeability compared to other zones (Table 9). In addition, the defined reservoir quality index parameter can be used as a support for permeability behavior. It was observed that higher permeability zones have better the rock quality index (Table 14)

Table 14: Permeability and rock quality index for all zones across the wells

Zones	Permeability (mD)	Porosity (v/v)	RQI
Zone 1	4.63	0.07	0.17
Zone 2	35.3	0.13	0.44
Zone 3	22.30	0.08	0.42
Zone 4	40.06	0.11	0.45
Zone 5	14.94	0.06	0.26
Zone 6	36.50	0.10	0.46
Zone 7	5.63	0.06	0.19
Zone 8	36.97	0.09	0.46
Zone 9	3.48	0.05	0.14

7.1.5 Fluid saturation

In this study the water saturation was calculated using the Archie's equation and based on the zonation derived from well correlation. Since in the fluid calculation the petrophysical parameters such as formation water(R_w), the cementation exponent (*m*) and tortuosity factor (*n*) are important, these factors can vary within a short vertical distance and can assume a multitude of values as indicated by the incorporation of the rock types to the water saturation calculations. This potential therefore needs to be recognized in relation to reservoir characteristics since these parameters can be the main source for controlling fluid saturation in Lansing Formation. As earlier demonstrated, the computed water saturation could be affected by the complexity of facies and diagenesis of rocks within the zones if not taken into consideration as shown by the example using well B. Horineck for improved water saturation calculation (Fig. 5.5). With the introduction of rock types defined by the rock mechanical facies that allows proper definition of the petrophysical parameters such as formation water(R_w), the cementation exponent (*m*) and tortuosity factor (*n*), hydrocarbon saturation can be improved by 0-30 %. If we translate this to about 200 wells in the Rawlins County that was producing about 19 million barrels annually in pre-improved reservoir characterization era, production can be improved by between 0-5.6 million barrels of oil per year.

7.2. Rock facies hydraulic flow units

Rock mechanical facies which represent the rocks' dynamic and mechanical properties was used in this study to characterize and subdivide reservoir formations. The rock mechanical facies recognized from the input data were four types, i.e. type 1, 2, 3, and 4. These four rock types were correlated to initial reservoir zones. It was observed that most of the initial reservoir zones (9 zones) can lie in more than one rock mechanical facies. The best facies recognized are the type 4 followed by type 3, 2 and 1 in descending order. Therefore, mapping both lateral and vertical variation of the rock mechanical facies for some reservoir zones may provide a basis for implementing different reservoir characterization practices in different areas/zones of the field. The ultimate use of this information was demonstrated in the improved water saturation calculation for well B.Horinek that takes into account the rock type in the assignment of key petrophysical parameters used in Archie equation. Using the rock types in the computation, it was found that error in water saturation can vary between 0-30 percent.

Individual hydraulic flow units were identified based on integration of data regarding the distribution of rock quality index (RQI), petrophysical properties (particularly permeability and porosity) and flow zone indicator (FZI). Evaluation of this data for 9 wells reveals that there are major 6 hydraulic flow units across the wells within the Lansing Formation and that a good prediction of the hydraulic units can be predicted from either the histogram plot of log FZI, or the normal probability plot of the same log FZI. The hydraulic flow units were numbered as H1, H2 H3 H4 H5 and H6. The increasing order of flow characteristics is H1-H6, meaning that H6 has the best flow zone indicator. On observation, one reservoir zone can have more than one flow zone indicator, and FZI is also linked to the rock quality index (RQI). The reasonable link between the RQI and flow zone depict the relationships of the integration of rock petrophysical properties. High quality flow units have high rock quality index and vice versa. This information can be used in further reservoir performance estimation during the flow simulation.

7.3. Conclusion

The study of carbonate reservoirs within the Lansing Formation in Rawlins County, Kansas was carried out for improved reservoir characterization. Well logs from 9 wells consisting of such logs as gamma ray log, resistivity log, sonic log, acoustic log and bulk density were used in the evaluation. Only one well has core data.

On the basis of the work conducted it can be concluded that the Lansing carbonate formation has a complex lithology which is typical of mature carbonate formations. The rock quality can vary within a particular zone. The effect of this can be seen in the unusual distribution of both porosity and permeability, which are some of the key petrophysical parameters needed for adequate reservoir characterization. It is therefore important to account for this varied petrophysical parameters when assessing the reservoirs for hydrocarbon saturation for future development. The error that can arise in saturation computation if the varied rock quality is not taken into account could be between 0-30 percent.

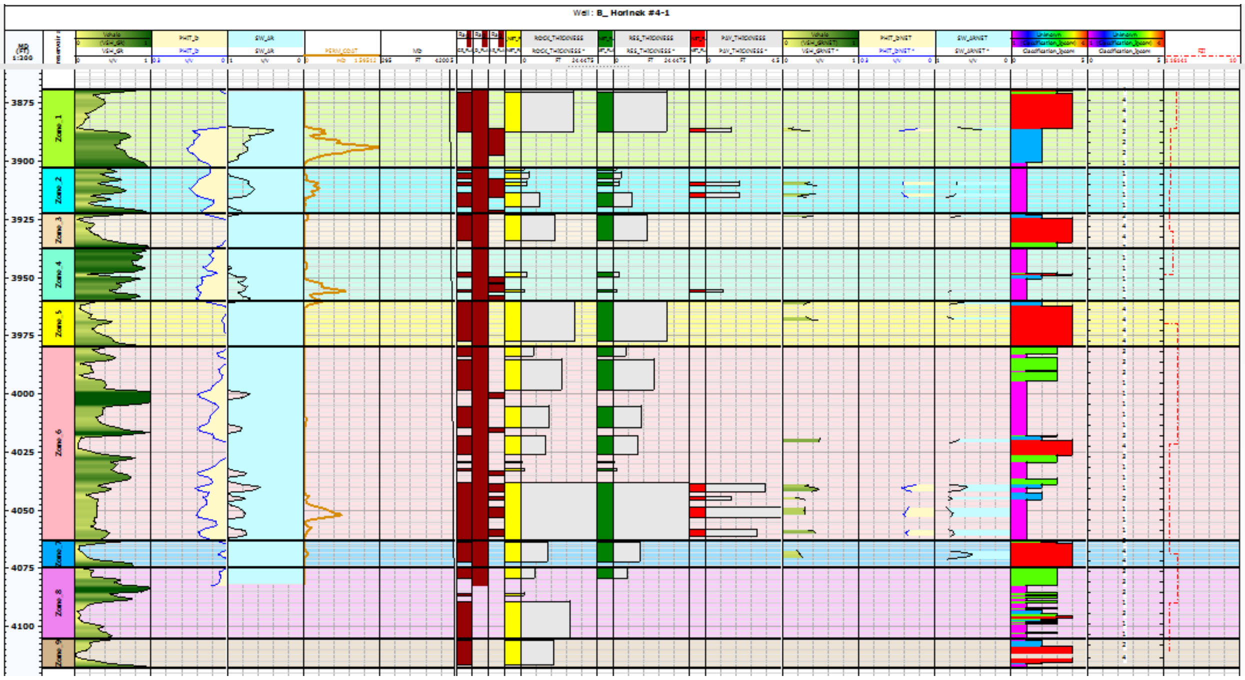
On the other hand, hydraulic flow units were found to be related to the rock quality index within the Lansing reservoirs. Application of hydraulic unit method that is correlated to rock quality index which is related to lithology can be an effective tool in distribution of horizontal and vertical permeability, initial water saturation, residual oil saturation among others during a field wide reservoir simulation model. In addition the rock facies classification provided an easy classification method that could aid in improving the reservoir characterization of the Lansing carbonate reservoirs.

8.0 APPENDICES

Appendix 1: Values of permeability and porosity (* 'means that no value could be found).

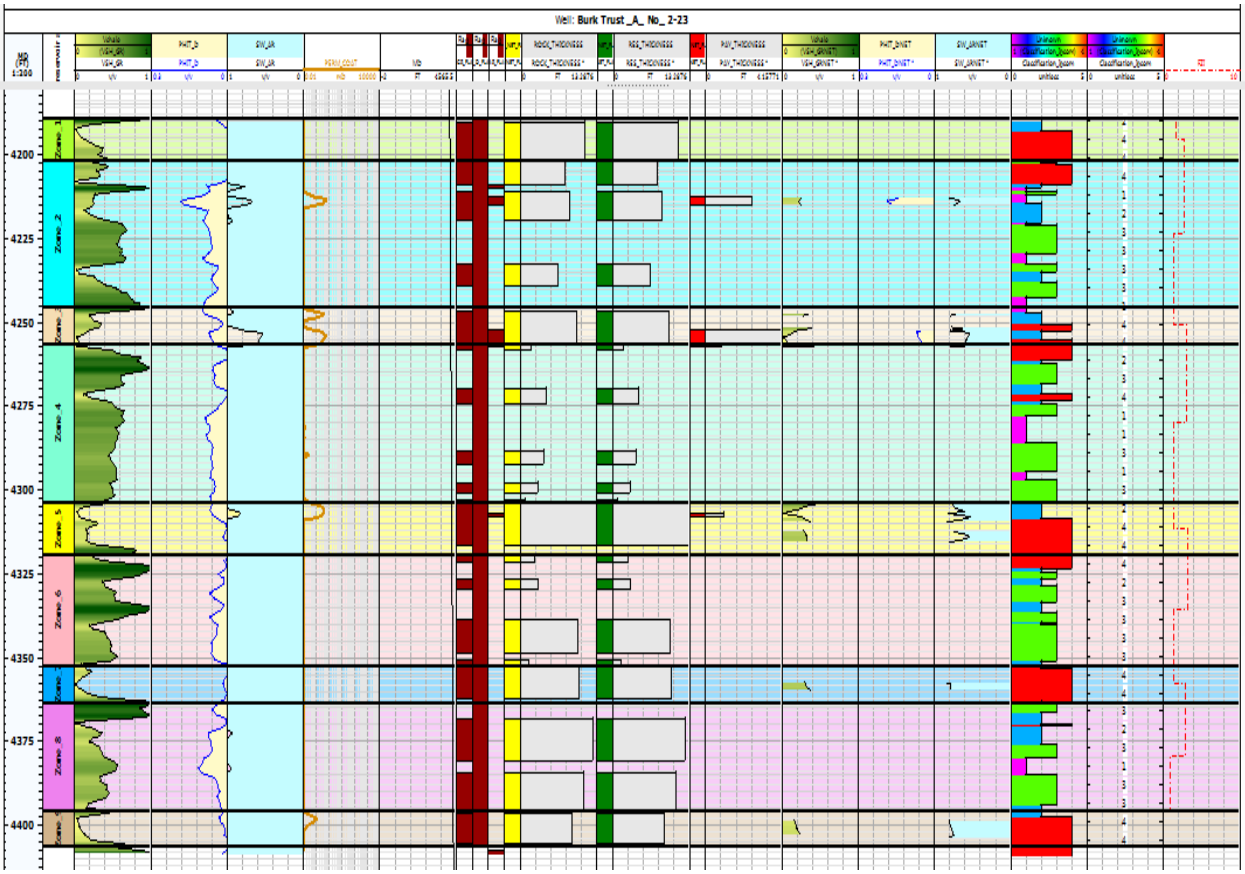
Depth (FT)	Sample#	Porosity (%)	Permeability (md)
3968	S2A	0	0
3968	S2B	2,6	0
3970	S3A	23,1	2,29
3970	S3B	22,5	2,16
3971	S1A	27,9	9,12
3971	S1B	27,2	8,86
4006	S4	10	4,37
4006	S5A	21,8	10,24
4006	S5B	12,7	7,23
4008	S6A	2,7	0
4008	S6B	5,5	0
4010	S7A	12,9	7,5
4011	S8A	8,3	0
4029	S9A	1,7	0
4029	S9B	1,8	0
4032	S10A	2,1	0
4032	S10B	4	0
4121	S111	*	63,91
4121	S11B	28,9	28,65
4123	S12	16,8	5,32
4144	S13A	15	22,51
4144	S13B	20,1	46,07
4145	S14A	31,2	45,41
4145	S14B	35,1	77,83
4148	S15A	18,5	0
4148	S15B	17,6	0
4148	S16A	17,19	3,51
4148	S16B	15,7	0,87
4148	S17A	25,8	67,8
4148	S17B	*	67,57
4148	S18A	38	67,94
4148	S18B	30,2	58,81
4153	S19	18,1	13,76

