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Forfatter: Niwaz Ahmad	…………………………… (signatur forfatter)
Fagansvarlig: Karl Audun Lehne Veileder(e):	
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Contents

Abstract

Permeability has been calculated for three exploration wells from the “Smørbukk” field, from the mid – Norwegian Sea. Permeability from logs, cores and cross plots have been derived and compared with permeability from well testing.

Permeability from logs alone is derived by the Timur’s correlation. It is observed that this permeability is affected by the shape of the well. Timur’s correlation is based on porosity and water saturation, porosity has been calculated from density log which is easily affected by the shape of well. And the constants in the correlation must be corrected for each formation to give a good match.

Permeability from cores, gives a good overview of the permeability distribution in the cored interval, but is difficult to scale up for the un – cored interval. The Arithmetic scaling gives much higher values than the geometric method. Gas slippage (Klinkenberg effect) has also been discussed, this effect leads to wrong (higher) permeability and must be corrected for at low pressures.

Test	Top	Bottom	K DST	K Arith	K geom
6406/2-1					
DST 7	4427	4495	0,03	0,05	0,44
DST 6	4645	4704	4,2	16,62	0,61
DST 5	4816	4858	3,2	5,89	0,43
DST 4	4910	4924	4,0	0,94	0,76
DST 3	5021	5041	0,49	1,45	1,06
DST 2	5099	5170	6,5	8,515	0,67
DST 1	5201	5227	0,29	0,41	0,98
6406/2-2					
DST 2	4714	4745	15	56,40	1,62
DST 1	4868	4927	0,7	9,18	1,59
6406/2-4SR					
DST 2	4684	4704	0,07	4,02	0,95
DST 1	4874	4904	16,1	26,8	1,71

Permeability from cross plot gives a good overview of permeability distribution, as seen from the result. The best permeability is from well testing; the effective permeability of the tested interval is calculated. All effects are counted for in the permeability, as seen in the literature study, minerals and overburden pressure reduces the permeability.

Introduction

Permeability is one of the most important parameters affecting almost all phases of the reservoir management and well performance. Permeability describes formations ability to conduct fluid flow, and can be affected by different factors as grain size, distribution, overburden pressure, minerals and so on.

There are different ways to measure permeability:

- Permeability from logs
- Permeability from cores
- Permeability from cores and logs
- Permeability from wireline testing

Permeability measured from logs, cores and from combination of both are to be calculated, and then compared with the permeability found from well testing.

The field used in the comparison of the permeability is *"Smørbukk",* from the Norwegian continental shelf off mid – Norway. The geology, formations and minerals are also to be interpreted from three exploration wells at Smørbukk.

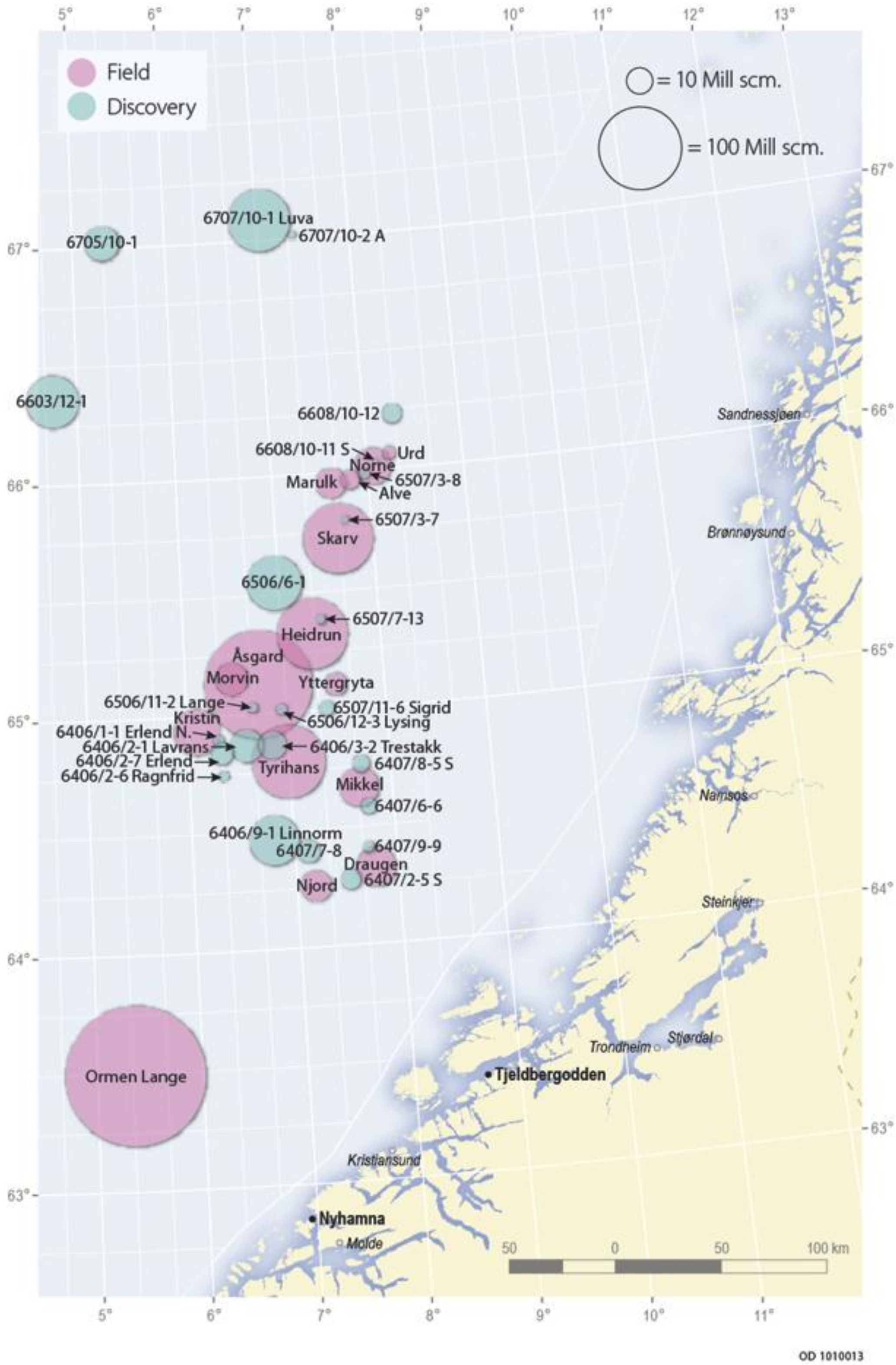
The three wells used in the interpretation are:

- 6406/2 – 1
- 6406/2 – 2
- 6406/2 – 4SR

"Interactive Petrophysics v. 4,0" , is to be used in the interpretations.

Åsgard Field

Åsgard field is located on Haltenbanken in the Norwegian Sea, about 200 km west of the coast of mid Norway.



[Figure 1: Åsgard field in the Norwegian Sea, source:2]

Åsgard field consists of the deposits Smørbukk, Smørbukk South and Midgard. This field is located at 240 – 300 m depth. The field is about 60 km wide and 20 km long. Smørbukk is located on the block 6506 – 12. Smørbukk was discovered by Statoil in 1985, Smørbukk and Midgard are gas condensate fields, while Smørbukk South is oilfield.

Production from the field began in the second quarter of 1999 and gas production began about 18 months later. The development of Asgard field represents the developments of the technology. It is drilled 59 wells in the field for production and injection. Fixed platforms are also replaced by remotely operated systems, which are controlled from the surface.

The reservoir in Smørbukk field consists of faulting in the formation, in the direction of north and west. The field consists of these formations:

- Garn
- Ile
- Tofte
- Tilje
- Åre

Formations

In the well there will be different formations.

Spekk formation: is 8 – 73 meters in thickness and consist of shale deposited in marine environment. Spekk has high radioactivity and consists of 5 – 8 % of organic material.

Melke formation: does also consist of shale, and is moderate rich on organic material (1 – 4 %). The thickness varies between 117 – 282 m, and is deposited in open marine environment.

Garn: consist of medium – grained sandstone, deposited from delta front and have a thickness of 41 – 44 m.

Not: is a marine shelf deposition, with a thickness of 24 – 34 m. It consists mostly of shale, with gradual increase of siltstone upwards in the formation.

Ile: consists of sandstone with a thickness of 60 – 80 m, there are also thin layers of shale and siltstone in the formation. In the bottom there is fine – grained sand with very thin layers of shale. Further up in the formation, there is coarse – grained sand with thicker layers of shale.

Ror: was formed by a transgression, it consists of shale with traces of sandstone. This formation can be found over and below Tofte. Thickness of the upper part of Ror varies between 53 – 73 m, while the lower part have a thickness of 0 – 21 m. the thickness of lower Ror are decreasing in the direction of north and west. The deposition of Ror was “disturbed” by a delta fan, which led to the deposition of Tofte formation.

Tofte: consist of coarse – grained sandstone and have a thickness of 0 -84 m.

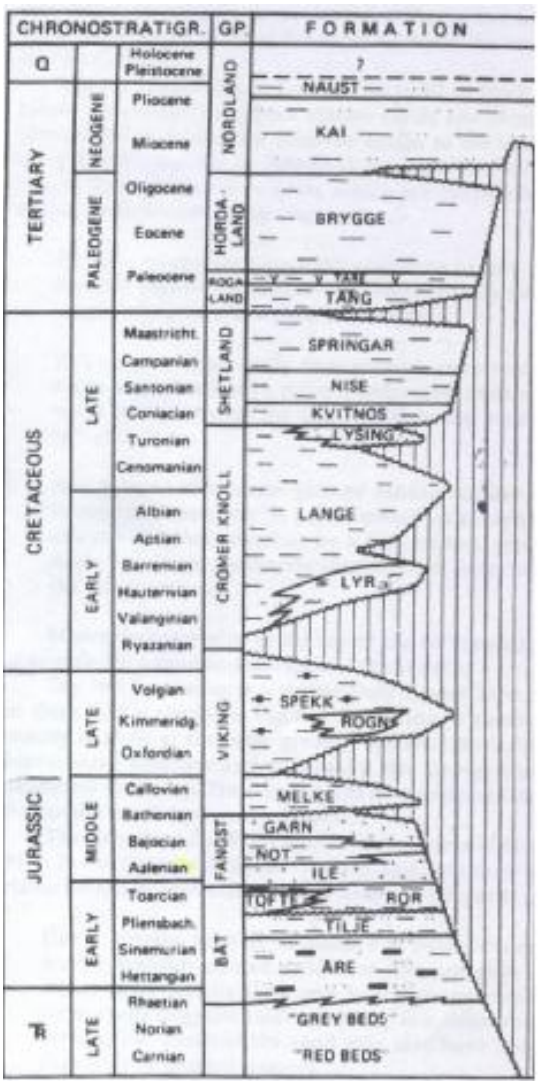
Tilje: can be divided in three parts

- Tilje 1: fine – grained sand, with layers of medium – grained sand. The thickness of these layers varies from 20 – 60 cm in thickness.

- Tilje 2: in the bottom there is shale, above this there is a layer of fine – grained sand with layers of clay with organic material.

- Tilje 3: fine – grained sand with traces of shale

Åre: is the oldest formation, drilled through in the field. It is from the upper Jurassic period, to the lower Jurassic period. Seismic analyses have shown that the thickness can be up to 500 m, and consists of coal, sandstone and shale. The coal in this formation is the source rock.



[Zonation with time of deposition]

Reservoir

The 8urassic8 in Haltenbanken is sandstone from the middle 8urassic period. Permeability is varying with the grain size, deposition and digenesis. In Tilje and Ile there are variations in the vertical permeability over short distances. This is explained by the varying grain size and the deposition environments. It is seen reduced permeability and porosity in the Garn formation, which is caused by quartz. Quartz is formed by “Styolittes” in the clay, which can be found in the whole formation. One other reason to the reduction is Illite, which can fill the pore throats and reduce the porosity as well as permeability.

Sandstone from the Jurassic period contains feldspar with varying amount of mica. In the reservoir there are also seen layers of carbonates in the sandstone, these layers are not more than 2 m in thickness and will not exceed more than 2 % of the formation. These carbonate layers acts as barriers and prevents the formation fluid from flowing further. Below a depth of 4000 m there will also be zircon, rutile and tourmaline in the formation.

In the formation there is a lots of gas condensate, especially in the Tilje formation. Surveys of the reservoir shows that migration and accumulation of hydrocarbons began in the Eocene period, but most of the accumulation (about 85 % of the total) has occurred in the last five million years. The hydrocarbons have migrated from the coal in Åre formation.

Smørbukk field is found on the edge of a fault block, which is dipping downwards in the direction of southeast. In West and North there are found faults in the whole formation. The faults in west continue to Heidrun field, forms a inclined plane between these two fields. The fault in north was created due to an extension of this plane.

Hydrocarbons in Åsgard are trapped in several zones, mostly in sandstone zones with layers of shale that separates them. Shale layers forms vertical barriers. An example of this is the gas condensate trapped in the Garn formation, below Melke formation that is shale. In north and west the hydrocarbons are trapped because of the faults, reservoir zones are in contact with shale so it forms a trap.

West of the faults there is overpressure in the formation, and there are no hydrocarbons there. It is assumed that the high pressure is reason of that.

[1]

Permeability

In porous rock, it is possible to see small spacing between the rock grains. This Spacing will contain liquid, which sometimes can be water, oil or gas. The permeability of the rock is a measurement of how easy this liquid can run through the rock. The permeability is measured in Darcie's. One Darcy is defined as a fluid with viscosity 1 *cp* is flowing at a rate of 1cm^3/s through a porous medium with a cross section of 1 cm^2, creating a pressure difference of 1 *atm/cm*. In the geological context 1 Darcy is too great, so 1/1000 fraction is used, which is then called millidarcy (mD).

This is known from the Darcy's law, and is given by

$$q = -\frac{k}{\mu}\frac{dp}{dx} * A \quad \text{(Darcy's Law)}$$

Permeability of given rock to flow of homogeneous fluid is constant, provided that the fluid does not interact with the rock. Permeability measured by air must be corrected for "slippage" effect or Klinkenberg effect, this is discussed later.

The permeability is affected by different factors. Formation rocks can be clean or it may contain clays. The presence of clays can affect log readings, and as well have a significant impact on the permeability.

Consolidation is a mechanical property, which will influence the acoustic measurements and have an impact on the stability of the borehole walls. This will also affect the ability of the formation to produce flowing fluids.

