Reservoir Rock Properties

From here on, sedimentology and petrophysics are important for a good understanding of the course material.

I realize that not everybody has a solid background in these fields, so please ask questions when the pace is too high, but keep them to the essentials.

In the first part we will mainly focus on sandstones, and in the second part on carbonates.

Principal Properties

The two principal properties required from a rock to be a viable reservoir rock are porosity and permeability.

Porosity is the capability of a rock to hold fluids in pores. It is expressed as a volume percent of the total rock and can range from very low porosities (a few %) to very high (over 40% in some chalks). Pores can be of many types, particularly in carbonate rocks.

Permeability is the capability of a rock to transmit a fluid. It depends crucially on the connections between the pores. Darcy's law establishes the basic relationship between pressure, flow rate and permeability.

Permeability: Darcy's Law

$$Q = k(P_1 - P_2)A/L\mu$$

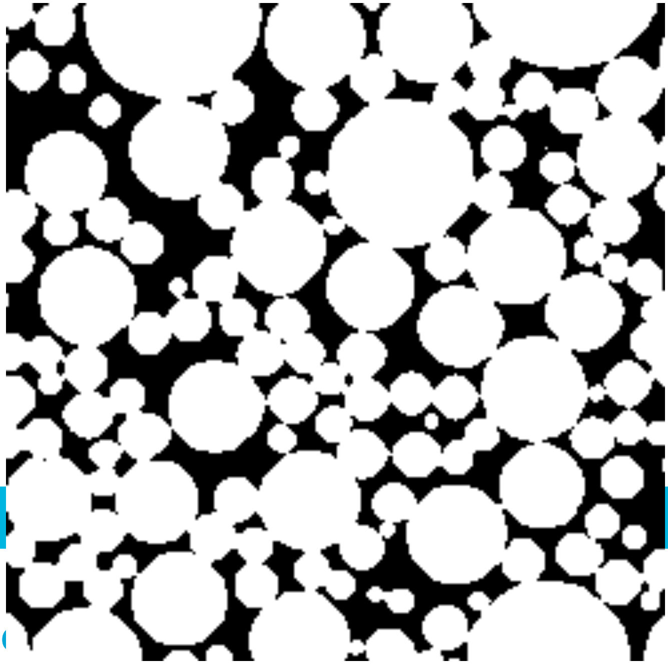
where is Q the flow rate, k the permeability, P_1-P_2 the pressure drop over distance L, A the area cross-section of the sample, and μ the viscosity of the fluid. The permeability unit is Darcy and is defined as the ability for a fluid of 1 centipoise viscosity to flow at a velocity of 1 cm/s for a pressure drop of 1 atm/cm. Permeabilities in an oil reservoir are rated as follows:

Poor	1-10 mD
Fair	10-100 mD
Good	100-1000 mD
Excellent	>1000 mD

For a gas reservoir, the permeabilities are ten times lower for a given rating.

