Aberdeen Formation Evaluation Society

Why you cannot Map Net Sand.

AFES Seminar 2017

All barrels are not borne equal – The Net definition dilemma

September 27th 2017

Lloyd's Register

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Why you cannot Map Net Sand by Andy Beckly
27th of September 2017

Abstract

Why you cannot map Net Reservoir. This talk argues that the definition of Net depends on the rock and on the fluids that you want to get out of it. Based on a large core data set, the talk shows the impact of different cutoff techniques in relation to NTG and associated averages. Also, an interesting overview of petrophysical averages is presented of the oil fields in the North Sea. On top of that, different rocks require different cutoff techniques. In the 'world-according-to-Andy', hydrocarbon volumes would be classified per habitat and per fluid type.

Biography

Andy has just retired from his Principal Geologist role with LR. Andy was with BP from 1985 to 1999, after which he joined RML which was merged into Senergy and later LR. Andy's 31 years of experience cover the entire life-cycle of the upstream business from frontier exploration in deep water West Africa, through field development to late field-life management and Cessation of Production (COP). Andy worked on a large number of well known fields including Bruce, Harding, Keith, Beauly, Miller, and Schiehallion, and on many others spread out over most of the UKCS during his time as consultant.

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It’s a simple request

To paraphrase a conversation that sort of happened

“We would like maps of reservoir quality”

“What for?”

“So we can read off the values for a prospect”

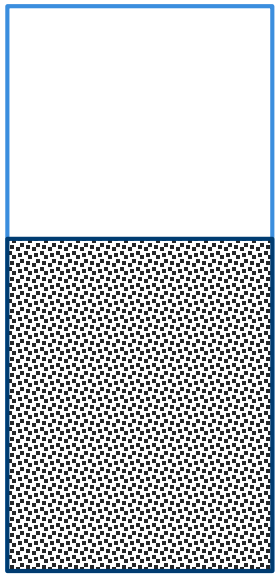
“That isn’t possible”

Puzzled expression.

“A reservoir that has a NTG of 100% for gas could have a NTG of 0% for heavy oil. Reservoir ‘quality’ depends on the fluid you are trying to get out of it.”

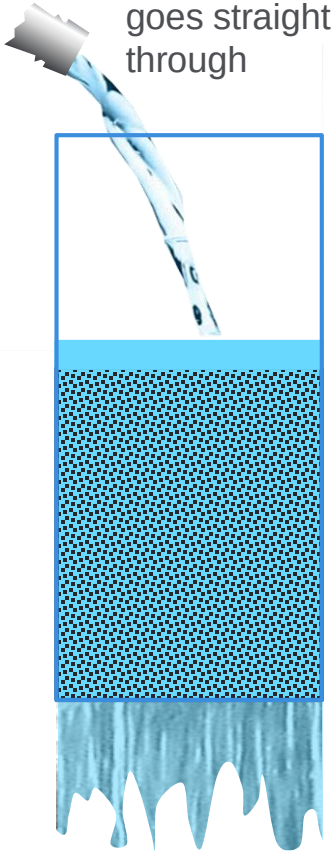
The key issue here is that net reservoir is not an intrinsic quality of the rock itself but of the reservoir- fluid interaction.

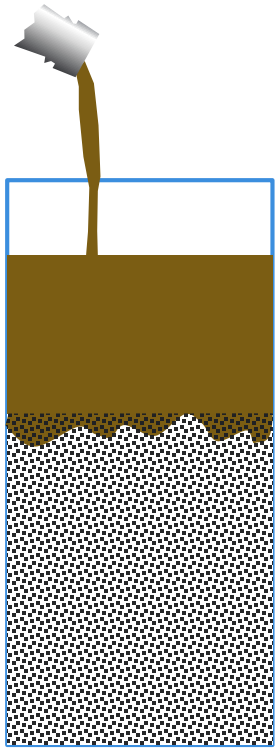
A simple thought experiment



Vessel with well sorted sand in lower portion and porous base equivalent to sand

Pour in water: goes straight through



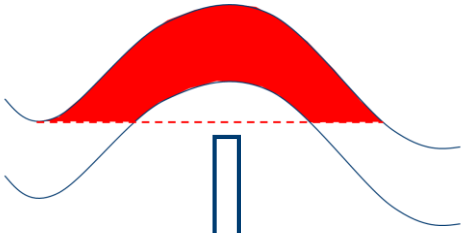


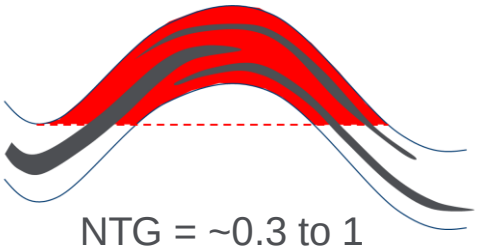
Pour in treacle; Ponds on the surface with limited penetration of sand

But both pour out of the bottle fine

How net / NTG can get used

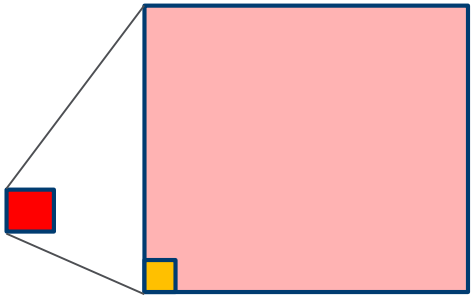
The unconstrained variable: the difference between 1000 mmstb and 10 mmstb



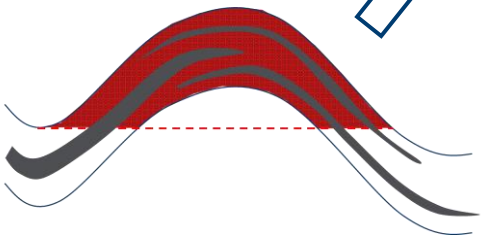


NTG = ~0.3 to 1
of the GRV

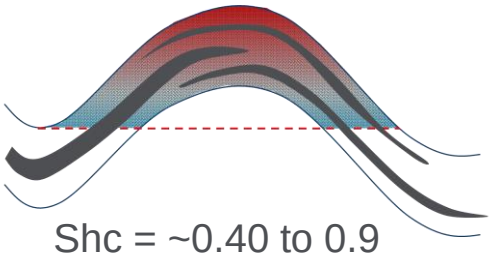
ExpFac. is fluid specific : but so are the other reservoir parameters



HIIP = GRV (mmcum) x NTG x Porosity x Saturation x Expansion Fact.



Phi = ~0.06 to 0.36
of the NET



Shc = ~0.40 to 0.9
Of the net pore volume

So how does that play out in reality?

Could just leave it there: but would be a very short talk.

So to add some substance

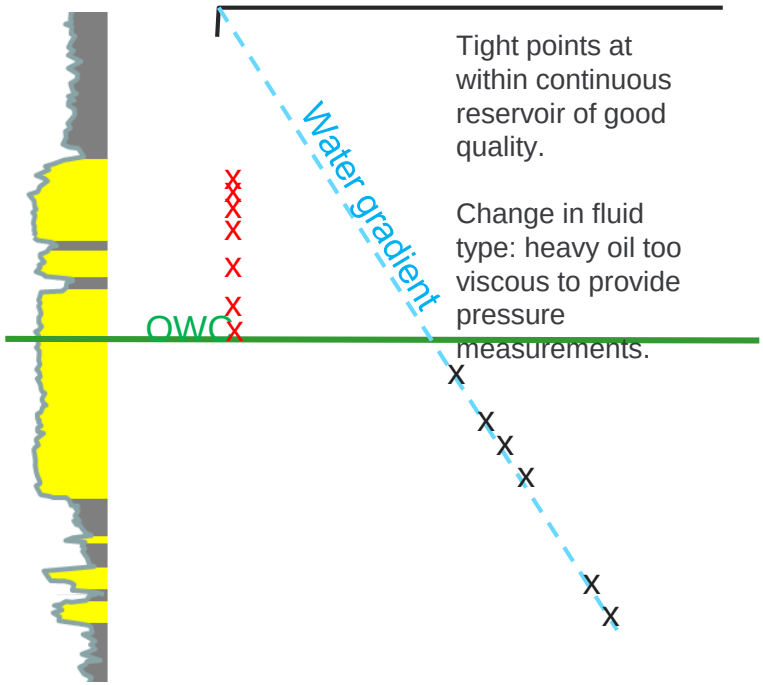
- Examples that lead to this realisation
- If we accept the fluid matters: is there any relationship between phase and ‘reservoir quality’ for developed fields
- Some thoughts on averaging
  - Impact on average of different approaches.
- A reminder on heterogeneity.
- Conclusions

This talk is about raising questions as much as providing answers. As such it is meant to be mildly provocative.

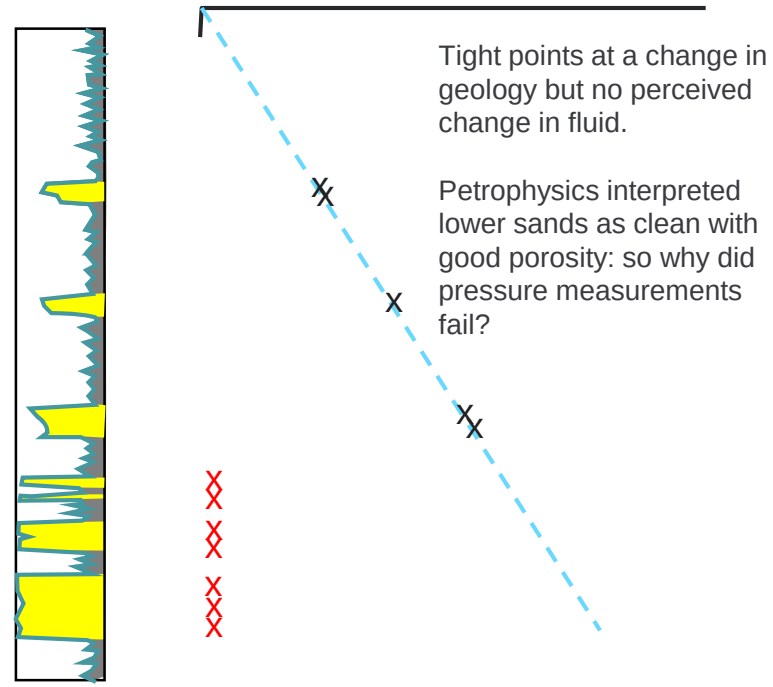
- Should point out that these views are coming from a geologist.

