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ESTIMATION OF PERMEABILITY IN SILICICLASTIC RESERVOIRS FROM WELL LOG ANALYSIS AND CORE PLUG DATA; BASED ON THE DATA FROM AN EXPLORATION WELL OFFSHORE NORWAY

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A report submitted to the Department of Geoscience and Petroleum NTNU, in a fulfillment of the MSc. Degree in Petroleum Geophysics.

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Abstract

Many approaches to estimating permeability exist. By considering the importance of rock types, various petrophysical models have been developed. This project explores techniques for applying well logs and other data to the problem of predicting permeability in uncored wells, because continuous log measurements such as NMR measure static properties of the Formation which may or may not correlate with permeability.

By finding relationships between well log measurements and permeability we can obtain continuous permeability values for the entire interval covered by well logs. These relationships are often not the same for the entire reservoir section and different correlations need to be established for each part of the reservoir. Due to the high costs of coring and laboratory analysis, permeability in most un-cored wells is estimated using correlation equations developed from limited core data. Most commonly, permeability is estimated from various well logs using either an empirical relationship, or some form of statistical regression.

The empirical models may bring wrong estimations in regions having different depositional environments if adjustments to constants and exponents in the model are not applied (Mohaghegh, Balan, & Ameri, 1997) and significant uncertainty exists in the determination of irreducible water saturation. On the other hand, statistical regression has been proposed as a more flexible solution to the problem of permeability estimation. Conventional statistical regression is generally performed parametrically using multiple, linear or nonlinear (quadratic) models that require *a priori* assumptions regarding functional form.

Empirical models relate porosity, permeability and irreducible water saturation. The main advantage of these methods is that unlike other methods, they do not require laboratory core analysis for permeability computations, hence can be used to wells that do not have core data and at early stages of exploration where the costs of coring are expensive.

The four empirical methods (Tixier,Timur Coates& Dumanoir and Coates) were applied to compute permeability as a function of computed porosity and water saturation and it was seen that permeability is underestimated by all empirical models because adjustments to constants was not possible and even the reservoir was not at irreducible water saturation.

On the other hand statistical regressions have been proposed to be a relative strong method in permeability prediction capability particularly multiple variable regressions. All regression methods do not have better consistency in following the actual trend in permeability; this is because of the tendency to average the entire data set to achieve reasonable values for statistical indicators. This is usually one of the weak points of all regression methods.

Conclusively it has been seen that statistical methods are better capable of predicting permeabilities in un-cored well as compared to empirical models. Empirical models requires some modifications to constants before applying them directly, though they are useful in predicting permeability trends in early stages of exploration where the cost of coring are extremely expensive. On the other hand multiple variable regression seems to be the best method in predicting permeability regardless of its few drawbacks.

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Nomenclature

φ = *Porosity*

K = *Permeability*

Sw = *Water saturation*

$Swirr$ = *Irreducible water saturation*

$Tcfg$ = *Trillion cubic feet of gas*

TVD = *True vertical depth*

MD = *Measured depth*

GOC = *Gas oil contact*

OWC = *Oil water contact*

mD = *mill Darcy*

m = *Cementation exponent*

n = *Saturation exponent*

w = $m=n$

ρ_h = *Hydrocarbon density*

S = *Surface area per unit bulk volume*

A_1 = *Kozeny constant*

Ro = *100% water saturated Formation resistivity*

d_o = *oil density*

d_w = *brine density*

ΔR = *Change in resistivity*

ΔD = *Change in depth*

$Rtcorr$ = *Corrected Formation resistivity*

$Rtlog$ = *Well log Formation resistivity*

$RDEP$ = *Deep Induction log*

MVR = *Multiple variable regression*

NEU = *Neutron log*

DEN = *Density log*

GR = *Gamma ray log*

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1 INTRODUCTION

1.1 General introduction

In the petroleum industry petrophysicists are primarily employed to answer three main questions; first is how much fluid a reservoir rock can hold, how much of that is water and how quickly it can be extracted. In other words to find out porosity, saturation and permeability. Porosity and permeability are two important petrophysical parameters used as input to building reservoir models. The porosity is an expression for the storage capacity of the rock whereas permeability is one of the parameters controlling the fluid flow in the reservoir. Porosity can be determined quite accurately from analyses of core plugs and well logs, however the permeability of a rock can only be measured accurately on core plugs. For many reservoirs there is a lack of core material for much (if not all) of the reservoir, we then have to rely on available well logs to determine the reservoir parameters.

By finding relationships between permeability, porosity and other well log variables, we can estimate a continuous permeability values for the entire reservoir. These relationships are often not the same for the entire reservoir section and different correlations need to be established for each part of the reservoir. Due to the high costs of coring and laboratory analysis, permeability in most uncored wells is estimated using correlation equations developed from limited core data. Most commonly, permeability is estimated from various well logs using either an empirical relationship, or some form of statistical regressions.

The empirical models may bring wrong estimations in regions having different depositional environments if adjustments to constants and exponents in the models are not applied and significant uncertainty exists in the determination of irreducible water saturation (Mohaghegh, Balan, & Ameri, 1997). On the other hand, statistical regression has been proposed as a more flexible solution to the problem of permeability estimation. Conventional statistical regression is generally performed parametrically using multiple linear or nonlinear models that require *a priori* assumptions regarding functional form.

Some of the methods presented above are applied to a heterogeneous hydrocarbon bearing sandstone of the Intra-Melke Formation, and the results are compared to core-determined permeability which is considered to be the reference. The objective is to establish the porosity-permeability model suitable for permeability determination from well log data from Pil and Bue oilfields offshore Norway.

1.2 Problem statement

Well logs may do a good job of porosity estimation because the physical properties they measure are determined by bulk amount of fluids and solid materials that make up the whole volume of rock. Also certain log measurements (resistivity) are very sensitive to amount of water and type of fluids contained in the rock volume and so can be used to quantify and determine water saturation and hence hydrocarbon saturation. Therefore provided that there is a comprehensive set of log variable that works properly, log analysis can normally be relied on to give accurate approximation of porosity and water saturation. On the other side permeability is determined by the structure of the pore system and this is something that most physical logs does not respond to. As a result, there is no general tool and/or equation that can be relied on to generate accurate permeability curves. Up to now a trusted way of constructing the accurate permeability curve is to base it on routine core analysis. And because it's so expensive to core the whole well interval, we normally rely on the log variables to fulfill the uncored interval.

1.3 Research Objectives

The objectives of this project are:-

- To improve permeability prediction from well logs by establishing relationships between permeability and well log variables. In such doing permeability can be easily computed from logs in uncored well sections
- To validate the developed models "characteristic permeability relations" using data from literature and industry sources for heterogeneous Intra-Melke Formation
- To suggest a general methodology applicable for permeability determination in uncored wells.

1.4 Study area location

The study is based on the data from exploration wells 6406/12-3A, 6406/12-3B and 6406/12-3S from PIL and BUE oil fields located in continental shelf of the Norwegian Sea at NS degrees 64° 1' 52.32" N, EW degrees 6° 45' 17.58" E, NS UTM [m]7102598.45, EW UTM [m] 390320.66 UTM zone 32 (NPD, 2013).

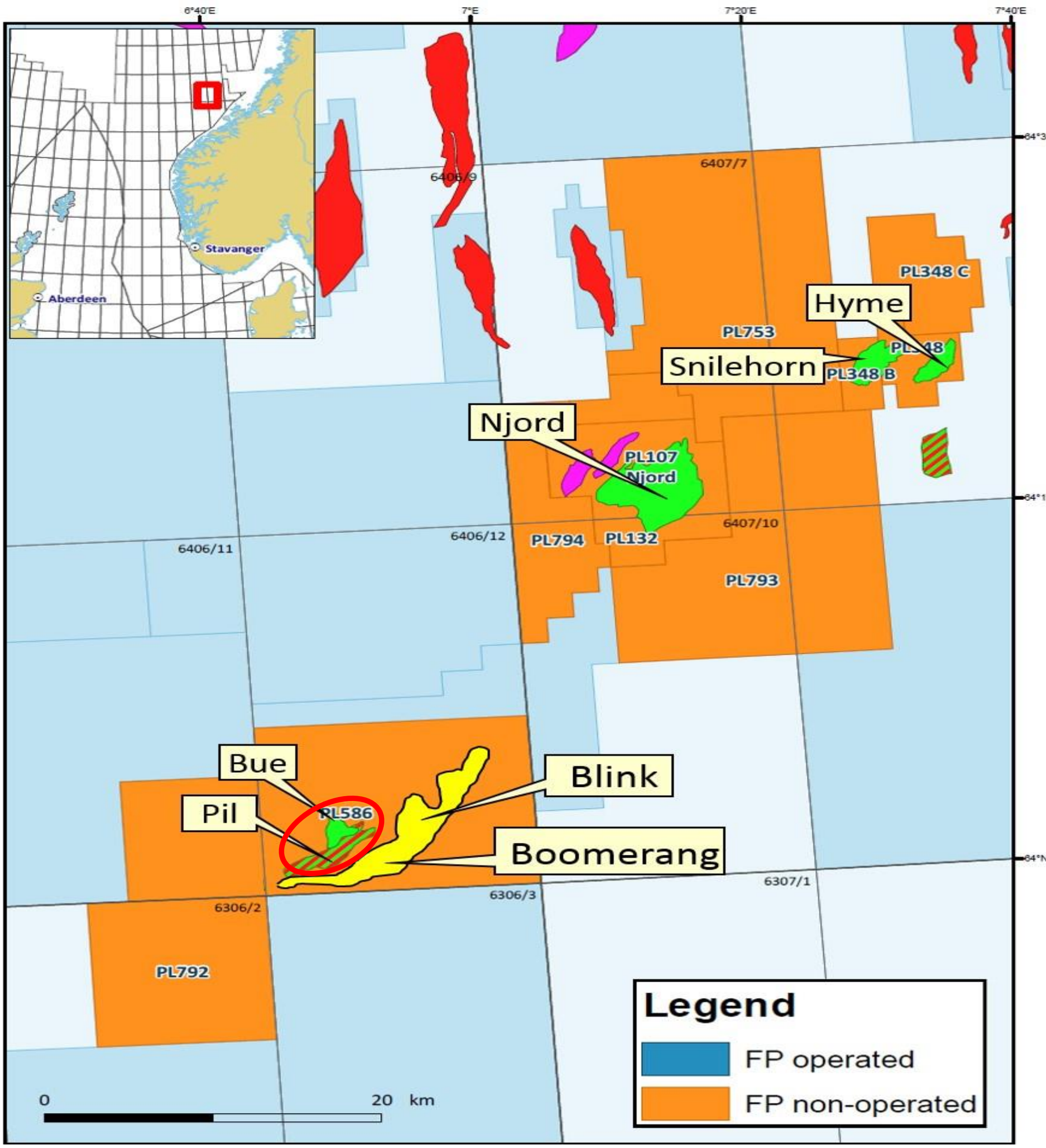

Figure 1; Location of the study area at Pil and Bue oil fields (Red circle). Image adopted from (Faroe Petroleum , 2017)

1.5 Data availability

Permeability data is obtained from laboratory core analysis. Core data are particularly good for generating permeability curve because data density is almost the same as well log data. Core permeabilities are also normally measured with a single fluid at relatively low pressure. A whole series of corrections are needed to convert the measured absolute permeabilities at ambient conditions to effective permeabilities for reservoir fluids at reservoir conditions. A commonly used method is known as Klinkenberg permeability correction.

Core data used in this project are porosities, saturations and Klinkenberg corrected permeabilities from three wells; 6406/12-3S, 6406/12-3A and 6406/12-3B from PIL and BUE oil fields. These wells stratigraphically crosscut reservoir rock of Intra-Melke Formation which is the interval under the study. All the wells have geophysical log data and core analysis data for this study. All well logs are compatible in terms of depth and resolution and are corrected for different environmental effects. Well logs used for porosity-permeability model development were gamma ray, neutron log, deep induction log and density log, however other logs were applied in the petrophysical analysis and computations.