Formations can be homogeneous, fractured or layered. The existence of fractures, induced or natural, alters the permeability significantly. In layered rocks, the permeability can be very varying in the different layers, and the thickness of the different layers can vary from a fraction of an inch to tens of feet.

The internal surface area of the reservoir rock is used to evaluate the possibilities of producing fluids from the pore space. So this is related to granular nature which can be described by the grain size and distribution. Grain size and the distribution will also affect the permeability.

Permeability can be measured by different methods;

- Permeability from cores
- Permeability from logs
- Permeability from logs and cores
- Permeability from production tests

[3, 14]

Mineral effect

Most oil and gas formations contain clay minerals that either was originally deposited during sedimentation precipitated from flowing water or were formed by the action of heat, pressure and time on minerals already present. Clay minerals can damage the permeability, there are two major mechanisms behind this. The first mechanism is swelling, and the second is migration. In swelling, clay imbibes water into the crystalline structure and increases in volume. This can cause plugging of the pores in which it resides. During migration clay minerals can be dispersed when they come in contact with other fluid and be transported until a restriction is encountered (usually a pore throat). These minerals can block the path and restrict flow.

Most common clays:

- Smectite
- Kaolinite
- Illite
- Mixed layers

Basically most clay surfaces of the most common clays in the formations have many negatively charged. These negative charges are responsible for the sensitivity to fluid. Clay minerals exist naturally in stacked or randomly arranged platelets within the pores. Within the pores they are found as either pore – lining or pore – filling minerals surrounded by saline water. Usually Na^+ or Ca^{2+} makes up the salts and is fixed onto the clay surfaces by electrical attraction effectively neutralizing the negative charges. In this state the clay is stable, when a less saline fluid comes in the pore it can dilute the connate water and reduce its salinity. As the cation cloud covering the clay surface becomes spread, water molecules come in between clay platelets, resulting in swelling (Smectite clays and some mixed layers) or dispersion (Kaolinite, Illite, Chlorite and mixed layers). This type of damage is mostly irreversible and requires acid stimulation for removal.

[4]

Rock structure

It has generally been known that grain size is a fundamental variable controlling the permeability in unconsolidated rocks. This fact is well seen from the basic intrinsic permeability equation:

$$k = C * d^2$$

Where k is intrinsic permeability; C is a dimensionless constant describing the path tortuosity, particle shape, sediment sorting and possible porosity; and d is either the diameter for the pore throat or grain diameter. That permeability varies with the grain size was first reported by Hazen in 1911 and has later been experimentally verified by numerous investigators. The sand grains found in the coastal environments are well – sorted, rounded and are close to the ideal for which these relationships are developed.

It was originally used the 10^{th} percentile of grain size, but small deviations from the ideal sediment properties can induce large deviations in sediment permeability. Later it was shown that the exponent had to be less than two for non – ideal sediments, and the exponent decreased with decreasing texture maturity.

Smaller grain size will reduce the permeability significantly compared to the ideal, well – sorted homogeneous sediments. Some fine – grained sands can have high interconnected porosity, although the individual pores and pore channels are quite small. As a result the available paths for the movement of the fluid are quite restricted and tortuous. In practice permeability are rarely estimated from grain size for field applications because the estimates are usually very different from the actual measured values. Inclusion of clay and silt in small percentages can reduce the permeability by orders of magnitude, while inducing negligible changes in grain sizes.

Sedimentary diagenesis in form of physical compaction or precipitation of cements can also alter the permeability without reducing the grain size.

When grain size analysis is done by sieving, some of the finest sand will be lost. This will give a uncertainty in permeability estimate by grain size. The expression given earlier commonly fails to reproduce either the mean permeability or the variability in permeability of natural sand sediments.

[5,6]

Permeability from logs

The goal of deriving permeability from logs is elusive, since logs make static measurement whereas permeability is a measure of dynamic properties. The only exception is the Stonley wave (which can be measured in the sonic log). The Stonley wave actually moves the fluid in the rock, all other log – based methods relies on correlations with dynamic permeability measurements made with cores or tests.

Permeability can be seen as a tensor and strongly dependent on direction. For example, the process of sedimentation usually causes the horizontal permeability to be much greater than the vertical permeability.

Secondly it is not obvious how permeability should be scaled up to larger volumes, whether it should be averaged arithmetically, harmonically, geometrically or in some other way. This makes it difficult to compare permeability measured at different scales.

Formation fluids in the measured volume, will also affect the permeability. If there are two or more fluids, they can seriously impede each other's flow, so that the effective permeability of each fluid is less than the absolute permeability. In addition the salinity of the water flowing through shaly sand can affect the clays and alter the permeability (of core samples).

Permeability measured from different techniques can be very different. Permeability can be calculated with both resistivity and porosity log measurements. The resistivity logs can be used to make some broad and quantitative estimates because they depend on some extent on the result of fluid movement.

One of the methods is based on the length of the transition zone between water at the bottom of the reservoir and oil or gas at irreducible saturation above. The longer this zone is, the higher the capillary forces and the lower the permeability will be. Changes in the resistivity in the transition zone can be related to the permeability.

Another type of estimate is based on the invasion zone. The depth of invasion is manly dependent of the drilling history, but in very low – permeability formations there are some sensitivity to the formations. In high – permeability reservoirs gravity causes the filtrate to move upwards or downwards depending on the density of the formation water. The vertical invasion profile holds information on the vertical permeability. In general the shape of the invasion front radially away from the borehole can be related to the relative permeability of the different fluids.

Porosity is used much more than resistivity to estimate the permeability.

[7]

Permeability – porosity correlation

Most models can be characterized by a linear relationship in the log – log permeability-porosity coordinate system, with following form:

$$Log\ (k) = [a * log(\varphi)] + b$$

Where k is permeability, φ is the porosity and a and b are calibration constants. There are several models which describes the permeability, and according to those models the parameters a and b can vary as shown in table below.

Table 1: Values of a, in the different equations.

Model	***a* slope**
Windland	~ 1.5
Pore dimension models	~ 2
Amaefule	~ 3.0
Bourbié *et al.*	~ 3 – 8
Surface area models	~ 4
Timur	4.4
Grain-based models	~ 5
Berg	5.1
Lucia	~ 4 – 9
Civan	0 - ∞
This model	0 - ∞

The parameter *b*, can be interpreted as the flow zone indicator (FZI) or as an interconnectivity parameter. This parameter is variable defines different types of rocks. Differences in the models can be explained by parameterization options between porosity and permeability. Most authors expressed the permeability as a function of the dominant rock type under the study. The dominant rock characteristic is grain geometry or pore space geometry, which can vary widely.

[8]

Capillary pressure and permeability

Capillary pressure curves can also be used to predict permeability, these are direct indicators of the pore geometry of the rocks. This again controls the permeability. Permeability is generally obtained as a function of either one or two parameters.

In a reservoir that contains water and hydrocarbons column, the saturation may vary from 100 % water at the bottom of the zone to a maximum oil saturation (and irreducible water saturation) at the top. There is gradual transition between these two extremes in saturation. The transition interval may be very short for porous and permeable formations, or it may be quite long in formations of low permeability.

One parameter is enough when using the segment above the transition zone, because the water saturation tends to be a fixed value at irreducible conditions (S_{wi}). Two points are needed when using the bending or the flat part of the capillary pressure curve, these points' falls in the transition zone, where saturation and capillary pressure keep changing. This point in the transition zone is set by water saturation (S_w) and a pore throat ®.

One important factor is the effective oil permeability at irreducible water saturation conditions. The most interesting part is the vertical/oblique portion of the capillary curves at irreducible water saturation. This behavior necessarily involves the major and much smaller pore systems contribution to flow. Higher pressures are required to drain the smaller pores to overcome the natural resistance of the flow paths.

Buoyancy, hydrodynamic forces and capillary pressures control migration of hydrocarbons. Normally much larger forces are involved in the extraction of hydrocarbons, the limit of this is set by irreducible conditions. When no additional pore system can contribute to the flow, the irreducible saturations have been reached. This signifies a true permeability definition, which is independent of pressure changes. The irreducible water saturations can wary from 10 % to more than 50 %.

Permeability transform values from well logs are generally calibrated to air permeability, and usually assumes "equivalent" to liquid permeability. Air is preferred in permeability measurements because of its convenience and availability. Air is a relative inert fluid toward the core material, for a strongly water wet system with a clean smooth wetting surface, the contact angle for air is equal to zero. Wettability is considered unimportant in for porosity/permeability core analysis.

A good correlation generally exists between irreducible water saturation and permeability. Resistivity (R_t) correlates with permeability too, explained by Ohm's law and Darcy equation similarities. Effective porosity is one of the most common parameters found to correlate with permeability. Exceptions to these correlations have also been found, problems arise when the electric characteristics of the rocks are changed due to variations in the resistivity/salinity of the formation water or because of the presence of clay minerals.

[8]

Permeability estimate from porosity and resistivity

In many cases there may exist a correlation between porosity and permeability. But these correlations are usually derived for a certain formation, and therefor they do not exhibit general application or validity. A more general empirical relationship was proposed by Wyllie and Rose, which includes irreducible water saturation. Wyllie and Rose proposed this equation:

$$k = C * \frac{\varphi^x}{(S_{wi})^y}$$

Based on the general equation of Wyllie and Rose several equations have been proposed which can be used to derive permeability from porosity and irreducible water saturation.

By Tixier

$$k^{0,5} = 250 * \frac{\varphi^3}{S_{wi}}$$

By Timur

$$k^{0,5} = 100 * \frac{\varphi^{2,25}}{S_{wi}}$$

By Coates - Dumanoir

$$k^{0,5} = \frac{300}{w^4} * \frac{\varphi^w}{{S_{wi}}^w}$$

By Coates

$$k^{0,5} = 70 * \frac{\varphi^2(1 - S_{wi})}{S_{wi}}$$

Where k is permeability in mD, φ is porosity, S_{wi} is irreducible water saturation and w is textural parameter related to the cementation and saturation exponents, $w \approx m \approx n$.

All these relationships are based on intergranular porosity data, and there for their application is usually restricted to sandstones.

[9,10]

Nuclear magnetic resonance

Is a measurement of spin and magnetic properties of nuclei, and was first successful in 1946. First well logging application was introduced by Chevron in 1960. The interest of magnetic resonance for logging was initially based on the newly discovered method for detecting protons. Which is hydrogen in common pore fluids, and hence a measure of porosity.

Most nuclei have a magnetic moment. From the classical point of view each nucleus is equivalent to a magnetic dipole. In the presence of an externally imposed magnetic field, the dipoles will tend to line up in the direction of the field lines. Each nucleus will have an angular momentum in addition to the magnetic momentum. The angular momentum can be described as a vector, which is oriented along the axis of rotation.

There are two important implications exploited in NMR measurements followed by the properties of the nuclei. The existence of the magnetic moment allows electromagnetic energy to be absorbed by the magnetic dipole, by changing the orientation of the magnetic moment with respect to the external magnetic field. The existence of the angular momentum (or spin), along the same axis as the dipole moment will tend to resist any change in the orientation of the angular momentum vector.

Introducing an external magnetic field will create a torque, which in turn produces a precession of the angular momentum vector about the axis of the applied filed. The precession frequency is governed by the intrinsic magnetic moment and the applied external magnetic field. It is known as the Larmor frequency.

The operating principle of a magnetometer consists of using a coil to apply a magnetic field, roughly 100 times the magnitude of the earth's field. After a few seconds, some of the magnetic moments of the protons are aligned with the external field, which is oriented nearly perpendicular to the earth's field. When the applied magnetic field is removed, the induced magnetic moment will begin to precede about the remaining field (which is the earth's field). The frequency of the precession is proportional to the local magnetic field. The precession of the induced magnetic moment of the sample will induce a sinusoidal voltage in the coil to establish the magnetic field. This effect is referred to as nuclear free induction. The measurement of the local geomagnetic field consists of determining the frequency of the voltage induced in the coil.

Hydrogen is the only nuclear species encountered in formations that can be easily detected by the nuclear induction technique. The first requirement is that a nucleus has nuclear angular momentum and magnetic moment. Many of the most common elements do not have sufficient numbers of isotopes which possess these attributes, for example carbon, magnesium, sulfur and calcium. The elements that possess the attributes are much less detectable than hydrogen. Measurements of proton free – precession in earth formations reflects nearly exclusively hydrogen. Because of the technique used in the progress, the only hydrogen detectable will be that associated with fluids in pores, either water or hydrocarbons. The measurements will not be sensitive to hydrogen associated with hydroxyls in clay minerals contained in the shale. So the nuclear magnetic measurement in a wellbore is related to the porosity of the formation.

The NMR process involves a series of steps that are common for laboratory experiments or similar implementations adapted for borehole measurements. The first step is the alignment of protons in an external magnetic field, which is produced by NMR logging instrument. The time constant associated with the polarization is called the longitudinal time constant T_1.

In the second step there is provided a magnetic field, to rotate the polarized protons by 90 degrees to the “transverse” plane. The magnetic field is provided at the Larmor frequency, this will produce a measurable signal. Once the protons have been rotated, they continue their precession, but perpendicular to the polarizing field. This will create an easy detectable fluctuating magnetic field. The protons will rapidly diphase, so that the transverse magnetic field disappears.

Much of the dephasing of the proton precession in the transverse plane might be caused by imperfections in the polarizing magnetic field at the location of the proton. These dephasings are reversible and can be described by a characteristic time constant T_2. Many pulse – echo schemes, consisting of polarizing pulse sequences have been derived to overcome the reversible dephasing.

Since the NMR measurements are related to fluids saturating porous rocks, there are four properties of interest. The hydrogen index, the longitudinal relaxation time T_1, the transverse relaxation time constant T_2 and the diffusion constant related to the viscosity.

For the conventional logging tool, the borehole signal had to be removed. This is done by adding paramagnetic ions to the mud and circulates it to produce a uniform mixture. This method is very expensive and time consuming.

The modern tool avoids this problem and it is called inside – out NMR. Instead of using earth’s magnetic field for producing the precession of the protons, two opposed magnets are located inside the tool. The opposition of the two dipole magnets produces a radial magnetic field, in the halfway between the two magnets. This field is increased to a maximum, controlled by the magnetic length and then decreases with increasing distance. This creates a region of roughly toroidal field around the tool, the field will be relatively constant and producing a net magnetization radially outward. With this type of configuration, the more classical pulsed NMR measurements can be performed, without being influenced by the borehole.

To make the measurement an oscillating current in the coil, with the Larmor frequency is used to flip the net magnetization by 90 degrees. Once the turning signal is turned off, the coil is acting as a receiver to record the signal from the protons.