Examples of where mobility was a warning.

- RFT/ MDT mobility data is a direct measure of the rock fluid interaction: clue is in the units **mD/cP**



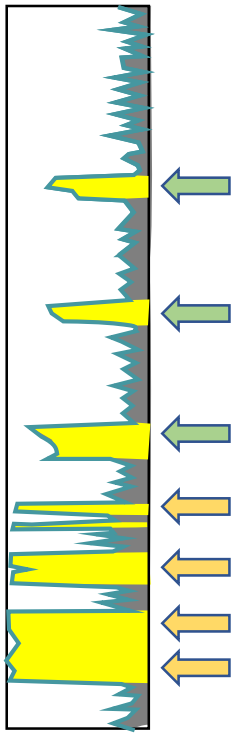
Eocene of the CNS



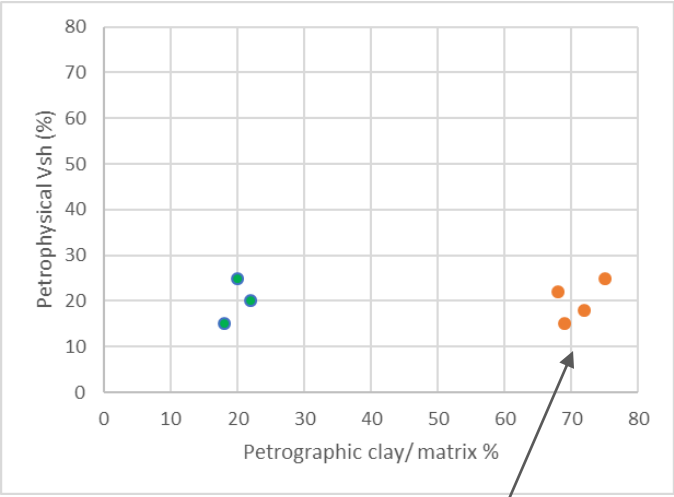
Cretaceous offshore West Africa

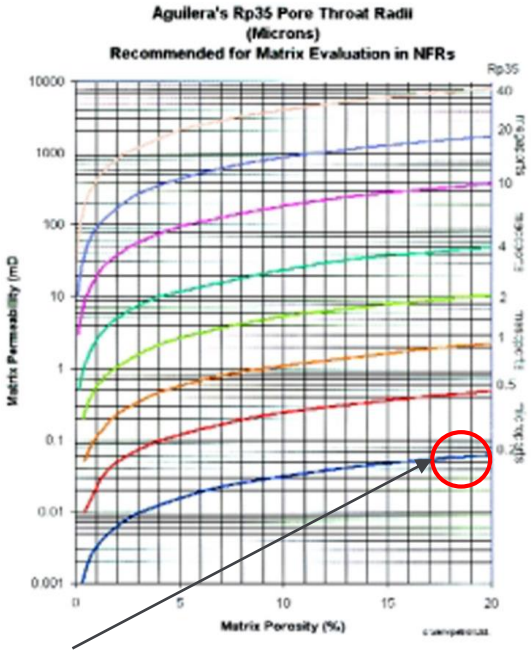
x ‘Tight’ pressure point

A good reservoir that wasn't.



Sandstones described as wackes





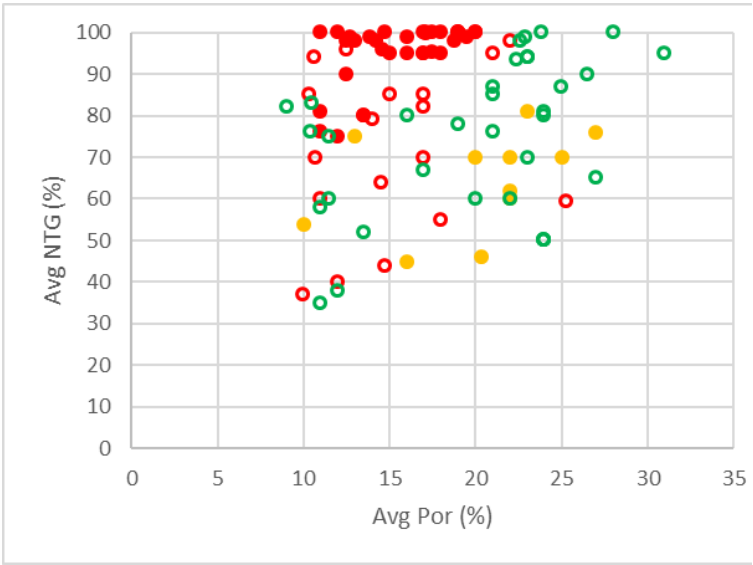
Estimated likely position 'reservoir on Winland R35 curves.

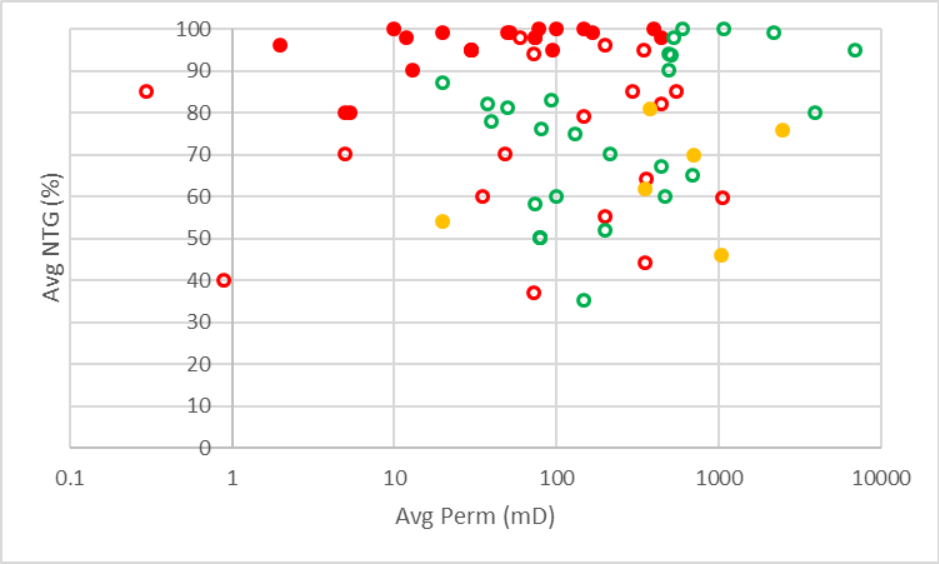
XRD and SEM showed the matrix to be dominated by sub-optical micro-crystalline quartz. Not a reservoir despite good porosities.
Subsequent capillary work showed the interval to contain some of the best seals.

So... porosity may not be the best guide to net reservoir

Is there any relationship between fluid type and Net sand ?

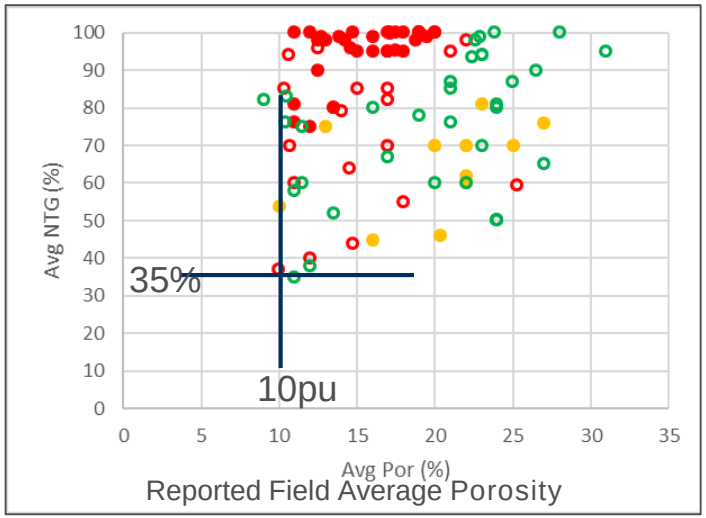
- Took the data from compilations and used this to compare reported average reservoir parameters based on fluid type.