B_ Horinek #4-1



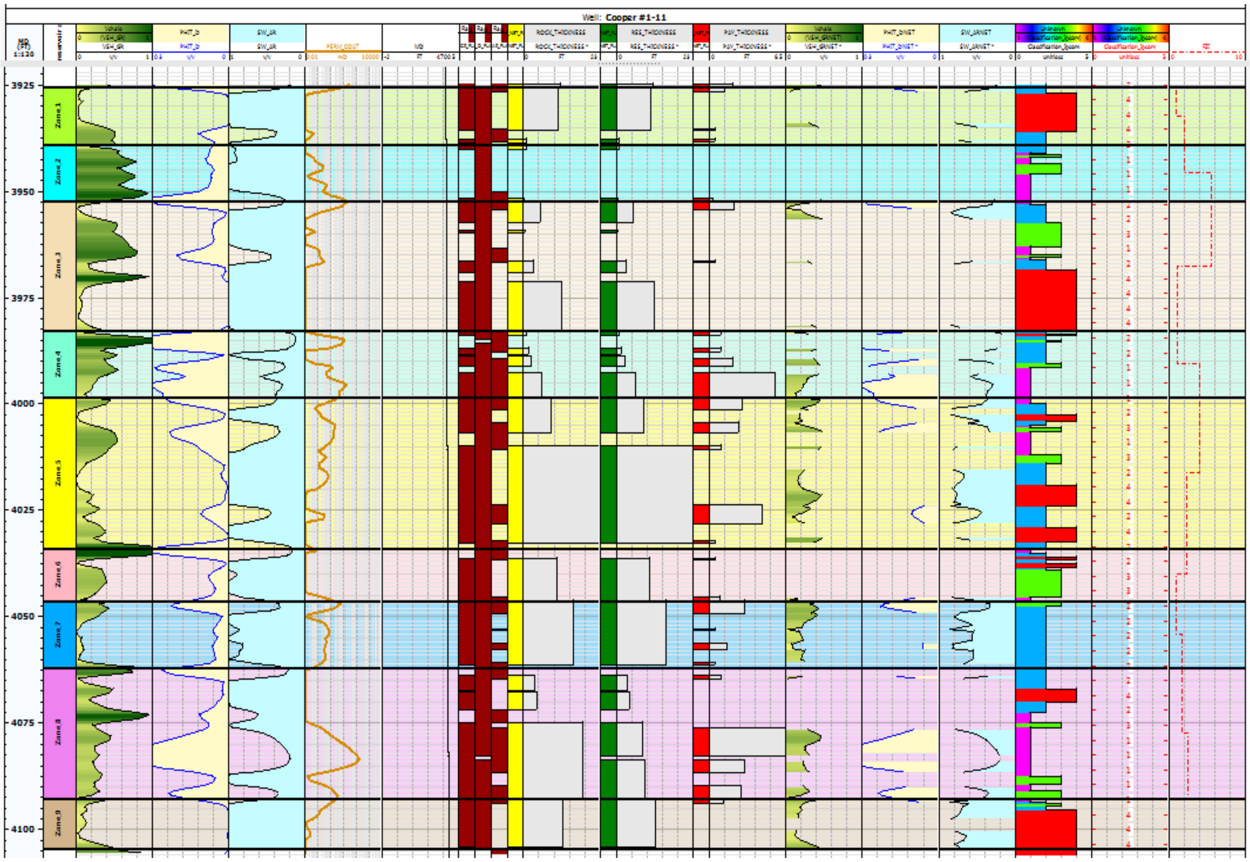
Appendix 2: Overall petrophysical parameters, rock facies and flow units in B_ Horinek #4-1

Burk Trust_A_No_2-23



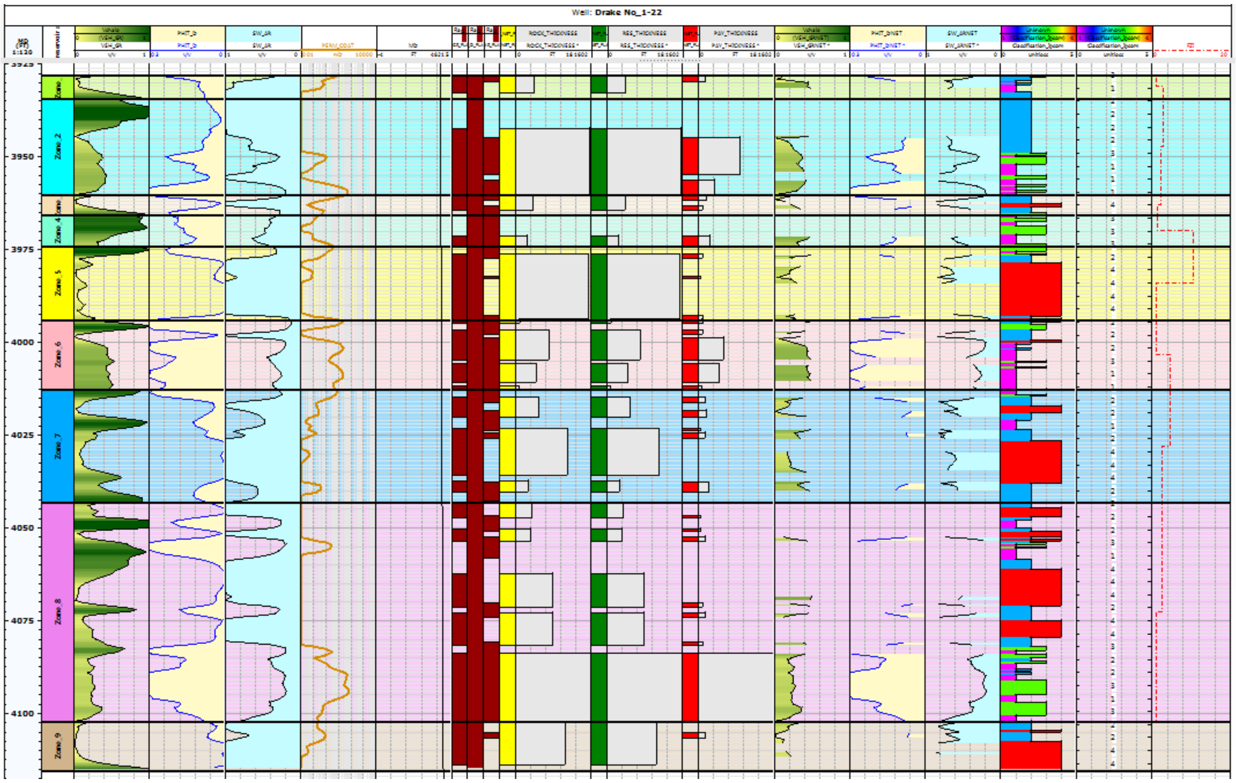
Appendix 3: Overall petrophysical parameters, rock facies and flow units in Burk Trust_A_No_2-23

Cooper #1-11



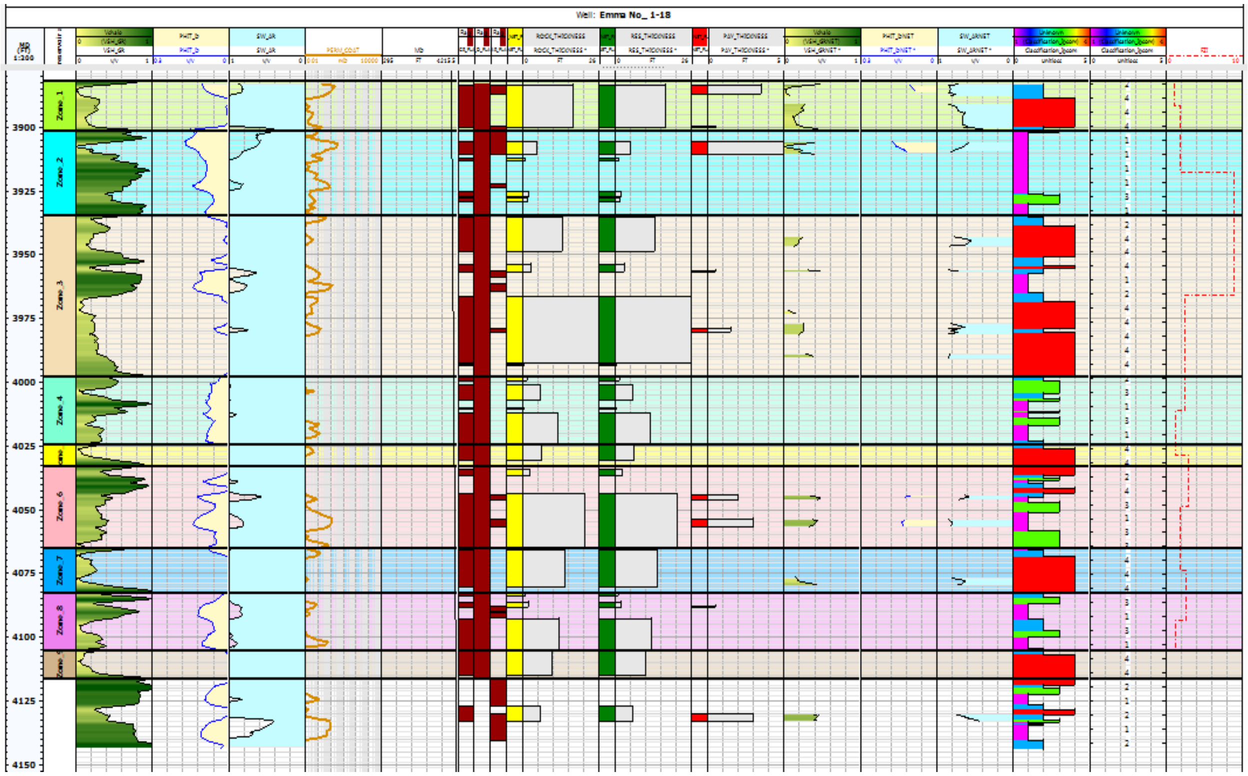
Appendix 4: Overall petrophysical parameters, rock facies and flow units in Cooper #1-11

Drake NO_1-22



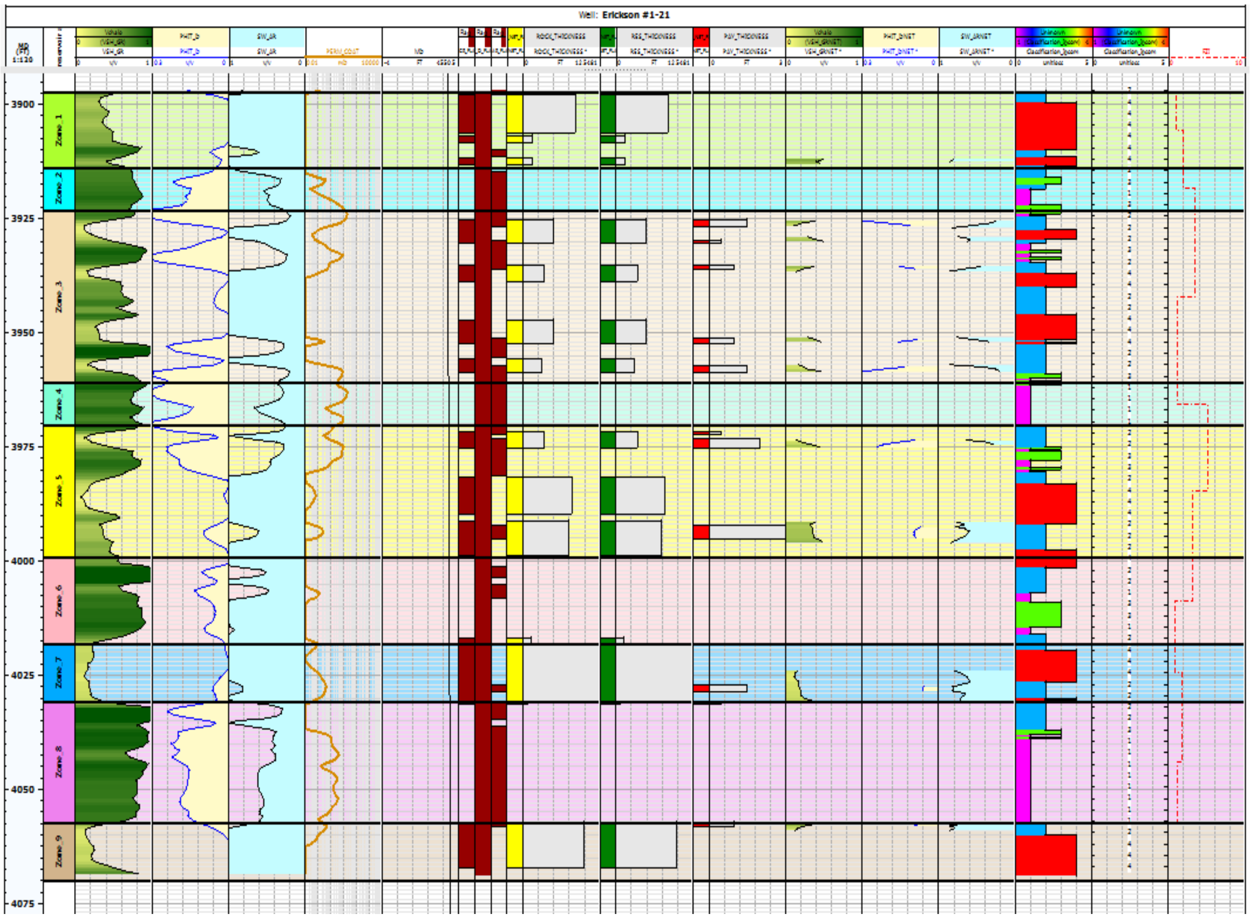
Appendix 5: Overall petrophysical parameters, rock facies and flow units in Drake NO_1-22

