Net pay and net reservoir in Conventional reservoirs

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To paraphrase a popular saying, definitions of net pay are like belly buttons – everyone has one! Here's mine.

For me, net pay means that the rock could flow hydrocarbons. I'm not going to propose economic limits, because that varies from project to project, and a definition should apply everywhere. I'm also not going to specify drawdown limits, because that too depends on the setting. Instead I will focus on basic geological and reservoir engineering principles.

We know that in conventional reservoirs, hydrocarbon saturation is a function of reservoir quality and elevation above the free water level. High in the column, better quality rock has higher hydrocarbon saturation than poorer quality rock. As we get near the free water level, elevation takes over, and rock nearer the free water level will have lower hydrocarbon saturation than rock which is higher.

We also know that conventional reservoirs always trap some hydrocarbons, so we can't reduce hydrocarbon saturation to zero (assuming primary depletion, or primary imbibition in the form of aquifer influx or water injection). So given that, my definition of net pay is:

> Net pay is rock in which the hydrocarbon saturation is greater than the residual saturation.

This is equivalent to saying that in net pay, the relative permeability to the hydrocarbon phase is greater than zero.

We can modify this definition to estimate net reservoir in wet zones, by asserting that net reservoir is rock that would produce hydrocarbons if it were above the free water level. More practically, we can say that net reservoir has the same petrophysical characteristics as net pay, except for hydrocarbon saturation.

Notice that my definition makes no reference to permeability, porosity or shale/clay content, even though those are the other properties traditionally used for net pay. I'll show how they can be integrated into the definition, using an example.

My example is a released data set downloaded from the Australian Government's website. The well I selected penetrated a thick gas-bearing sandstone interval. In this study I used only the conventional core analysis data, as shown in the vendor's core log in Figure 1: core log from example well. Wire line log data is also available, but I focused on the core.

The core GR shows a thick, low GR section with very good porosity and permeability, with a fining-upwards section above. Core permeability ranges from nearly 10D to 0.01 mD, and porosity from 30% to less than 5%. Clearly much of the section would be able to produce gas, but some would not. How do we determine the net pay?