Leman Gas
Other Gas
Brent Oil
Other Oil

Selection Bias



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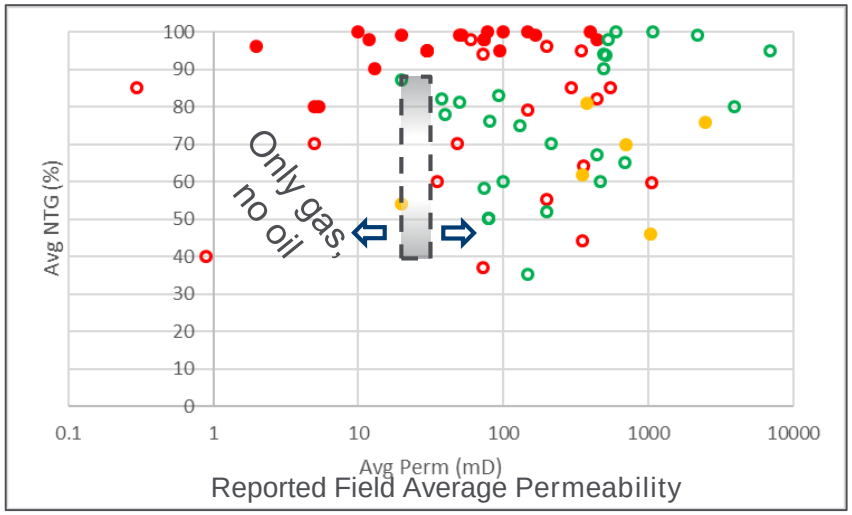
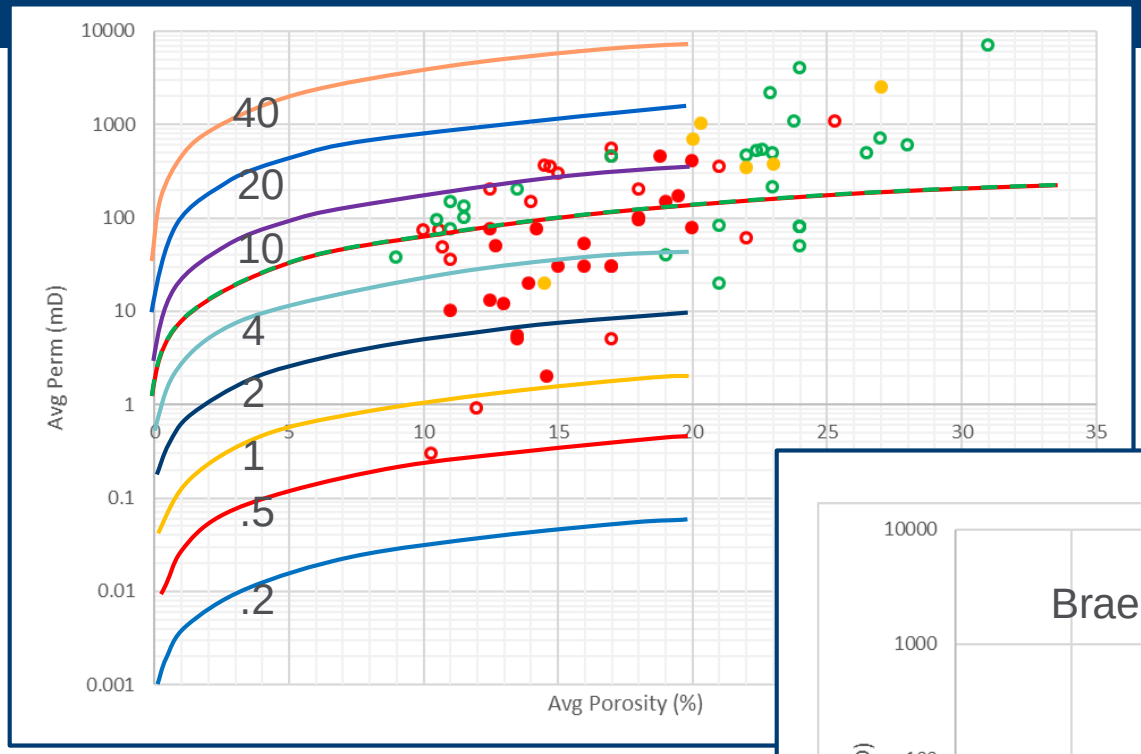
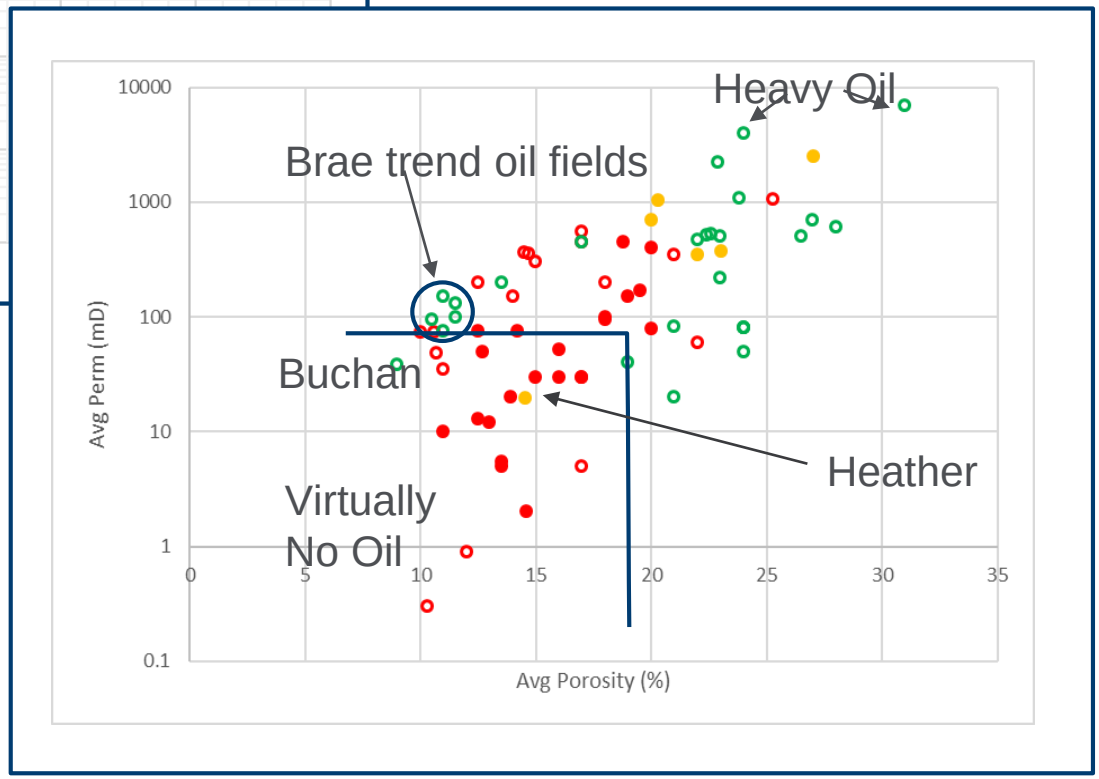


- Selection/ Survivorship Bias: Only developed fields, the ones that work.

- Leman reservoirs ~100% NTG. But with oil… many might have disappeared from the plot
- 'Economic constraints': 10% por and 35% NTG identical for oil & gas fields. (=> percolation theory? or biased decisions?)
- Greatest distinction of oil and gas fields on permeability. Gas extends into lower perm territory than oil => indicating low perm can be considered Net.
- However, apart from high NTG of Leman no obvious relationship…Why?

Combining Porosity and Permeability

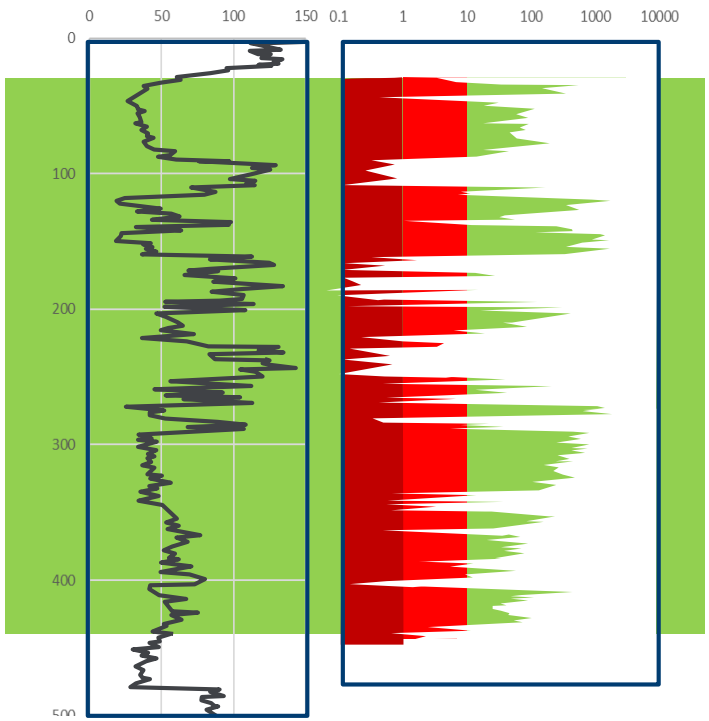




Winland R35 lines. Values pore throat size relating to 35% HC saturation
Implication is that porosity alone is a poor discriminator of Net

Compare a typical Gas and Oil reservoirs

Brent Reservoir: classic oil reservoir



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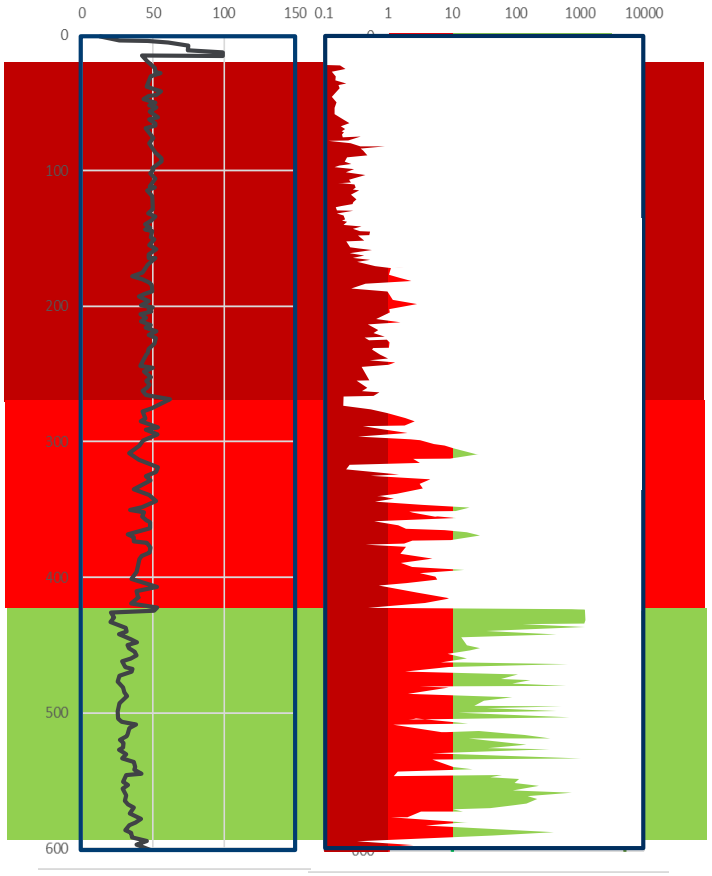
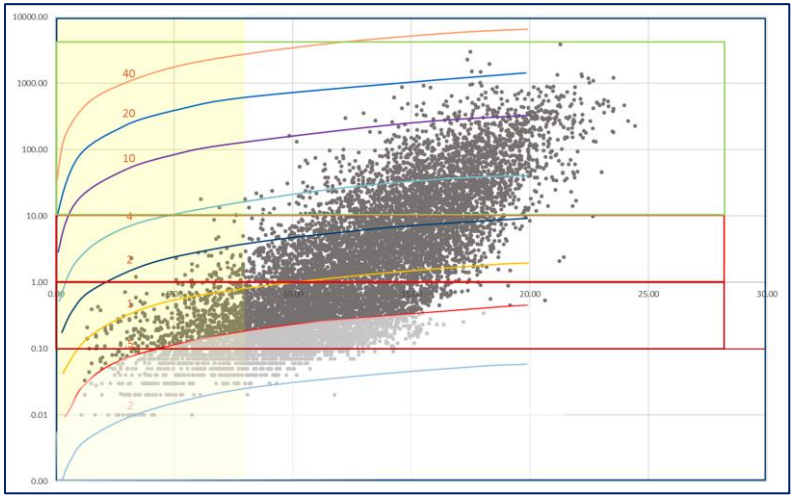
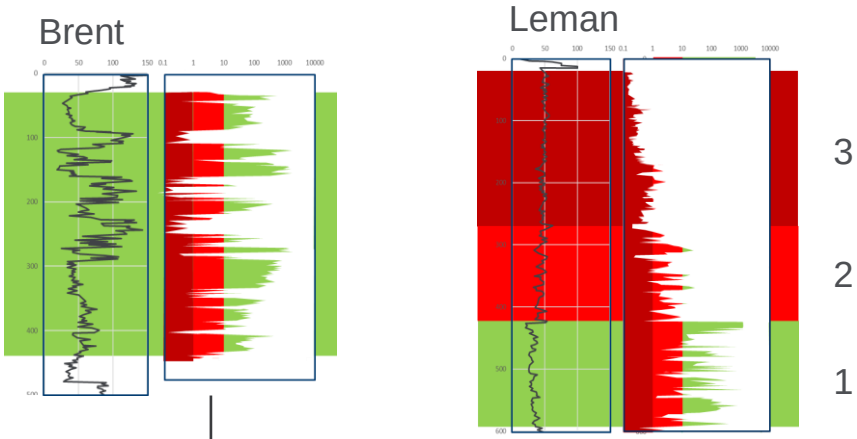
Poorer Leman Reservoir: classic gas reservo