The procedures under this study are as follows;

- Two of three wells are selected for model development.
- The developed model is applied to the third well. Using the third well log data, a permeability profile for the well will be predicted.
- The predicted permeability profile will be compared to actual laboratory measurements of permeability for this well.
- The best model (Method) will be recommended as useful model for the field.

There are many software packages that could be used in this particular project, but we selected only two of them. IBM SPSS software will be used for statistical analysis and Schlumberger Techlog will be used for reservoir analysis and description.

2 LITERATURE REVIEW

2.1 Review of Petrophysical Parameters (*φ, k, Sw*)

The major purpose of a petrophysical study is to determine if, and how much, hydrocarbons are present in the drilled Formation. This is done by looking at logs, determining several properties for the Formation among them the most important are porosity, saturation and permeability.

2.1.1 Porosity

The porosity of a rock, measures the capacity a rock has to hold fluid in between the matrix grains. Porosity can be quantitatively determined through the ratio;

$$\varphi = \frac{\textbf{Pore volume}}{\textbf{Bulk volume}} \tag{1}$$

Where *pore volume* denotes the interstitial volume and *bulk volume* denotes the total rock volume. From this (equation 1) it is evident that porosity is a fraction between zero and one and is often given in percent. Figure 2 below shows the rock matrix and the interstitial pore spaces

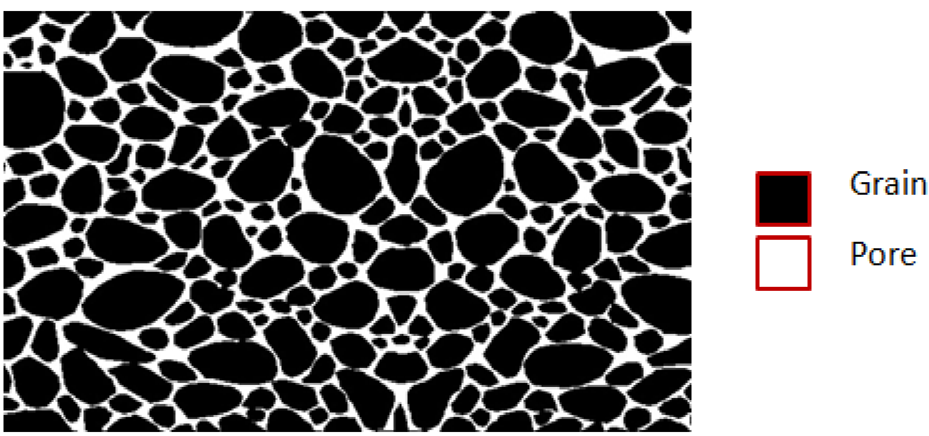

Figure 2; a proportion of pore spaces in a bulk volume of rock. Black potion denote rock matrix and white signify pore spaces (figure adopted from (Zoltán , 2005))

Some of these pores can be isolated from the rest of the pores due to cementation, compaction and shale distribution during the Formation of the rock. These isolated pores do not contribute to the volume of hydrocarbon that can be produced, and therefore porosity can be divided into total and effective porosity (Zoltán , 2005).

Porosity calculation is a very important step of well log analysis and it could only be done correctly if the lithology interpretation is correct. There are many approaches that can be used to calculate the porosity from well logs, one may opt to use density log, sonic log, neutron log, or combination between them, but the most trusted method is neutron-density log combination (Neutron-density cross plot)

2.1.2 Saturation

In petrophysical evaluation, water saturation determination is the challenging part especially in shaly-sand reservoirs yet is used to quantify more important complement, the hydrocarbon saturation (1-Sw). There are different approaches used to quantify *Sw* each with its own complexity leading to different *Sw* values that may equate to considerable differences in hydrocarbon pore fraction (HCPF). Archie (Archie, 1941) developed a famous equation to calculate water saturation from well log parameters. This model is used for Formations in which clay/shale content is low (Clean Formation). Equation (2) together with other methods, saturation can be easily determined from well log interpretation.

$$Sw^n = \frac{aRw}{\varphi^m * Rt} \tag{2}$$

2.1.3 Permeability

Permeability, **K**, is the property of the porous medium that measures the capacity and ability to transmit fluids (Kennedy, 2015). If there are no interconnected pores in the reservoir rock, the permeability is zero. This parameter is important for the reservoir quality as it controls the flow rate and flow direction of the fluid contained in the porous medium. This project tries looks at how permeability curves can be generated and in particular how logs can be used to estimate permeability curves. Permeability curve have a number of application in Formation evaluations including the following.

- Populating static and dynamic reservoir models.
- An input to saturation height equations.
- Defining net (pay) through a cut-off.
- Quantitatively defining heterogeneity.
- Predicting well performance.
- Operational work such as defining perforation programs.

2.2 Geological setting of an area

The Norwegian Sea covers most of the continental margin between approximately 62 and 69N. The tectonic history of the Norwegian continental shelf is divided into three major episodes 1) Late Silurian – Early Devonian which was the final closure of the Iapetus ocean during the Caledonian Orogeny, 2) Late Devonian – Paleocene Characterized by a series of extensional deformation culminating with the continental separation between Greenland and Eurasia and 3) Earliest Eocene to Present which is active Seafloor spreading between Eurasia and Greenland with the formation of Passive continental margin to the coast of Norway (Gradsten, Anthonissen, & Brunstand, 2010).

Rifting and formation of N-S to NE-SW trending rotated fault blocks occurred on the Halten Terrace and parts of the Trøndelag Platform in late Permian/early Triassic times (Figure 3). This was followed by deposition of a thick continental Triassic succession. Drilling in the Helgeland Basin has proven up to 2500m thickness of Triassic (Grey and Red beds) including two Middle Triassic evaporite intervals up to 400m thick. The evaporite intervals represent detachment levels for later extensional faults. These thick sequences are related to pronounced subsidence and deposition in a fluvial sabkha environment. This tectonic event was possibly preceded by Carboniferous and Permian rifting (Brekke, Williams, & Magnus, 2008)

The Halten Terrace where the well 6406/12-3S was drilled is a highly prospective geological province in the Norwegian Sea. Notable giant fields include Åsgard (1 bnbbls + 6 Tcfg), Kristin (232 mmbbls + 0.9 Tcfg), Victoria (1.5 Tcfg), Tyrihans (270 mmbbls + 0.9 Tcfg) and Heidrun (1 bnbbls + 1.4 Tcfg) (NPD, 2013). These accumulations are mainly located in Jurassic tilted fault blocks which have proved to be highly prospective. Further potential exists in inversion anticlines and stratigraphic traps containing Cretaceous sandstones. Key producing horizons include Garn, Åre, Tilje, Tomma and Fangst. The Viking group has not been intensively explored yet it shows the potentiality of having producible hydrocarbon from mainly Intra-Melke and Melke Formations

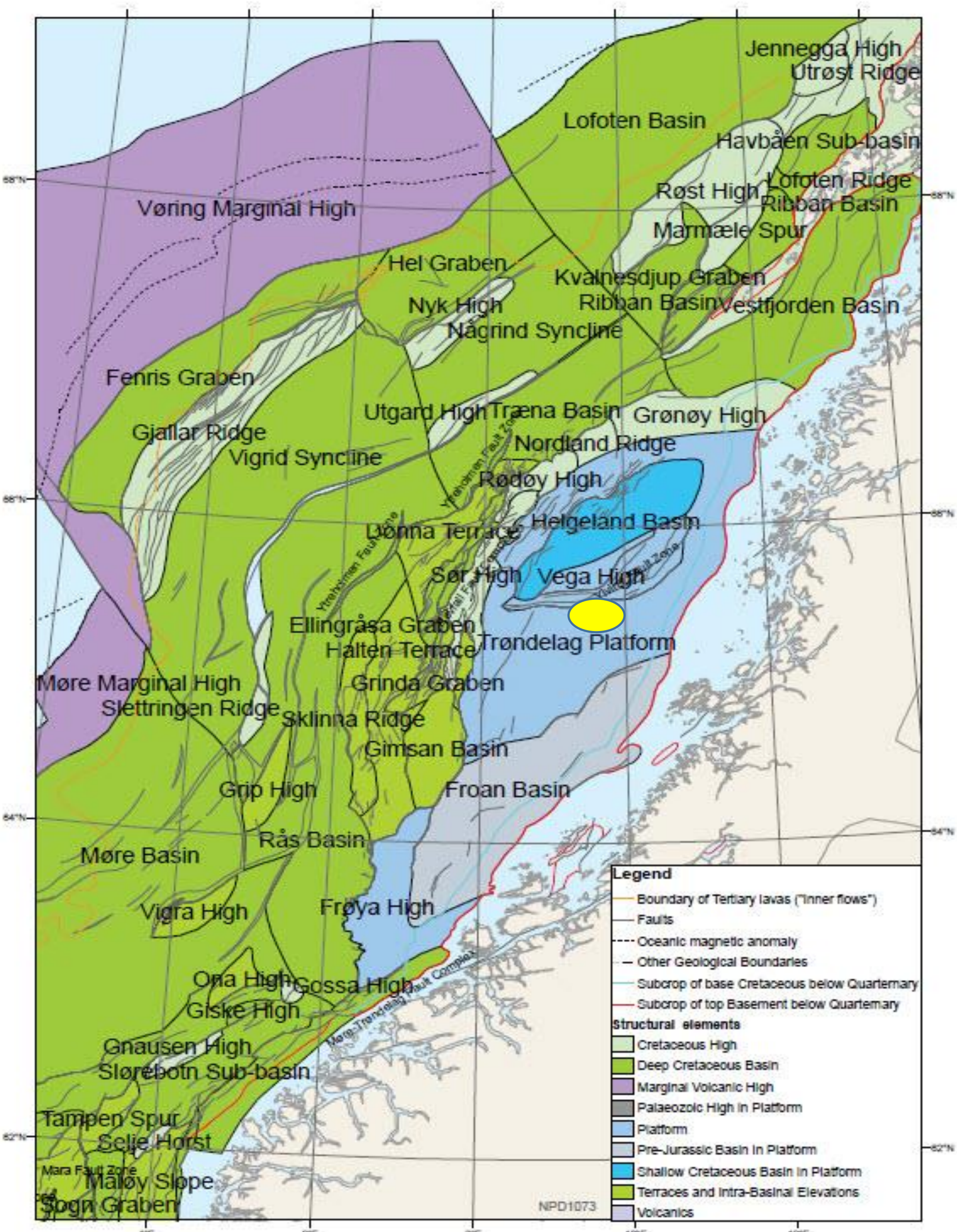

Figure 3; structural elements in the Norwegian Sea after (Brekke, Williams, & Magnus, 2008). A point marked yellow is the drill well location.