Emma No_1-18



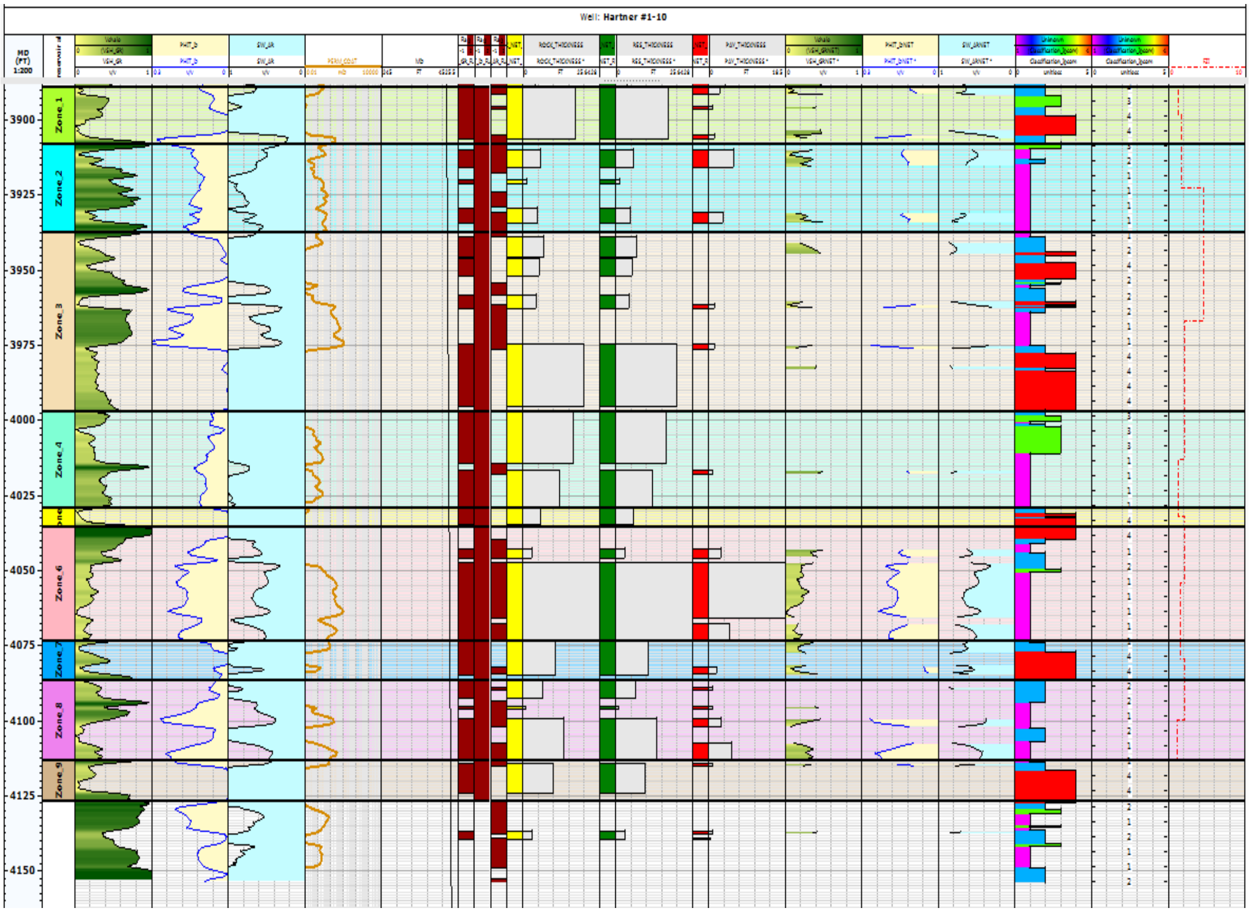
Appendix 6: Overall petrophysical parameters, rock facies and flow units in Emma No_1-18

Erickson #1-21



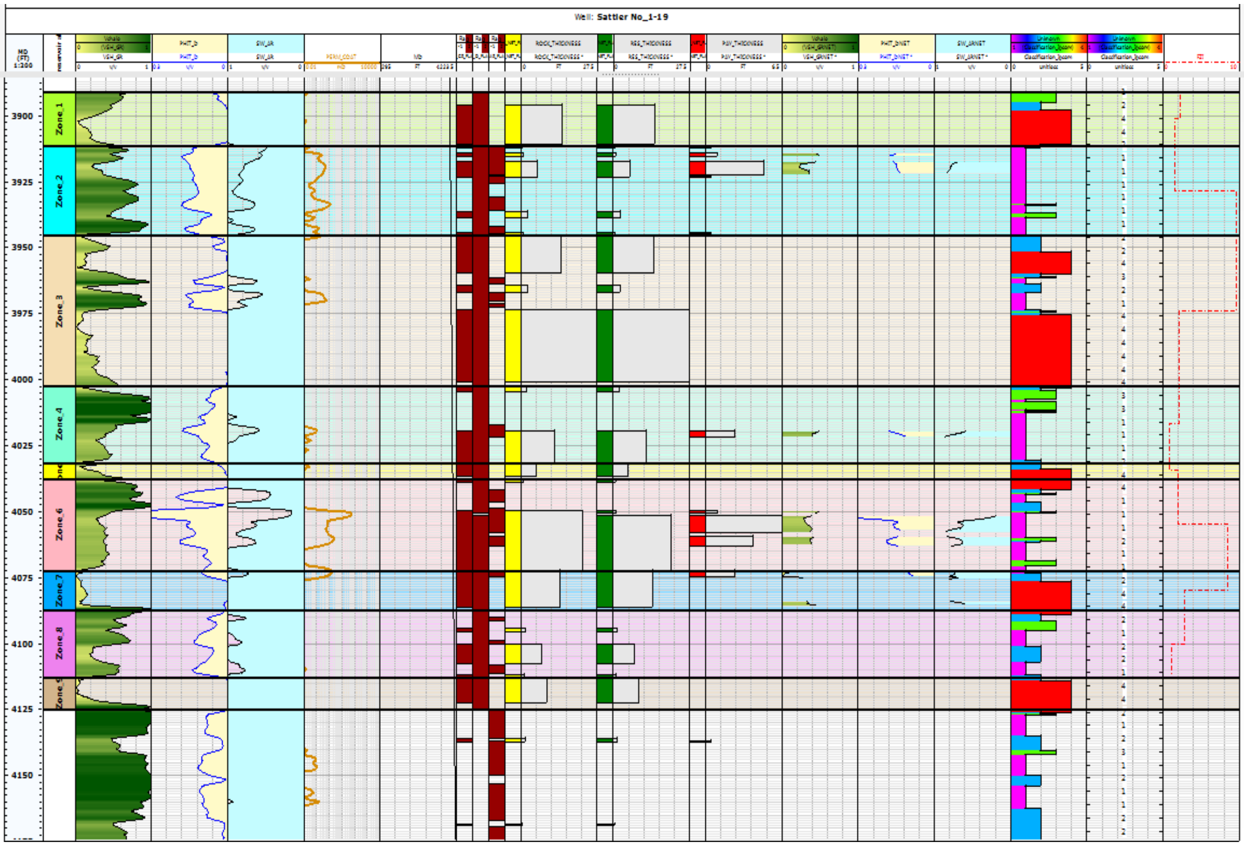
Appendix 7: Overall petrophysical parameters, rock facies and flow units in Erickson #1-21

Hartner #1-10



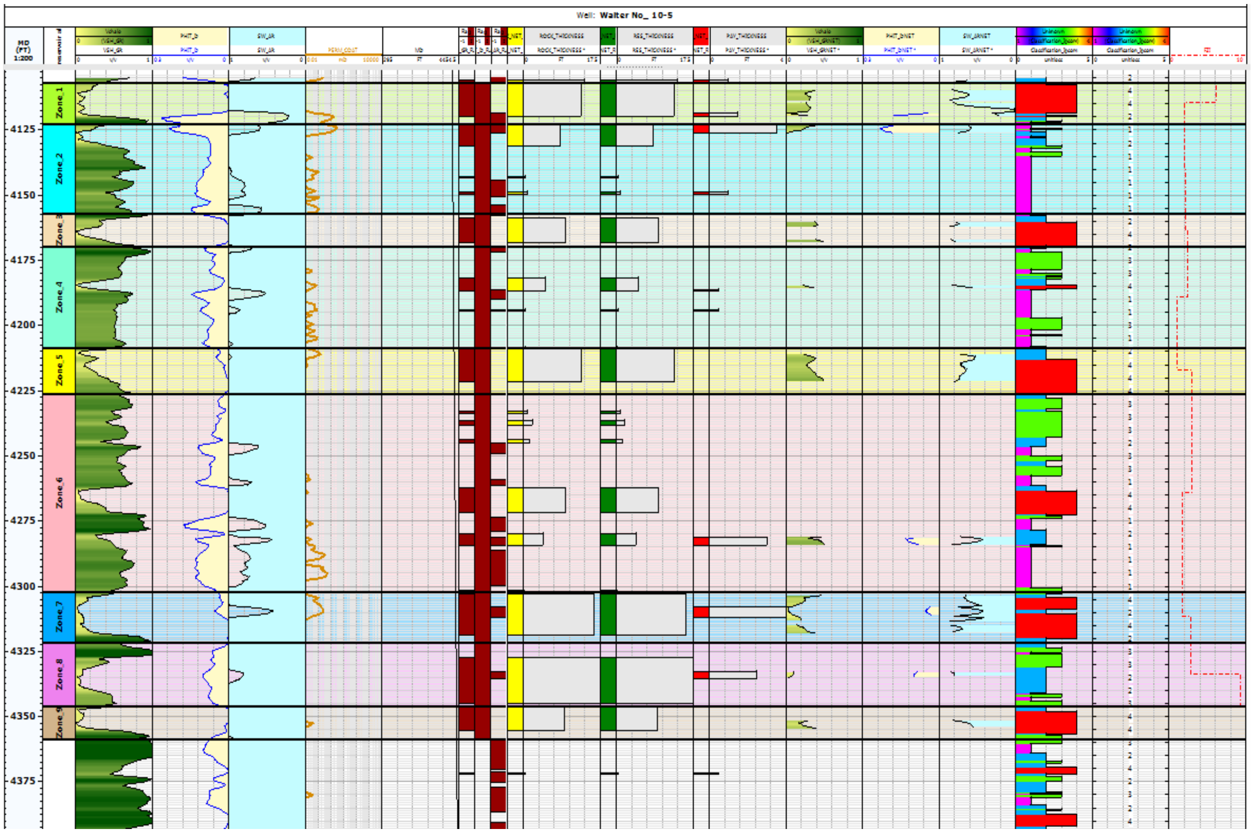
Appendix 8: Overal petrophysical parameters, rock facies and flow units in Hartner #1-10

Sattler No_1-19



Appendix 9: Overall petrophysical parameters, rock facies and flow units in Sattler No_1-19

Walter NO_10-5



Appendix 10: Overall petrophysical parameters, rock facies and flow units in Walter NO_10-5

Appendix 11. Well Logging Methods

Well logging is a technique of making petrophysical measurements in the sub-surface of the earth formation through a drilled borehole in order to determine the chemical and physical properties of the rocks. All the data and information recorded will be represented and interpreted with the help of a dedicated program. The purpose of well logging is to provide a measure of the rocks properties in a cheap and quick method. These methods are used in order to determine:

- The hydrocarbon type
- The volume of the reservoir
- The potential of the reservoir
- The types of fluid flow and at what rate
- The optimization of the well construction
- The optimization of the hydrocarbon production

The well logging techniques depend on the type of necessary measurement, this can be divided in two:

- Cased hole (a borehole where steel casing pipes have been placed and cemented), which provides information for Reservoir Production and Development.
- Open hole (a borehole drilled in the formation), where all the petrophysical measurement are made for the Formation Evaluation.