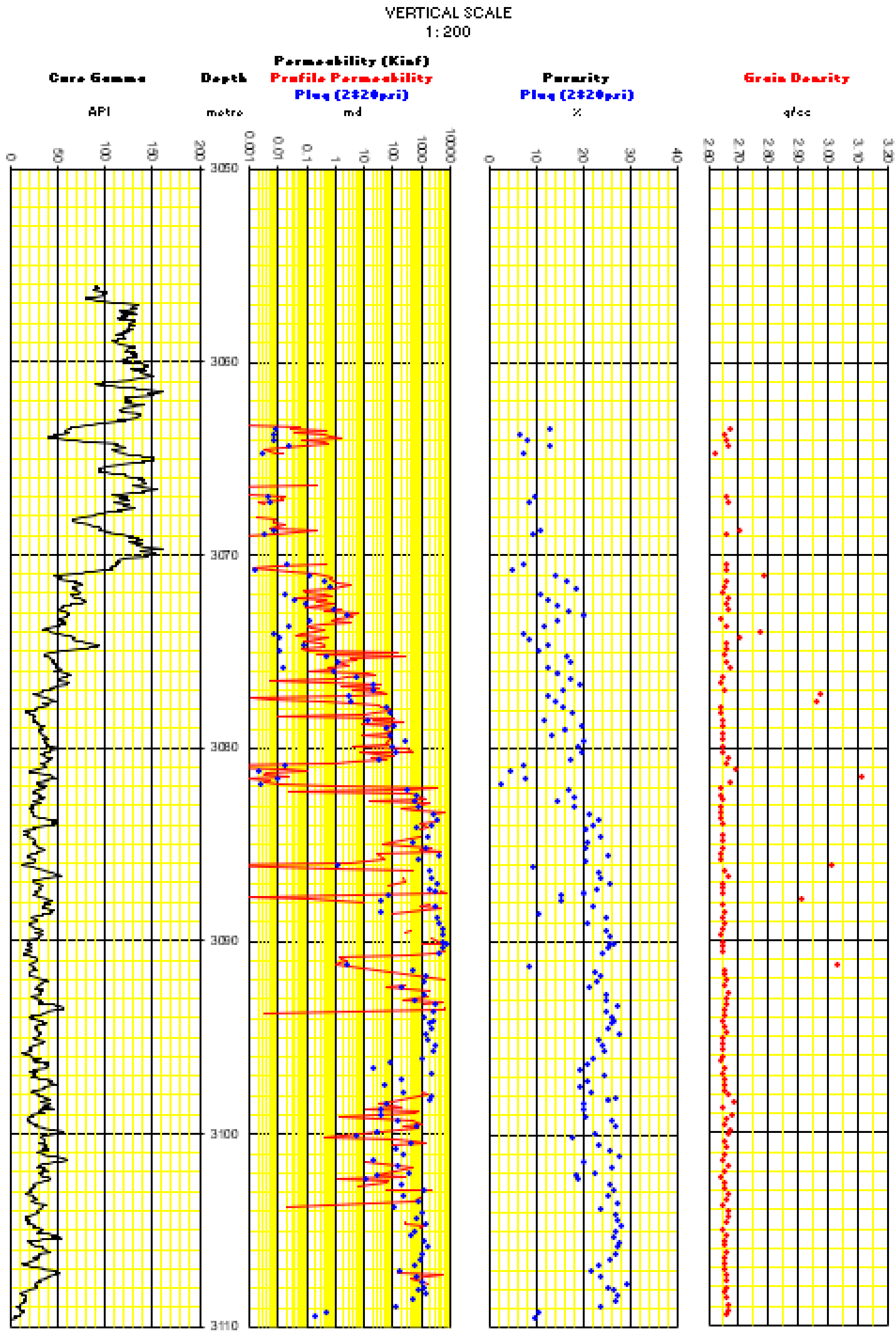

Figure 1: core log from example well

To apply my definition, we need to know two things –

- The initial gas saturation
- The residual (or trapped) gas saturation

The data set includes a small number of Dean-Stark water saturation measurements. Since the well was drilled with oil-based mud, we can assume that these data are a reliable estimate of initial water saturation. They are shown in a cross-plot against core permeability in Figure 2: Dean-Stark Sw vs permeability. We commonly see that Dean-Stark Sw is well correlated to permeability, and there is a reasonable trend here. This trend can be used to estimate initial gas saturation for all the core plugs, based on their measured permeability.

For cores cut in water-based mud, we can't use Dean-Stark data because it will be affected by filtrate invasion. In that case we can use Sw data from special core analysis studies to establish the trend.