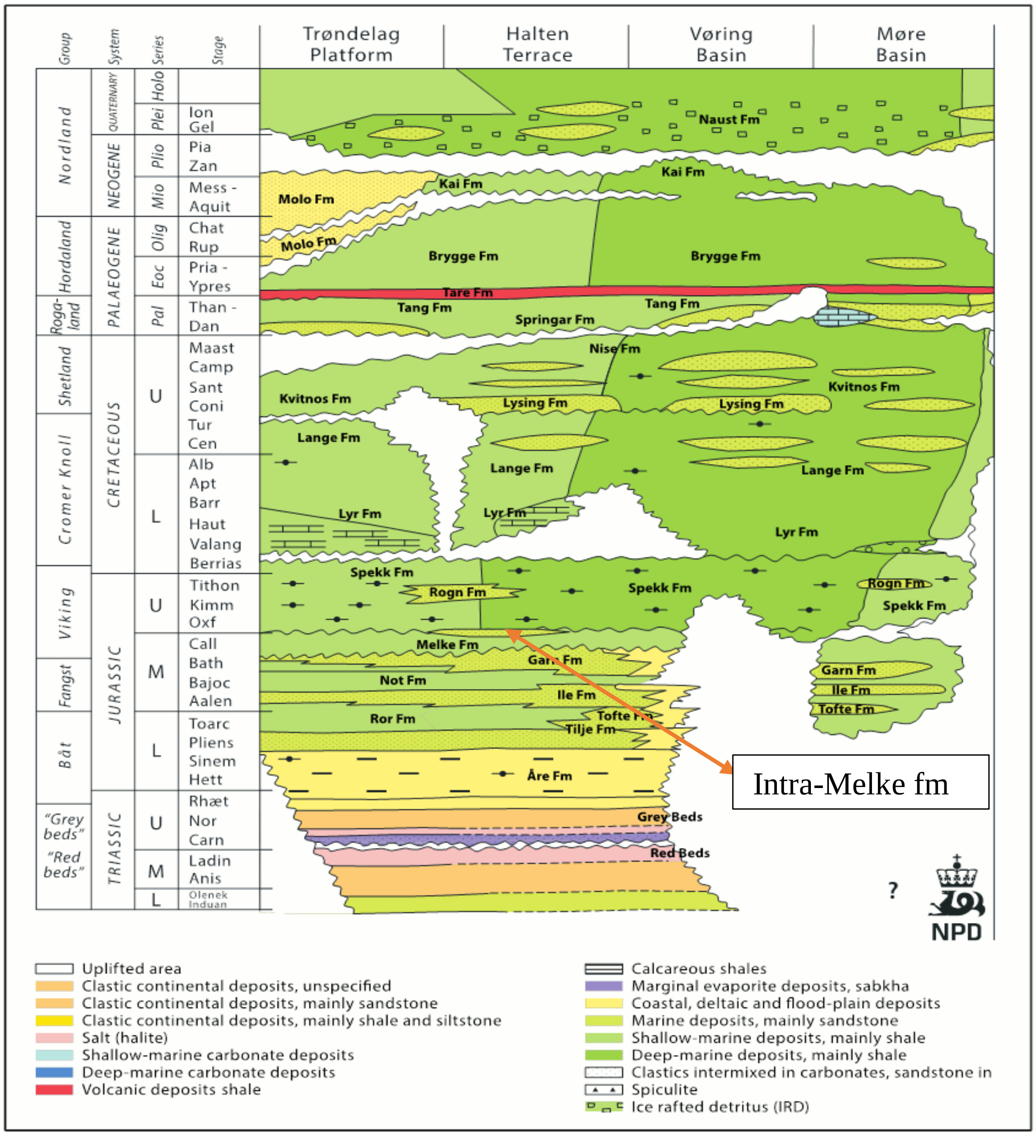

Figure 4; Stratigraphy of the study area after (Brekke, Williams, & Magnus, 2008)

2.2.1 The Viking Group

The Viking Group is defined in the northern North Sea and on Haltenbanken and Trænabanken. It is divided into four Formations, the Melke, Rogn, Intra-Melke and Spekk Formations. The group is present over most of the Trøndelag Platform, but thins toward the Nordland Ridge where it is locally absent (Figure 4). The dominant lithology of the Viking Group is mudstones and siltstones, with the exception of locally developed sands (Rogn Fm) in the Draugen field area and on the Frøya High. Sediments correlated with the Viking Group have been found by shallow drilling and seafloor sampling in the eastern part of the Trøndelag Platform (NPD, 2013). The thickness of the Viking Group in the type well (6506/12-4) is 124.5m and 61m in the reference well (6407/9-1). Thicknesses up to 1000m are indicated on seismic data in down-faulted basins, and well 6507/7-1 on the Dønna Terrace drilled 658m sediments of the Viking Group (NPD, 2013).

2.2.1.1 The Melke Formation

The Melke Formation (Bajocian to Oxfordian) is deposited in an open marine environment over most of Haltenbanken, but contains local sands in parts of the Dønna Terrace, the Revfallet Fault Complex and over the southern part of the Rødøy High. In the type, well (6506/12-4), the thickness is 116.5m, but thicknesses in the order of 550m have been drilled in the area west of the Nordland Ridge (NPD, 2013).

2.2.1.2 The Intra-Melke Formation

Intra-Melke sandstone Formation (early to late Callovian) forming a significant hiatuses at the Melke/Spekk Formation boundary and at an Intra-Spekk Formation level (NPF, 1991). These sands have very good to excellent reservoir quality. In this study we are focusing on the Intra-Melke Formation intercalated with Melke Formation deposited in an open marine environment over most of Haltenbanken, and contains local sands in parts of the Dønna Terrace, the Revfallet Fault Complex and over the southern part of the Rødøy High.

2.3 Well histories

Three wells 6406/12-3S, 6406/12-3A, and 6406/12-3B were drilled in the southern end of the Halten Terrace in the Norwegian Sea to test the PIL and BUE prospects. The 6406/12-3S well was planned to test the PIL prospect whereas the 6406/12-3A was targeted to test the BUE prospect. Well 6406/12-3 S found gas over oil in Intra Melke Formation sandstones in the PIL prospect. This result led to the decision to drill an appraisal of the discovery. The appraisal well was designated 6406/12-3 B, which confirmed oil in Melke Formation sandstones in pressure communication with the primary well 6406/12-3S. The last sidetrack well, 6406/12-3A, was designed to test the BUE prospect and to evaluate fluid contacts and connectivity with the PIL discovery (NPD, 2013)

Contrary to projection, there were no Rogn Formation sandstones in the 6406/12-3S well, instead, the well encountered Intra Melke Formation sandstones at 3514 m (3276.5 m TVD). These sandstones had well to excellent reservoir quality and contained a 227 m TVD gross hydrocarbon column. The hydrocarbons in the reservoir zone consisted of a 93 TVD m thick gas cap overlying a 134 TVD m oil leg in. The GOC is located at 3608 m (3370 m TVD) and the OWC at 3742 m (3504 m TVD). Pressure data indicated a single gas gradient over an oil leg. Below the OWC, the well penetrated a further thick high net to gross reservoir package of Intra Melke sandstones with a continuous water gradient (NPD, 2013).

At the top of the Jurassic section, the well 6406/12-3B encountered a different stratigraphy from the 6406/12-3 S well. Immediately below BCU, a 35 m MD Spekk/Rogn/Spekk succession was penetrated. Hydrocarbons were present within these rocks but not moveable. Below the Spekk Formation, at 3761 m (3440 m TVD), the well encountered over 500 m of Intra Melke Formation sandstones. These sands are interpreted to contain similar facies as those encountered in the 6406/12-3S discovery immediately below the BCU. The Intra Melke sands contained an 82 m oil column in very good to excellent quality reservoir sandstone with an oil-water contact at 3844 m (3522 m TVD), 18 m deeper than in the 6406/12-3S well. Pressure data confirmed the same oil gradient as in 6406/12-3S. There was no gas cap. A second hydrocarbon column of 10 m was seen approximately 360 m below the oil water contact (NPD, 2013).

The 6406/12-3 A well entered the Jurassic reservoir rocks approximately 900 m to the northwest of the 6406/12-3 B Pil reservoir entry point. The well encountered Spekk Formation claystones on either side of a Rogn Formation sandstone reservoir and below this is a Melke Formation heterolithic package. Top Rogn Formation was at 4053 m (3421 m TVD) with top reservoir sands at 4059 m (3426 m TVD). The Rogn reservoir was of good to very good quality and contained an 18 m oil column with an OWC at 4083 m (3444 m TVD). No gas cap was anticipated or present. Data including the oil water contact position and oil type indicates the 6406/12-3A discovery is separate from 6406/12-3 S discovery (NPD, 2013).

Table 1: The lithostratigraphy of three drilled well in PIL oil field. All wells crosscut an Intra-Melke Formation which was used in permeability models development

6406/12-3A		6406/12-3B		6406/12-3S	
Top depth [m]	**Lithostrat. unit**	**Top depth [m]**	**Lithostrat. unit**	**Top depth [m]**	**Lithostrat. unit**
348	NORDLAND GP	348	NORDLAND GP	348	NORDLAND GP
348	NAUST FM	348	NAUST FM	348	NAUST FM
1091	KAI FM	1091	KAI FM	1091	KAI FM
1230	HORDALAND G	1230	HORDALAND G	1230	HORDALAND G
1230	BRYGGE FM	1230	BRYGGE FM	1230	BRYGGE FM
1961	ROGALAND GP	1961	ROGALAND GP	1920	ROGALAND GP
1961	TARE FM	1961	TARE FM	1920	TARE FM
2087	TANG FM	2087	TANG FM	2031	TANG FM
2332	SHETLAND GP	2332	SHETLAND GP	2235	SHETLAND GP
2332	SPRINGAR FM	2332	SPRINGAR FM	2235	SPRINGAR FM
2678	KVITNOS FM	2449	NISE FM	2318	NISE FM
3715	CROMER KNOL	2659	KVITNOS FM	2573	KVITNOS FM
3715	LANGE FM	3452	CROMER KNOL	3312	CROMER KNOLI
4019	LYR FM	3452	LANGE FM	3312	LANGE FM
4041	VIKING GP	3695	LYR FM	3505	LYR FM
4041	SPEKK FM	3726	VIKING GP	3514	VIKING GP
4053	ROGN FM	3726	SPEKK FM	3514	INTRA MELKE F
4114	SPEKK FM	3728	ROGN FM	3912	MELKE FM
4124	INTRA MELKE F	3748	SPEKK FM		
4180	MELKE FM	3761	INTRA MELKE FM SS		
		4264	MELKE FM		

3 METHODOLOGY

3.1 Empirical models for porosity-permeability relationship

These are models based on the correlation between permeability, porosity and irreducible water saturation. To apply these methods several steps haves to be taken one being porosity determination from well logs. First; porosity is determined from density log and it show a good agreement between log-determined and core determined porosities for well 6406/12-3S (Figure 5).

Knowing that permeability is very sensitive to cementation factor ‘m’, second step is to determine a consistent value for this parameter. This factor is determined from Pickett plot by establishing a water line in a 100% water saturated zone, in this case Zone_4 (Figure 14 and Attachment of well log curves showing zonation). Cementation exponent is obtained to be 1.95.

The third step is to determine water saturation. The saturation exponent *n* is assumed to be 2, and Indonesian model (SPE, 2015) for water saturation is applied to estimate saturation across the well interval. Cross plot of porosity against water saturation of well 6406/12-3S is presented on Figure 6. By comparing with depth, theoretical irreducible water saturation, with petrophysical calculated water saturation it is possible to recognize the presence of mobile water though we have to assume that the reservoir is at irreducible water saturation.

Reservoir zonation was done according to fluid content shown in well log curves (Attachment). In this case Zone_1 was shale; Zone_2 was Gas; Zone_3 was oil while Zone_4 was interpreted as water bearing.