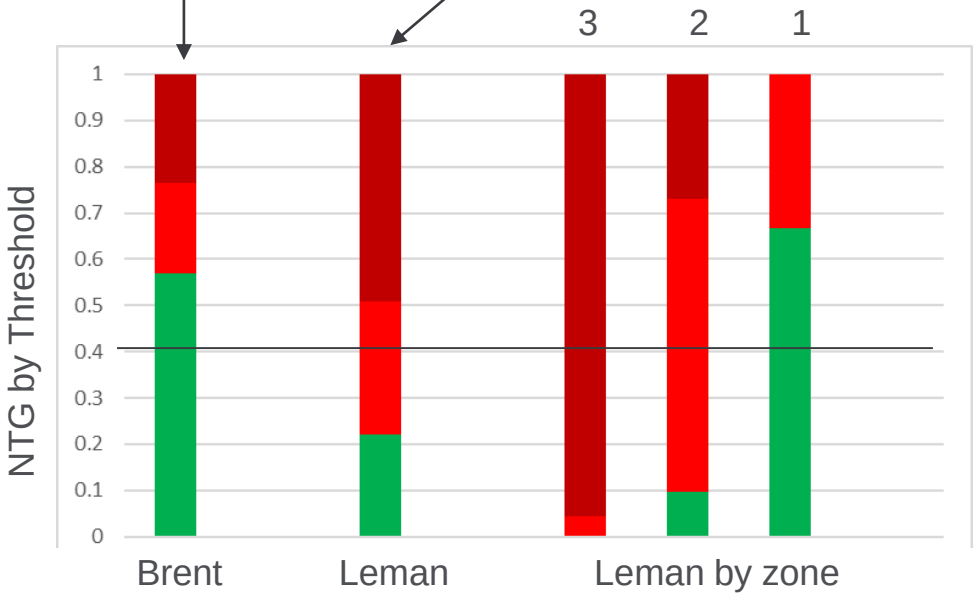


Could argue that NTG is relatively constant: it is the Gross that changes, so is it really about heterogeneity

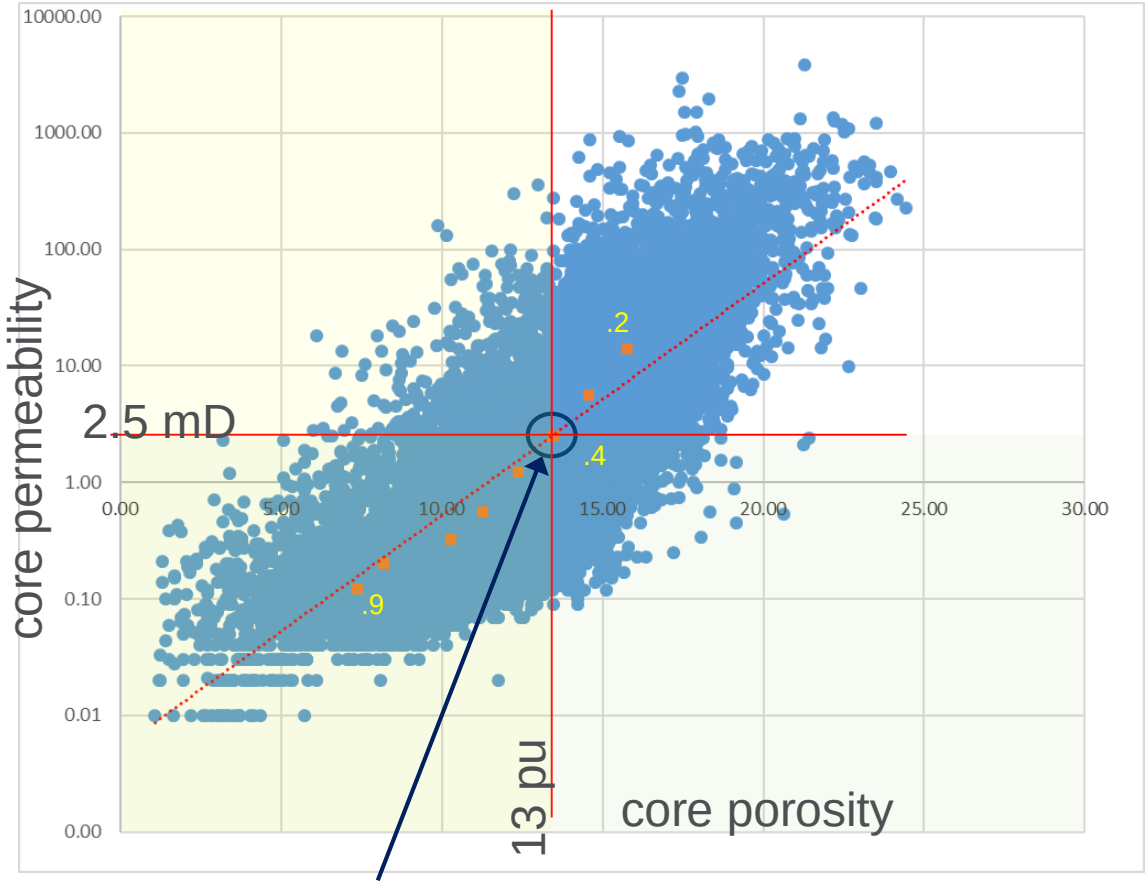
So what if we ‘bin’ the reservoirs we were looking at.







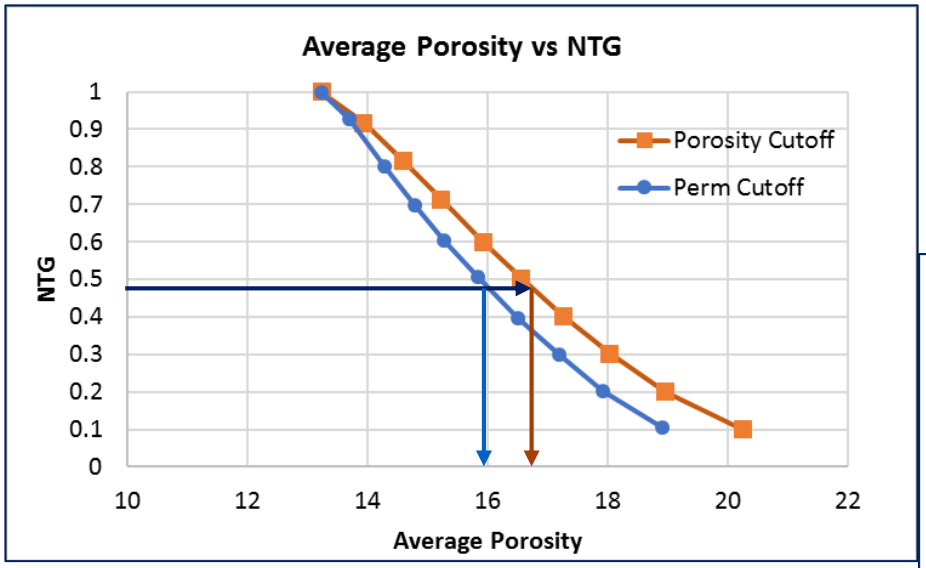
Back to the questions of averages and cut-off