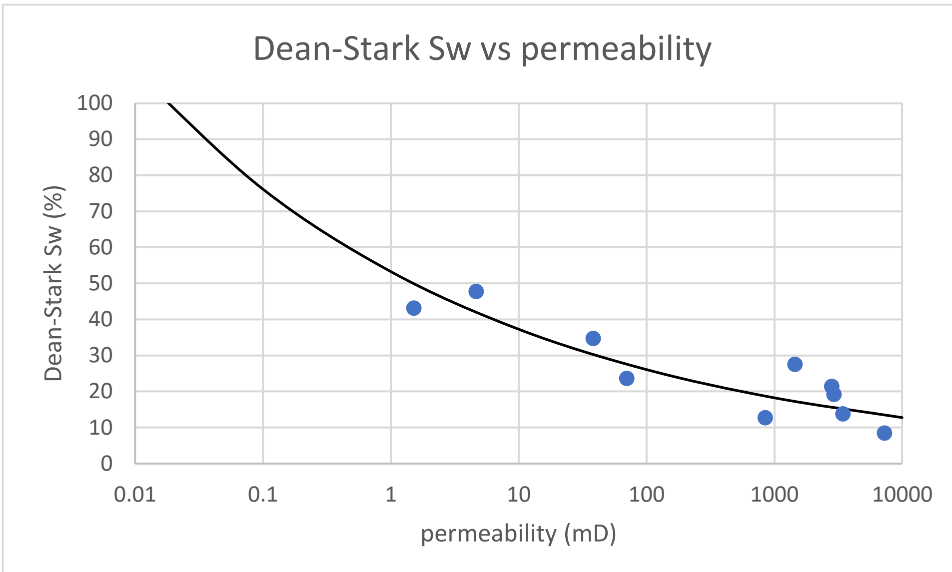

Figure 2: Dean-Stark Sw vs permeability

Residual gas saturation is a little harder to determine. No special core analysis data was available for the well, so I used some published data.   Figure 3: published trapped gas data was taken from a Society of Core Analysts paper, "Trapped Gas, Relative Permeability and Residual Oil Saturation of an Oil-Wet Sandstone", by J.G. Kralik, L.J. Manak, A.P. Spence, and G.R. Jerauld, ARCO. It shows maximum trapped gas saturation vs porosity for a variety of reservoirs. "Maximum trapped gas saturation" is the trapped gas saturation either measured or inferred for a core plug with 100% initial gas saturation. Actual trapped gas saturation will be lower, depending on the true initial gas saturation. There is a reasonable correlation with porosity, and this was used (with initial gas saturation from the permeability transform) to estimate trapped gas saturation for each core plug.

This step is a lot simpler for oil reservoirs, because residual oil saturation does not usually vary with reservoir quality, so a single value (or a range) can be used.

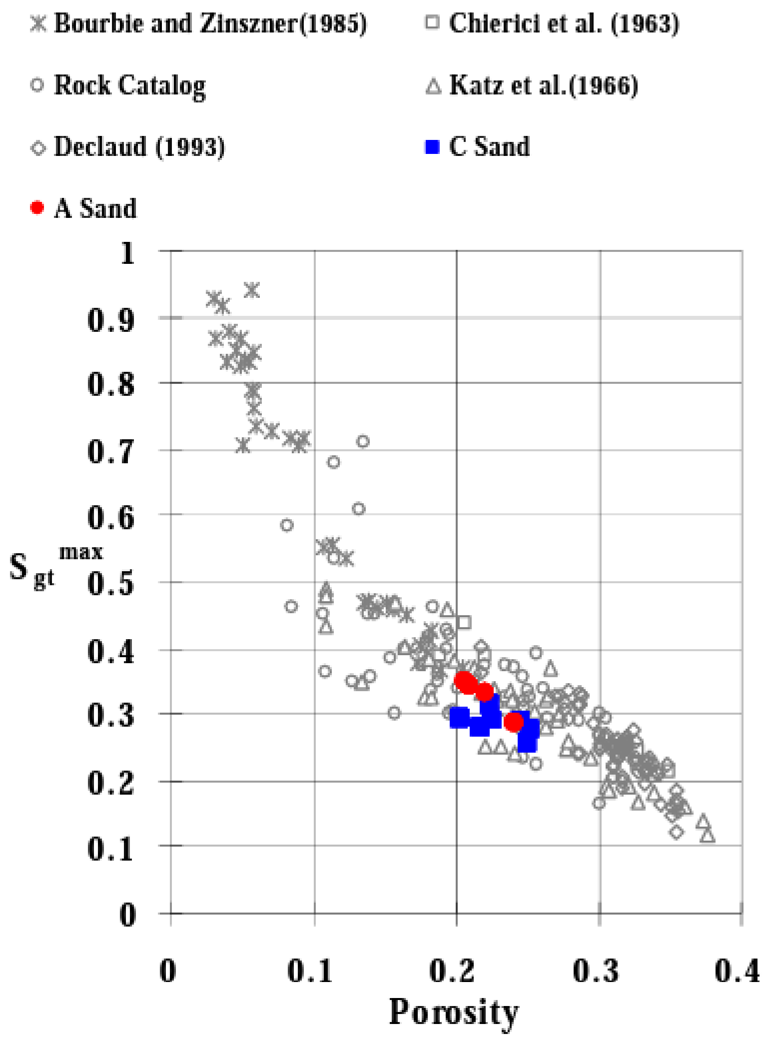

Figure 3 Maximum trapped gas vs. porosity level for extracted samples compared to literature values.