Well logs can be generally divided in two main categories, mechanical and wireline. The role of the **mechanical logs** is to register data such as, the rate of penetration or ROP, the type of the rocks and reveals the oil and gas. All this data are provide by drilling-time logs, cutting samples logs and mud logs**. Wireline logs** are realized by introducing special tools in and out of the borehole. A wireline it refers to a cable with shielded insulated wires inside, connected to a tool such as a sonde, which is lowered in to the well in order to gain information and data about resistivity, conductivity and formation pressure among with details about wellbore dimensions.

Another possibility is to make the measurements of the rock properties in the borehole during the drilling. This method is called Logging while drilling (LWD) and is using the sensors inside the thick-walled drill collars located in the bottom of the drill string, close to the drill bit.

In order to obtain as much data as is needed a number of instrument packages is used, they can contain, gamma ray, formation density and neutron porosity. All this are putted together in order to create the sonde. A sonde is built with one or more arms which can be extendable in order to let the sensors take contact with the well walls. At the moment when the sonde is pulled out from the borehole it receives data about the electrical, acoustical and radioactive properties of the rocks and their fluids, in some cases even register the geometry of the wellbore. All this process is happening with the help of a logging unit from where the wireline it's starts and from where all the data are examine and process. In usual the logging unit is mobile in order to can have the possibility to move from a location to another or in case of an offshore platform the unit takes stationary position.

11.1 The borehole environment

The borehole environment is the rocks and the fluids which are situated on the drilled walls. In the moment that the drill makes the hole, all the in situ properties are changing, the changes of material condition are made since a new material is add it. Responsible for these changes is the drilling mud which fills the wellbore and invades the pore spaces of the rock. The drilling mud is a mixture of chemicals, water and solids in order to carry out the cuttings made by the drill. Another role that the drilling mud has is to control the pressure from the formation. To have control of the pressure a weighting additive is added such as barite, this will help to increase the hydrostatic pressure of the mud column in order to have enough to hold the formation walls. This excess of pressure will prevent the well from kicking or flowing. The drill mud also cleans, lubricates and maintains the drill bit cold.

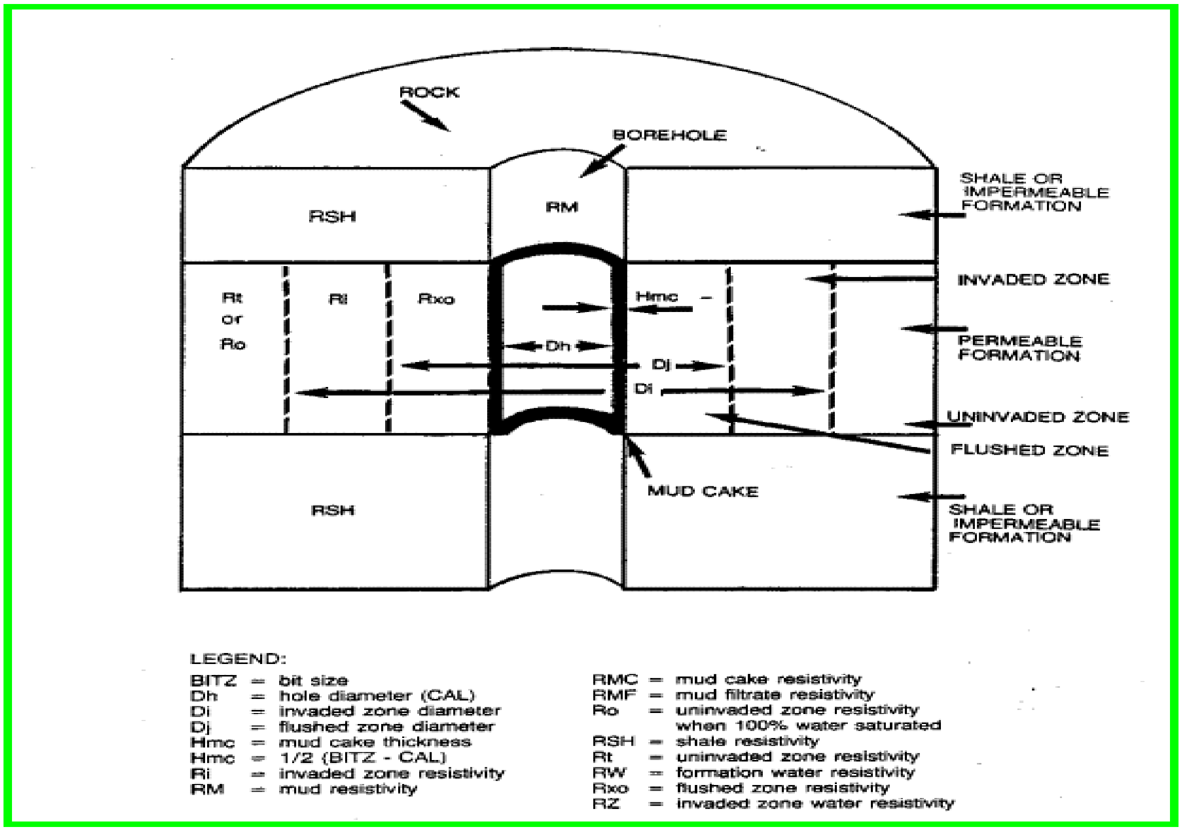


Figure 27: Bore hole environment

Explanation of the figure above:

We will start from the top with the mud resistivityR_m, followed by the mud-cake R_{mc} which is form with the help of solid particles stuck in the walls of the borehole. During the invasion of the mud the formation is acting as a filter and filters the mud, this is called mud filtrateR_{mf}.

The borehole diameter is always bigger than the bit diameter in order to leave the mud to wash out the badly cemented porous rocks and to allow the mud-cake to build-up on the porous and permeable formations.

Noticeable are the three zones located parallel to the borehole, flushed zone R_{xo} , transition zone R_i and uninvaded zoneR_t. The first two zones are the invaded one and are contaminated by mud filtrate. The flushed zone is right next to the borehole, fact that makes the most contaminated zone, in that area the mud filtrate has flushed out the formation's water R_w, and the hydrocarbons. In the transition the fluids are mixt due to the fact that is located between the flushed zone and the uninvaded zone, we will find there formation's fluid and mud filtrate. The last zone the uninvaded one, doesn't have trace of contamination since is far away from the mud filtrate.

11.2 Logging methods

11.3 Mechanical methods

Is an automatic or semiautomatic, field laboratory unit which helps in the determination of characterization of the resistance to drilling of the component rocks from the specific study case.

11.3.1 Caliper logging

The caliper logging is a method that uses a caliper tool in order to determine the size and the shape of the drilled hole. All the data measured by this device is plotted in units of inches.

Most of the caliper tools are mechanical and it uses the hydraulic pressure or springs to push the arms out against the wall. These particular tools are in need of calibration before any kind of measurement, the calibration is made by putting the tool in artificial well, made by rings on the same diameter as the borehole.

There are many types of caliper log described by the developers but only two major types; calipers that attach to other instruments/tools and they send corrected data regarding the size and shape of the borehole, it is using his large contact with the walls in order to determine the diameter of the fluid column. The second one it's called independent calipers which will supply information regard the well conditions. It builds with small tips which will have a large contact on the hole.

The caliper tool are equip with two or more arms, this depends on the type of the well, or the type of the borehole that in not all the time circular, and in this situations it is needed to choose a caliper with several arms since the one with two will not give an accurate data, because the reading of the tool is made on the longer axis of the oval cross section. They are calipers built with 30 arms mounted on the tool which will give precise data of the borehole diameter.

Figure 28: Caliper log tool with multiple arms

Now consider a caliper log in a formation where the data will show enlargement of the wellbore and shrinkages. In this situation it is know that enlargements means that in that particular depth will be found shales. Now since the drill mud in made primarily with water will cause the shales to disintegrate leaving behind caverns and swelling of the shales. On the other side if it is limestone or sandstone which is more permeable rocks a mud-cake will form and that will make the borehole to shrink. These particular two types of rocks give different situations, in case of limestone the wall will not have any kind of trace of deviations form on the walls, these deviations are cause by the drill bit in usual and in case of sandstone the mud-cake will not invade the formation zone.

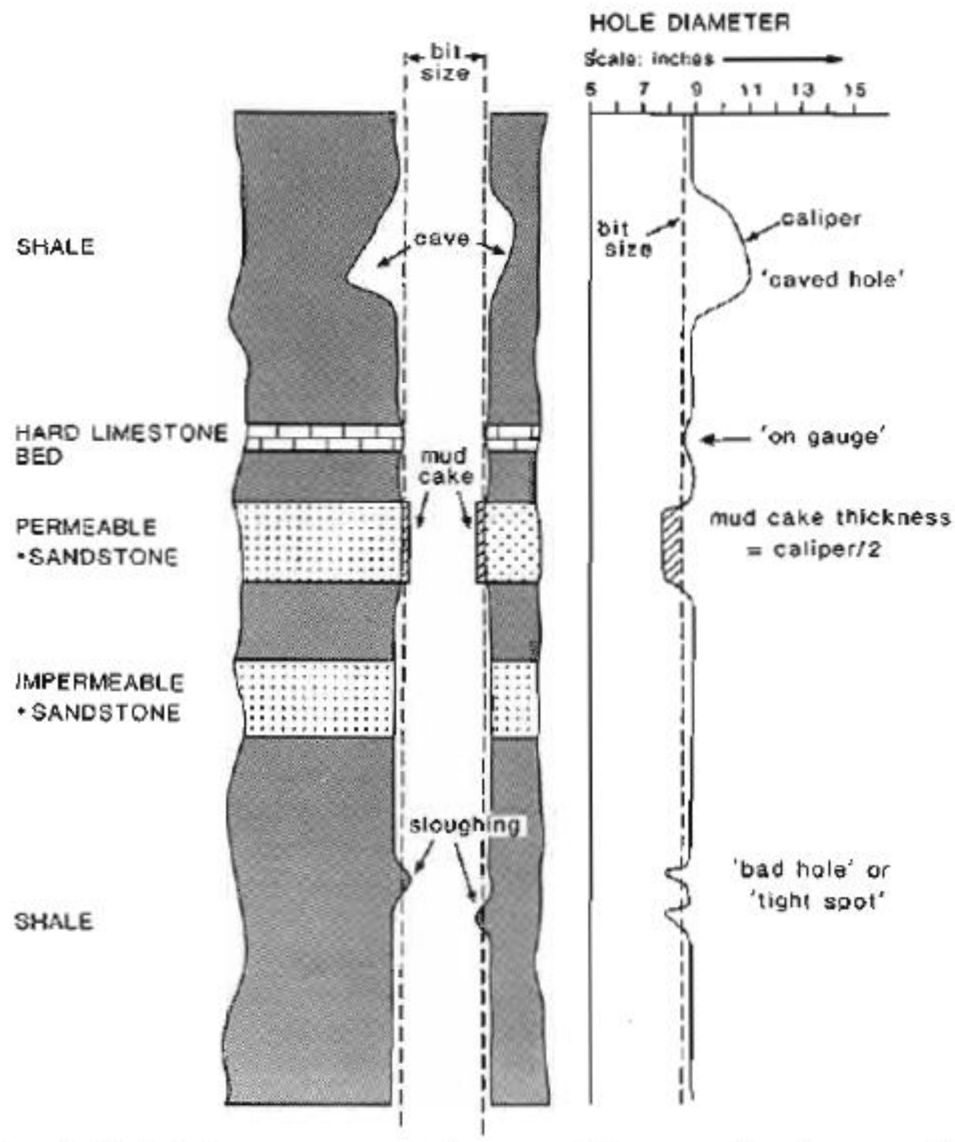


Figure 29: Caliper log

The caliper tool log is used in two main situations, the first one is to provide the engineer with all the diameter information in order to execute the future calculations for the cased or plugged and abandoned, the volume of the well should be find in order to put the right amount of cement. The second reason is to give the property data for calibration of the other log tools which is needed in order to give accurate information.