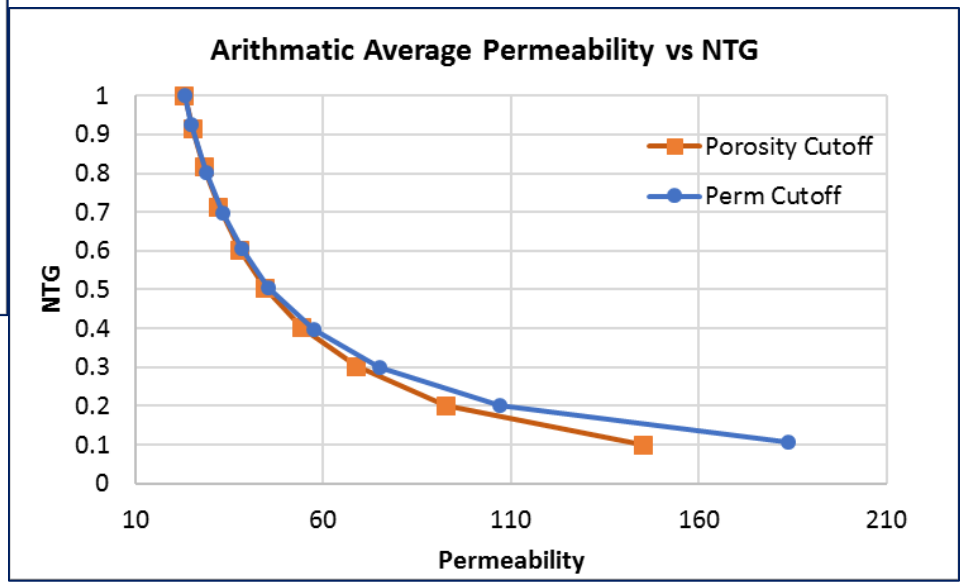
That is a cloud of core plug measurements from an SNS (Leman Field)

Orange points: NTGpor = NTGperm,
Example for NTG=0.4, Por cutoff = 13 ~ Perm cutoff = 2.5 mD

The impact of the choice of cut-off (Porosity vs Permeability)



Big difference in porosity average



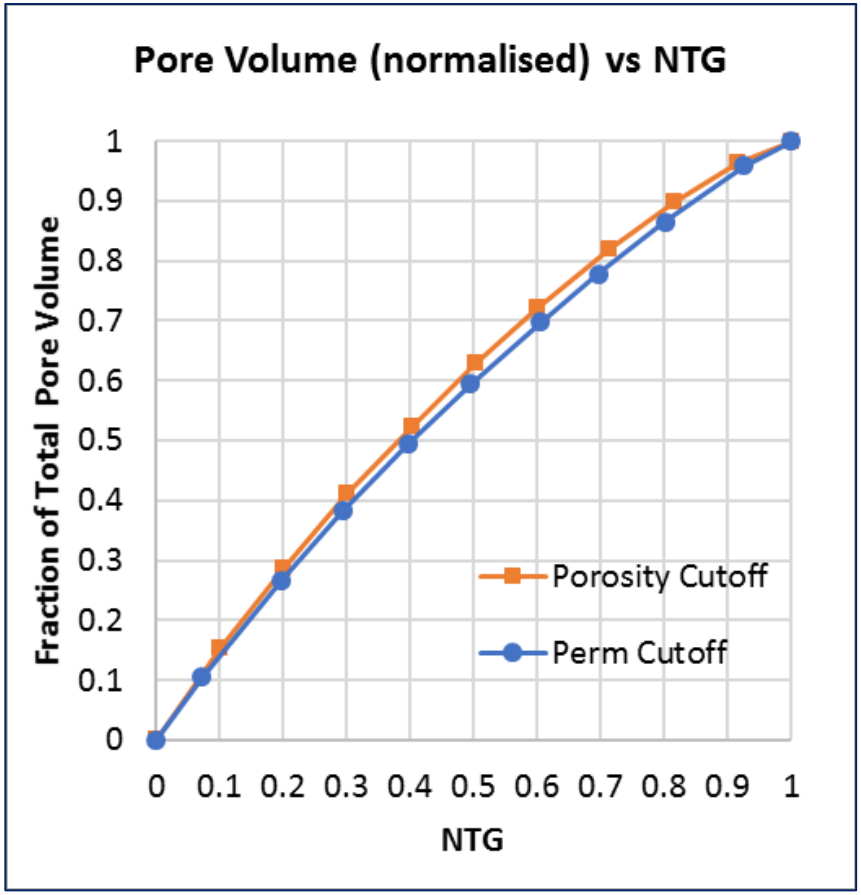
Little difference in perm average (not expected by authors! Probably because Arithmetic average dominated by highest perm values)

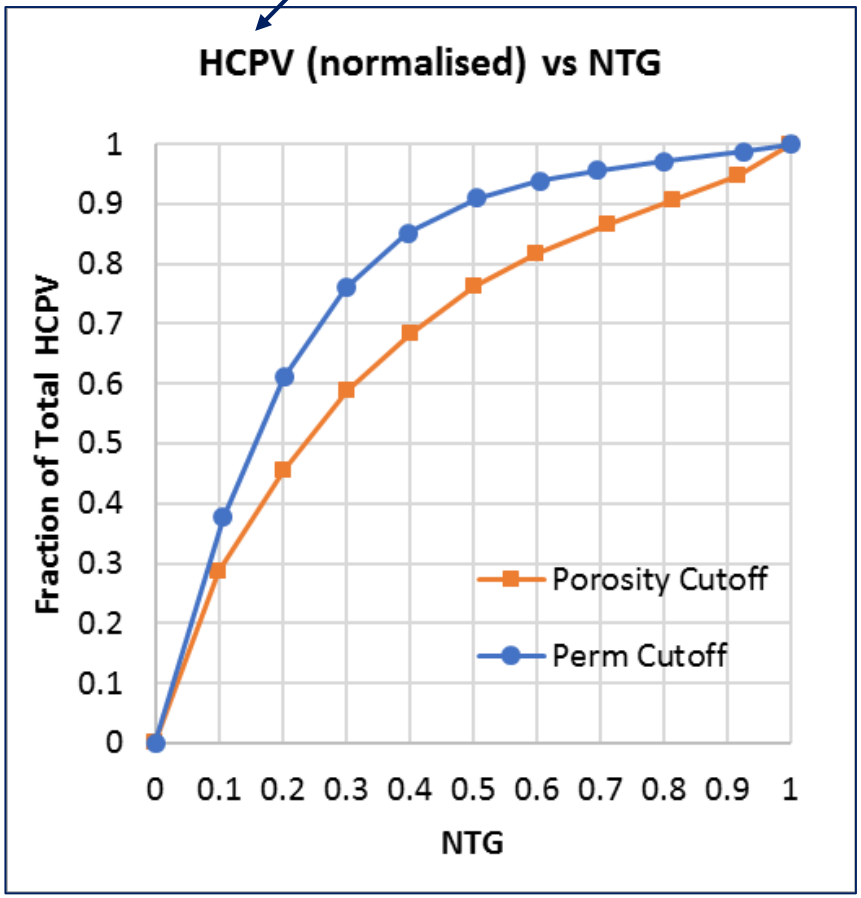
Pore Volume and Hydrocarbon Pore Volume

Timur : 'a' = 8581 'b' = 4.4 'c' = 2

$$K = a \cdot \frac{Phi^{b}}{Swi^{c}}$$

Pseudo HCPV computed from Swirr estimates



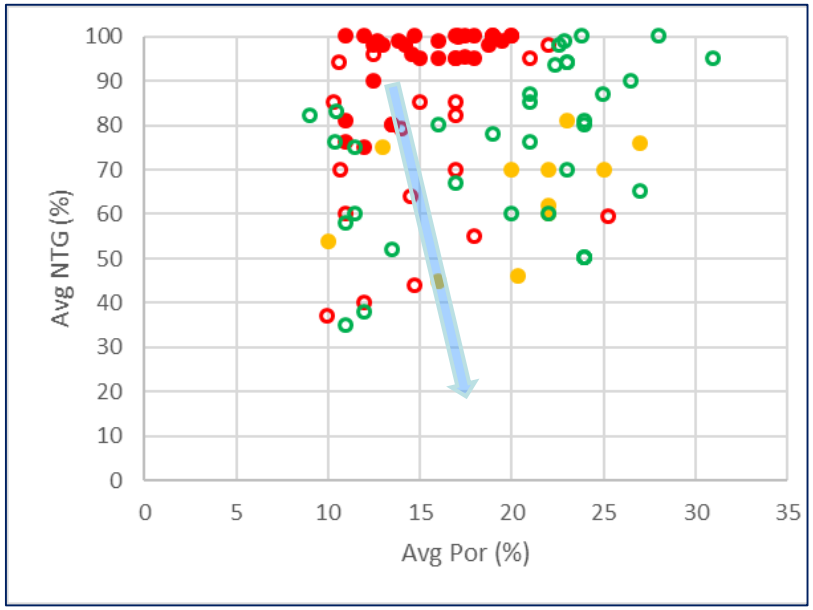


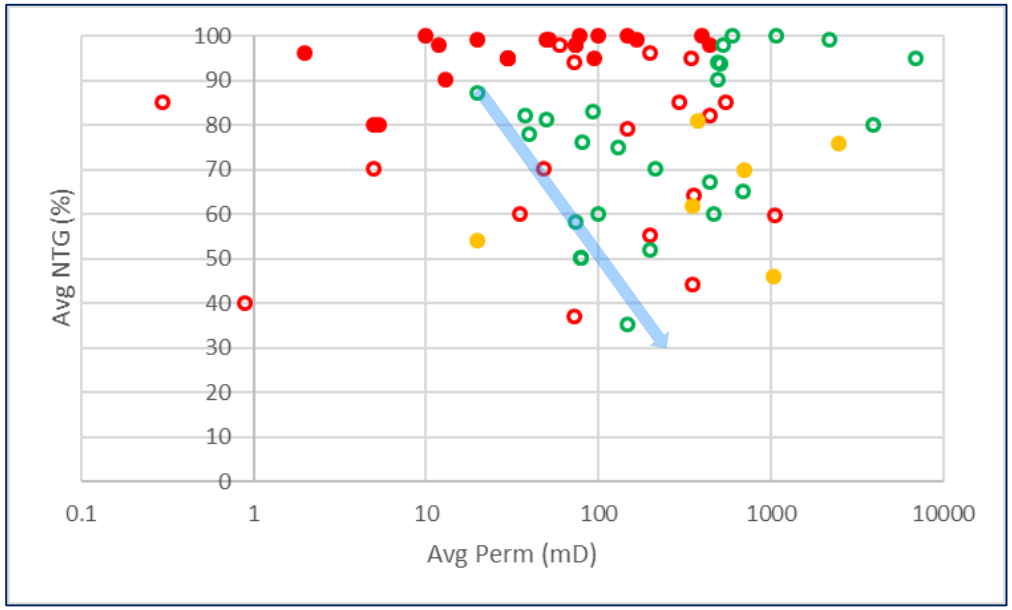
PV different, but not much

HCPV very different !!