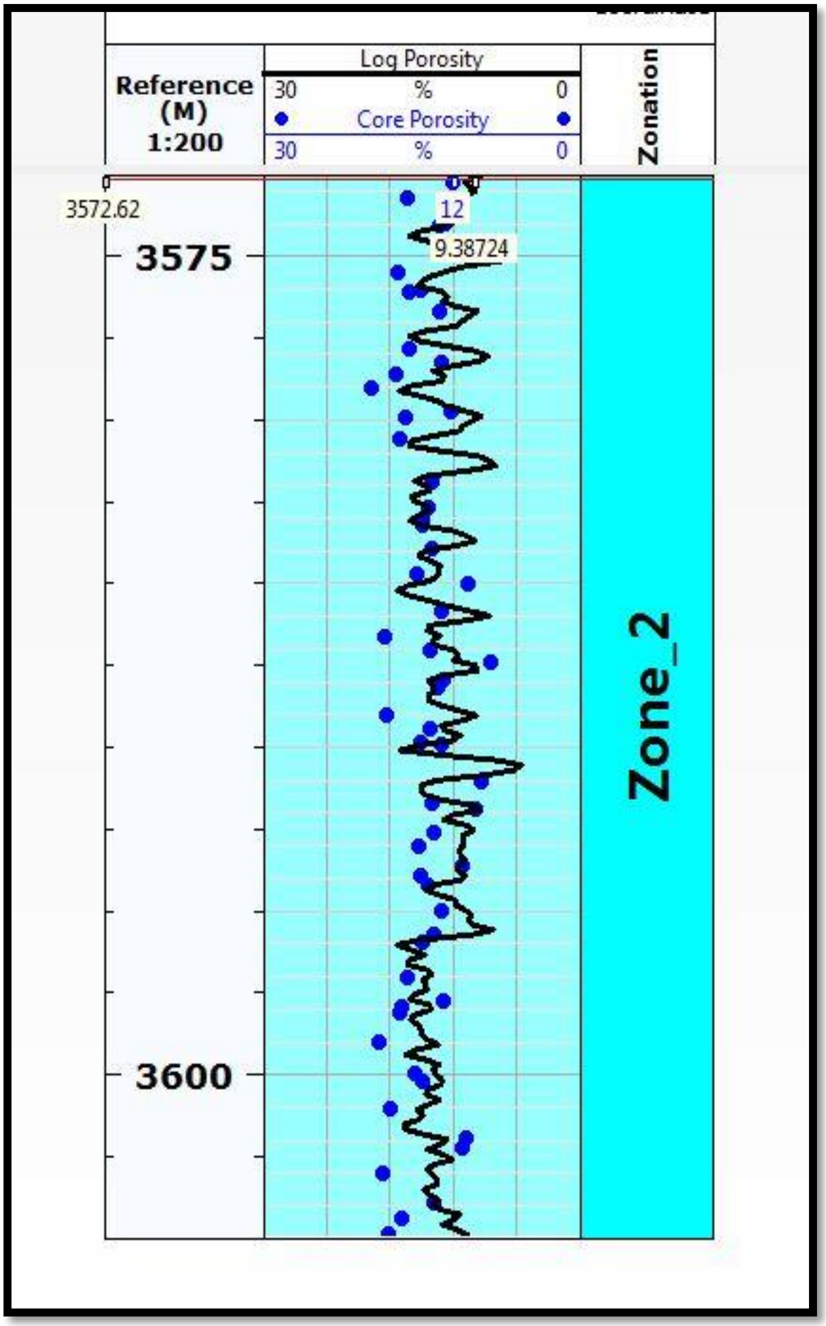

Figure 5; Log and core porosity for well 6406/12-3S which was used to develop empirical models for permeability determination. Density log porosity was computed and related to Core porosity in a specific zone of interest. There is a good agreement between core and log porosity.

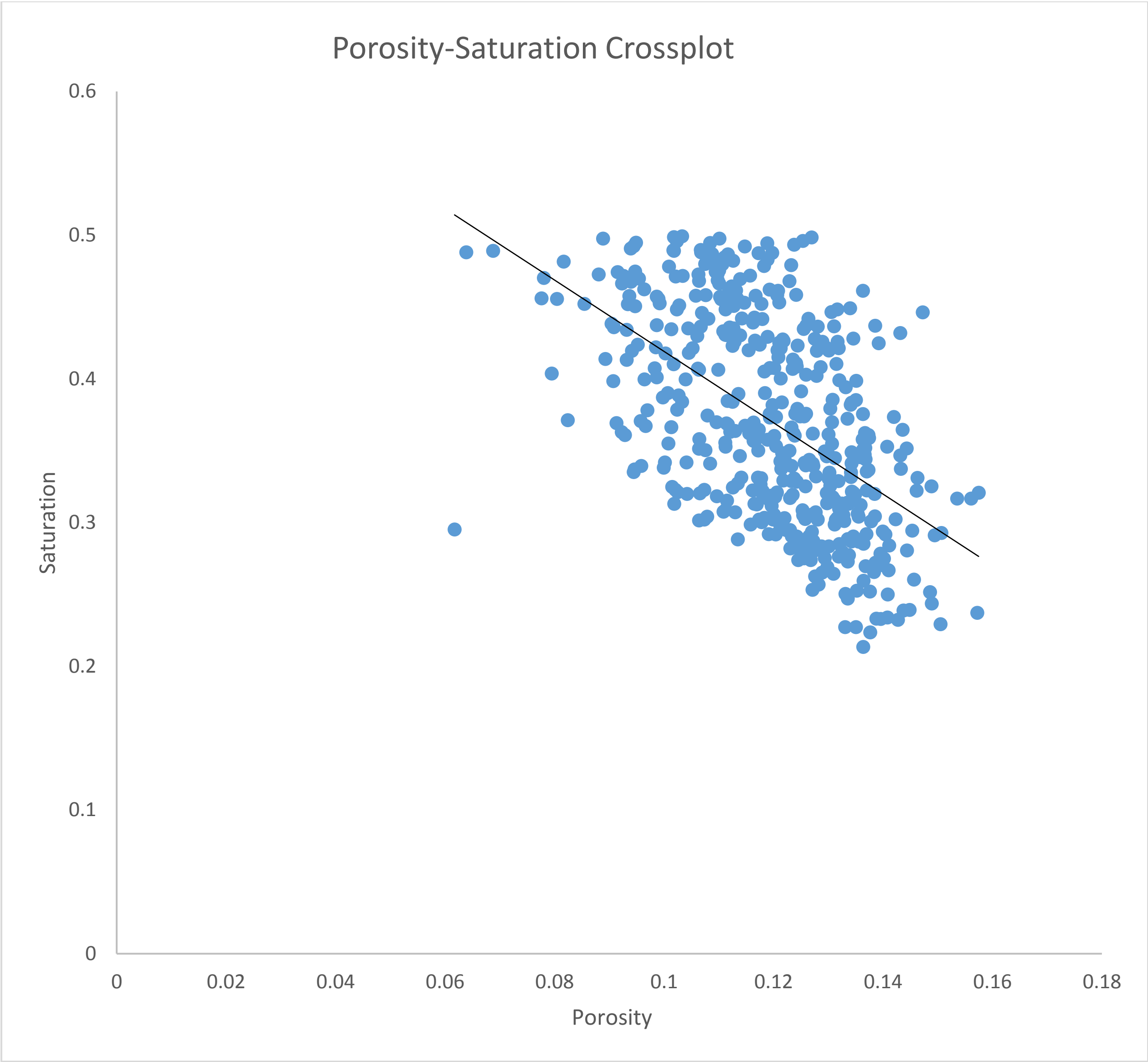

Figure 6; Porosity-Saturation cross plot

Having done those procedures, four empirical methods discussed below (Tixier,Timur Coates& Dumanoir and Coates) are applied to compute permeability as a function of computed porosity and water saturation with the assumption that a reservoir is at irreducible water saturation.

3.1.1 Kozeny-Carmen

The first equation measuring permeability property of the rock was proposed by Kozeny and later modified by Carman (Shahab , Balan, & Ameri, 1995).

$$K = A_1 \frac{\varphi^3}{S^2(1-\varphi)^2} \tag{3}$$

Note symbols defined in Nomenclature

This methodology will not be applied in this project for permeability estimation because the equation is valid for rocks of uniformly sized spheres, and the surface area can only be determined by core analysis and only with special equipments (Shahab , Balan, & Ameri, 1995).

3.1.2 Tixier model

Tixier (Tixier, June 1949) developed the model for permeability determination by exhausting the empirical relationship between resistivity and water saturation, water saturation and capillary pressure and capillary pressure with permeability and he came out with the method to determine permeability from resistivity gradient (Shahab , Balan, & Ameri, 1995). He derived some mathematical equation and finally Tixier presented his model in equation 4 below.

$$\sqrt{\frac{K}{20}} = \frac{2.3}{R_o(d_w - d_o)} * \frac{\Delta R}{\Delta D} \tag{4}$$

Note: symbols defined in Nomenclature

The resistivity gradient is determined from a deep investigation tool, and corrected for borehole effects. This method assumes that saturation exponent, n, is equal to 2, and that at any water saturation, capillary pressure is related to permeability (Tixier, June 1949). The model is limited in its application by absence of well logs showing exact oil-water contacts and poor estimation of fluid densities as it exists in the reservoir. Also the calculated permeability is an average for the zone corresponding to the resistivity gradient (Shahab , Balan, & Ameri, 1995).

3.1.3 Timur

Based on the limitations to apply Konzen-Carmen (Kennedy, 2015) equation especially in finding specific surface area of the grain, Timur (Timur, 1968) proposed a generalized and simplified equation in the form of;

$$K = A\frac{\varphi^{B}}{Swir^{C}} \tag{5}$$

Timur statistically evaluated the constants A, B and C based on laboratory experiments conducted to more than 155 samples from different field. He applied a Reduced Major Axis (RMA) method with high correlation coefficient and he obtained the constants as A= 0.136, B = 4.4 and C= 2. From his paper (Timur, 1968). Timur assumed a cementation exponent of 1.95 applies in all field whereas porosity and water saturation are in percentage (Shahab , Balan, & Ameri, 1995).

3.1.4 Coates & Dumanoir

Coates and Dumanoir established an improved permeability equation in an oil bearing Formation with oil density of 0.8 g/cc (Shahab , Balan, & Ameri, 1995). In a condition where hydrocarbon density is not equal to 0.8, Coates and Dumanoir proposed a correction equation given as.

$$\frac{Rtcorr}{Rtlog} = 0.077 + 1{,}55\rho_{h} - 0.627\rho_{h}^{2} \tag{6}$$

With the support of core and log studies Coteates and Dumanoir established a common exponent for saturation and cementation factors as *w*, whereas $m = n = w$ and therefor a generalized equation for permeability estimation is given as;

$$\sqrt{k} = \frac{C}{w^{4}}\frac{\varphi^{2w}}{R_{w}/R_{ti}} \tag{7}$$

$$\text{Where } C = 23 + 465\rho_h - 188\rho_h^2 \tag{8}$$

$$w^2 = (3.73 - \varphi) + 0.5\left[log_{10}\left({}^{R_w}/_{R_t}\right) + 2.2\right]^2 \tag{9}$$

Refer to nomenclature for definition of symbols

To apply this equation the Formation should be at irreducible water saturation, the problem comes how to know if the Formation is at stated condition. If the Formation is not at irreducible water saturation the assumed value of *Rt* is less than the value of *Rti* and the resulting exponent *w* from equation 9 will be wrongly estimated. Coates and Dumanor presented the methodology to test whether the Formation is at irreducible water saturation or not, they also provided a correction for those Formations that are not at irreducible water saturations and shaly-Formations, but will not be discussed in this project. The equation of Coates and Dumanoir is the first to satisfy the condition of zero permeability at zero porosity and when Swirr = 100%. Because of the corrections provided, this method can be applied to Formations that are not at irreducible water saturation, and to shaly Formations (Shahab , Balan, & Ameri, 1995).

3.1.5 Coates and Denoo

Coates and Denoo (Shahab , Balan, & Ameri, 1995) proposed the formula below for permeability estimation in milidarcies. The equation also satisfies the condition of zero permeability at zero porosity and when Swirr = 100%. (Shahab , Balan, & Ameri, 1995)

$$\sqrt{K} = 100\,\frac{\varphi^2(1 - Sw_{irr})}{Sw_{irr}} \tag{10}$$

Refer to nomenclature for definition of symbols

The last four methods above are applied on well 6406/12-3S in Intra-Melke Formation interval from 3520m to 3690m to compute permeability in gas and oil zones. Computed porosity and water saturation from logs of well 6406/12-3S are the main inputs for permeability determination by empirical methods. The bulk density measured by the tool (Density log), results from combined effects of the fluid (porosity) and the rock matrix was used to compute density porosity.

Since we assumed that a reservoir is at irreducible water saturation, the computed water saturation by the Poupon-Leveaux (SPE, 2015) method was used as *Swirr*. All the inputs was computed and analyzed by the Schlumberger Techlog software.

3.2 Statistical models; Porosity-permeability by regression techniques

3.2.1 Correlations

Correlation is a measure of association between two or more variables. The variables are not designated as dependent or independent. Correlation coefficient is a single summary number that tells you whether a relationship exists between two variables, how strong that relationship is and whether the relationship is positive or negative. (Higgins, 2005).

The value of a correlation coefficient can vary from minus one to plus one. A minus one indicates a perfect negative correlation, while a plus one indicates a perfect positive correlation. A correlation of zero means there is no relationship between two variables. When there is a negative correlation between two variables, as the value of one variable increases, the value of the other variable decreases, and vice versa. In other words, for a negative correlation, the variables work opposite each other. When there is a positive correlation between two variables, as the value of one variable increases, the value of the other variable also increases. The variables move together.

Variable selection is more important in this method of permeability prediction, core permeability data will be converted to logarithm of permeability to increase the correlation coefficient between permeability and other variables in the regression because of the fact that permeability typically varies over several orders of magnitude (XIE, 2008).