11.3.2 Wireline Logging methods

The most used methods of wireline logging are; acoustic, electric and nuclear. The first one uses the sonic waves to measure the time it takes the sound to travel inside the formation, electric method measure the artificial and natural electrical properties of the formation and the last one nuclear logging is measures the induce or natural radiation located in the formation. All this methods are used in order to measure the formation properties such as: porosity, density and a lot of other characteristics which helps revealing the hydrocarbons or the water inside of the formation.

11.3.2.1Acoustic/Sonic Logging

The Acoustic/Sonic logging measure how fast sound can travel through the formation. The method is used in order to provide information regarding the liquid/gas saturation of the pore spaces and porosity. They are other information that can be find using acoustic logging such as identifying lithology or fractures of the formation or when a cement job is taking place inside the borehole or data regarding the permeability of the rocks.

The principle that stays on the base of this method is recording the interval transit time (Δt) of a compressional sound wave over the formation. The travel time depends on porosity and lithology, and it is measured in microseconds per meter/foot$(\mu sec/m, \mu sec/ft)$. The time travel depends on the porosity of the rock (EQ.8.1), if the rock is porous than the sound will travel in shorter time. Other situation will be if the rock pores are filled with gas then the time will travel slowly so Δt increases; same situation will happen if the formation is shaly.

$$\emptyset_{sonic} = \frac{\Delta t_{log} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}} \qquad \text{EQ.11.1}$$

Where:

- $\emptyset_{sonic} = sonic\ derived\ porosity$
- $\Delta t_{log} = interval\ transit\ time\ formation$
- $\Delta t_{ma} = interval\ transit\ of\ the\ matrix$

- $\Delta t_f = interval\ transit\ time\ of\ the\ fluid\ in\ the\ borehole$

The above formula is used when the formation composite is made by consolidate carbonates or sandstone, having a intercrystalline or intergranular porosity. The reason that the formula is not adequate on the fractured rocks is because the sonic log can record only matrix porosity. But even in this situation, the percentage of the fractured or vuggy porosity can be calculated by subtracting sonic porosity from total porosity. EQ.11.2

$$\emptyset_{sonic} = \left(\frac{\Delta t_{log} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}}\right) * \frac{1}{C_p} \quad \text{EQ.11.2}$$

The only difference which can be spotted is that C_p called compaction factor.

There are situations when the interval transit time of the formation increase due to the oil and gas , this is called hydrocarbon effect and it can be corrected with the help of the empirical formulas :

$$\emptyset = \emptyset_{sonic} * 0{,}7\ for\ gas \quad \text{EQ.11.3}$$

$$\emptyset = \emptyset_{sonic} * 0{,}9\ for\ oil \quad \text{EQ.11.4}$$

Acoustic/sonic logging procedure is running in a open hole full of liquid since the mud from inside is an important piece, helping to get an acoustic coupling between the tool and the formation.

Table 15: Table of different velocities

	Velocity		
Rock or Fluid Type	**(m/s)**	**(ft/s)**	**Transit time (us/ft)**
Fresh Water	1,500	5,000	200.0
Brine	1,600	5,300	189.0
Sandstone			
Unconsolidated	4,600-5,200	15,000-17,000	58.8-66.7
Consolidated	5,800	19,000	52.6
Shale	1,800-4,900	6,000-16,000	62.5-167.0
Limestone	5,800-6,400	19,000-21,000+	47.6-52.6
Dolomite	6,400-7,300	21,000-24,000	42.0-47.6
Anhydrite	6,100	20,000	50.0
Granite	5,800-6,100	19,000-20,000	50.0-52.5
Gabbro	7,200	23,600	42.4

Taking into consideration a type of acoustic logging sonde and see how it is operating. As an example a two-receiver acoustic logging sonde will be explain; this consists of a sound generator located at the top of the sonde and two receivers which are installing in the bottom. To operate the sonde will emit a sound on a specific frequency; this will break through the mud and the wallcake and hit the formation. Once arrived over there the sound will go up and down in order to send information to the receiver located on the sonde. Since the sound is making an up and down movement, dependent on the location on the sound the information will be send to the receiver, if the sound is traveling downwards than the information will be send first to the top receiver and after to the bottom one, in this way the travel time can be calculated.

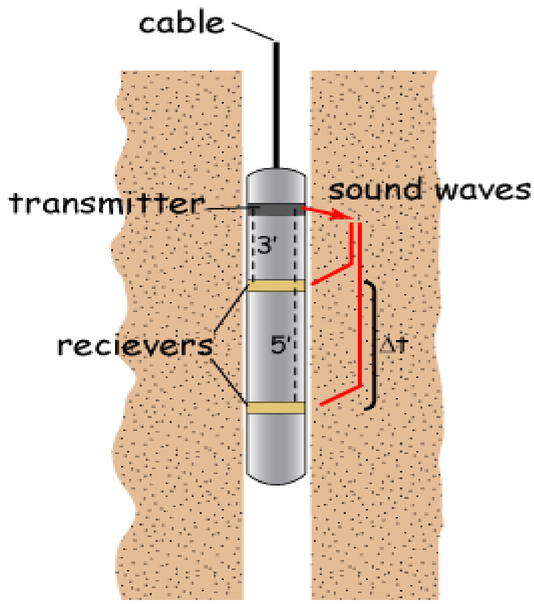


Figure 30: Cross section

All the information gained from the acoustic log is represented by a curve on a velocity versus whole depth plot. In usual the acoustic logging is accompanied by gamma ray devices or a SP electrode in order to provide more data.

Since the Δt is so influenced by so many factors, there are other calculations in need to be made. One of them is to find the *time average formula* which will determine the velocity gain from the average time for a wave to go through the formation, EQ.11.5

$$\frac{1}{v_b} = \frac{\emptyset}{v_f} + \frac{1-\emptyset}{v_{ma}} \quad \text{EQ.11.5}$$

Where:

- $\emptyset = fluid$
- $1 - \emptyset = matrix$
- $v_b = velocity\ in\ bulk\ materia$
- $v_f = velocity\ of\ the\ fluid\ in\ rock\ porosity$
- $v_{ma} = velocity\ in\ the\ matrix$

The formula will be applied only if all the terms are accomplish, terms such as high pressure in order to achieve the terminal velocity or intergranular porosity up to 0.35 and rock fully saturated with fluid.

All in all even if this method has his limitation, she proved to be very useful in determining the formation porosity, and when is run in combination with gamma ray and SP logs , and fulfill all the other conditions, then the acoustic log will provide with first-rate porosity data.

11.3.3 Electrical Methods

The main reason of using this particular methods is to determine the water saturation (S_w) from the formation. But in order to have a precise data regarding water saturation is mandatory to find the formation water (R_w) first. Having all this information it is possible to determine the STOIIP (STOCK TANK OIL IN INITIAL PLACE). The methods can provide information for lithology, shale porosity, source rock, well correlation and can provide with a better view of the hydrocarbon zones.

The Electric logging uses the electric current to pass through the formation conducted by the salt water located inside. The movement of the current will be recorded and plotted in order to have an overview on the measurements.

But all this data about the electrical resistivity depends on some nature factors that can influence the information:

- Salinity, as is well know the water is a good conductor of the electricity, the proportion of the conductive varies according to the concentration of the ionized salt in the salt water.
- Temperatures, rocks at high temperature are a better conductor.
- Conductive minerals, they can conduct the electricity if they are sufficiently abundant.

- Oil and sand, can affect the conductivity since both of them increase the resistivity of the formation.

11.3.3.1 Spontaneous Potential Logging (SP)

Was one of the first technologies of logging in the oil and gas industry. This method helps to divide the reservoir in two big categories, non-reservoir (shale) and reservoir rocks (sandstone, carbonate). SP is using a tool that measures naturally distributed charges. The method of collecting data is by introducing two electrodes in to the ground, which will provide data about the current flow. Another usage of the method is to determine the correlation between wells and facies analysis. And the most important is the determination of the quantitative evaluation of resistivity of formation water (R_w) this can be made only if the value of the mud filtrate resistivity is found previously, in this way calculation for finding the clay volume can be made. Also SP logging method can come with information regarding the lithology, bed correlation of the well or information about the shalliness of the formation.

The way that the tool is collecting data is by introducing one of the electrodes in the bottom of the bore hole and the other one will stay on the surface, touching the soil. Using the electrodes an electric current will be sent inside of the formation, one of the electrodes will be insensitive to the changes of the temperature, water chemistry and water flow. Material used in creating this electrode used inside of the well is made by copper-copper sulfate solution contained in a porous ceramic container. But a problem with maintaining them occur then the companies chose to use more classical materials such as, lead, stainless steel or bronze.

SP logging response to the electric current which rises from electrochemical factor located in the borehole. Electrochemical factors are present because of the differences between the salinity of formation water resistivity within permeable formation and the mud filtrate.

They are some factors that make the SP log possible:

- First the fluid used in the borehole has to be conductive; this means that the drilling mud is water-based.
- A difference in the borehole fluid and the formation fluid of the salinity should exist; otherwise the SP current will arise due to the difference in fluid pressure.
- A porous and permeable bed needs to be between the impermeable formation and low porosity formation.

SP currents are created with the help of two electrochemical factors; shale potential and liquid junction potential. Assuming that we have NaCl in our system, and formation fluid is more saline than mud filtrate.

Shale potential is made when two solution take contact on a semi-permeable membrane. In our lithology can be seen that they are shale rock around the borehole walls, this will indicate a large negative surface caused by the clay minerals located in the shales. Due to the similarity of the charge the Na^+ ions are easily passing the negatively charge, shale layers while for Cl^- ions are impossible to break through. The positive charge appears in the dilute solution and the negative charge will be created in the concentrated solution. Therefore from the dilute solution will arise an overbalance of Na^+ ions.

The second method, *liquid junction potential* will arise when multiple solutions with different salinity will take contact through a porous medium. The most common type of salinity that can be found in formations are sodium chlorite, therefore will be a contact between two or more of sodium chlorite solutions with different salinities. The mixing will happened through the porous membrane. The ions will mix at unequal rates causing a separation of the charge, since the Na^+ ions are big and not very fast, and the Cl^- are smaller and faster. Cl^- Ions will have an increase of the saturation in the dilute solution due to the mobility that they have. The potential will be created between the positively charge concentrated solution with Na^+ and, negatively charged dilute solution with over plus of Cl^-.

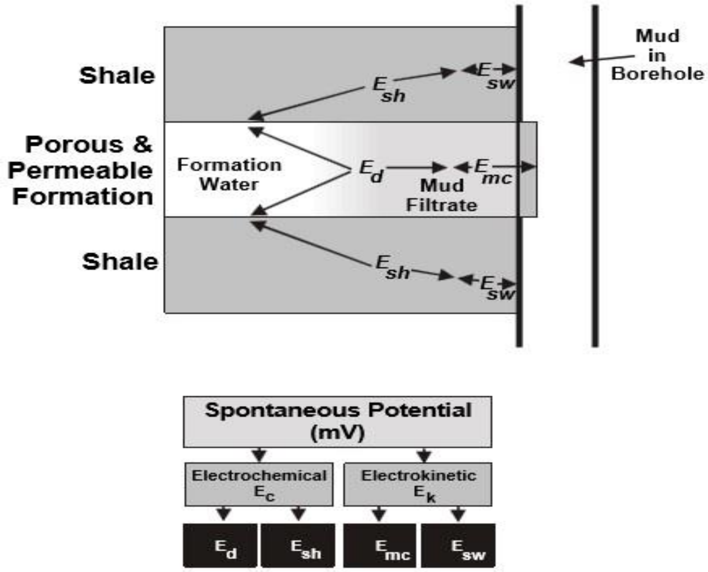


Figure 31: Electromotive force of the spontaneous potential

11.3.3.2 Electrochemical Influence

Liquid junction potential/diffusion potential is the spontaneous potential, and electromotive force which will act at the intersection between the invaded an uninvaded zone. SP will rise due to the different salinity that can be found in the borehole fluid and formation fluid. In this case is mud filtrate.