The advantage of such system is the avoidance of mud doping and the availability of the signal with minimum delay. This enables a more precise determination of the volume of the moveable fluids, since the uncertainties of extrapolating to the end of the polarizing are avoided.

One of the claims for using the NMR is to obtain a lithology – independent porosity. This minimizes the complications from having to know the hydrogen index of the pore fluids and under emphasizes the ability of NMR to determine the irreducible water saturation. The irreducible water saturation, related to the water – cut, helps to establish the production potential of a zone.

All the relationships that have been developed to calculate permeability from NMR are based on a combination theoretical and experimental measurement. The physical basis comes from the notion that permeability, depends most strongly on the size of the pore throats of the medium. The casual link to NMR is that some measure of the T_2 distribution (for example the mean log value) is related to the pore dimension, and the pore size dimension is also related to the throat size. The last link is more reliable among sandstones than carbonates. There are teo general transforms used to estimate the permeability.

The first is referred to as Timur – Coates, and is given by:

$$k = a * \varphi^4 * \left(\frac{FFI}{BVI}\right)^2$$

Where *FFI* is the volume of the free fluid and BVI corresponds to the bound volume fraction.

FFI can also be defined as:

$$FFI = \varphi * (1 - S_{wi})$$

The second approach is given by:

$$k = a * \varphi^4 * {T_{2,LM}}^2$$

Where $T_{2,LM}$ is logarithmic mean value of the measured T_2 distribution. For both approaches the constant a, the exponent of the porosity (4) or on the NMR parameter (4) may need to be adjusted to local conditions to give a better fit to known values of permeability.

[7, 10]

Permeability from cores

Core plugs are dried and cleaned, to measure the permeability. Each core plug are tested at ambient conditions. Organic solvents such as toluene, naphtha and methanol are used to clean the plugs. Darcy's law is applied to measure the permeability values using a gas permeameter apparatus at ambient conditions under steady – state flow. In routine core analysis, almost all permeability's are obtained by flowing gas, either air or nitrogen through the samples.

The permeabilities are measured by first placing them in a core holder, and applying an overburden pressure of 200 – 400 psi. Next dry gas is flowed through the core until steady state flow is achieved. Then the flow rate, upstream pressure, and pressure drop are measured. The gas permeability can then be calculated:

$$k_a = \frac{2000 * P_a * \mu * Q_a * L}{\left({P_1}^2 - {P_2}^2\right) * A}$$

Where P_a is the atmospheric pressure, P_1 is the upstream pressure, P_2 is outlet pressure.

There is also another method, called "*the transient pulse method*". A porous sample is connected between upstream and downstream reservoirs of a pore fluid. Pore fluid pressures are set to a prescribed value, prior to a measurement. At the beginning of a measurement ($t = 0$), a small pressure pulse ΔP_0 is introduced to the upstream reservoir. The pressure in the upstream reservoir decays as the fluid flows through the sample, while that in the downstream reservoir rises. When the fluid flow is sufficiently slow, the flow is approximately isothermal. The pressure difference decays as follows:

$$\Delta P(t) = \Delta P_0 * e^{-\gamma t}$$

Where decay constant γ is given by:

$$\gamma = \frac{k}{\mu\beta} * \frac{A}{L} * \left(\frac{1}{V_1} + \frac{1}{V_2}\right)$$

Where μ is viscosity, β is isothermal compressibility, V_1 and V_2 are volumes of upstream and downstream reservoirs. When the pore fluid is an ideal gas isothermal compressibility becomes $1/P$ and viscosity is independent of the pressure the permeability can be calculated:

$$k = \mu\gamma\beta * \frac{L}{A} * \left(\frac{V_1 V_2}{V_1 + V_2}\right)$$

Permeability is then determined from the pressure evolution in the reservoirs. The transient pulse method is suitable for permeability measurements of low permeability materials, since the determined permeability is without measuring fluid flux. Fluid flux in such materials is to low measure with standard techniques.

Another method is the pore pressure oscillation method, for low permeability materials. Its application is limited since it requires an elaborate fluid pressure oscillation system. The transient pulse method can be carried out with a much simpler system.

[11, 12]

Overburden pressure

Reservoirs are under considerable compressive stress as a result of the weight of the overlaying formations. Overburden pressure affects the reservoir properties. The pressure causes only a small decrease in the porosity, which can usually be ignored. The porosity is only reduced by almost 5 % of the original porosity. The effect of overburden pressure on permeability is greater and varies considerably with the type of reservoir rock. The effect of overburden pressure on relative permeability is small or nonexistent.

The gas permeability of tight sand stone is markedly reduced with increasing overburden pressure, in fractures permeability can be reduced to as much as 6 % of the initial permeability. Water saturation also reduces the gas permeability.

[13]

Klinkenberg effect

Permeability measurements can sometime be affected by the fluids used in the tests. This is caused by some interactions between the fluid and the porous medium. To avoid this problem gases are often used to determine permeability. The uses of gases introduce other problems, such as turbulent flow behavior, increased uncertainty in gas rate measurements and at low pressure, the Klinkenberg effect. The rock permeability to gas is not the same as for liquids, since the gas permeability is pressure dependent.

The Klinkenberg effect is seen on low pressures, measurements of gas permeability give erroneously high results as compared to the non – reactive liquid permeability measurements. This effect is known as the "gas slippage effect" or as the Klinkenberg effect, found by Klinkenberg in 1941.

Klinkenberg found that the gas permeability of a core sample varied with both the type of gas used in the measurements and the average pressure in the core. One of the conditions for the validity of Darcy's Law is that the requirement of laminar flow. At low pressures in combination with small pore channels this condition is broken. At low pressures gas molecules are often so far apart that they slip through the pore channels without almost without any interactions, this gives an increased flow rate. At higher pressures, the distances between the molecules are smaller so they interact more strongly as molecules in liquids. Compared to laminar flow, with constant pressure difference, the Klinkenberg dominated flow will have higher flow rate than laminar flow.

In early core analysis the Klinkenberg permeability was estimated by using a steady – state estimate for permeability measurements at different mean pressures or by using the correlation:

$$k_m = k_L(1 + \frac{b}{p_{mean}})$$

Where k_m is measured permeability, k_L is the liquid permeability and b represents properties of the rock depending on the type of gas used in measurement.

Corrections to measured gas permeability's due to the Klinkenberg effect are normally moderate to small corrections. In most laboratory measurements of gas permeability, it is safe to neglect Klinkenberg effect if the gas pressure is higher than 10 bar. As for the reservoirs, the pressure will be much higher than 10 bar and the significance of the Klinkenberg effect is of no importance.

[14]

Scaling of permeability

It is relatively simple to derive the permeability from the porosity. Once the permeability has been derived, it is important to examine this for the intervals where the permeability goes to very high values. Most sandstone formations do not exceed about 1500 mD, but there are top – quality reservoirs with porosities above 35 % with permeability's up to about 4000 mD. It is also possible to apply a cut off value to cap the permeability at a level that is supportable by the core data. In non – reservoir formations, the permeability should usually be set to a very low value, for example 0,001 mD. For making zonal averages of the permeability there are three types of averages:

The first one is arithmetic average, which is given by:

$$k_{arith} = \sum k_i * \frac{h_i}{\sum h_i}$$

This average is appropriate to use if the flow in the reservoir is in the direction of the bedding plane. Small impermeable streaks will have very little effect on the average.

The second one is geometric average, which is given by:

$$k_{geom} = \exp\left(\sum \log(k_i) * \frac{h_i}{\sum h_i}\right)$$

In effect, the average of the logarithms of the individual permeability's is used, and at the end the exponent of the logarithms are taken. This average is appropriate to use if the flow in the reservoir is partially in the direction of bedding plane and partly normal to the bedding plane. Impermeable streaks will have some influence on the average, but not big enough to destroy the average.

The third is the harmonic average, which is given by:

$$k_{harm} = \frac{1}{\left(\sum\left(\frac{h_i}{k_i}\right)/\sum h_i\right)}$$

The average of the inverse of the individual permeability's is used, and the results are inverted at the end. This average is appropriate to use if the flow in the reservoir is normal to the direction of the bedding plane. Impermeable streaks will completely dominate the zonal average.

These three methods can give very different values for the same formation. Typically the arithmetic method will give a result 10 times higher than the harmonic method, while the geometric method will be somewhere in the middle.

In horizontal well there is an additional effect due to the fact that the vertical permeability is greater than the horizontal permeability. The average permeability, which is partially influenced by the vertical permeability and partly by the horizontal permeability, is given by:

$$k_{av} = k_h * \frac{(1+\alpha)}{2}$$

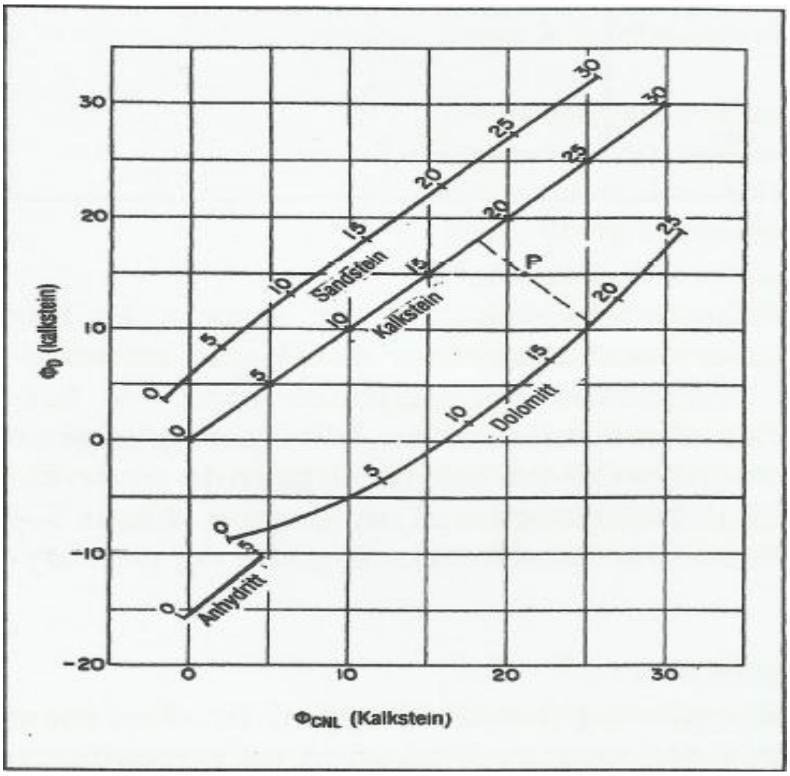
Where α is the vertical permeability divided by the horizontal permeability.

[15]

Permeability from cores and logs – Cross plots

Cross plots have widely been used in determination of porosity, lithology and in different zone parameters (for example GR_{min}) for petrophysical calculations. Cross plots can also be used to indicate minerals, also in more complex formations with three minerals. One of the most used cross plots is density – neutron cross plot, based upon density and porosity logs.

Density – porosity cross plot is the most used method in determination of lithology and porosity, for a simple clean formation. If the formation is clean sandstone, limestone or dolomite in a waterzone, the points in the plot will be along the lithology lines in the figure below.



[Figure : Crossplot from density and neutron log, with sandstone, limestone and dolomite indication.]

The crossplot can also be used to determine fractions of different minerals. The distance between sandstone-, limestone- and dolomite line indicates a good dissolution for these lithologies. The most common 24vaporates (as halite and anhydrite) are easily identified with the crossplot. Formations containing clays are difficult to identify, because of its high values in neutron log and low values in density log. This will give points in the lower right corner in the plot when the volume of clay increases. This makes it difficult to part sandstone from dolomite and limestone. In a gas zone the points will be moved to the upper left corner, and it becomes difficult to part sandstone from dolomite.

There are also other possibilities of cross plots, for example sonic – neutron, density – sonic and porosity – permeability.

[16]

Permeability from well tests

The general formation evaluation consists of using seismic to evaluate the reservoir, logs provides initial information about the fluid type and producibility. Well testing provides confirmation, detailed fluid properties, accurate pressure measurements and production evaluation. Formation testing is the final step before production is started and provides essential information to design the well completion and production facilities. There are two different technologies that can be used for testing:

- Wireline formation testing uses a sonde that can be positioned at a selected depth in the formation to provide measurements of pressure and fluid type, with limited production data.
- Well testing uses a packer lowered in drill pipe or tubing. The tested interval is not precisely defined and downhole measurements are limited, but the volume of fluid produced enables complete evaluation of production potential.

There are many applications of well testing, and they can be grouped into four fundamental classes:

- Formation pressure measurement
- Formation fluid characterization
- Reservoir characterization
- Skin and permeability measurement

Skin and permeability measurement:

The pressure measurements are interpreted to give the reservoirs dynamic properties, which are relevant to fluid flow. These parameters can for example be formation permeability and any occurrence of skin (for example formation damage) which impair the flow. The measurements will help to determine

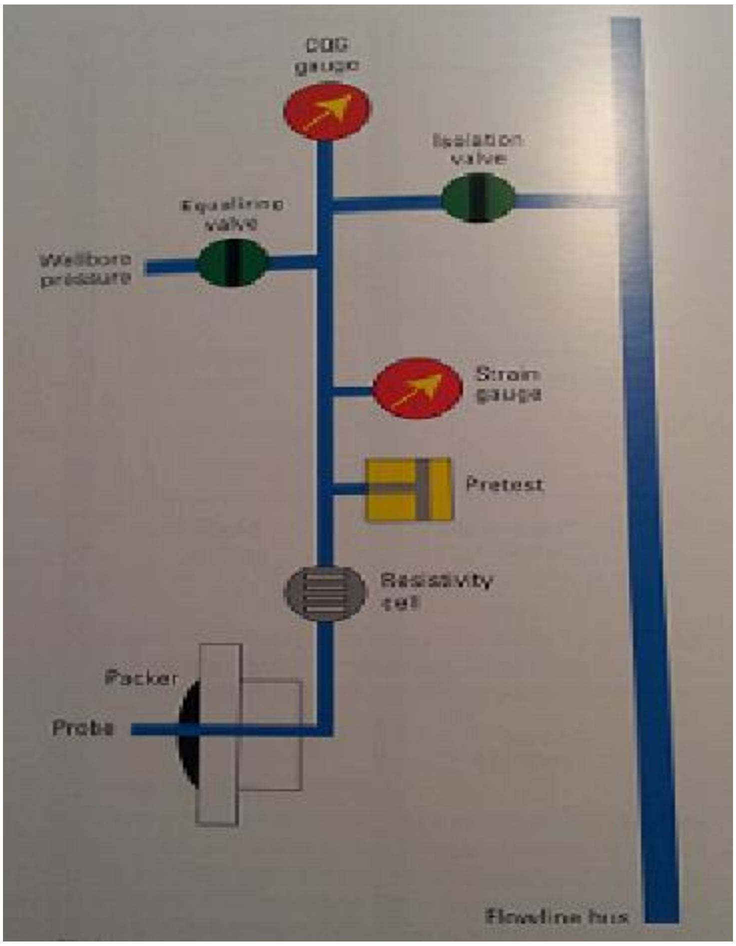
- Reservoir permeability
- Well deliverability
- A damaged or stimulated well condition
- Vertical rock permeability
- The efficiency of stimulation treatments

Openhole Wireline testing

The history of wireline testing began with the single – test tool in the 1950s. The main object of this tool was to collect a fluid sample. The tools had to be pulled out after each sample was taken. Multiple (repeat) wireline pressure testing was introduced in 1974, which theoretically could take infinite pressure points and two fluid samples. The MDT tool was introduced in 1988. It was designed to take multiple fluid samples per run, in addition to distributed pressure points. This new tool made it possible to make an immediately reservoir pressure profile, which was largely unavailable at that time.