Table 2 is a correlation matrix which summarizes correlation coefficients between variables, note that variables have been selected according to their high relationship with the dependent variable (permeability), to avoid the so called multicollinearity. In statistics, multicollinearity (also collinearity) is a phenomenon in which one predictor variable in a multiple regression model can be linearly predicted from the others with a substantial degree of accuracy. In this situation the coefficient estimates of the multiple regression may change erratically in response to small changes in the model or the data (Hyötyniemi, 2001).

Table 2; A correlation matrix

Correlation Matrix						
		Core permeability	DEN	GR	RDEP	NEU
Core permeability	Pearson Correlation	1	.057	-.002	-.211	.094
	Sig. (2-tailed)		.277	.968	.000	.070
	N	369	369	369	369	369
DEN	Pearson Correlation	.057	1	.554	-.508	.675
	Sig. (2-tailed)	.277		.000	.000	.000
	N	369	581	581	581	581
GR	Pearson Correlation	-.002	.554	1	-.669	.724
	Sig. (2-tailed)	.968	.000		.000	.000
	N	369	581	581	581	581
RDEP	Pearson Correlation	-.211	-.508	-.669	1	-.721
	Sig. (2-tailed)	.000	.000	.000		.000
	N	369	581	581	581	581
NEU	Pearson Correlation	.094	.675	.724	-.721	1
	Sig. (2-tailed)	.070	.000	.000	.000	
	N	369	581	581	581	581

3.2.2 Model development

Model development for porosity-permeability relationship and prediction will rely on the data obtained from Conventional Core Analysis (CCA). This type of measurement involves moving fluids through the pore system and so directly responds to permeability. Normally continuous log measurements such as NMR, Caliper and ‘Stoneley waves’ infers to whether the Formation is permeable or not but they do not provide quantitative measurements of permeability.

Core permeabilities are used here to produce the model over which permeability curves from well log will be generated. Regression analysis which is a statistical technique for estimating the relationship among variables is used to establish equations which later will be used to generate permeability curves. In this study three wells (6406/12-3S, 6406/12-3A and 6406/12-3B) from the same field crosscutting the same Intra-Melke Formation (Table 1) and that had both well logs and core analysis were selected. Figure 7 shows their relative locations. Two of the three wells will be used for model development and the established model will be applied to the third well to obtain its permeability profile.

In developing the permeability vs. porosity relationships, we need to identify the extent to which the reservoir interval needs to be subdivided into zones. The subdividing of the core data over the reservoir interval should be into logical subdivisions that are strongly influenced by the depositional environment. This will naturally account for major differences in grain size, sorting, and key mineralogical factors. A single permeability vs. porosity correlation for a reservoir interval with different depositional environments can lead to under-prediction of permeability by an order of magnitude in an interval of better-sorted rocks compared with poorly sorted rocks (Kennedy, 2015).

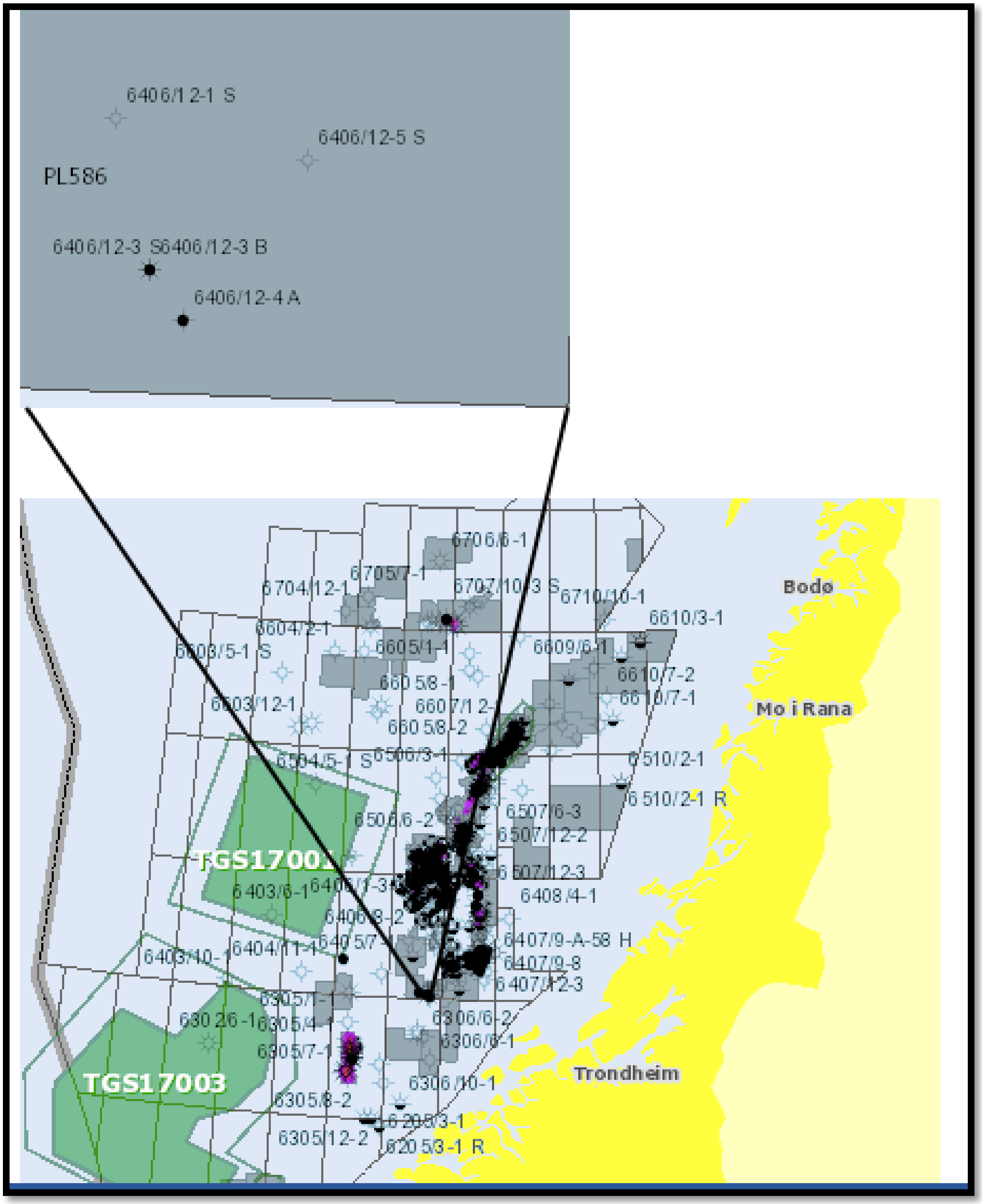

Figure 7 Relative locations of the three drill well used for model development and testing (figure downloaded from Fact Map NPD)

3.2.2.1 Simple linear Relationship

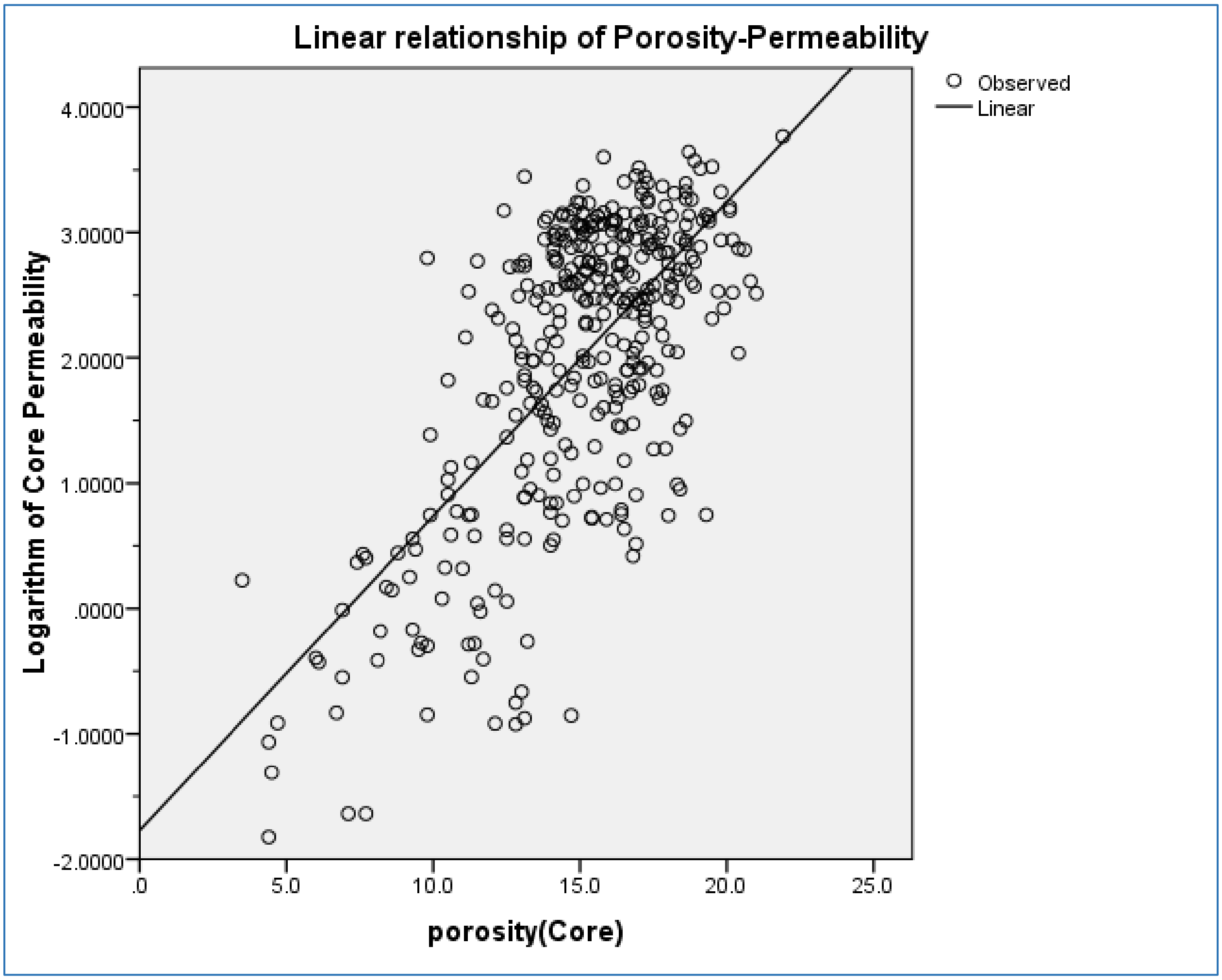

Figure 8; Porosity permeability cross plot and their linear relationship for modeling

Figure 8 is a cross plot of core porosity and core permeability for well 6406/12-3S in Intra-Melke Formation and its relationship for modeling. The porosity-permeability crossplot defines a reasonable linear trend of permeability against porosity, where by log-permeability and porosity are dependent and independent variables respectively. Log linear relationship model to be fitted is described in equation 11 below whereas the constant and coefficient are determined by simple linear regression analysis. The analysis is performed to define the constants A and B in equation 11 using the IBM SPSS statistical software, where core permeability and core porosity are the input data.

$$Log(K) = A + B\varphi \tag{11}$$

The points on Figure 8 defines a log linear relationship for which log permeability (log K) on porosity regression gives the constant of intercept A=-1.773 and the coefficient of porosity B = 0.251. The correlation coefficient for this well is 0.678 and the linear model for permeability estimation is given as:

$$Log(K) = 0.251\varphi - 1.773 \tag{12}$$

Where in this case porosity is given in fraction. The equation 12 above is known as semi-log relationship and is commonly applied for permeability estimation in clean homogeneous sandstone Formations, which is not always the situation. The equation may do a good job of finding average permeability but at the cost of making the reservoir appear more homogeneous than is really the case (Kennedy, 2015).