If the only source of salinity will be NaCl, and the borehole fluid will be smaller than the formation fluid, a movement of negative charge from uninvaded to the invaded zone will be created, this is called diffusion.

$$E_d = -11.81 * \log(\frac{R_1}{R_2}) \qquad \text{EQ.11.6}$$

Where:

E_d= diffusion potential

R_1= Resistivity of the solution with less salinity

R_2= Resistivity of the solution with more salinity

To find electromotive force:

$$E_c = -K * \log(\frac{a_w}{a_{mf}}) \quad \text{EQ.11.8}$$

Where:

E_c= is the electromotive force

K= co-efficient which is proportional with the absolute temperature. Value of it is 71 at $25^{\circ}C$ [k=65+0.24T (℃)]

a_w= chemical activity at water formation temperature

a_{mf}=chemical activity of mud filtrate formation temperature

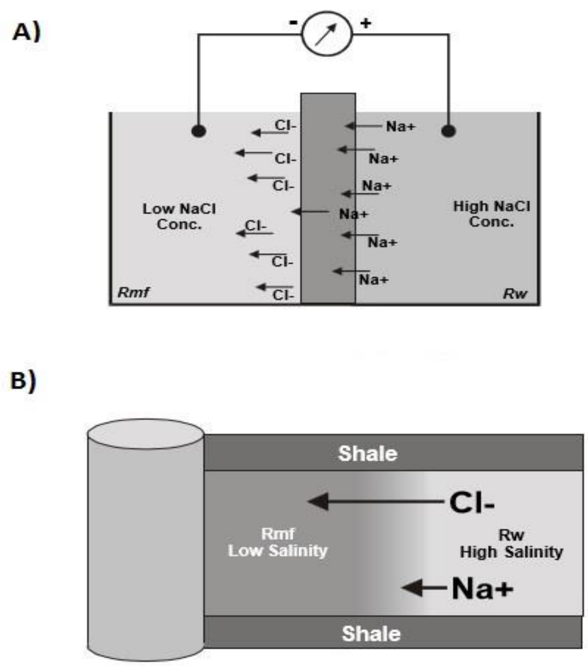


Figure 32: A) Diffusion potential in a lab, B) in a borehole

Shale/membrane potential is the spontaneous potential found at the intersection between uninvaded zone and shale zone. The shale zone can be electro negatively perm selective or anionically, having the presence of a double layer, the movement of the anions will be decelerated. This property will leave the shale preferentially positive, making a potential between the uninvaded zone and the shale zone. As a result will be a current flow from the uninvaded zone of the formation to the shale zone, or is special cases can flow to the borehole.

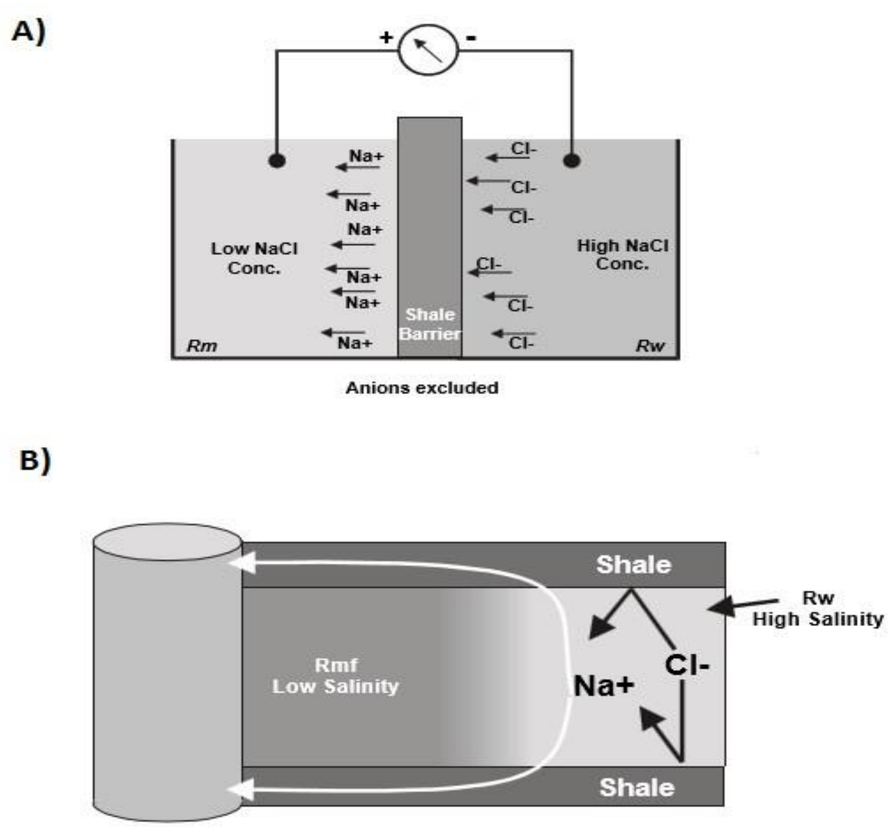


Figure 33: A) Membrane potential in lab, B) in a borehole

11.3.3.3 Electro-kinetic Influence

It's based on two different phenomena which are acting oppositely in order to cancel each other. The biggest influence on this effect is the different pressure between borehole and formation, having a differential pressure biggest than 500 psia has an important contribution as well. All of this stand as a contribution for the fresh waters and mud filtrate from the layers.

Mud cake potential appears when the charge ions will migrate from the mud cake to the permeable zone by invaded them. In usual spontaneous potential will not move forward from the mud cake due to his low permeability, but they are cases where will get in touch with the invaded zone.

As shale, mud cake has the same property of anionic permselectivity, and due to this property a net current flow will be migrate from the borehole to the mud cake.

Shall wall potential, appears on the flow of the fluid which move from the borehole to the mud cake, since is trying to break through an impermeable zone the value measured over there will be very small.

Representing total electro kinetic potential EQ.8.9:

$$E_k = E_{mc} + E_{sw} \qquad \text{EQ.11.9}$$

Where:

E_k= total electro kinetic potential

E_{mc}= mud cake

E_{sw}= shale wall potential

Static spontaneous potential (SSP), is the total voltage gained from the diffusion of ions, from the membrane and liquid intersection. This happens from the appearance of the mud in the well. Since the values of the resistivity of mud filtrate and formation water decreasing, SSP will decrease to.

SP current flows through, invaded zone, uninvaded zone, borehole and the surrounding shale, with a big fraction of the current, fact that goes to a SP deflection which will travel through the borehole. Due to the deflection, a potential drop makes his appearance, besides the fact that is a big difference between the borehole cross sectional area and the formation cross sectional area, the resistance will increase.

Having this case, the total potential drop will be the total electromotive force, the SP deflection ideally opposite a thick, clean formation. As a result the values of the SP will be similar with SSP.

In this case the shaliness found in the bed it's ignored, furthermore he acts as a membrane since is a perfectly cationic.

11.3.3.4 Resistivity and induction Logging

An important electrical log technique is *resistivity's logging*, which is a resistance of a particular compound to the passage of the electricity. This method generates and sends through the formation a current flow, the response from the rock formation will be calculated. This can be expressed using EQ.8.10

$$R = \frac{r*A}{L} \qquad \text{EQ.11.10}$$

Where:

- R=resistivity
- r=resistance
- A=cross-sectional area
- L=length of the resistor

Conductivity on the other hand is the ability of a material to conduct an electric current. Induction logging produce a current which is send through the formation in order to measure the ability of conduction from the rock formation. Basically the induction logs are the inverse function of the resistivity logging.

Resistivity is used mainly to define the two bearing zone, hydrocarbon against water bearing zone. There is high resistivity in to the hydrocarbons, pores and matrix of the rocks and fresh water since they all are nonconductive. The resistivity of the rocks is decreasing as the salinity of the water located within the pores is increasing. The same type of logging is used to measure the oil and gas volume from a reservoir. Other functions can be measured by using resistivity logs; determination of the saturation, lithology and estimating the porosity, etc.

11.3.3.5 Induction logs

The main role of the induction tool is to interpret the well logging data capture from the oil mud, which is known as a nonconductive material. This method has been created in order to fix the problem regarding the damage that the mud is making in the formation, where the water-based mud is creating some water–sensitive shales to swell. Due to this phenomenon the permeability of the formation is decreasing and the production has difficulties. A solution for this problem is to work with oil-based mud or without mud.

This tool is built with two coil-devices. One of them has the role to transmit the AC current in to the formation and the second one is receiving the data. The way this method is providing information is, generating a time-varying primary magnetic field by the AC. The log is inducing a flow of eddy currents through the rocks. A second role of these eddy currents is to set up a secondary magnetic field which will has the role to induce a voltage in to the receiving coil. But before sending this data, as a last touch the current will be converted in DC. In the end, the magnitude of the current receive will be direct proportional with the electrical conductivity of the rocks.
Reason of making this logging is to get data about conductivity which is measured with milliSiemens per meter (mS/m), is giving good information on the lithology of the formation no matter what type of casing it is.

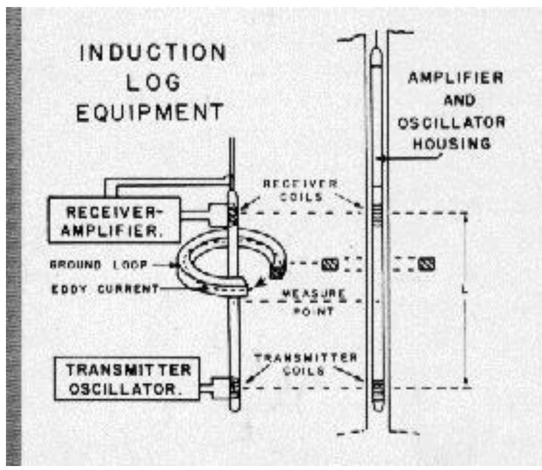


Figure 34: Induction Logging system

8.2.3.6 Conventional electrical logging

The principle which stays behind this logging method is that a current of certain intensity is sent between two current electrodes, which are A (sonde) and B (sonde or surface). But the potential difference is measure between two voltage electrodes mark with M and N. The configuration is made in function of the needed result which can be the bed resolution or depth investigation. They are some standard arrangements which are Normal log or Lateral log the difference between them is the position the electrodes.

Normal devices

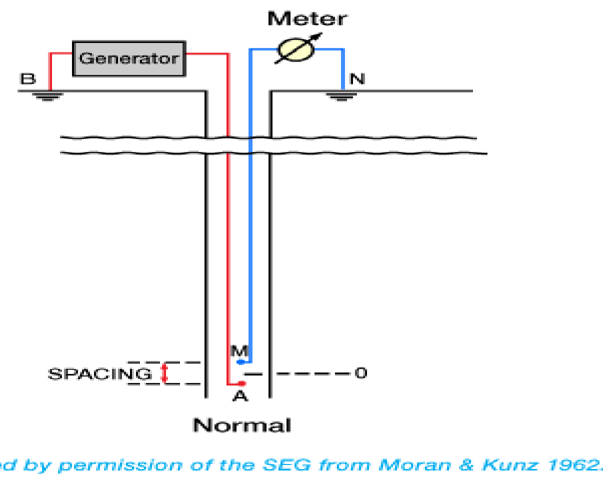


Figure 35: Normal Log

The normal log characteristics are the distances between AM which is small compared with BN, MB or MN. In this situation the measured of the voltage will made in the potential of M, this distance which is measured between the two electrodes is called spacing, and the point of the measurement can be found in the middle of A and M.

In case of a *lateral log* the measurement is made on the M and N which as I can be seen below they are very close. The point of the measurement will be between M and N, and the voltage measured will have almost the same value as the potential gradient found in the point O (point of measurement). The spacing in this situation will be the distance AO. This measurement will give asymmetric curves and this can be used in figure out the boundaries. But will not give a better interpretation that the normal log which has a symmetric curve and gives a better resolution.

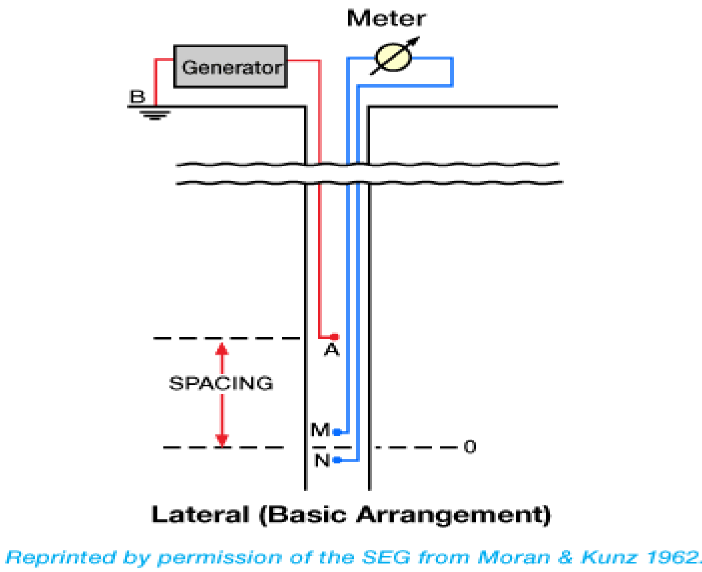


Figure 36: Lateral log

11.3.4 Microresistivity

This method has been used in order to measure the resistivity of the flushed zone. In order to proceed with the measurement, we need a microsonde tool which can be of two types, microlateral which is just a micro scale version of the lateral logging and the second one is called proximity log, it can get data only from a short distance from the formation.