Stricter cutoffs reduce NTG but increase averages

- Lower NTG -> weak trend towards better porosity average
- Lower NTG -> strong trend towards better permeability average

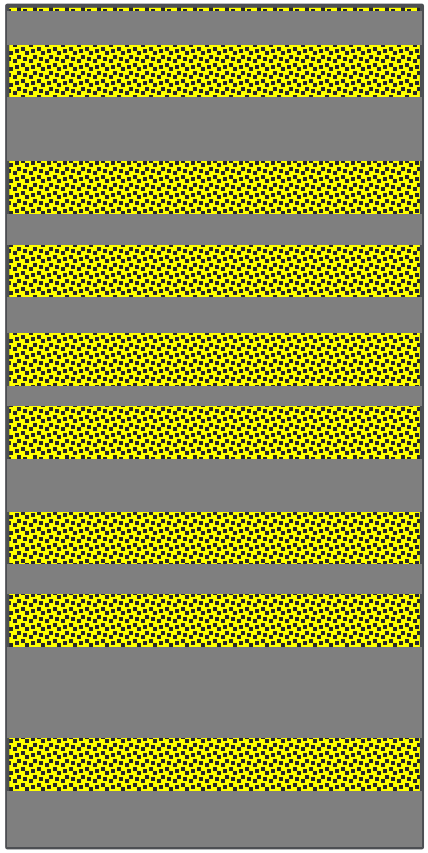




But Brent is less ‘gradational’: not good v very poor

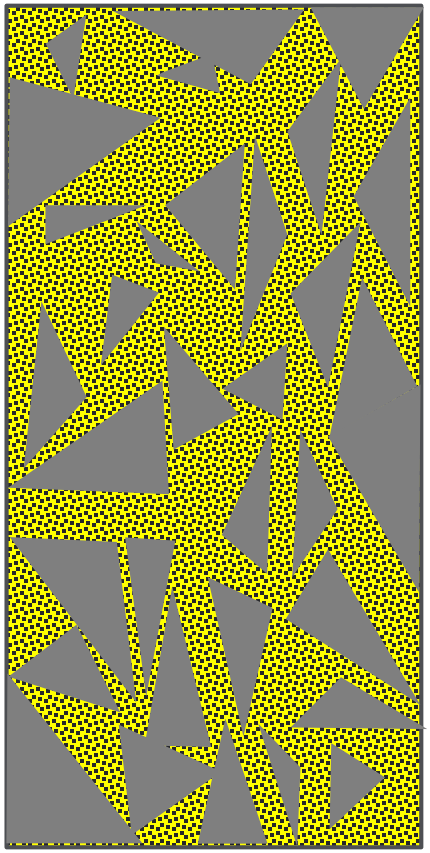
Heterogeneity and averaging net

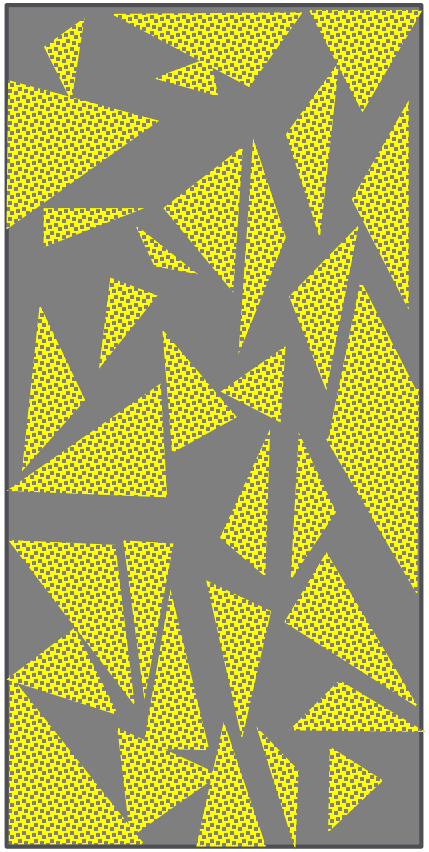
Conventional bedded deposition



Chaotic

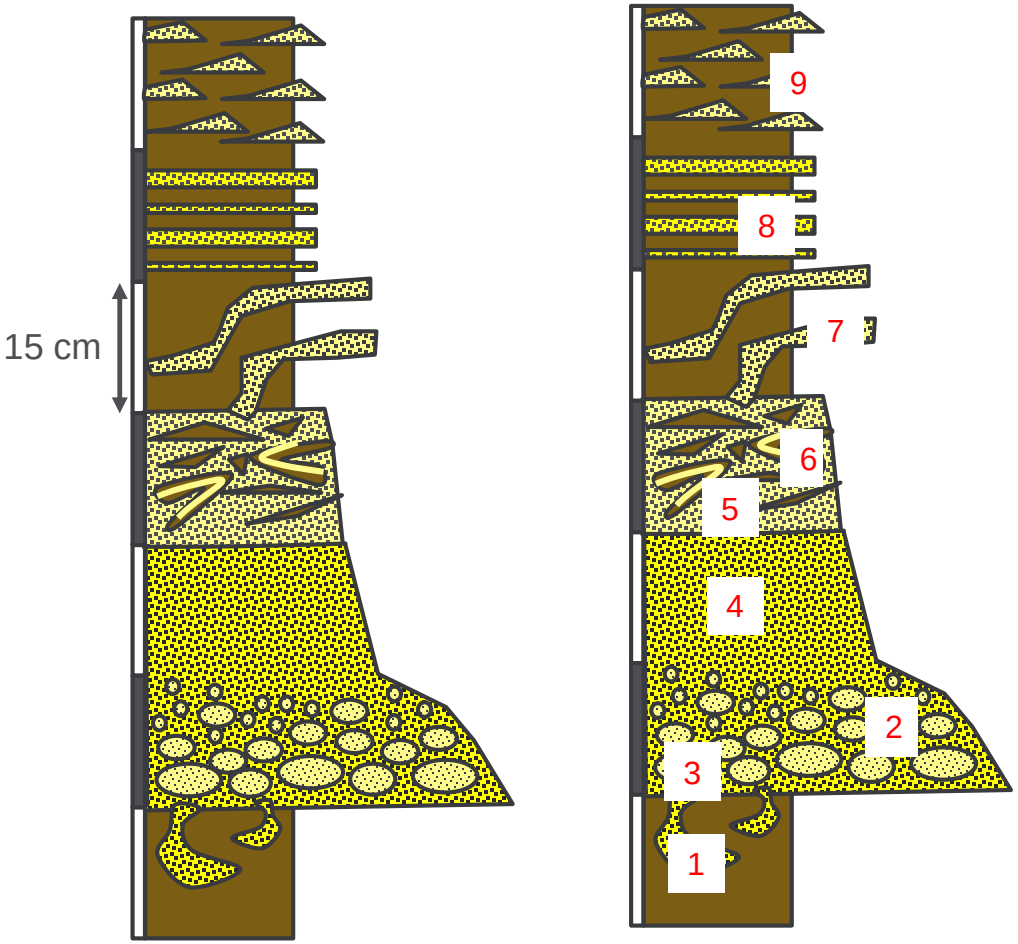
Injectites & Breccias/conglomerates





All have Petrophysical Vshale, NTG=50% but very different reservoir potenti

What types of sand can we expect to find in let's say 2m of gross?

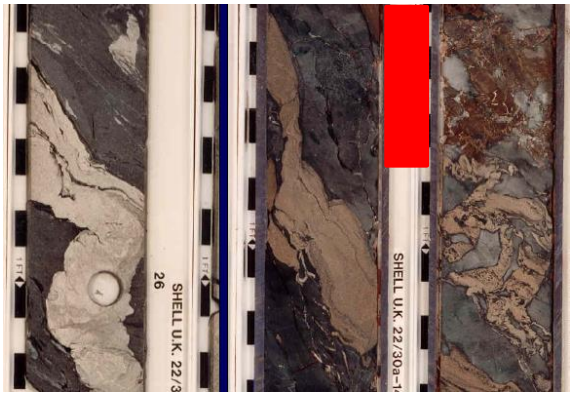


- Pseudo Real Example

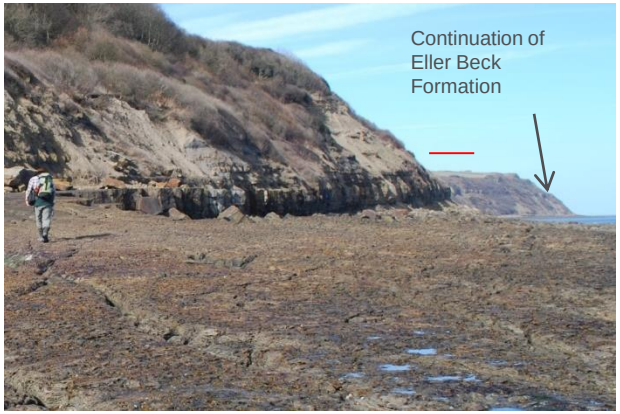
1. Loaded sand into mud
2. Coarse grained sandstone between clasts
3. Porosity in sandstone clasts
4. Medium grained sandstone
5. Fine grained sandstone
6. Sand beds in deformed clasts
7. Injected sand
8. Thin bedded medium to fine sand
9. Discontinuous rippled sand

- With conventional logs, this succession would be sampled with 7 log measurements