3.2.2.2 Quadratic relationship

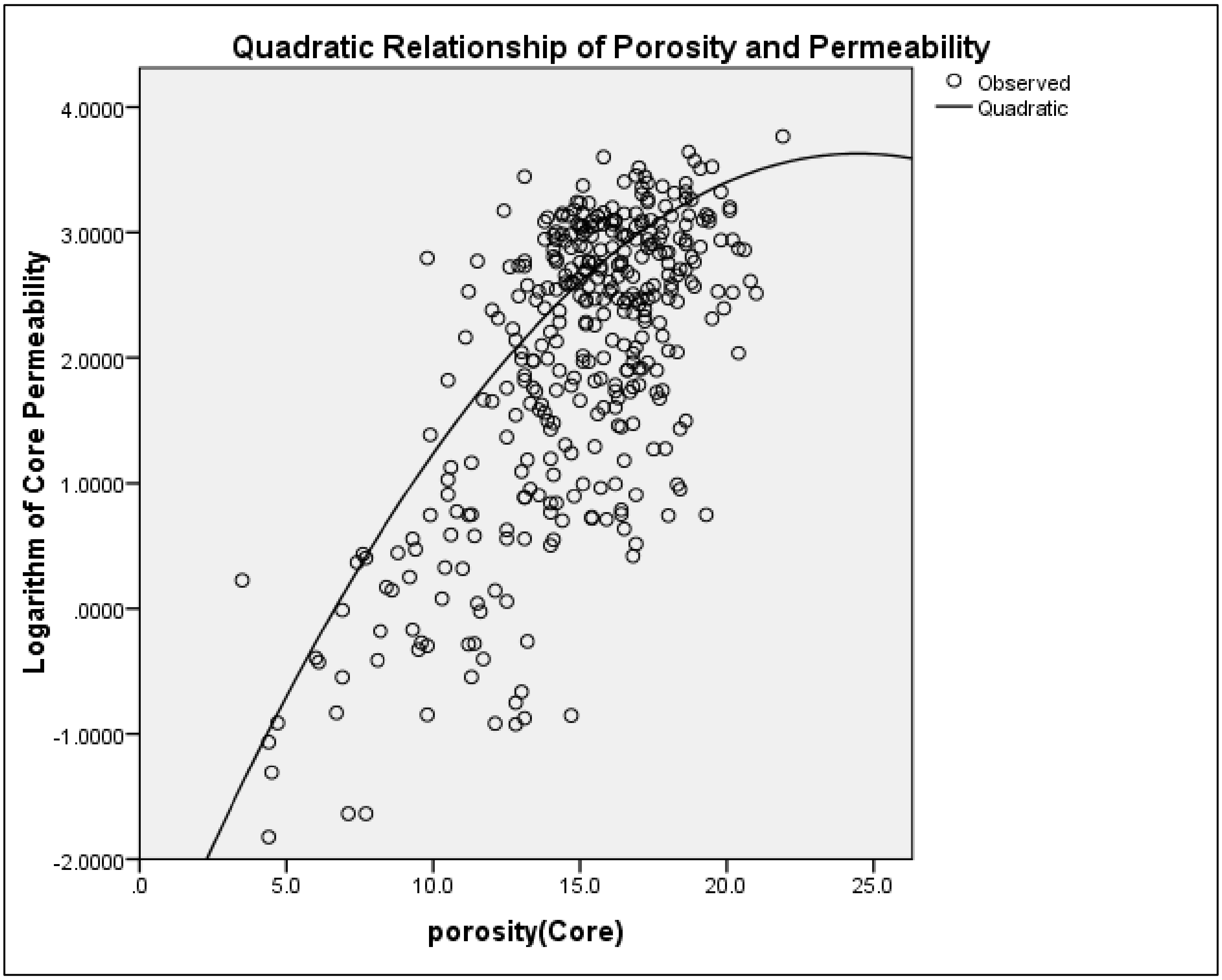

Figure 9; Porosity-Permeability relationship with a convex curve for modeling

$$Log(K) = A + B\varphi + C\varphi^2 \tag{13}$$

Inspections from Figure 8 shows general increase in permeability as porosity increases but the rate of increase seems to fall at very high porosities, thus a convex curve would appear to fit the data better (Figure 9) than a simple straight line used earlier. In this way a quadratic relationship of the form above (equation 13) has to be used. Here the same data from well 6406/12-3S in Intra-Melke Formation were used to develop a crossplot shown on Figure 9

From regression analysis using curve fitting procedure in IBM SPSS software the unknown constants A, B and C in equation 13 are determined. The independent and dependent variable inputs are porosity and permeability respectively. The correlation coefficient of 0.694 and R square of 0.482 gives the constant A = -3.22, coefficient of porosity B = 0.56 and the coefficient of porosity square C= -0.011 and so the quadratic model is given as:

$$Log(k) = -3.22 + 0.56\varphi - 0.011\varphi^2 \tag{14}$$

3.2.2.3 Porosity-Permeability Relationship with other log variables (Multiple variable Regression)

In the predictive equation additional independent variables (well log variables) with high correlation coefficient to the dependent variable are added. The dependent v ariable is still a logarithm of core permeability because permeability has a log-normal distribution (Hyötyniemi, 2001)

The model to be fitted is:

$$Y = B_0 + B_1X_1 + B_2X_2 + B_3X_3 \ldots \ldots \ldots \ldots B_nX_n + e \tag{15}$$

Where Y is the dependent variable to be estimated (permeability), X_1, X_2, X_3.....X_n are independent log variables and e is the standard estimation error (Shahab , Balan, & Ameri, 1995).

Using conditional probability (Ruzzo, 2011) in equation 15 above and taking expectation both sides we have:

$$E(Y/(X_1 \ldots\ldots X_n)) = B_0 + B_1X_1 + B_2X_2 + B_3X_3 \ldots\ldots\ldots\ldots B_nX_n \tag{16}$$

Where $E(Y/(X_1 \ldots\ldots X_n))$ the expectation of Y given that $X_1 \ldots\ldots Xn$ is has been occurred and the expected value of error is zero. The conditional mean of Y is written as

$$Y = E(Y/(X_1 \ldots\ldots X_n)) \tag{17}$$

The objective is to determine regression coefficients, and again the independent variable Y is the logarithm of core permeability because permeability is log-normal. Dependent variables $X_1 \ldots\ldots Xn$ are well log variables. A correlation matrix (Table 2) was analyzed to establish if there is a dominant independent variable with high correlation coefficient to the dependent variable, and to avoid multicollinearity (Hyötyniemi, 2001).

Before performing regression, several initial remedial steps has been taken to maximize the cogency and significance of the analysis results; One being shifting of the logs to ensure common depth registration, second was environmental corrections for borehole effect and third was zoning of the logs with data sampled from peak and through extremes to reduce extraneous errors introduced by transitional curve features (Shahab , Balan, & Ameri, 1995).

Based on the correlation matrix in table 2, the order in which the variables enter the model is, *NEU*, *DEN*, *GR*, *RDEP* and the model is given in equation 18. To determine the regression coefficients in equation 18, the horizontal core permeabilities from well 6406/12-3B and 6406/12-2S were used as dependent variable inputs while log measurements (NEU, DEN, GR, RDEP and AC) from the same interval in Intra-Melke zone were entered as independent variable inputs. The analysis is performed by the SPSS software.

$$K = Exp(A) * (NEU)^{B} * (DEN)^{C} * (GR)^{D} * (RDEP)^{E} \tag{18}$$

Refer to nomenclature for definition of symbols

The values of constants estimates (A, B, C, D and E) are determined by exploitation of multiple variable regression analysis using IBM SPSS statistical software and are listed in the Table 3 below

Table 3; Constant estimate for equation (16)

Parameter Estimates				
Parameter	Estimate	Std. Error	95% Confidence Interval	
			Lower Bound	Upper Bound
A	15.130	4.101	7.065	23.195
B	1.439	.384	.684	2.194
C	.928	3.428	-5.813	7.670
D	-1.542	.489	-2.504	-.581
E	-.144	.188	-.514	.225

Coefficients indicate how much the dependent variable varies with an independent variable when all other independent variables are held constant. Finally the multiple variable regression model for this field is given as;

$$K = Exp(15.13) * (NEU^{1.439}) * (DEN^{0.928}) * (GR^{-1.542}) * (RDEP^{-0.144}) \tag{19}$$

Refer to nomenclature for definition of symbols

4 RESULTS AND DISCUSSION (MODEL COMPARISON TO CORE PERMEABILITY)

4.1 Empirical models

Empirical models as discussed earlier relate porosity, permeability and irreducible water saturation. The main advantage of these methods is that unlike other methods, they do not require laboratory core analysis for permeability computations, hence can be used to wells that do not have core data and at early stages of exploration where the costs of coring are expensive. The rationale behind these methods is that permeability and irreducible water saturation are both controlled, to an extent, by grain size. Permeability is mainly controlled by pore throat size, but in an inter-granular rock that is itself strongly dependent on grain size (Kennedy, 2015)

The four empirical methods (Tixier,Timur Coates& Dumanoir and Coates) were applied to compute permeability as a function of computed porosity and water saturation. Figure 10 and Figure 11 presents the core and empirically computed permeability versus depth in in gas and oil zones of well 6406/12-3S.

From this figure, it can be seen that permeability is severely underestimated by all four empirical models, whereas average permeability of 0.4-5.4mD has been predicted contrary to average core permeability of 500-800mD. But among them the best method seem to be Coates & Dumanoir (PERM_C_D in Figure 10&11); this is because the model takes into accounts for the Formation that are not at irreducible water saturation and to shale-Formations. It also offers a correction factor for hydrocarbon densities different from 0.8g/cc (Shahab , Balan, & Ameri, 1995).

Table 4 below signify average permeability by all four empirical methods in oil and gas zones of well 6406/112-3S compared to average core determined permeability. Also from this table it can be seen that all methods highly underestimates permeability by more than 90%.

Table 4; Average permeability values by four empirical methods in oil and gas zone for well 6406/12-3S as compared to average core permeability for the same well.

Zones	Coates(mD)	Timur(mD)	Tixier(mD)	C & D	Core Permeability(mD)
Gas Zone	0.801	0.464	1.722	5.375	705.645
Oil Zone	0.455	3.15	1.452	5.136	489.395

For instance, clays and cements may form in the pore throats severely reducing the permeability but having a negligible effect on *Swir*. So these relationships tend to work best in clean sandstones that have undergone little diagenesis different from Intra-Melke Formation which has a significant amount of clays (V-shale gamma ray in figure 10&11). In short these relationships may work well with no modifications, they may work well after some modification or they may not work at all (Shahab , Balan, & Ameri, 1995).

Normally the presence of shale dramatically reduces permeability. Observing at Figure 10 and Figure 11 graphed with shale volume (gamma ray method), one can clearly realize that at high shale volume permeability is predicted low by all methods, but at some points particularly in gas zone permeability is predicted high at higher shale volume. This can be explained as the amount of gamma ray was not contributed from clay minerals, reasonably could be other sources that emits gamma rays such us feldspars .