Figure 3: published trapped gas data

We can now simply determine net pay as every level for which initial gas saturation is greater than the trapped gas saturation. This is shown in Figure 4: gas saturation and net pay flag.

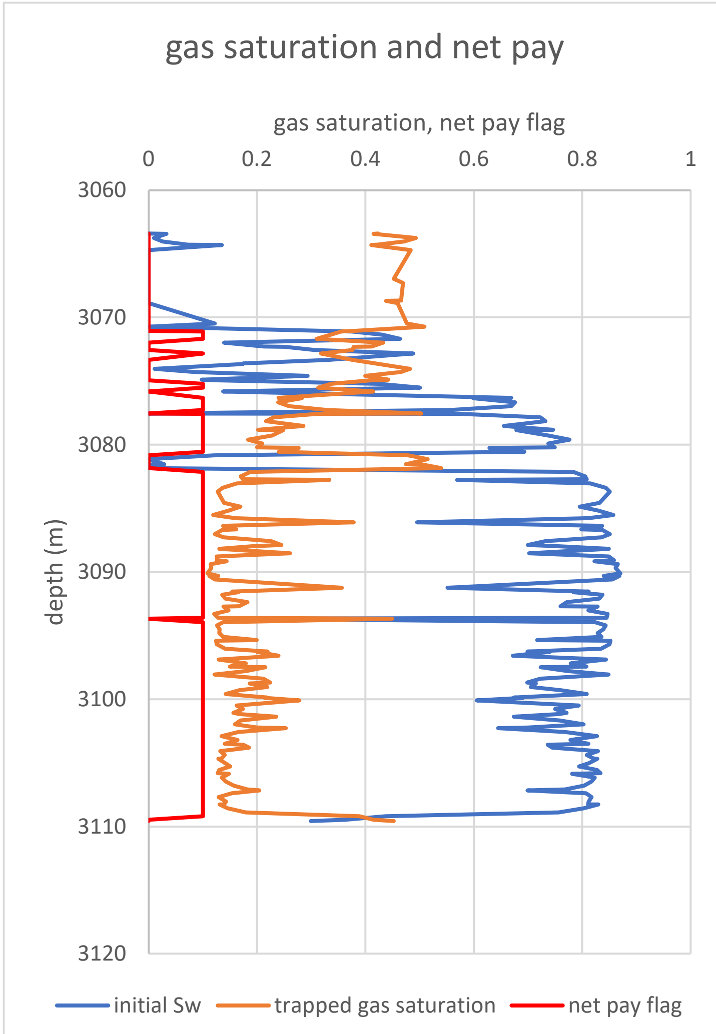

Figure 4: gas saturation and net pay flag

We now have a simple method of determining what is net pay, based only on core data. We need to extend it into the log domain, because in most fields only a small interval of the reservoir will be cored, but typically all wells will be fully logged. This is a simple step if we have reliable log-derived porosity and water saturation, but it can't be directly applied for net reservoir in aquifer wells, and log-derived water saturation tends to have poor vertical resolution, since it uses resistivity logs.

So how do we extend the analysis to include log-derived curves like Vshale, porosity and permeability, which have good vertical resolution and can be used in wet zones? In this example, I generated histogrammes of those parameters divided into net pay and not net pay, to see if there was a clear separation that could be used to pick a cut-off value.