Formation pressure is obtained by withdrawing a small amount of fluid to generate a short transient test, called a “pretest”. The pressure is then recorded until it becomes stabilize. In thick reservoirs with relatively high permeabilities, vertical pressure profiles are used to determine in – situ fluid densities and contact levels.

The permeability from single – probe tool represents a combination of vertical and horizontal permeability. Single probe measurements are affected by different factors such as mudcake blocking, non – Darcy flow, fines migration and formation damage. There are several modules and measure techniques to overcome the problems encountered. During fluid sampling there is an uncertainty about the sampled fluid, whether the fluid sample is truly representative of the reservoir fluids and the degree of contamination by the mud filtrate.



[Figure : Sketch of a single – probe module.]

Drillstem Testing (DST)

A DST string is a multiple array of downhole hardware used for temporary completion of a well. It is also used for longer – duration production tests. DTS is a safe and efficient method of controlling the flow while gathering essential reservoir data in the exploration, evaluation and sometimes development phase of a well. DST can also be used for preconditioning or treatment prior to permanent completion.

The DST assemblies can be customized.

The pressure controlled tester is operated by annulus pressure to control formation flow. This tester is very important part of the DST assembly. By operating the PCT valve, the reservoir can be opened to flow or shut – in. Downhole pressures are continuously monitored, the string is first lowered into the well and short test is performed. The initial flow period serves the purpose of cleaning the formation damage and measuring initial shut – in pressure after a short pressure buildup. The reservoir is then opened for a longer duration, often called the “final flow period”.

There are many advantages in combining perforating and testing operations. Perforating can be performed underbalanced, resulting clean perforations and an undamaged formation before testing.

It is also possible to fix permanent pressure monitoring systems, they are placed downhole with the completion string near the depth of reservoir. They are connected to the surface with a cable that runs the length of the completion string and exits the wellbore through suitable connectors. Advanced telemetry allows the sensors to be interpreted at any time. Most current systems record both bottomhole temperature and pressure.

Interpretation of well tests

One of the elemental basis for well test interpretation is that sometime during the test, the flow in the reservoir is radial and not influenced by any outer boundaries. In geometrical terms, this means that the flow lines are horizontal (no effect of gravity) and perpendicular to the wellbore axis. During conventional well tests it is very important that the flow in reservoir reaches radial flow regime, because of the mathematical solution of the diffusivity equation simplifies greatly. And it is only in this flow regime, that he tests can be interpreted for its target parameters such as permeability – thickness product and skin – factors.

In wireline testing radial flow may not always occur because of the configuration of the tool and depth of investigation. The interpretation of wireline test does not require that radial flow regime, other techniques can be used.

Calculation of Skin and permeability – thickness:

Skin is dimensionless parameter that represents the additional (positive or negative) pressure drop suffered at the sandface by the reservoir fluids flowing into the well, on account of near – wellbore flow restricting or flow enhancing situations.

Skin factor has been described by Hawkins:

$$S = \left(\frac{k}{k_{fd}} - 1\right) * \ln\frac{r_{fd}}{r_w}$$

Where k_{fd} is the permeability of formation damage, r_{fd} is radius of damage.

Permeability thickness can be calculated from semi logplot, of time vs pressure:

$$k_c = \frac{88{,}4 * q * \mu}{m * h}$$

Where m is the slope from semilog – plot.

From log – log plot of dimensionless time vs dimensionless pressure:

$$kh = 141{,}2 * Q * \mu * M_p$$

Where M_p is pressure match.

[10, 17]

Evaluation of Smørbukk field

There are 3 wells to be evaluated; the evaluation is done in *"Interactive Petrophysics v4.0"* from Schlumberger.

Zonation:

The different zones and their depths were found from www.npd.no , on the exploration wells site. Zonation is described in the result section.

Lithology:

The lithology was described in an article about "Haltenbanken". A crossplot from density – neutron logs were derived, to describe the reservoir quality.

Volume of clay:

Volume of clay is estimated from 2 methods

1. Volume of clay from gamma log.
2. Crossplot from density – neutron logs.

SCAL – report:

It is done very accurate tests of core plugs taken from Smørbukk field. Where different factors have been determined, factors from SCAL report:

- Lithology factor a and corrected factor a*, a = 1 and a* = 1,1
- Cementation factor m and corrected factor m*, m = 2,2 and m* = 2,3
- Saturation exponent n and corrected factor n*, n = 1,9 and n* = 2,0
- R_w which is the resistivity in formation water
- Formation factor F, from Humble formula

$$F = \frac{a}{\varphi^m}$$

And φ is the porosity.

The SCAL reports are also describing mineral and overburden corrections for the different formations. As mentioned earlier, Tilje formation contains illite which reduces the permeability.

Illite correction for Tilje formation is given by:

$$KLHI = 0,65 * KLH$$

Where KLHI is illite corrected permeability and KLH is permeability from cores.

Irreducible water saturations for different formations from SCAL report:

- Garn = 0,135
- Ile: -0,038 log (k) + 0,25 (k > 1mD) and -0,095 log(k) + 0,25 (k < 1 mD)
- Tofte: -0,053 log (k) + 0,294
- Tilje & Åre : - 0,0445 log (k) + 0,433

Overburden correction is given by:

Garn, Ile and Tofte	$Kwc = 0{,}7158 * Kw^{1{,}285}$	For Kw < 1mD
	$Kwc = 0{,}6804 * Kw^{1{,}0235}$	For Kw > 1mD
Tilje and Åre	$Kwc = 0{,}5551 * Kw^{1{,}039}$	For Kw < 1mD
	$Kwc = 0{,}6442 * Kw^{1{,}013}$	For Kw > 1mD

Overburden correction for porosity is given by:

$$PORC = 0,\ 97 * POR$$

Bad Hole:
Well 2 – 1 have a poor shape, so it need to be correlated for that, this is done in the program. Density curve is affected by washouts and cavings.

Porosity:

Total porosity can be calculated from density log:

$$PHIT = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$

Where ρ_{ma} is density of matrix, ρ_b is measured density and ρ_f is density of formation fluid. Density of matrix and formation fluid is found from porosity – density crossplot.

Effective porosity can be calculated from total porosity and neutron porosity.

$$PHIE = \frac{7\ PHIDC + 2\ NPHIC}{9}$$

Where PHIDC = PHIT – VCL*Phidcl (Phidcl is porosity of clay),
NPHIC = (NPHI + 0, 04) – VCL*(Nphicl + 0, 04) (Nphicl is neutron porosity of clay).

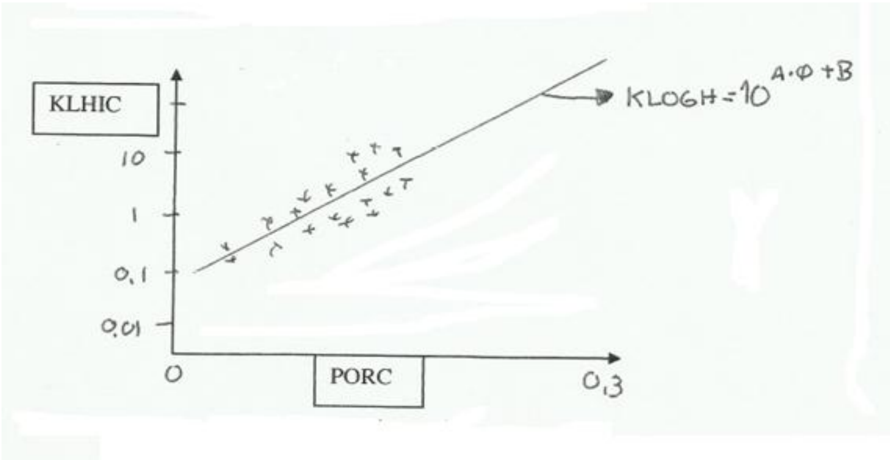
Water Saturation:
The total water saturation is calculated from Archie equation, which is given by:

$$S_w = \left(\frac{F * R_w}{R_t}\right)^{\frac{1}{n}}$$

Porosity used in the calculation of formation factor is the total porosity, and it is assumed that salinity in free water is equal to salinity in bound water.

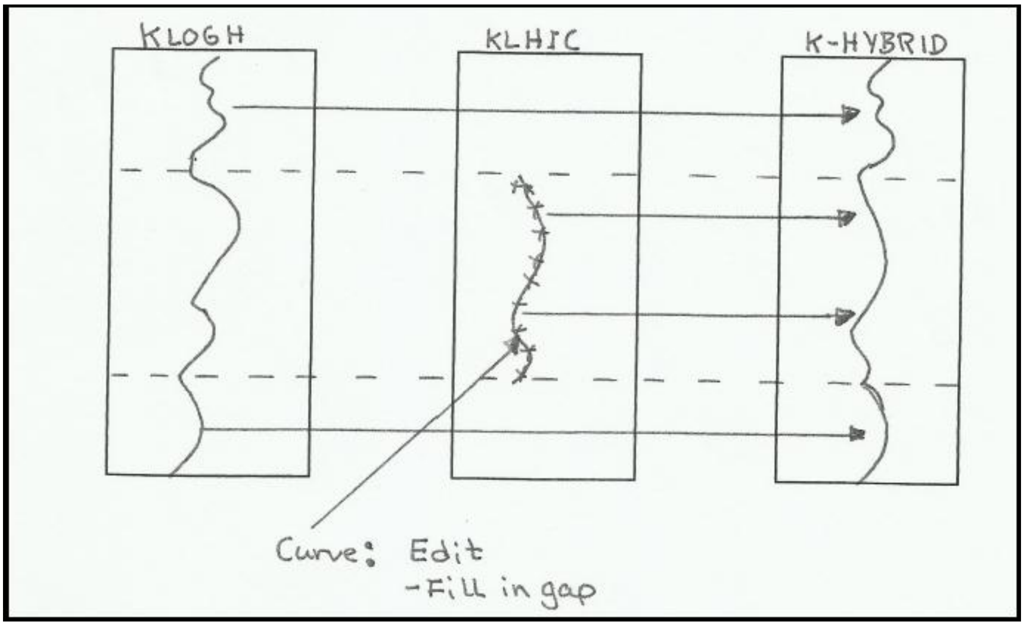
Permeability:

Total permeability can be calculated from the porosity – permeability (permeability from cores).



[Figure: Crossplot of porosity and permeability to determine formula for permeability]

This permeability can be used to determine a permeability profile for whole well, K – hybrid. Which is a combination of permeability from logs and cores, permeability from cores is used where permeability from cores are not available.



[Figure : Combination of permeability from cores and log]

The second method to evaluate permeability is Timur model, from IP. This is based on porosity and water saturation.

[18, 19]

Results

From the evaluation in Interactive Petrophysics, CPI plots and cross plots have been created. They can be found in the enclosure.

Table 2: Different curves in the CPI plot

Track	Description of curve
1	Zonation
2	Caliper
3	Gamma Ray
4	Depth
5	Density and Neutron
6	Sonic
7	Resistivity
8	Lithology
9	Water Saturation
10	Porosity (Total, Effective and Core porosity)
11	Permeability (K – hybrid, K Timur and Core permeability)

Scaling of Permeability from core values:

Table 3: Calculated scaling values DST permeabilities.

Test	Top	Bottom	K DST	K Arith	K geom
6406/2-1					
DST 7	4427	4495	0,03	0,05	0,44
DST 6	4645	4704	4,2	16,62	0,61
DST 5	4816	4858	3,2	5,89	0,43
DST 4	4910	4924	4,0	0,94	0,76
DST 3	5021	5041	0,49	1,45	1,06
DST 2	5099	5170	6,5	8,515	0,67
DST 1	5201	5227	0,29	0,41	0,98
6406/2-2					
DST 2	4714	4745	15	56,40	1,62
DST 1	4868	4927	0,7	9,18	1,59
6406/2-4SR					
DST 2	4684	4704	0,07	4,02	0,95
DST 1	4874	4904	16,1	26,8	1,71

Calculated values during evaluation:

Water resistivity from Tilje formation, at the water contact for all three wells.

6406/2 – 1:

Density of matrix: 2, 70
Density of fluid: 0, 58

Permeability from crossplot: 10 ^ (-3, 12 + 21,928*φ)

6406/2 – 2:

Density of matrix: 2, 65
Density of fluid: 0,8

Permeability from crossplot: 10 ^ (-2,69 + 17,38*φ)

6406/2 – 4SR:

Density of matrix: 2, 73
Density of fluid: 0,9

Permeability from crossplot: 10 ^ (-2,812 + 19,099*φ)

Conclusion

Permeability from logs is not easy to derive. Timur's correlation has been used here, which is based on water saturation and porosity. Porosity can easily be affected by bad hole (permeability derived from density log), and the constant in Timur's correlation must also be changed for each formation. Using the same constant will not give a good match with permeability from cores. This can be seen from CPI plots, the permeability from cores and logs (K-Hybrid) has a better match with the core permeability. Permeability from NMR has not been calculated.

Permeability from cores gives a good picture of the cored interval, but permeability from cores is difficult to scale up. Results from different scaling are very different; the Arithmetic values can be much greater than the geometric values. This is seen from the results of scaling. There are some local points with very high permeability or very low permeability, this gives inaccurate results in the scaling.