The microlateral logs are divided in two;

- MNL (micro normal logging) and is used for deep investigation.
- MLL (micro lateral logging) and the depth for this method is limited.

There are three possible methods of measuring using microsondes (LLS, MNL, MLL) all of them can be combined between them and used to get different results. This microsondes are having a standard measure of the tool, which is:

- 0.25 M, 0,0025 N for microlateral
- 0,05 M for micronormal

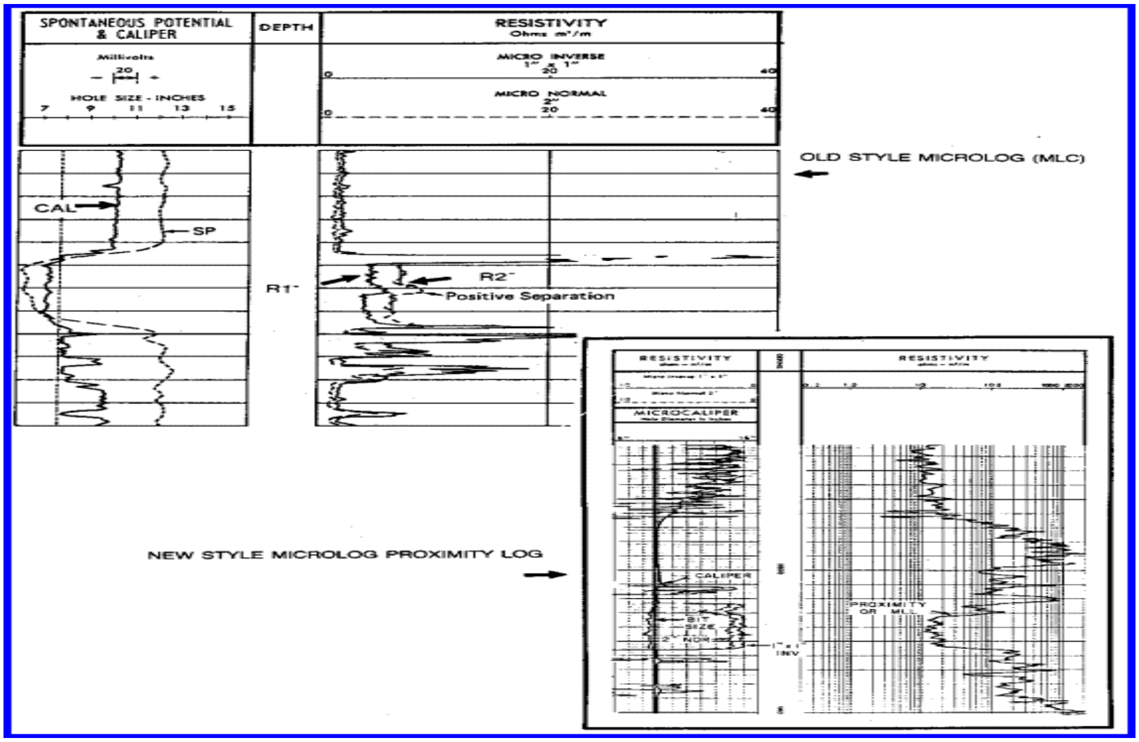


Figure 37: Micro logging

At this point it is known that the thickness is a major factor in the interpretation, in case of 15mm of mud cakes thickness the quantitative interpretation is out of the table the only one which can be made is the qualitative one. In the case that the thickness of the mud-cake is less than 10-15mm then $R_1 = R_{xo}$(resistivity in the flushed zone).

There are several methods that can be used in order to have an interpretation of the filtrate resolutionR_{mf} and mud cake resistivityR_{mc}.

1. *Lowe and Dunlap*

   In case of using freshwater mud resistivity, having the range between 0.1-2.0 ohm-m at 24℃, the measurement of the resistivity and the mud density will be in pounds per gallon.

$$\log(\frac{R_{mf}}{R_m}) = 0.396 - 0.0475\,\rho_m \qquad \text{EQ.11.11}$$

2. *Overton and Lipson*

This method of calculation is used when the mud resistivity of the drilling muds is between 1-10.0 ohm-m at 24℃ and the K_m values are between 0.350-8.35 and is depending on the mud weight (density).

$R_{mf} = K_m(R_m)^{1.07}$ EQ.11.12

$R_{mc} = 0.69(R_{mf})(\frac{R_m}{R_{mf}})^{2.65}$ EQ.11.13

Table 16: Mud Weight

Mud Weight		K_m
lbm/gal	kg/m³	
10	1200	0.847
11	1320	0.708
12	1440	0.584
13	1560	0.488
14	1680	0.412
16	1920	0.380
18	2160	0.350

3. *Method for NaCl*

The third method will be just a statistical approximation for predominantly NaCl mud:

$R_{mc} = 1.5\ R_m\ \ R_{mf} = 0.75\ R_m$ EQ.11,14

11.3.5 Calculation of the resistivity porosity

As it has been said before the hydrocarbons are a nonconductive, do to this factor the electric current is conduct in the pores by the water. This means that with the help of the resistivity measurements can determine the porosity.

In order to determine the porosity will be used the formation resistivity data which was taken from the flushed zone or invaded zone. To determine the shallow resistivity the follow devices are used: Proximity, microlaterallog, laterallog, short normallog, spherically focused log and microsfericall focused log.

The drilling mud injected in the borehole will displace the formation water located in the porous rocks. Porosity located in a water-bearing formation can be associated to shallow resistivity (from the flushed zone) using this equation:

$S_{xo} = \sqrt{F * \frac{R_{mf}}{R_{xo}}}$ EQ.11.15

$S_{xo} = 100\%$ in water-bearing zone => $1 = \sqrt{F * \frac{R_{mf}}{R_{xo}}}$ EQ.11.16

Solve F= $\frac{R_{xo}}{R_{mf}}$ EQ.11.17

It given that $f = \frac{a}{\emptyset^m}$ => $\frac{a}{\emptyset^m} = \frac{R_{xo}}{R_{mf}}$ EQ.11.18

$\emptyset = (\frac{a*R_{mf}}{R_{xo}})\frac{1}{m}$ EQ.11.19

Where:

$\emptyset =$ formation porosity

$a =$constant (1 for carbonate ; 0.62 for unconsolidated sand and 0.81 for consolidate sand.)

$R_{mf=}$ resistivity of mud filtrate at formation temperature

R_{xo} =resistivity of the flushed zone from shallow measuring devices

$m =$ constant (2 for consolidate sand and carbonates; 2.15 for unconsolidated sands)

$F =$ formation factor

Since the shallow resistivity is affected by the unflushed residuals of hydrocarbons located in the hydrocarbon-bearing zone, this will cause an increase of the shallow resistivity since the oil and gas holds a higher resistivity in comparison with the formation resistivity values. Due to this facts the value of the resistivity porosity are low, in order to correct this values it is need to calculate the water saturation of the flushed zone (S_{xo}). The equation below will help to calculate the relation between formation shallow resistivity and porosity:

$S_{xo} = \sqrt{F * \frac{R_{mf}}{R_{xo}}}$ EQ.11.20

Square both sides:

${S_{xo}}^2 = F * \frac{R_{mf}}{R_{xo}}$ EQ.11.21

Solve:

$$F = \frac{{S_{xo}}^2 * R_{xo}}{R_{mf}} \quad => \frac{a}{\emptyset_m} = \frac{{S_{xo}}^2 * R_{xo}}{R_{mf}}$$ EQ.11.22

Porosity equation:

$$\emptyset = [\frac{a(\frac{R_{mf}}{R_{xo}})}{(S_{xo})^2}]$$ EQ.11.23

Where:

$\emptyset$ =formation porosity

a =constant (1 for carbonate ; 0.62 for unconsolidated sand and 0.81 for consolidate sand.)

$R_{mf=}$ resistivity of mud filtrate at formation temperature

R_{xo} =resistivity of the flushed zone from shallow measuring devices

m = constant (2 for consolidate sand and carbonates; 2.15 for unconsolidated sands)

F = formation factor

S_{xo} = water saturation of the flushed zone ($S_{xo} = 1$- residual hydrocarbon saturation)

11.3.6 Resistivity profile

Resistivity of the formation (R_t) is one of the most important measures of the industry. The measurement is made with deep-reading logging tools and it can show the on touch zones of the formation where no mud filtrate is. Since this mud has a lower resistivity then oil and gas but higher than the water, can create confusions.

Figure 38: Resistivity curve profile

11.3.7 Radioactive methods

The radioactive methods are divided in two: Natural Gamma Ray and Neutron Logging. Both of the methods are recording the natural induce radioactive properties of the formation and they are used in order to determine the rock type and the nature of the fluid inside the rock.

11.3.8 Natural Gamma Ray Logging

Gamma Ray logging it used to measure the natural radioactivity from the formation. The radioactivity measured in usual comes from to major mineral: potassium, thorium and uranium. All this three minerals can be finding in the shale, fact that can be seen on the gamma ray charts generated by the software. Another low concentration of gamma ray can be seen in the shale-free sandstone and carbonates, because they hold a small quantity of radioactive materials in them. Even in clean sandstone can be found high gamma ray if, he has in the composition; micas, potassium feldspars or uranium rich waters.

Gamma ray log looked similar and shows almost the same response as a SP logging, but is consider a more advance method since doesn't depend on formation water resistivity or mud. Gamma ray log are used to determine the lithology of the formation, facies analysis and the inter-well correlation.

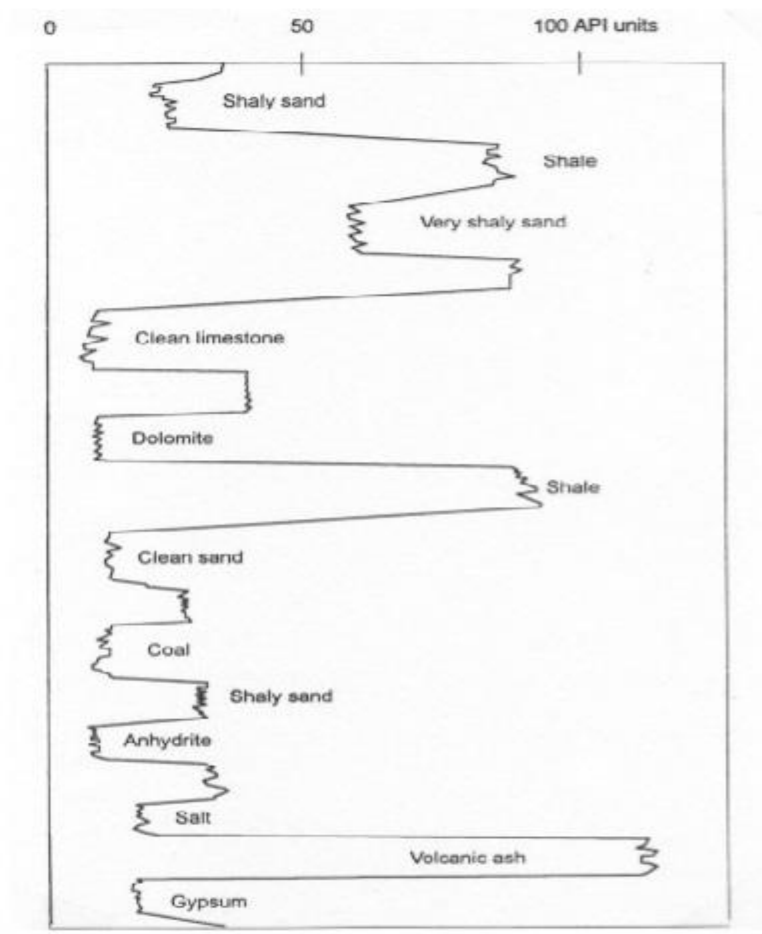


Figure 39: Gamma ray log response to different lithology

Gamma ray measurement is made with different tools; Simple and spectral gamma ray tools.

The first one is just a simple gamma ray detector which includes a photomultiplier and a scintillation counter. The scintillation is made by a sodium iodine Chrystal having the length of 5 cm and the diameter of 2 cm, and holds a impurities mirror of thallium. What this tool basically does is to shoot gamma ray through the crystal which causes a flash, this will be collected by the photomultiplier and store them in a condenser, this will stay over there for a set period of time, named a time constant. This energy which cumulates inside during the process will be the detector value at that depth for that time constant.