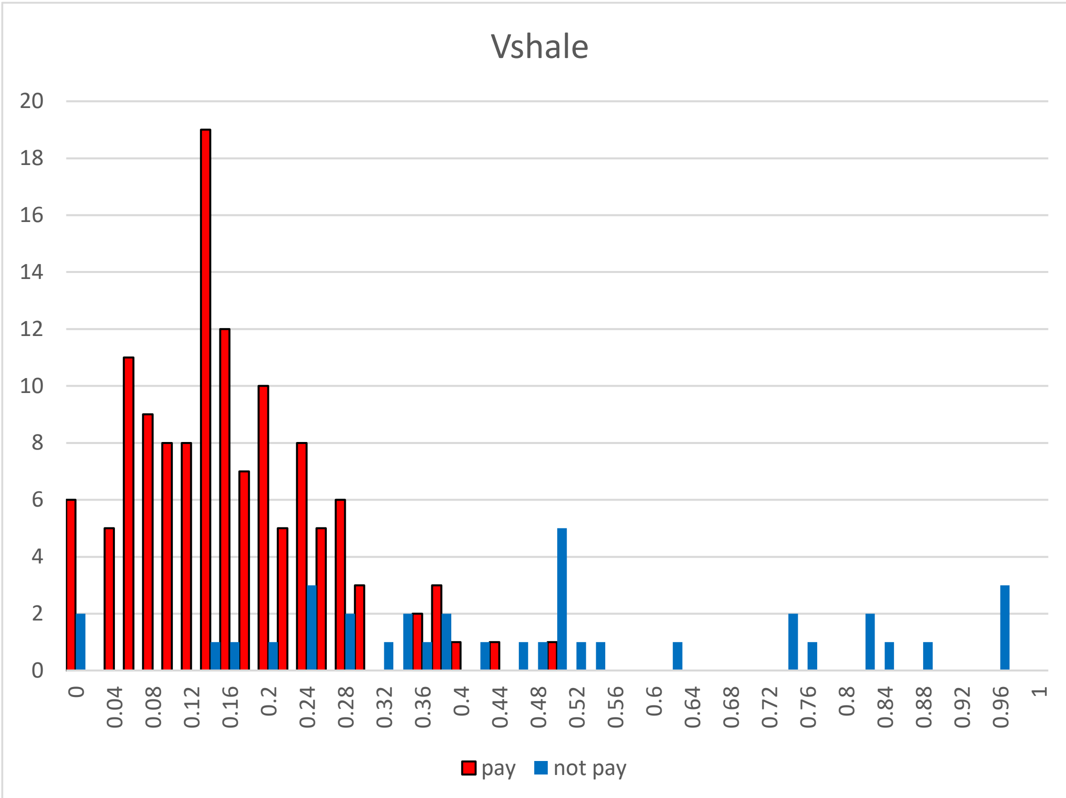

Figure 5: Vshale histogramme

Figure 5: Vshale histogramme shows the plot for Vshale (derived from the core GR). There is some overlap in Vshale between pay and not pay, but a reasonable cut-off is 40%.