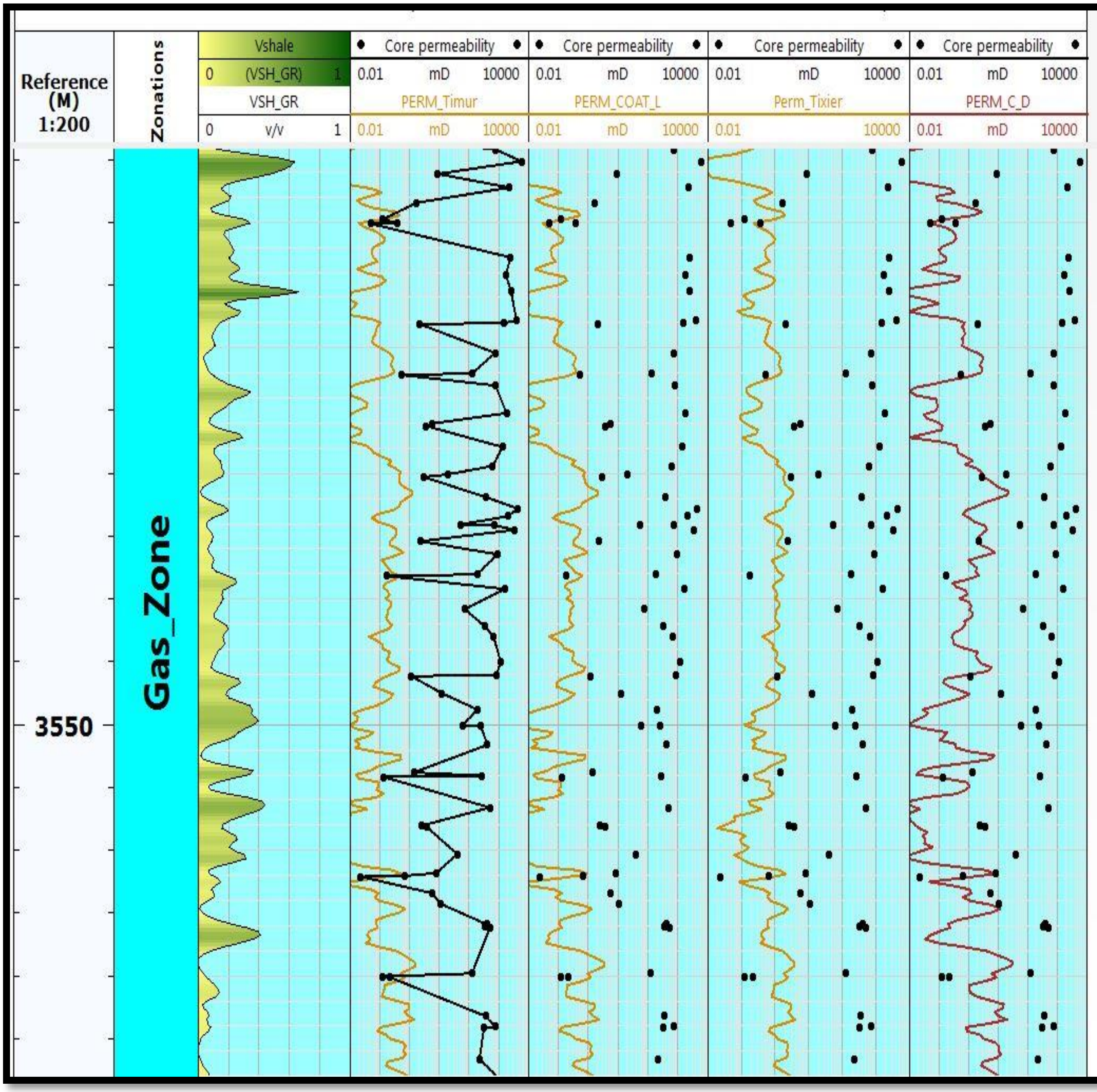

Figure 10: Computed permeability (mD) by four empirical methods (from left to right Timur, Coates,Tixier and Coates&Dumanoir) in gas zone for well 6406/12-3S, plotted together with core permeability for the same well against Depth(M)

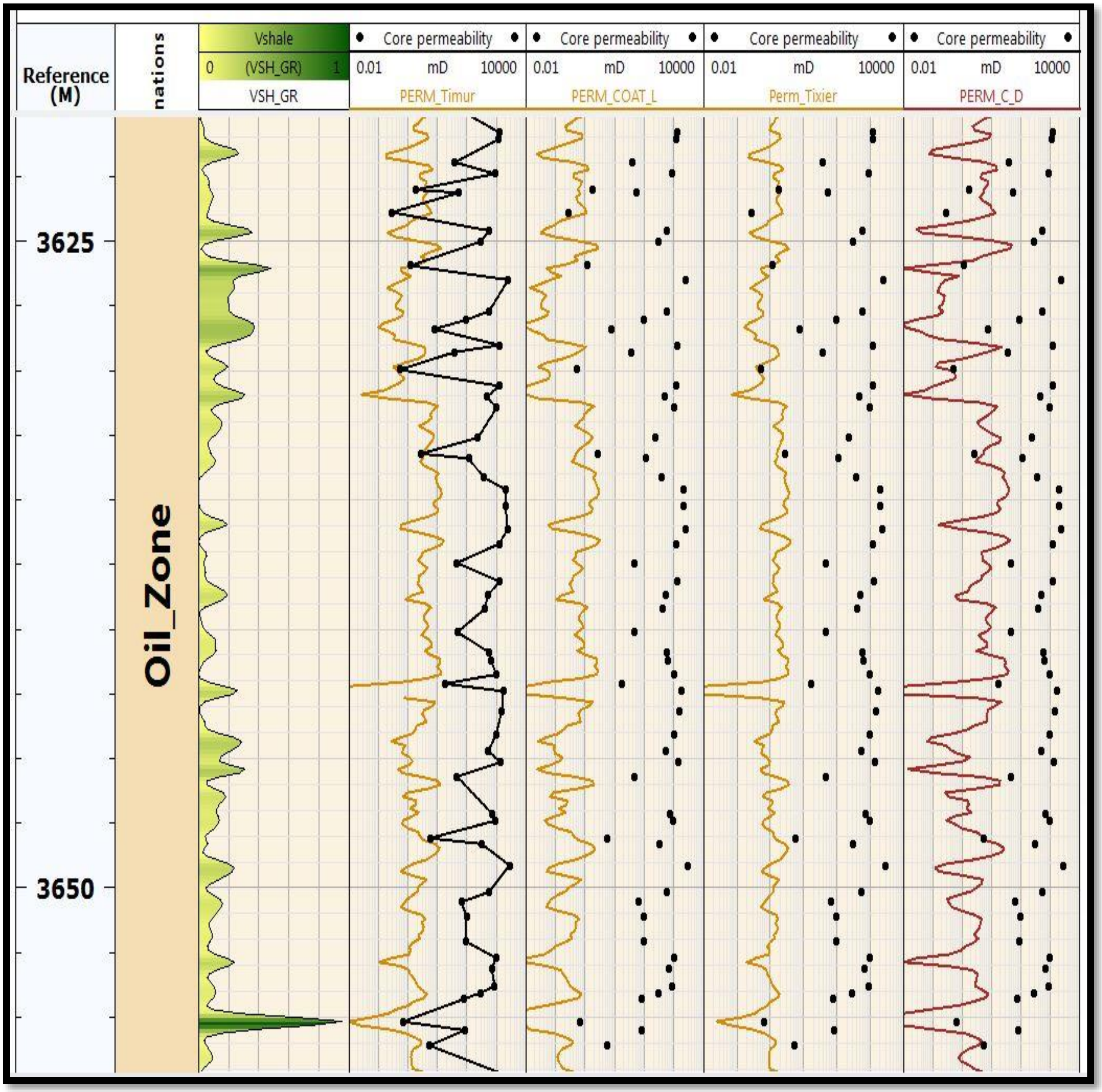

Figure 11; Computed permeability (mD) by four empirical methods (from left to right Timur, Coates,Tixier and Coates&Dumanoir) in oil zone for well 6406/12-3S, plotted together with core permeability for the same well against Depth(M)

As discussed earlier, empirical models for permeability prediction depends upon best estimates of effective porosity and irreducible water saturation from well logs. One of the most important contributions of these models is the employment of the relationship between porosity, irreducible water saturation and capillary pressure. The main problems of these models can be explained as follows; to get permeability one needs to know effective porosity and irreducible water saturation and these parameters are accurately measured in laboratory using core samples. Here the point is if core samples are available to measure these parameters, why not measure permeability instead of predicting it. To overcome the absence of core samples effective porosity and irreducible water saturation are then predicted from well logs with a certain degree of accuracy to be used in empirically developed models, but it should be noted that porosity calculated from logs is not necessarily effective, and calculating irreducible water saturation is not well established method.

All in all empirical models developed for a certain Formation perform poorly when used in other fields and also there is no generalization with these types of models.

4.2 Regression Methods

Both well 6406/12-3S and 6406/12-3B at an interval of 3520m-3690m and 3764m - 3886m respectively, within the Intra-Melke Formation was used to develop regression models for permeability determination. Well 6406/12-3A was not used for model development because part of the Intra-Melke Formation in this well was not a reservoir. Well log variables used for model development were Gamma ray, Neutron log, Bulk density and deep induction log and once the models were developed, were applied to well 6406/12-3S to generate its permeability curves.

Simple linear, quadratic and multiple regression models offered a porosity-permeability relationships presented in equation 12, equation 14 and equation 19 respectively. These equations were used to generate permeability curves shown on Figure 12 and Figure 13 below. Inspections from these figures and from Table 5 below shows that regression models performs better than empirical methods however simple linear and quadratic models still underestimate permeability particularly in gas zone.

Simple linear model predicted average permeability of 24mD in gas zone and 85mD in oil zone whereby the reference core permeability in gas zone is 700mD and in oil zone is 500mD (Table 5). This is to say simple linear model have underestimated permeability by 96% in gas zone and by 80% in oil zone and this signifies that porosity and permeability are linearly not related mainly because of reservoir heterogeneity. The equation 12 above is known as semi-log relationship and is commonly applied for permeability estimation in clean homogeneous sandstone Formations, which is not the case in Intra-Melke formation.

Quadratic relationship of porosity and permeability is the second method discussed in this project to provide better estimates of permeability than linear regression model (Table 5 and Figure 11). This is because of the fact that there was a general increase in permeability as porosity increases but the rate of increase tended to fall at very high porosities, thus a convex curve (Figure 9) seemed to fit the data better than a simple straight line. Permeability of 125mD in gas and 400mD in oil zones have been predicted by quadratic model. Also the model have underestimated permeability by 82% in gas zone while in oil zone predicted permeability is much closer to reference core permeability by 85% (Figure 13).

Multiple variable regression gives a better estimates on average than other regressions methods (linear and quadratic) used in this project. The methodology gave the average permeability of 800mD in gas and 400mD in oil zone which are values closer to average core permeability (table 5 below).,

Table 5; Average permeability values in gas and oil zone for three statistical models as compared to average core permeability. All values are in mD.

Zones (mD0	**Core (mD)**	**Linear (mD)**	**Quadratic (mD)**	**MVR (mD)**
Gas Zone	702.289	24.052	123.689	845.201
Oil Zone	489.395	85.482	415.186	402.162