Cross plots of total permeability and permeability from cores (corrected for overburden and illite) has been used to derive an expression for permeability. The derived expression can be used to calculate permeability for rest of the formation. Since the core permeability is used, it gives a good approximation to real permeability.

Permeability from well testing gives the best value of the permeability, compared to the other methods. Permeability is estimated from pressure buildup data (it can also be estimated from pressure drawdown analysis). Since permeabilities calculated from well testing are from flow tests, they are essentially effective permeabilities. This permeability will be the real permeability, where all effects (mineral and overburden) are counted for.

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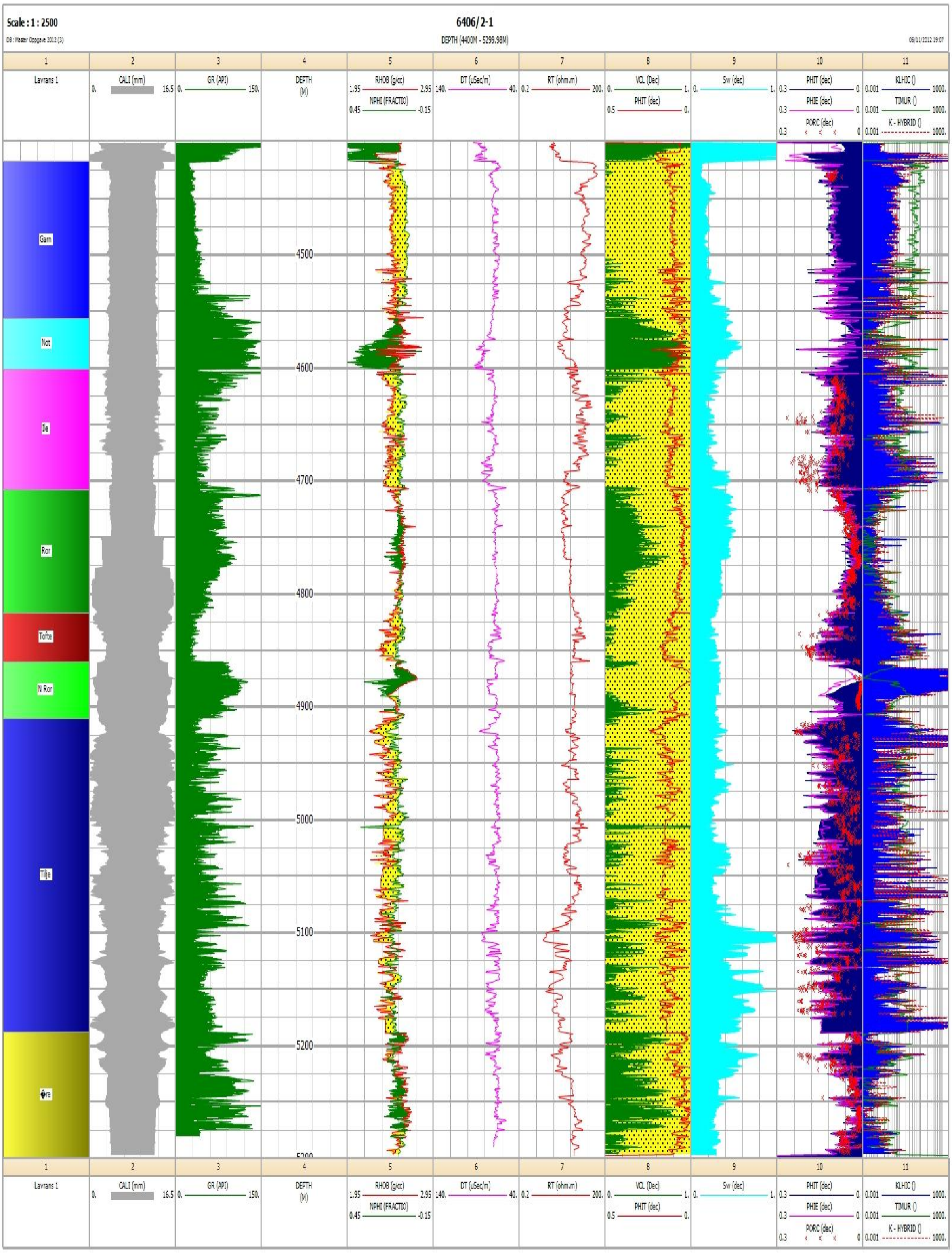
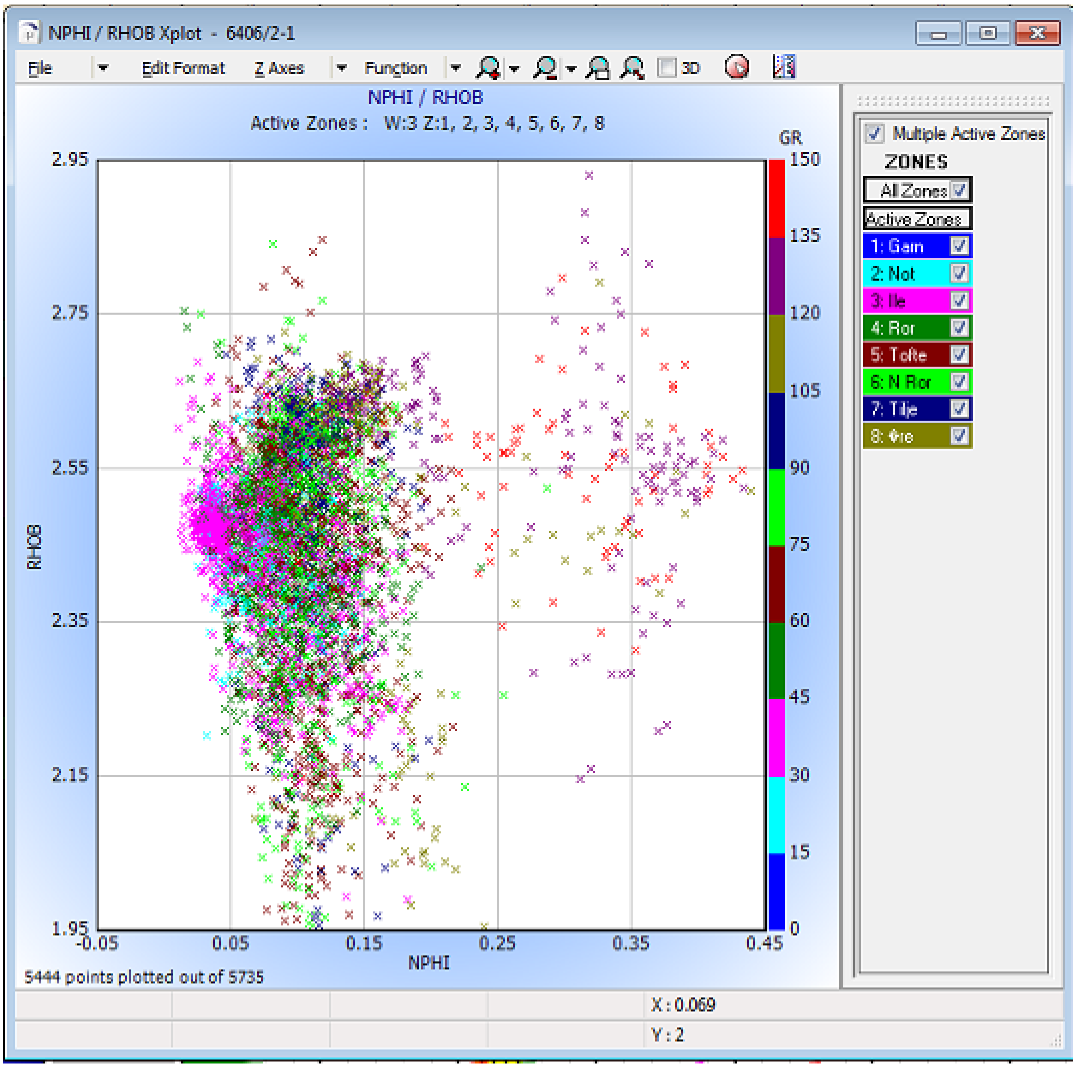
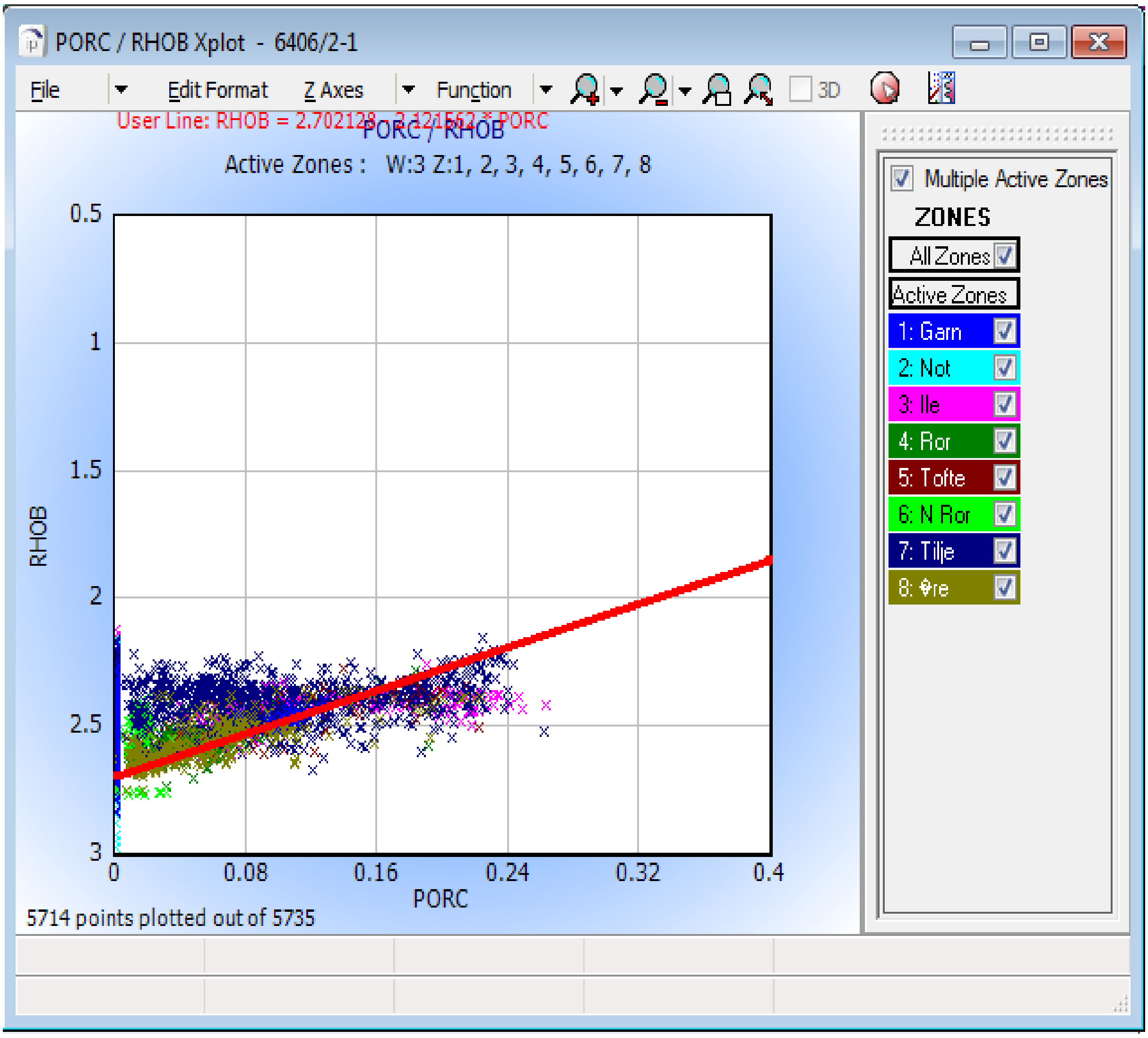
Enclosure



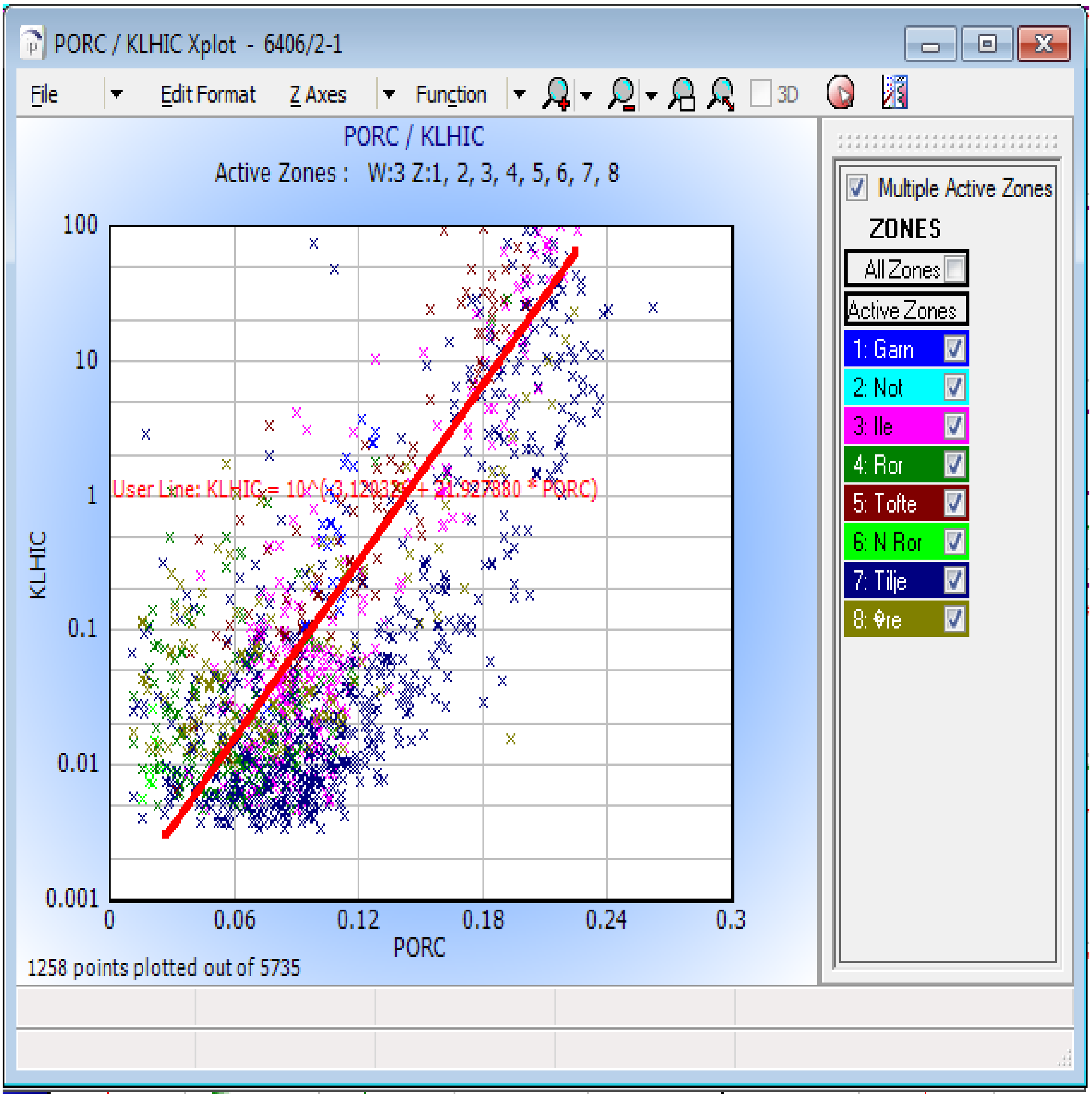
[Enclosure 1: Final CPI - plot]