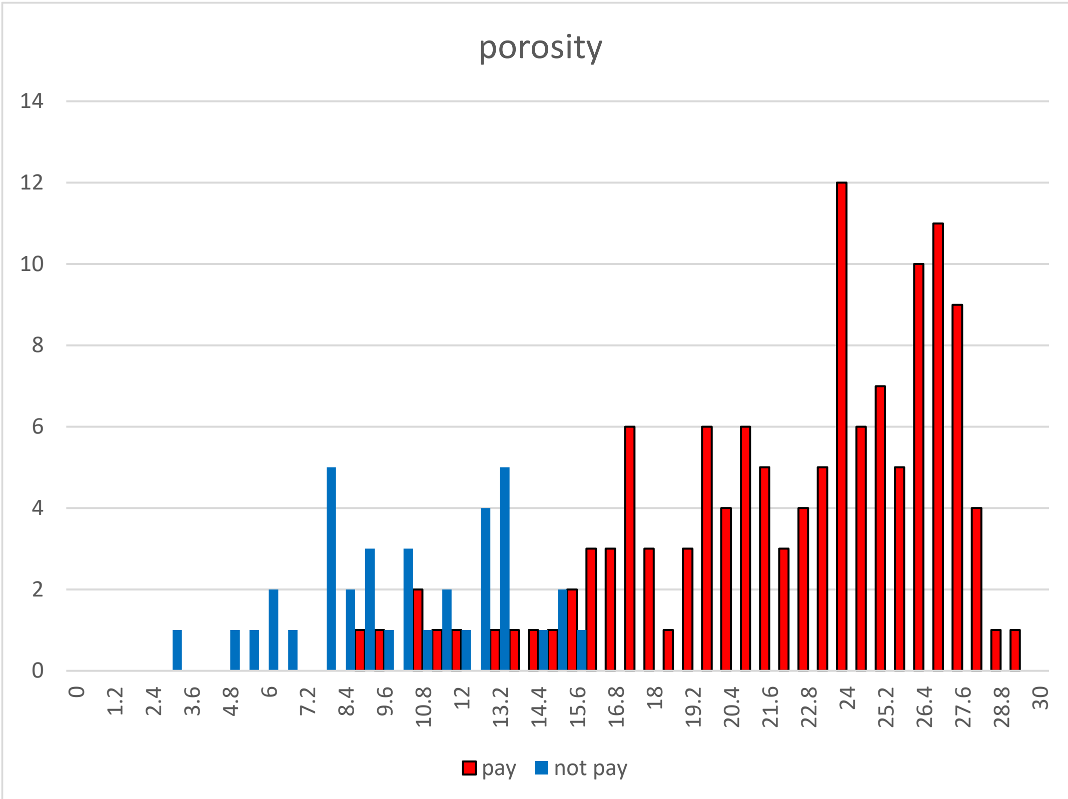

Figure 6: porosity histogramme

Figure 6: porosity histogramme shows the histogramme for porosity. Just as for the Vshale plot, there is some overlap, so there are some pay zones with low porosity, and some not pay zones with higher porosity, but a reasonable cut-off is 14%.

Paul Worthington proposed another core-based method for determining the porosity cut-off from core data. He plotted RQI vs porosity and looked for the porosity level at which RQI increases sharply. The plot for this data set is shown in Figure 7: RQI vs porosity. It suggests a porosity cut-off of around 15%, slightly more pessimistic than my value.