Scale really matters

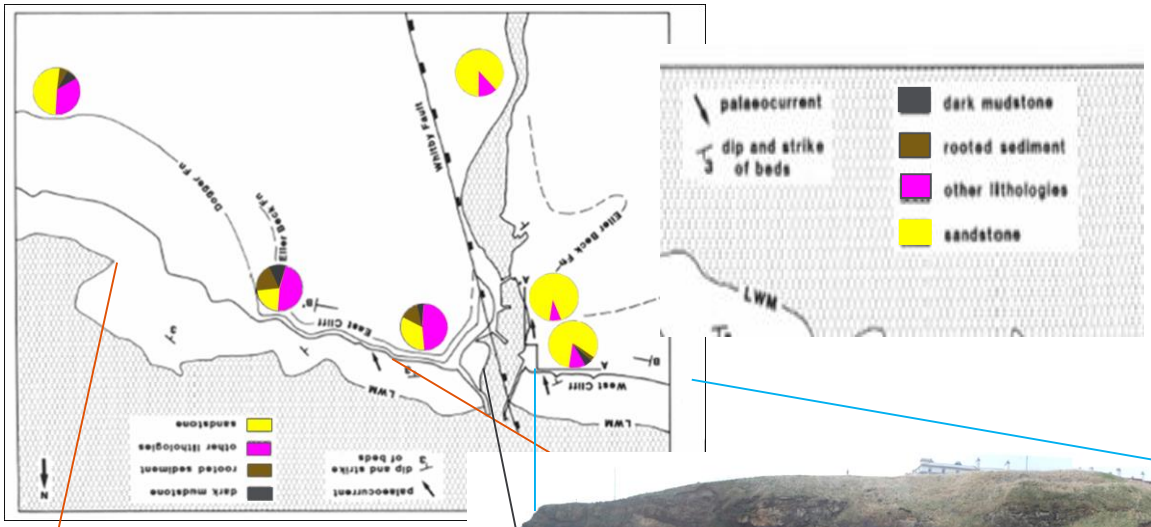


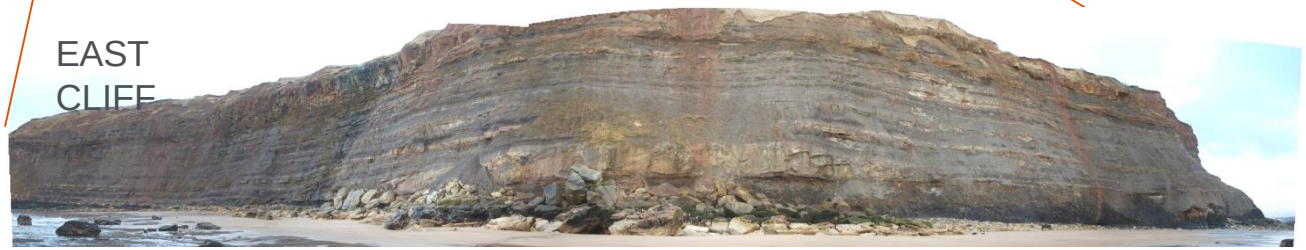
What is net in all these cases?



Red bars are approximate conventional log interval of 15cm

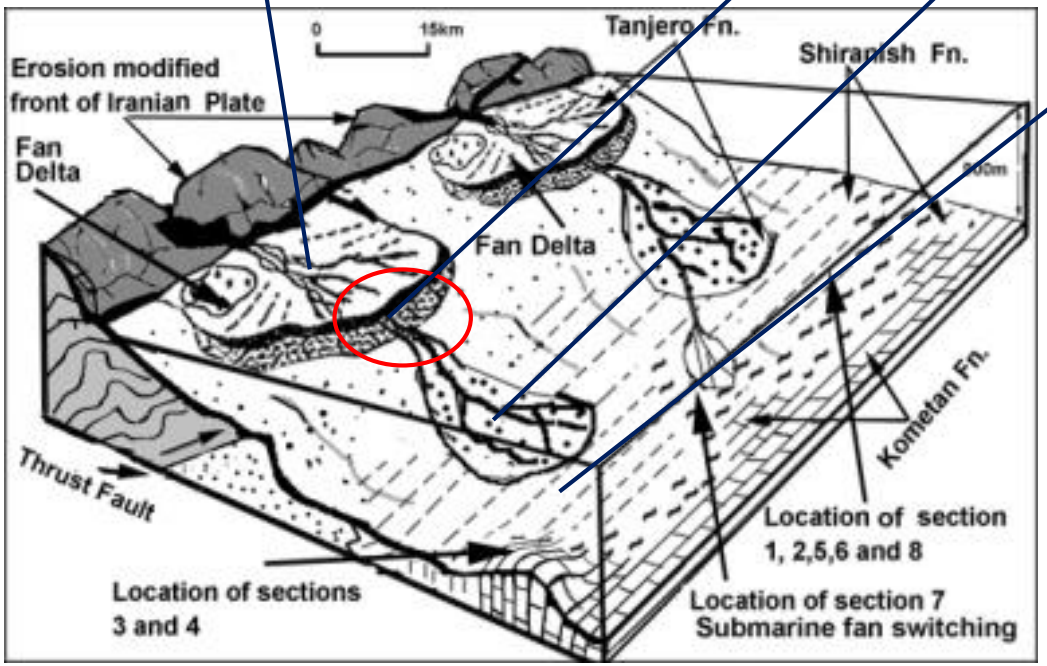
Heterogeneity varies laterally also: classic example from Whitby



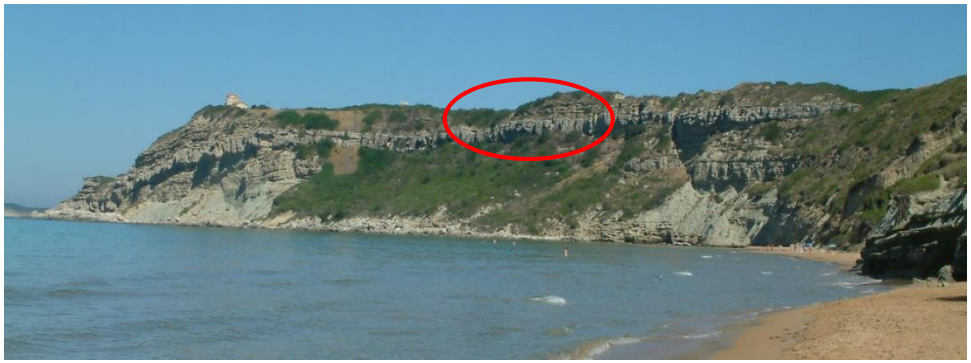


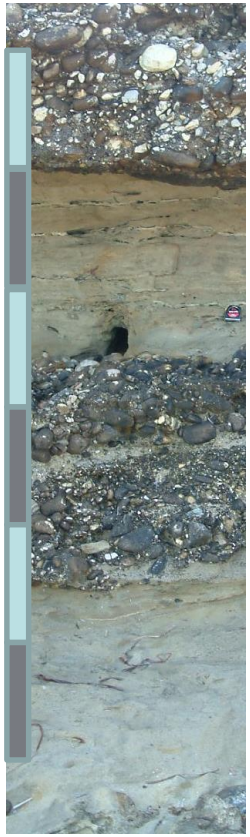
Arillas: NW Corfu. A complex succession

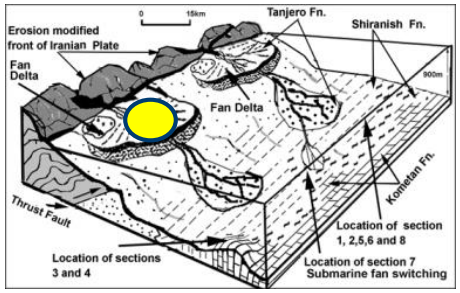
A potential depositional model



Conglomerates of the prominent headland.

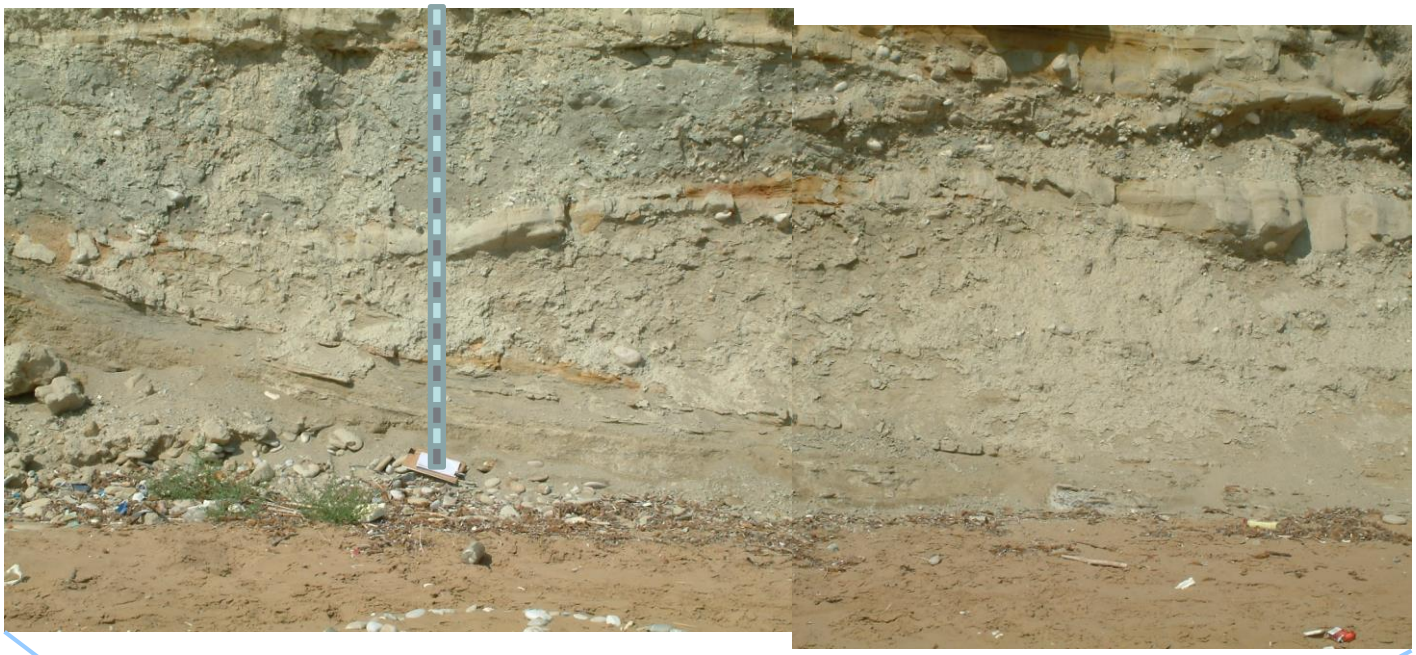




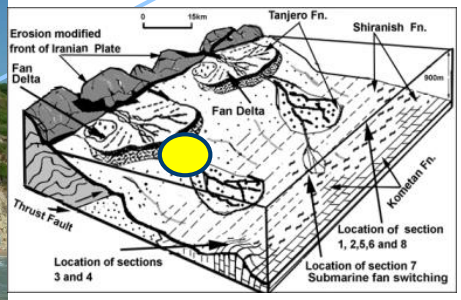


Stepping back again:

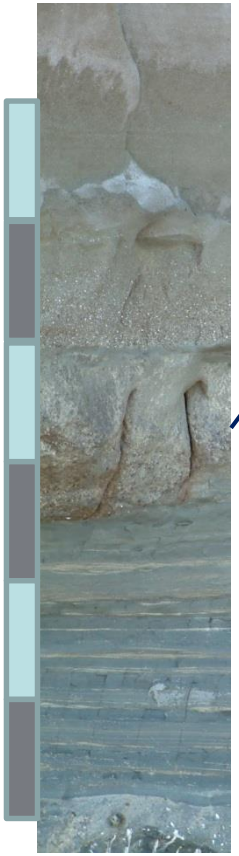
15cm increments

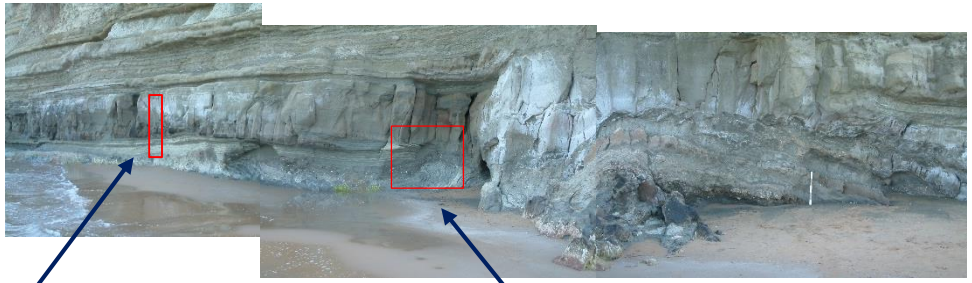


Base of conglomerate

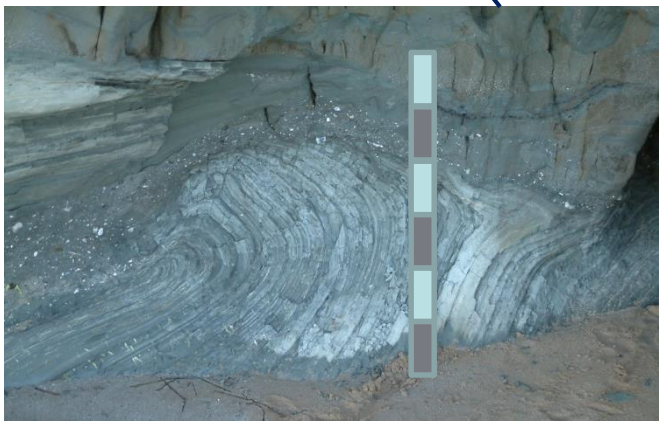


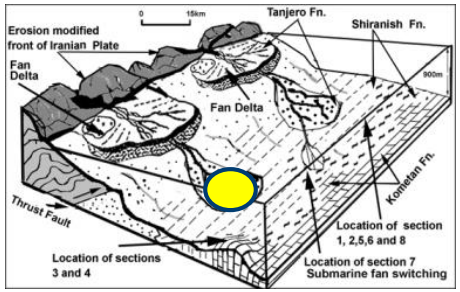
Stepping back for context





Gravity flows ponding on top surface of a debris flow.



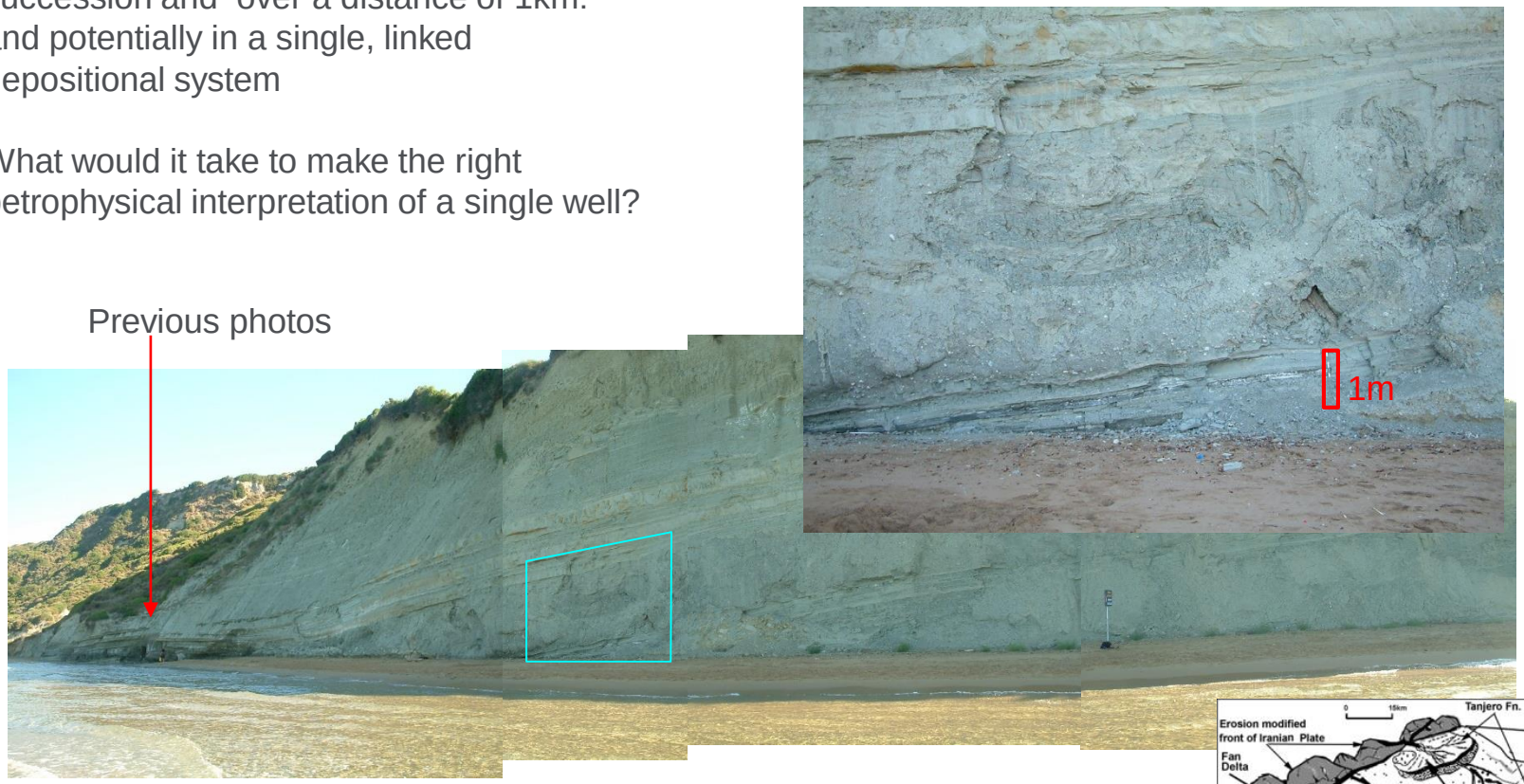


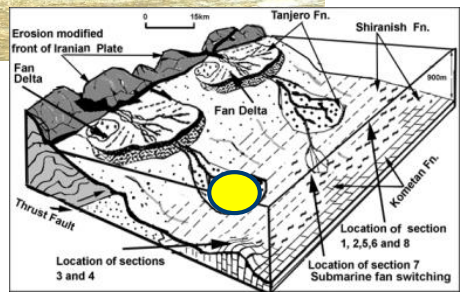
Debris flow beneath sandstones

So all this happening within circa 150m of succession and over a distance of 1km: and potentially in a single, linked depositional system

What would it take to make the right petrophysical interpretation of a single well?

Previous photos





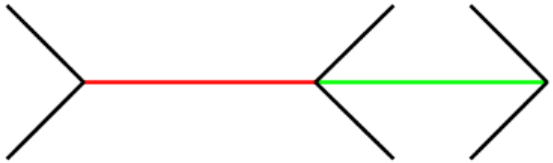
Averages are one thing, but what is/should be NET...

- What constitutes NET? Is it Net Pay?
  - Successful pressure points from MDT point?
  - Flow into a wellbore?
  - or anything that contributes to the recoverable hydrocarbons?
    - Any HC experiencing pressure decrease at some point in life of field?
    - => temperature, IOR, EOR or stimulation... in that case should PPs be speaking to REs before deciding on cutoffs????
- Plea for characterisation of all reservoirs in terms of proportions of rock/habitats of hydrocarbons
  - Reservoir should be both 1) petrophysically, and 2) geologically defined
  - Define hydrocarbon per habitat, and how a particularly HC phase would produce.
  - Probably not practical, but no excuse.
    - In big accumulations -> little difference in the long run.
    - Marginal and small discoveries -> potentially hugely important for correct evaluation of economic potential.
- If you change the net the Recovery Factor will also change: (is your analogue reliable)

Are we making wrong assumptions/

- Reservoirs are Rocks (not logs)
  - Different rocks -> different cutoff techniques (Permeability; Winland R35? But is porosity ever up to the task)
  - Need core to calibrate (how many wrong assumptions are lurking out there)

  - Context can be all
    - Poor quality in otherwise good reservoir either vertically or in a local area may be ignored whilst elsewhere it would be regarded as excellent.
    - Change the phase and it may be excellent.
    - What are we missing?



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