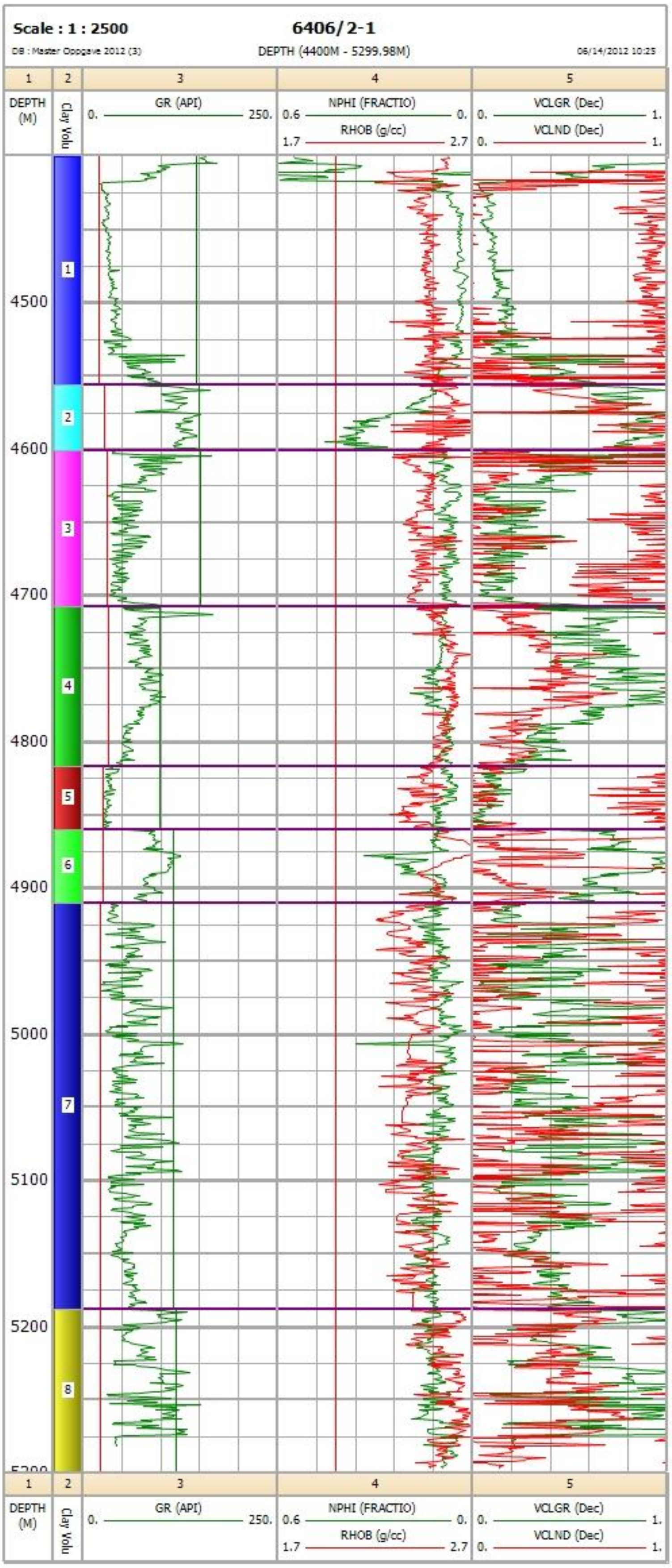
[Enclosure 2: NPHI vs. RHOB Cross plot, for reservoir quality]



[Enclosure 3: Porosity – density crossplot for determination of matrix – and fluid density]

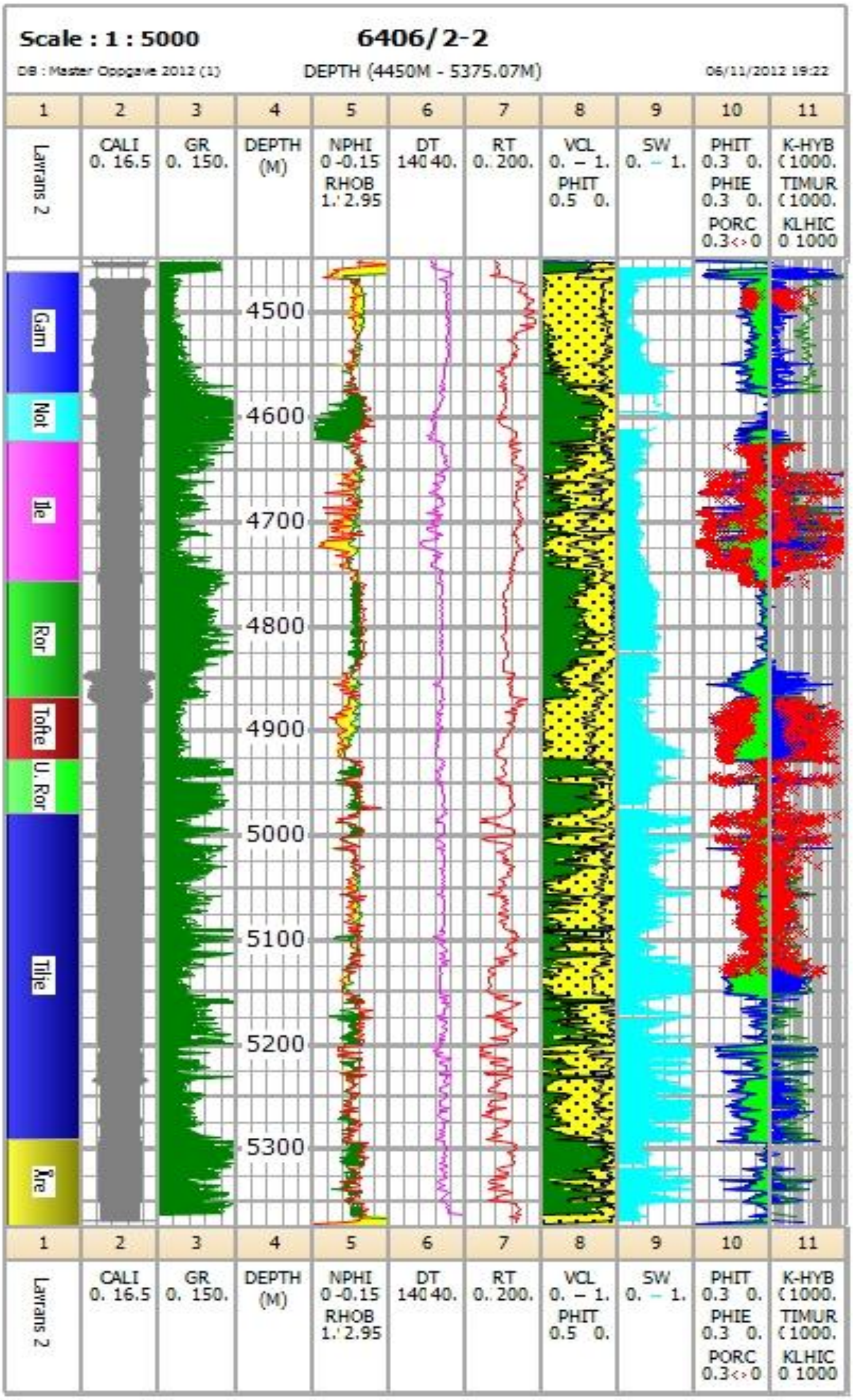


[Enclosure 4: Porosity and core permeability crossplot for determination of KLOGH (expression for permeability)]

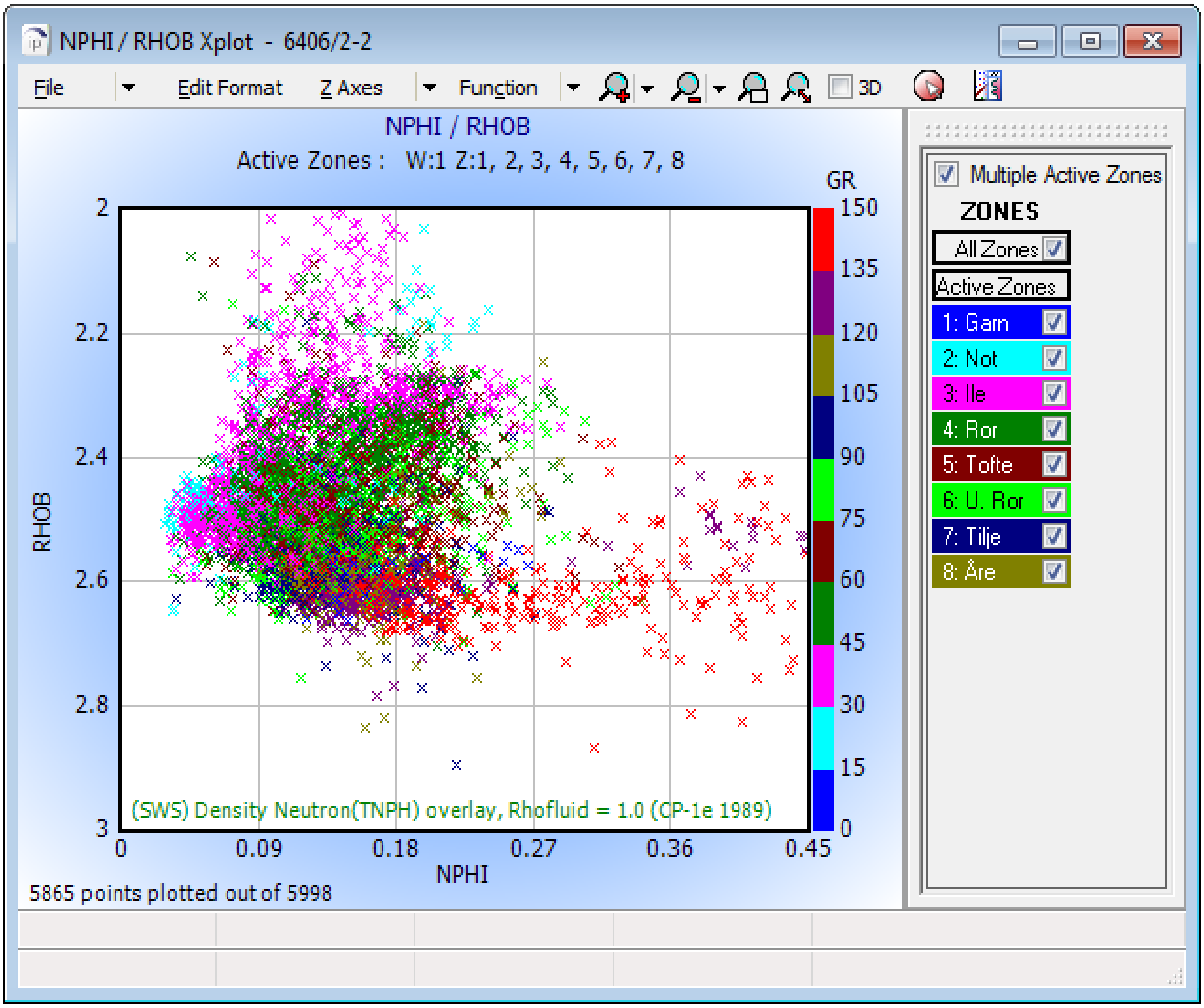


[Enclosure 5: Determination of Vshale with GR as indicator]

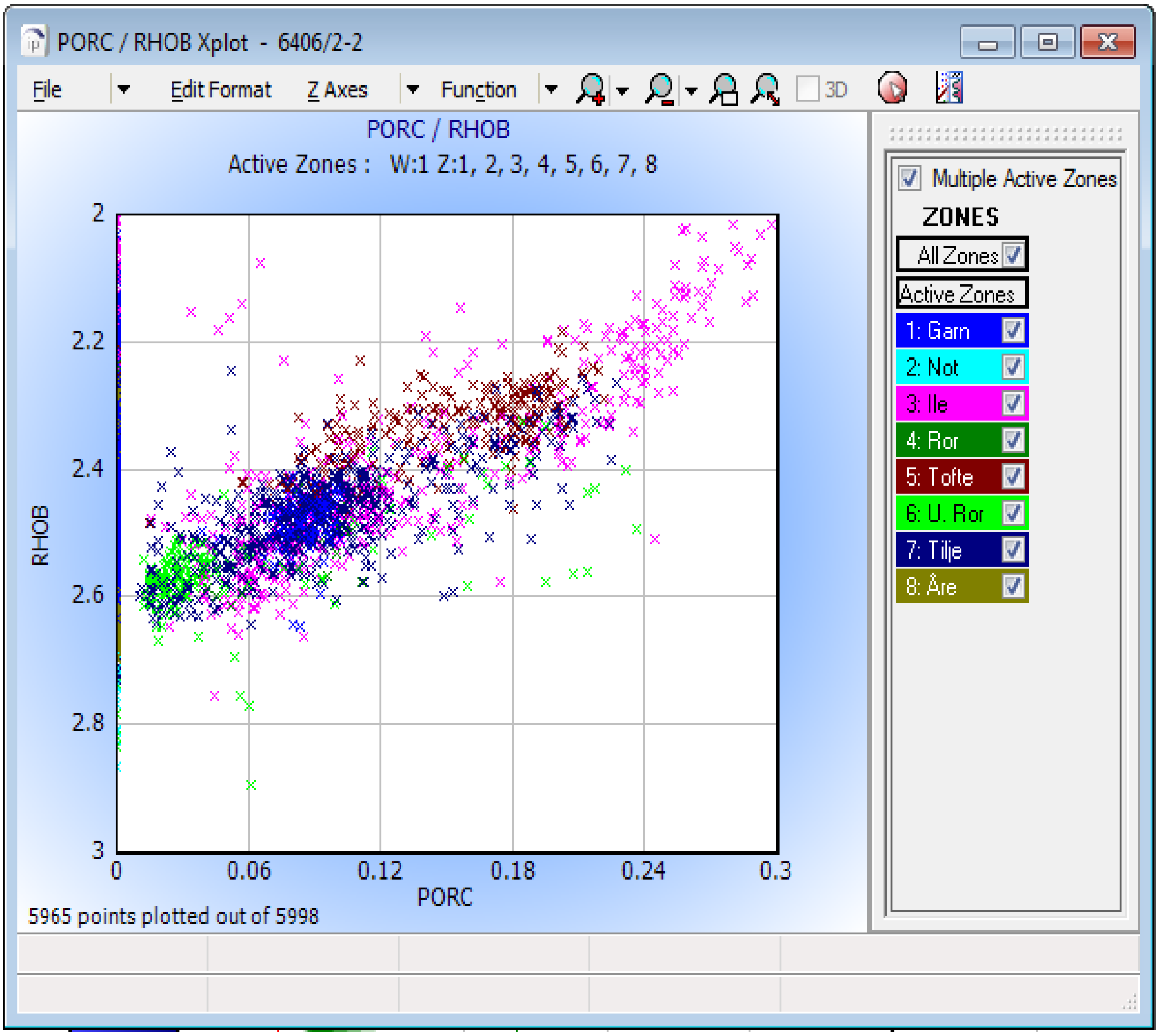
Well 6406 / 2 – 2:



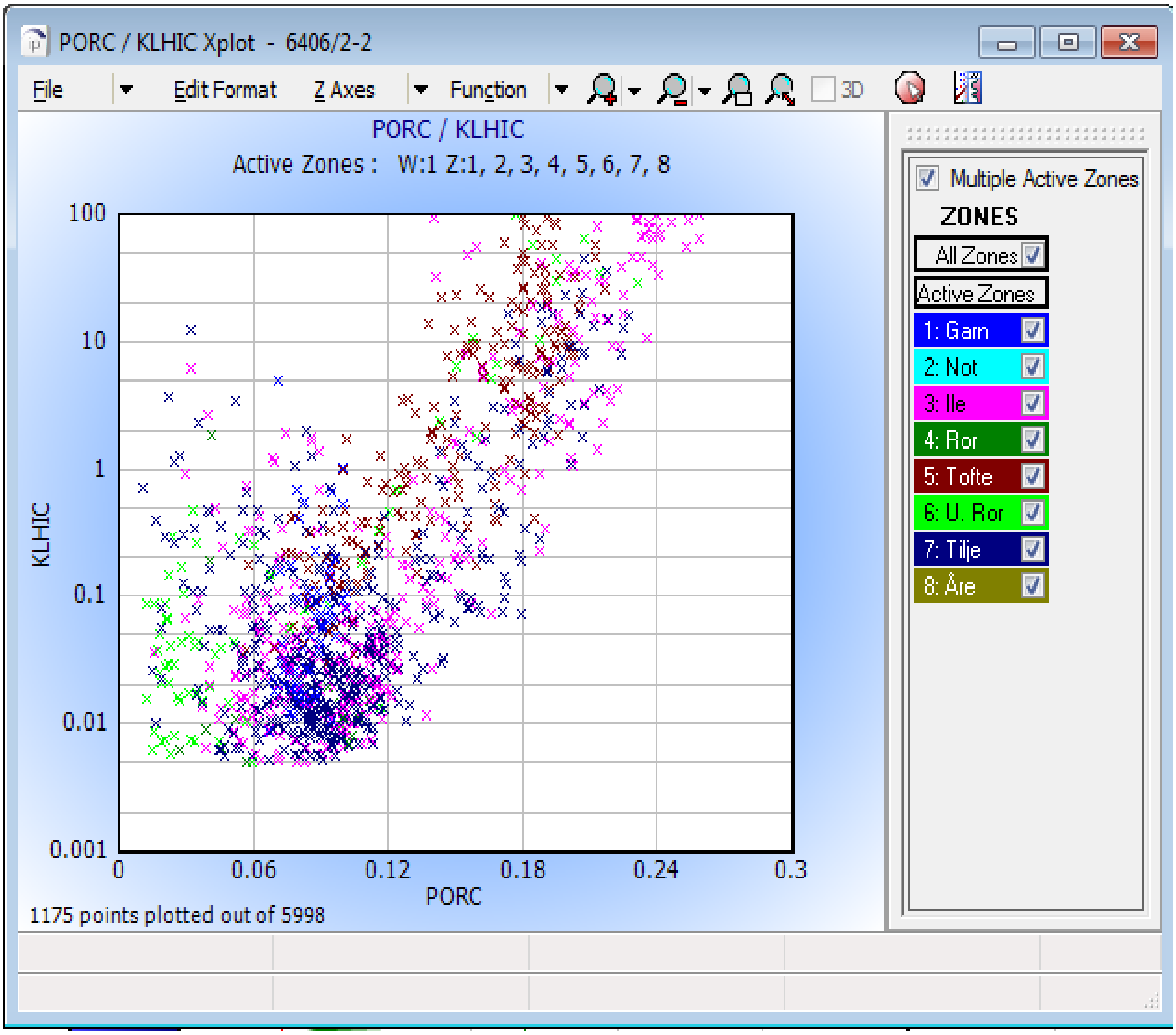
[Enclosure 6: CPI plot for well 6406 / 2 – 2]



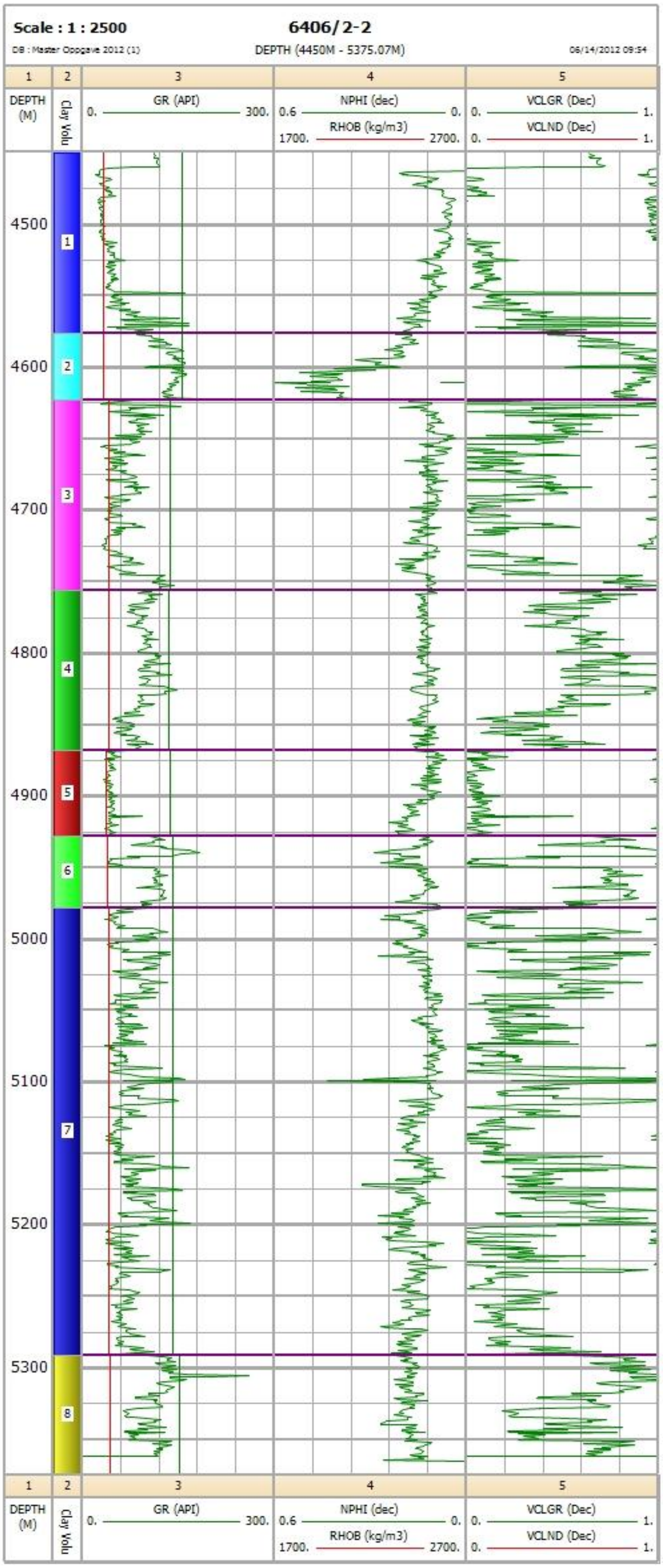
[Enclosure 7: NPHI vs. RHOB Cross plot, for reservoir quality]



[Enclosure 8: Porosity – density crossplot for determination of matrix – and fluid density]

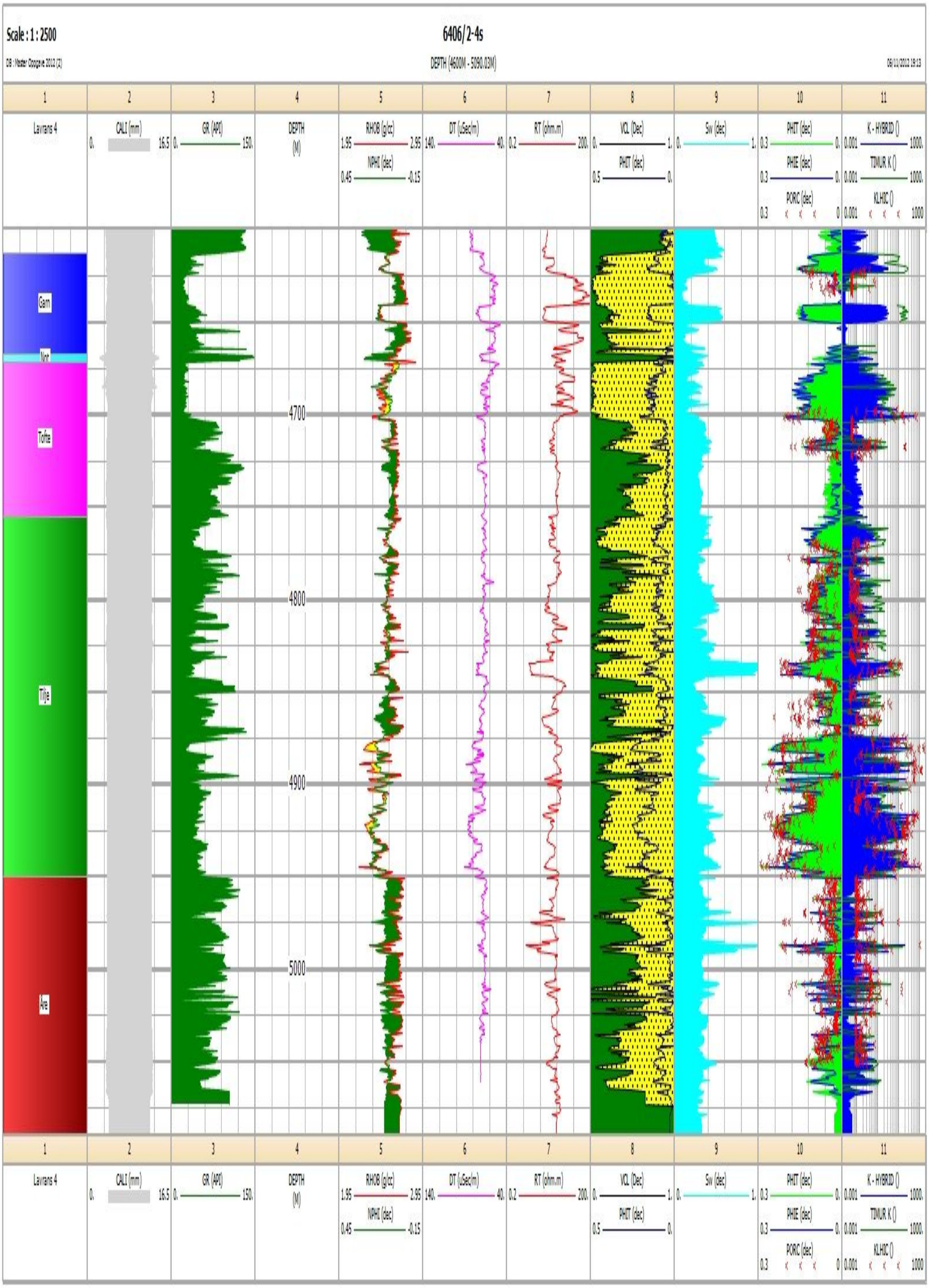


[Enclosure 9: Porosity and core permeability crossplot for determination of KLOGH (expression for permeability)]