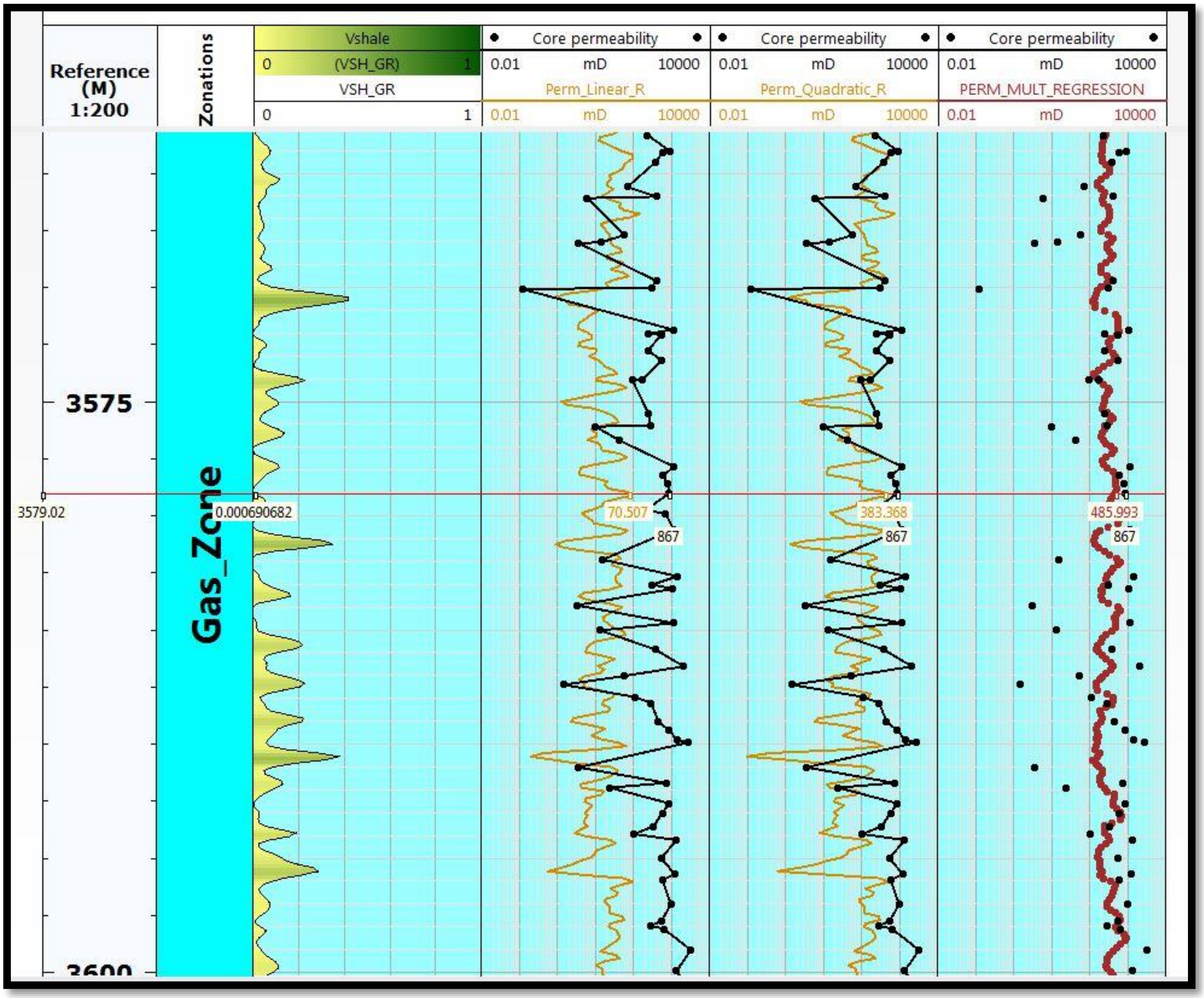

Figure 12; Prediction Models permeability values vs. core measurement for well 6406/12-3S in Gas zone. Multiple regression model seems to fit the data well followed by Quadratic model.

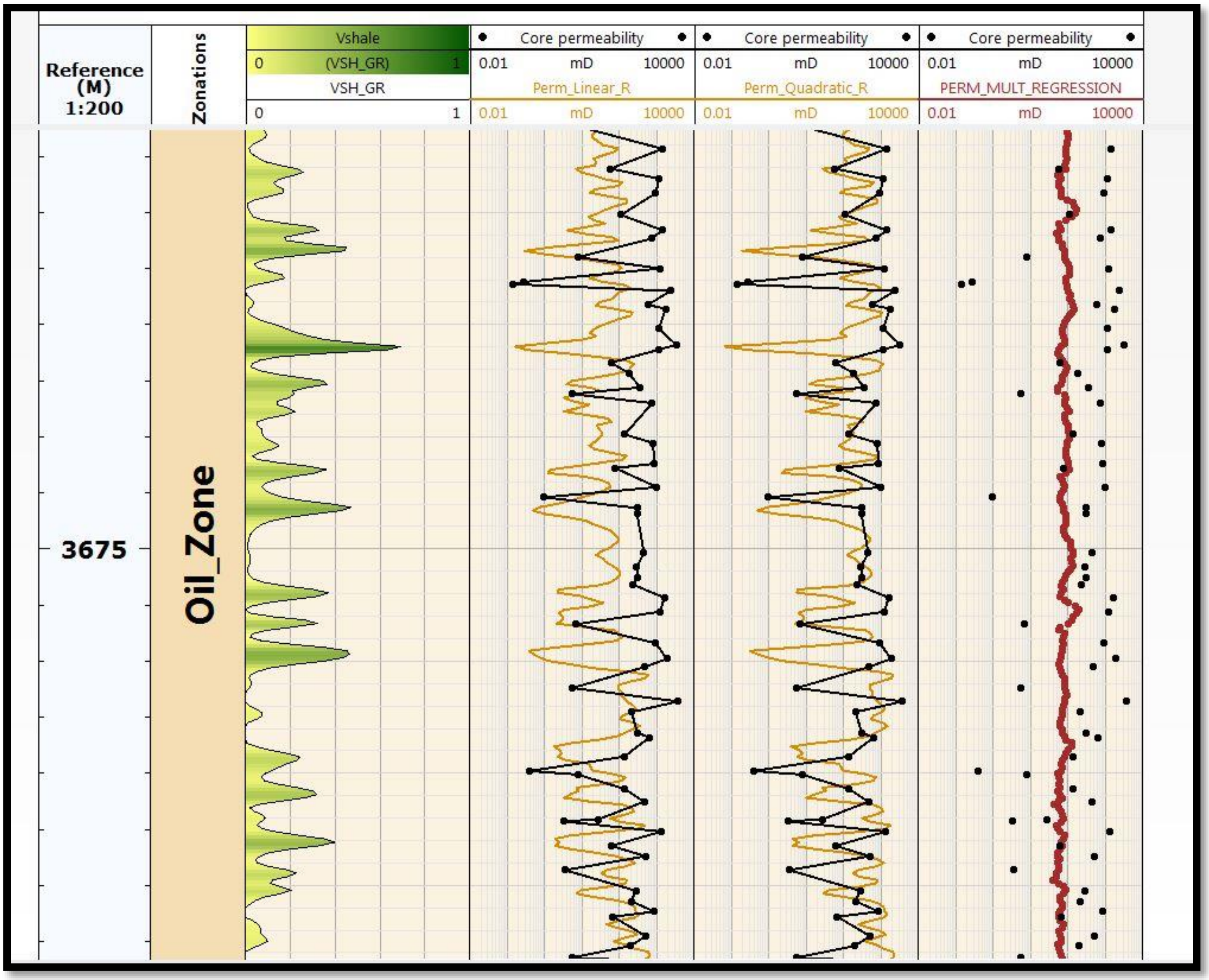

Figure 13; Prediction Models permeability values vs. core measurement for well 6406/12-3S in Oil zone. Quadratic model seems to fit the data well than multiple regression model

Figure 12 and Figure 13 shows the prediction of linear and quadratic regression models with continuous yellowish line while core measurements are shown in black line with dots. Multiple regression predictions are shown in red dots and core measurements are shown in black dots. Linear regression clearly underestimates permeability than quadratic do while multiple regressions displays better estimates. All regression methods do not have better consistency in following the actual trend in permeability; this is because of the tendency to average the entire data set to achieve reasonable values for statistical indicators. This is usually one of the weak points of all regression methods (Shahab , Balan, & Ameri, 1995).

5 CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusive remarks

Normally if the rock Formation has a fairly uniform grain composition and a common diagenetic history, then permeability patterns are simple, straightforward statistical prediction techniques can be used, However, if a field encompasses several lithologies, perhaps with varying diagenetic imprints resulting from varying mineral composition, then the permeability patterns are dispersed, and reservoir zonation is required before predictive techniques can be applied.

Any method that claims to predict permeability from un-cored well should be tested to prove its predictive capability. Empirical model for permeability prediction relates permeability with effective porosity and irreducible water saturation, and these parameters are quite well estimated from laboratory core analysis however some of them can be estimated from well logs. These methodologies have performed poorly for this purpose in predicting permeability curves because normally they need some modifications to constants before applying them and the assumption that a reservoir was at irreducible water saturation was not real as was shown in Figure 6. Because of these uncertainties empirical models were not suitable for permeability prediction in Intra-Melke reservoir

On the other hand permeability in siliciclastic reservoirs can be well predicted by statistical methods given that all statistical requirements and reservoir zonation has been applied. In this project quadratic and multiple regression models had better estimation capability of permeability than all other methods applied. These models are the one suggested to be applied in PIL and BUE oil field for permeability determination.

5.2 Recommendations

Multiple variable regressions are rather recommended method of permeability determination because of its ability to avoid picking/depending on a single predictor. Multiple regression models allow the examination of more sophisticated research hypotheses than is possible using simple correlations.

Since there is no generalized method for permeability prediction from well logs, more studies are required to find a global acceptable method. Artificial Neural Network is one of the statistical measurements that can be applied to improve permeability predictions. This methodology was not part of this project but it could be better method for permeability prediction if used properly especially in shale-sand reservoirs where almost all logs has been affected by the presence of clay mineralogy.

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APPENDIX

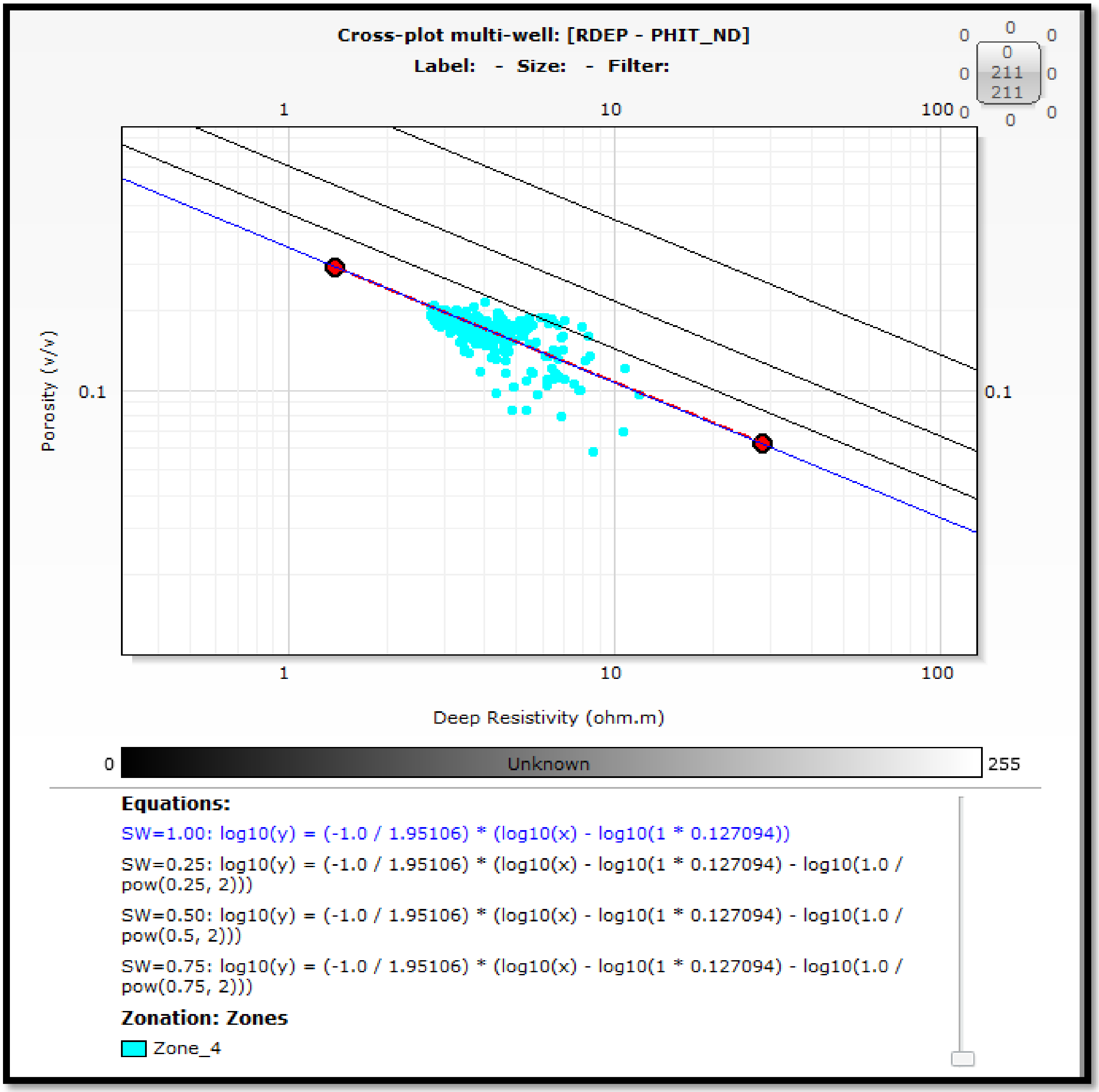

Figure 14; Picket plot, porosity function of resistivity. The slop of 100% water line (blue line) is -0.512 which yield cementation exponent 'm' as 1.95 for well 6406/12-3S. Figure created from Schlumberger techlog software