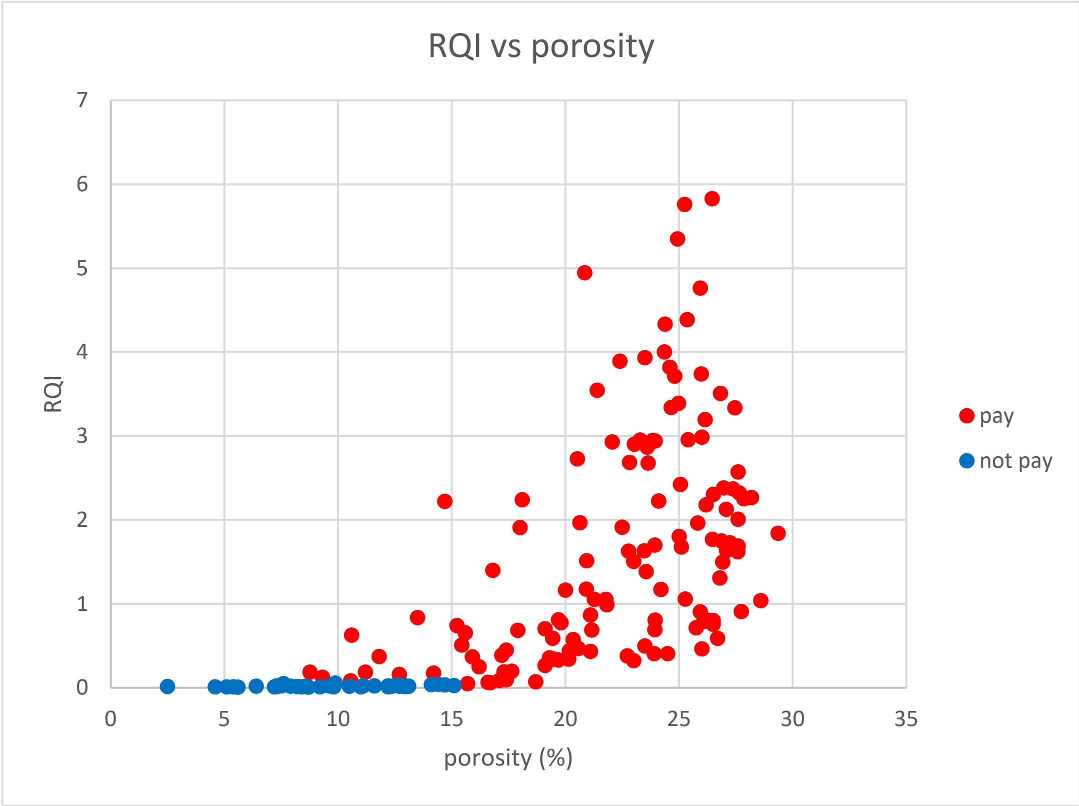

Figure 7: RQI vs porosity

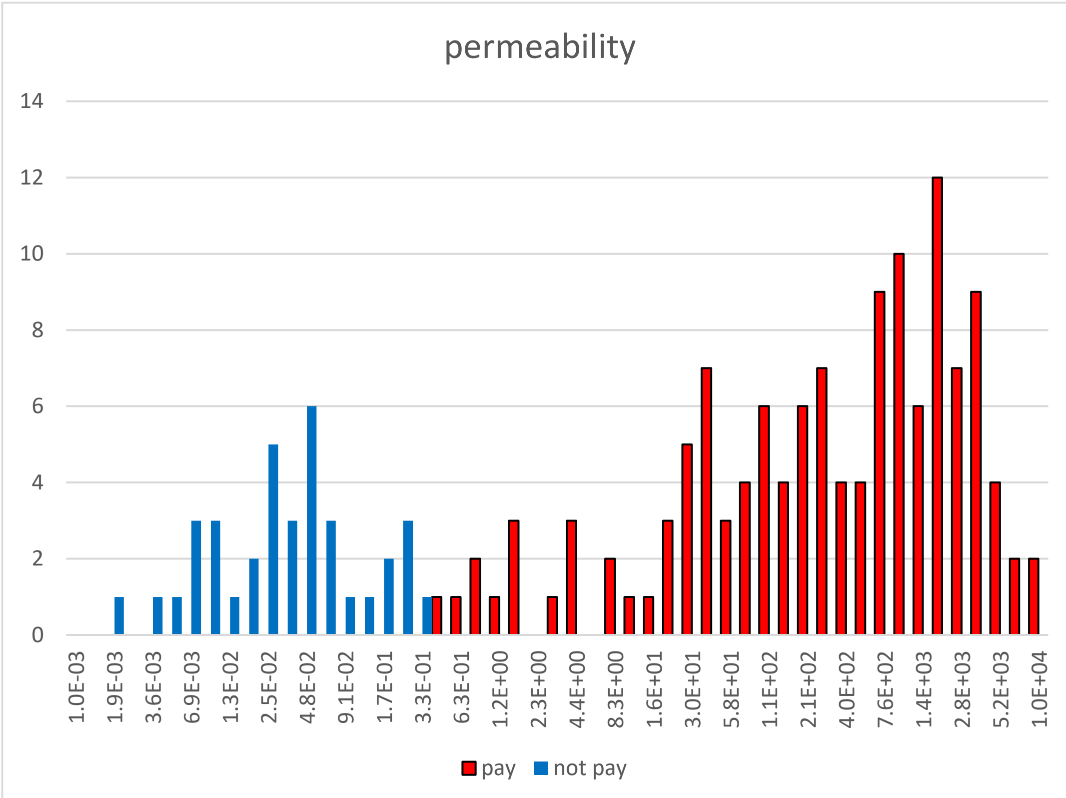

Figure 8: permeability histogramme

Figure 8: permeability histogramme shows the histogramme for permeability. The plot shows a sharp break between pay and not pay at around 0.5mD, but this may be due to the use of a permeability transform to estimate Sw. 0.5mD is higher than the rule-of-thumb for gas (0.1mD) but not unreasonable.

We now have a set of cut-offs that apply to both net pay and net reservoir:

- Porosity > 14%
- Vshale < 40%
- Permeability > 0.5mD

Note that this method does not give a single Sw cut-off value, because it varies with rock quality. We can differentiate between net pay and net reservoir by asserting that net pay is net reservoir rock above the free water level.