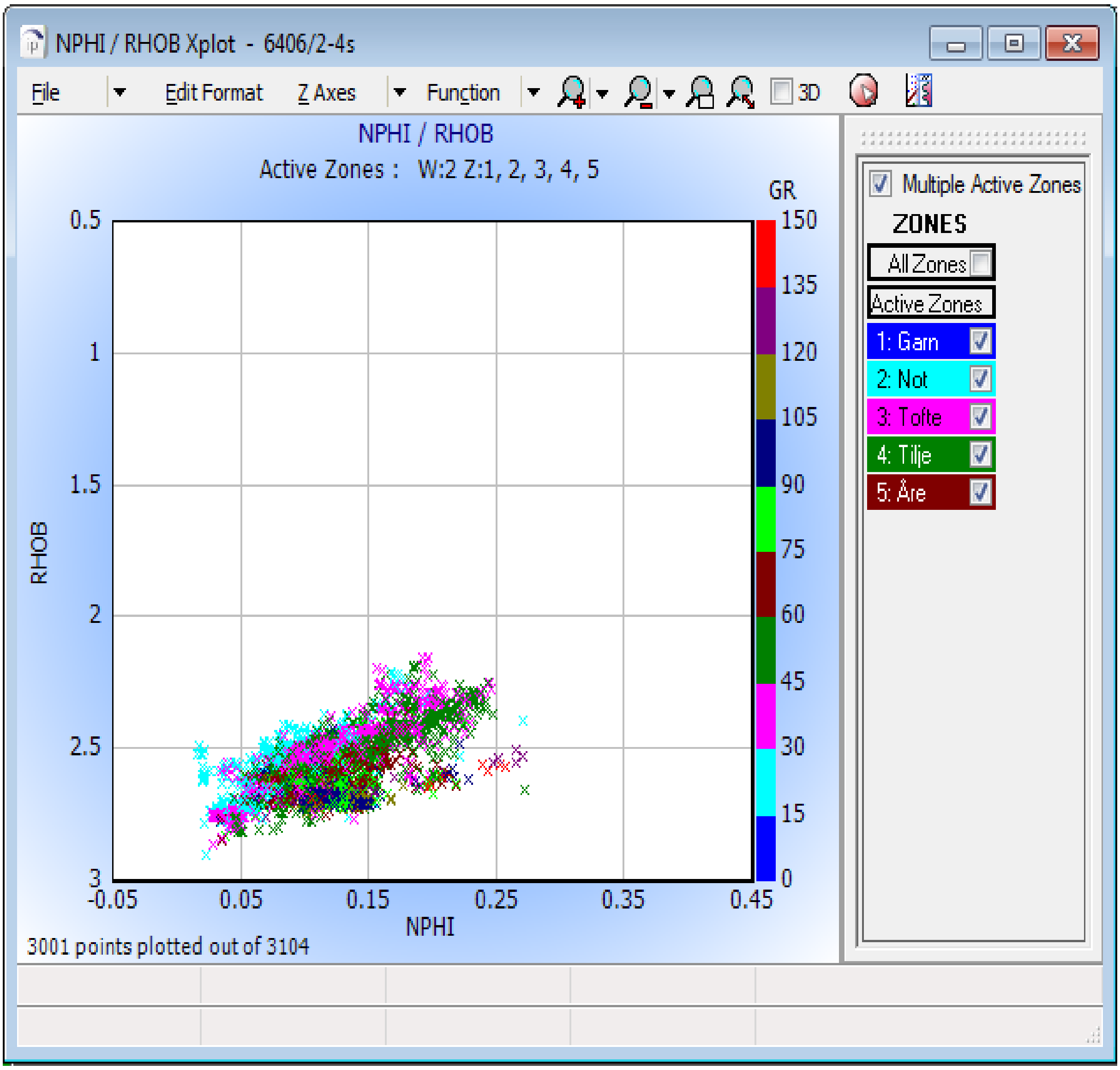


[Enclosure 10: Determination of Vshale with GR as indicator]

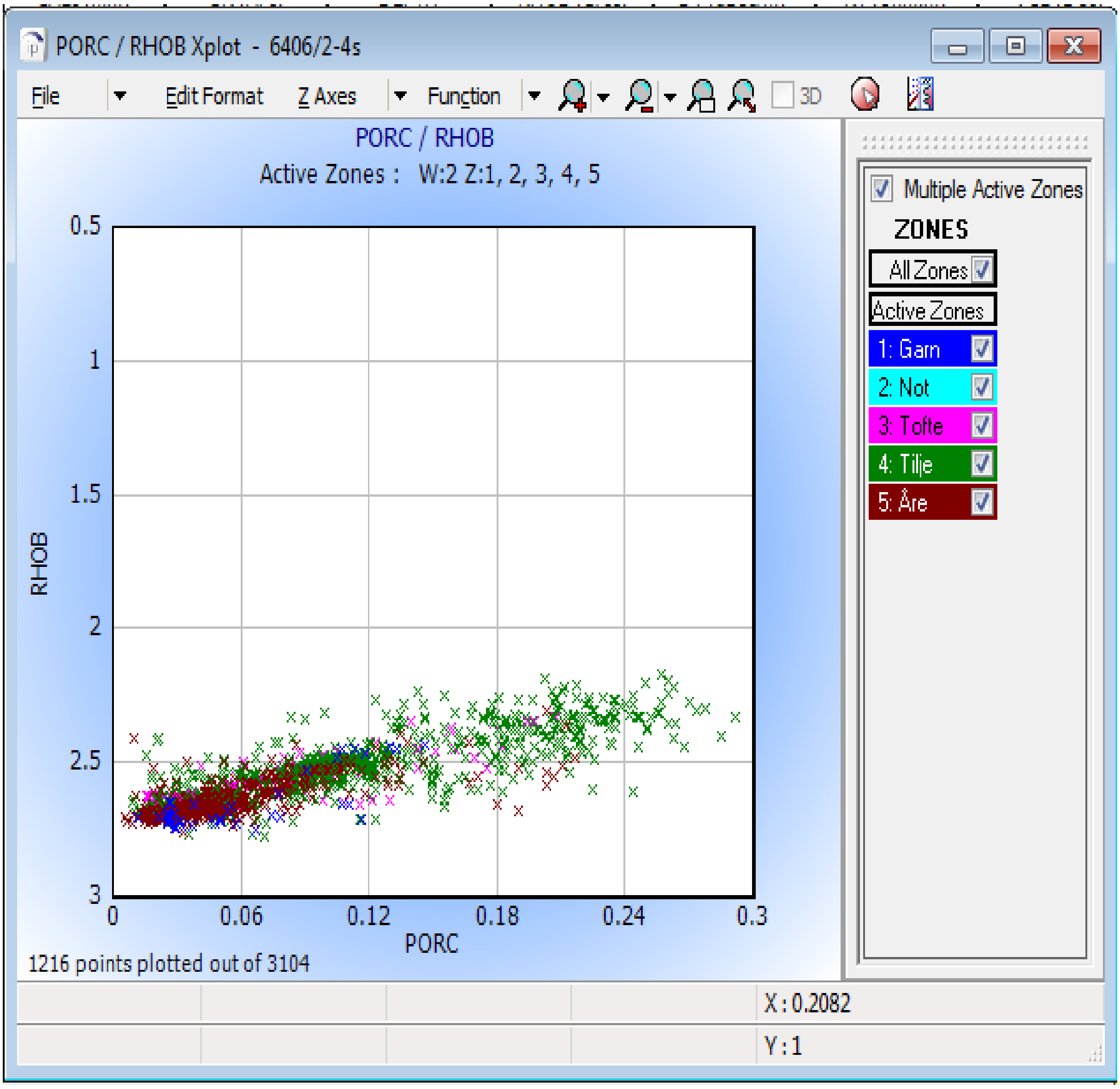
Well 6406 / 2 – 4SR:



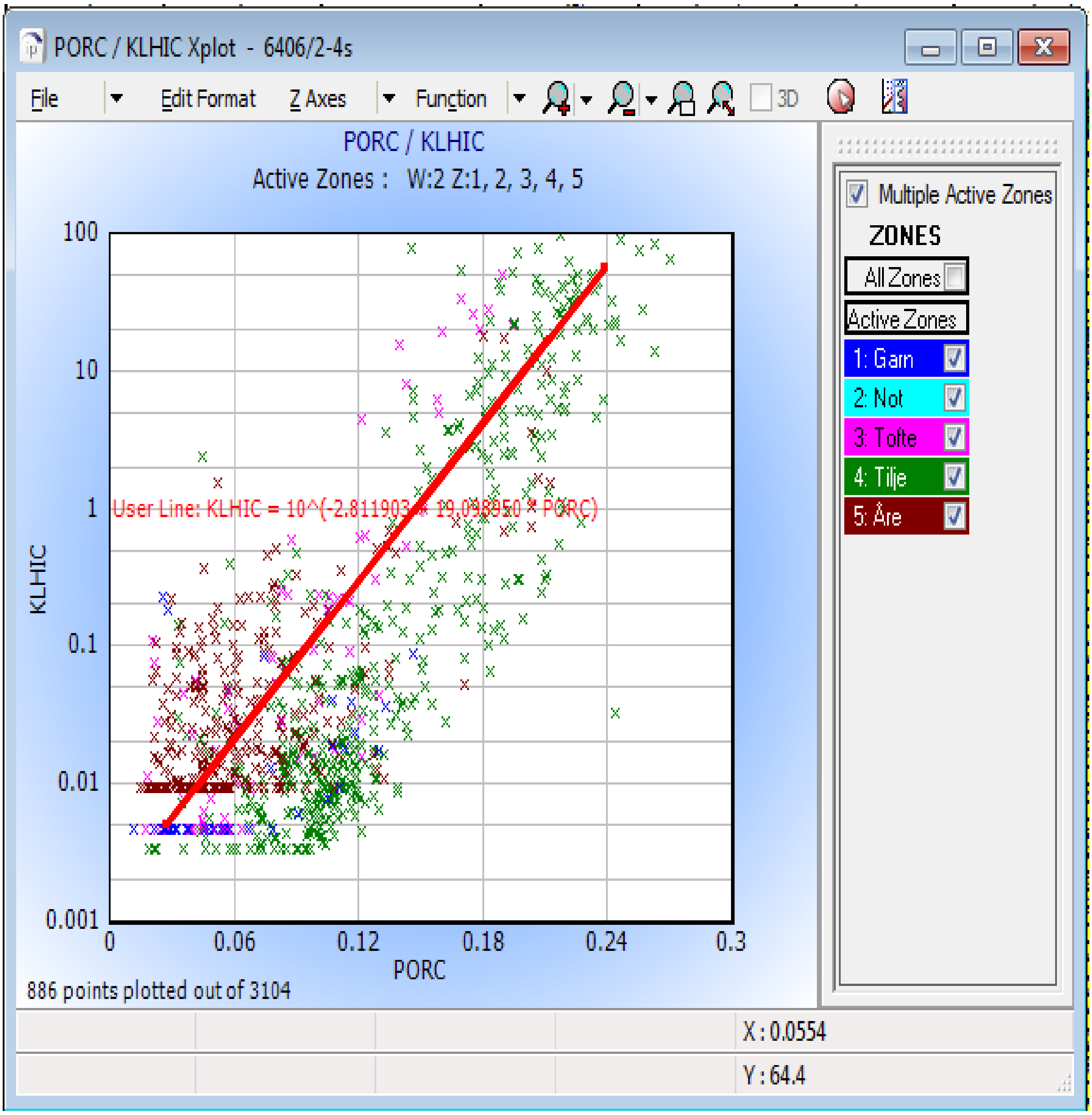
[Enclosure 11: CPI plot for well 6406 / 2 – 4SR]



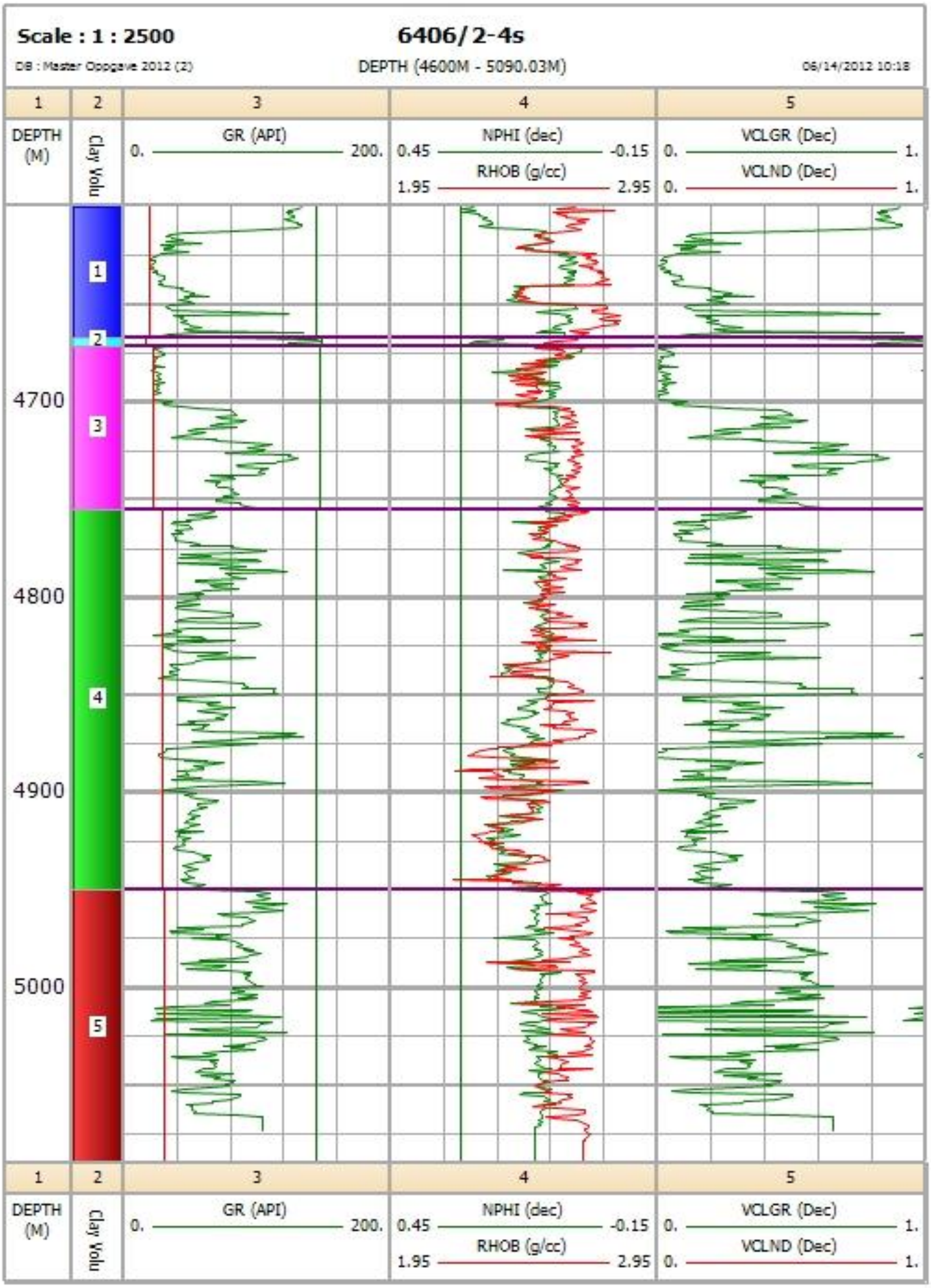
[Enclosure 12: NPHI vs. RHOB Cross plot, for reservoir quality]



[Enclosure 13: Porosity – density crossplot for determination of matrix – and fluid density]



[Enclosure 14: Porosity and core permeability crossplot for determination of KLOGH (expression for permeability)]



[Enclosure 15: Determination of Vshale with GR as indicator]