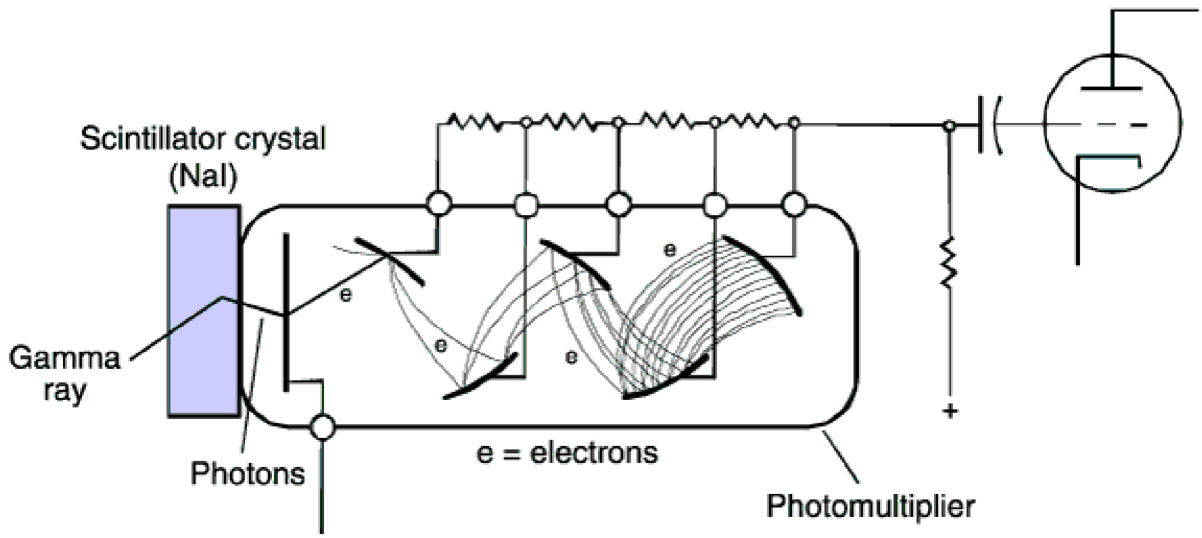


Figure 40: Schematic representation of a GR tool.

Spectral gamma ray tool has the same parts; the only thing that makes a difference is the larger Chrystal, 20 cm length and 5 cm diameter. This improvement will give the tool a better counting of the gamma ray and an increased sensitivity. In this tool when the gamma ray passes through the crystal, creates a flash in which will be measure the intensity of it, based on the energy created by the incident gamma ray. This will help to identify the gamma radiations in multiple, pre-defined energy windows. As a result given by the spectral tool, are the quantitative elemental abundances of, potassium, uranium and thorium.

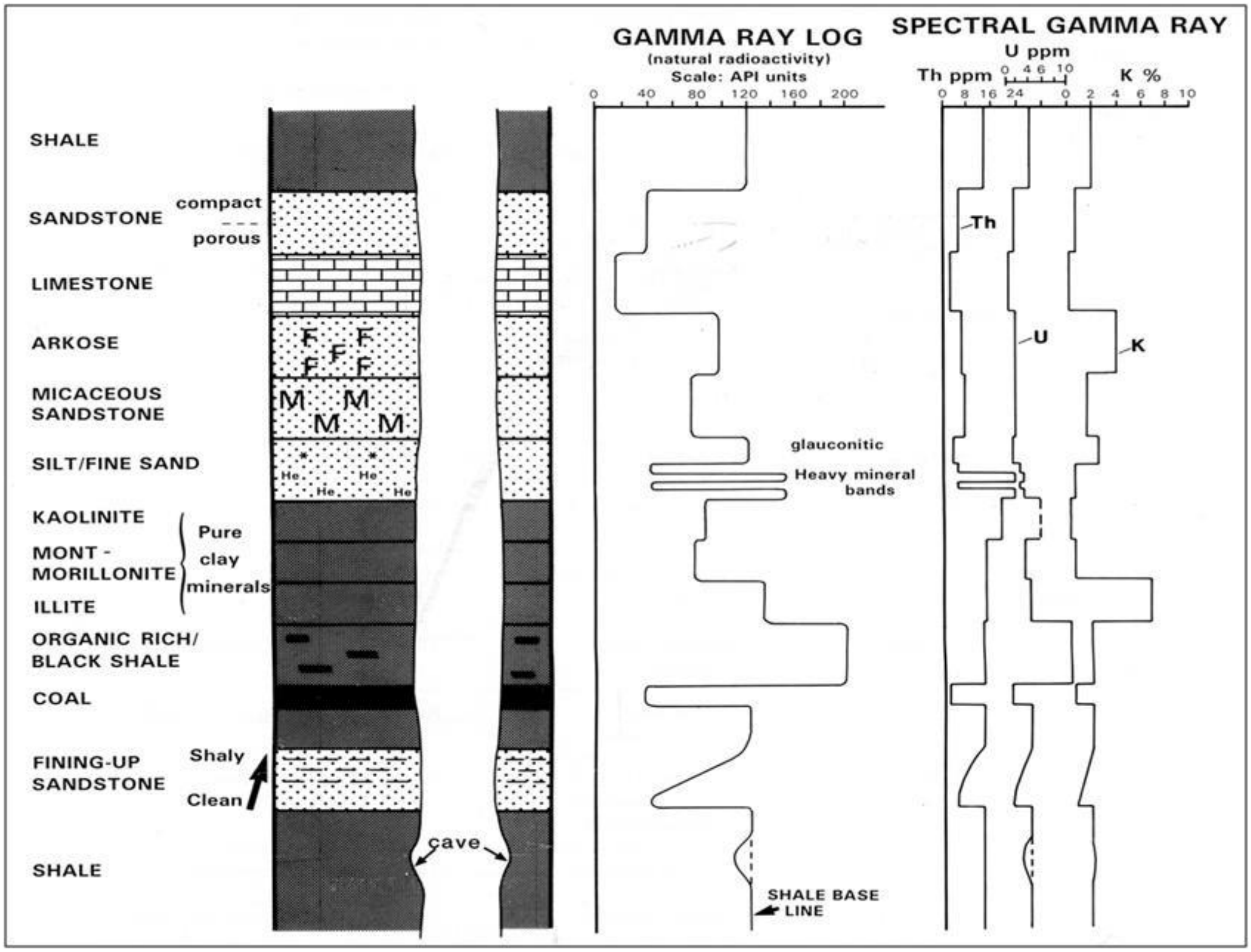


Figure 41: Gamma ray and spectral gamma ray interpretation

11.3.8.1 Neutron Logging

The neutron log method it is used for three purposes, the main one is to determine the porosity in the wellbore. Moreover it is used to determine the lithology and to identify the gas in a formation. As is know the neutron can be found in any nuclei of all elements except hydrogen, due to the fact that they have a similar mass, the difference is made in the charge. In order to get the data a neutron tool is drop in the borehole and in the moment of recovering, the tool source will bomb the rock formation with high-speed neutrons. This source is created from a chemical mixture between arnericium and beryllium. The tool once is in the borehole will start locating the hydrocarbons and the hydrogen in water zones from the porous formation. Once the neutrons are in wellbore, they will start to collide with the nuclei of the formation material.

Due to the collisions neutron energy will be lost. The maximum energy lost will be when a neutron gets in contact with a hydrogen atom since they have almost the same mass.

Since the hydrogen from a porous formation it can be found in the fluid-filled pores, the energy lost over there, will be related to the formation porosity.

When the rock pores are filled with gas instead of liquid the neutron porosity will be lowered, due to the gas density and the low concentration of hydrocarbons from the gas, this will be called *the* gas effect. After collecting the information a low reading of the porosity in the neutron log can be observed, but if it combine with the density log the gas effect can be seen clearly.

They are three major types of neutron logging:

Compensated neutron log; this tool is made of a source and two detectors, a short one and a long one. This makes the tool sensitive to the thermal neutrons therefore also to the hydrogen atoms. The tool was design to deal in most of the cases with liquid-filled pores of the rock formation, providing data about porosity.

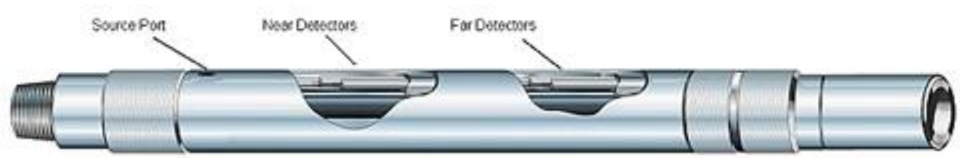


Figure 42: Compensate neutron tool

Gamma ray/neutron tool; is built only with one detector and a source. The tool is used either in open or closed borehole, and always have a central position. Mainly does the same as the above one but the difference is in his sensitivity on the borehole conditions (temperature, pressure, mud type and mud cake thickness).

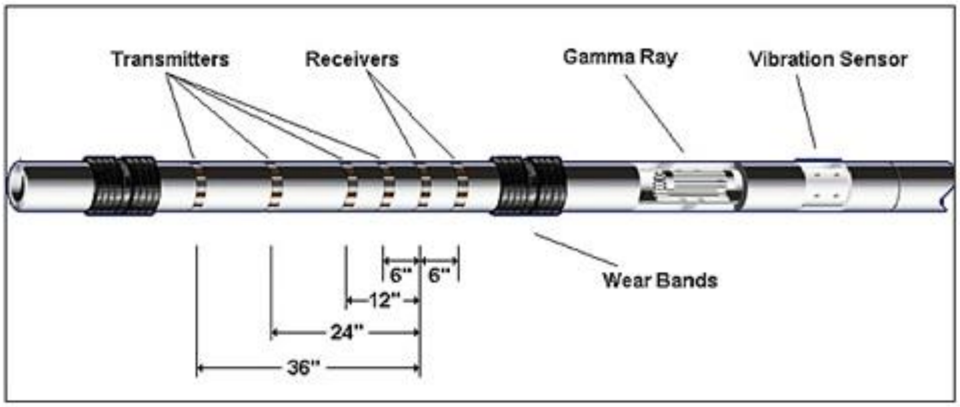


Figure 43: Gamma ray/neutron tool

Sidewall neutron porosity log; has the same built as the Gamma ray/neutron tool, but can be used only in open holes, and the tool needs to pressed against the wall. This tool is not affected by the hydrogen atoms, furthermore will be only sensitive to the epithermal neutrons.

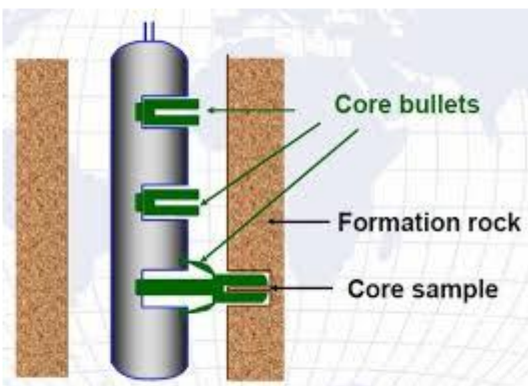


Figure 44: Sidewall neutron porosity tool

11.3.9 Density Logging

Density tool is made up of; a radioactive source, which releases gamma ray plus two detectors a short range one positioned near the source and a long range detector.
This tool will measure the bulk density of the formation, and is used to determine the total porosity. It also can be used to detect gas bearing formation and evaporates.
Density logging tool is sending the gamma ray in to the formation, if this formation has low porosity, the gamma ray will be absorbed near the source, and the detectors will count only the few gamma ray will remain. If is an opposite case with an increase porosity the gamma ray absorption will decrease and the detectors will have more gamma ray to count.
In case of a high density mud on the well bore, the data interpretation will be low since the tool it is affected. The reason was above, the high density will absorb the gamma ray.
Other measurements of this tool are made in order to provide data's for lithology, shale compaction, fractures and unconformities in the formation, determine minerals in evaporates deposits, gas detection or hydrocarbon density determination.
In order to calculate density porosity the following equation will be used:

$$\emptyset_{den} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \qquad \text{EQ.11.24}$$

Where:

- $\emptyset_{den}$ = density derived porosity
- ρ_{ma} = matrix density
- ρ_b = formation bulk density
- ρ_f = fluid density(1.1 gm/cc for salt mud,1.0gm/cc for fresh mud, 0.7gm/cc for gas)

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