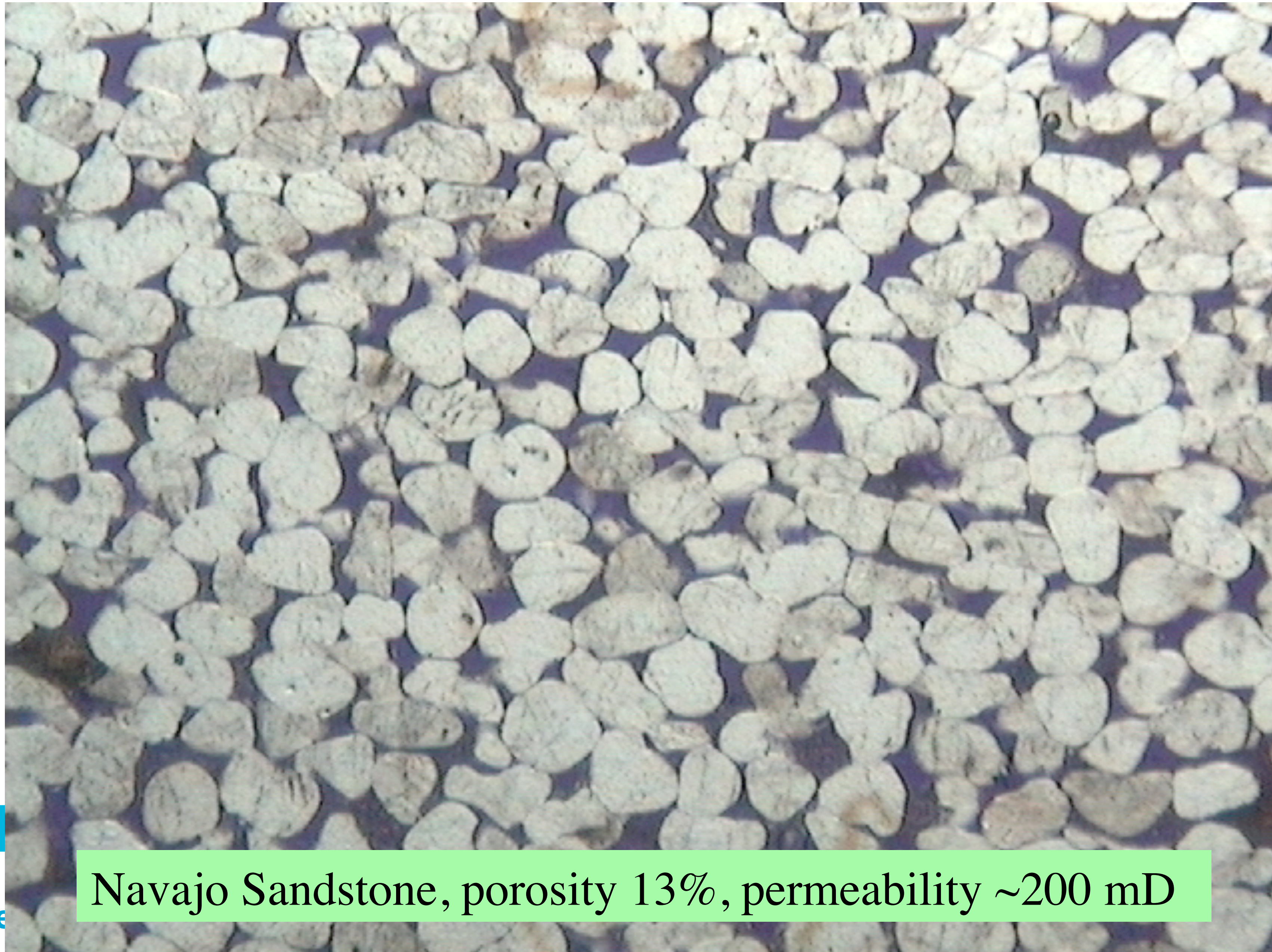
Controls on Permeability

Permeability has in fact the dimension of an area. One can visualize this as that part of the pore system in a rock that is available for fluid flow. This is in general the narrowest restriction, i.e. the transitions between pores, also called the pore throats. We therefore have to look at the pore system of rocks, and how it develops with time.



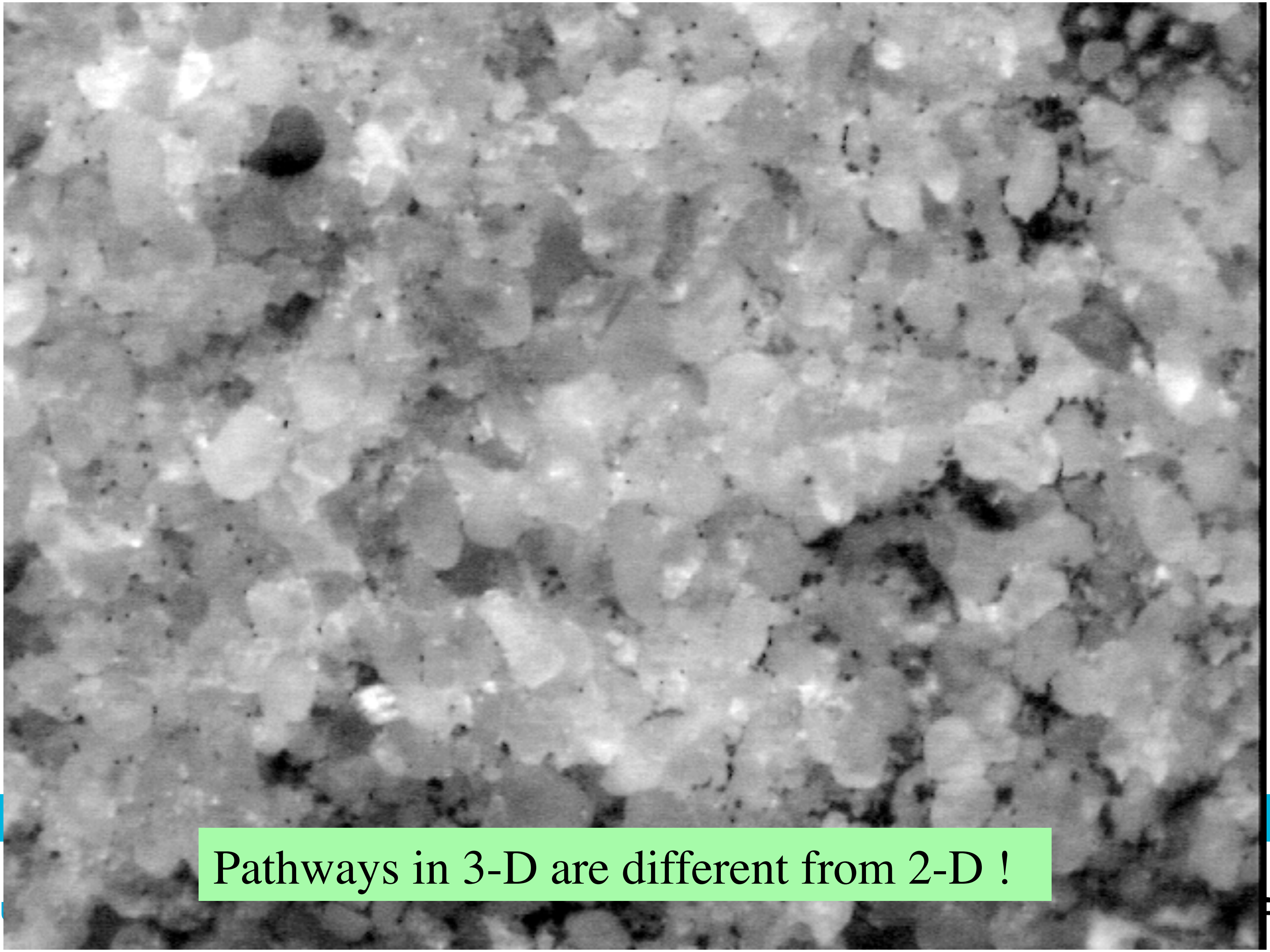
A slice through a granular system such as a sandstone might look like this synthetic image. The grains are white, and the pores black. Try to find a way from the left to the right in the pore space. Is this rock permeable? And what is its porosity?

Reservoir Sandstone in 2-D



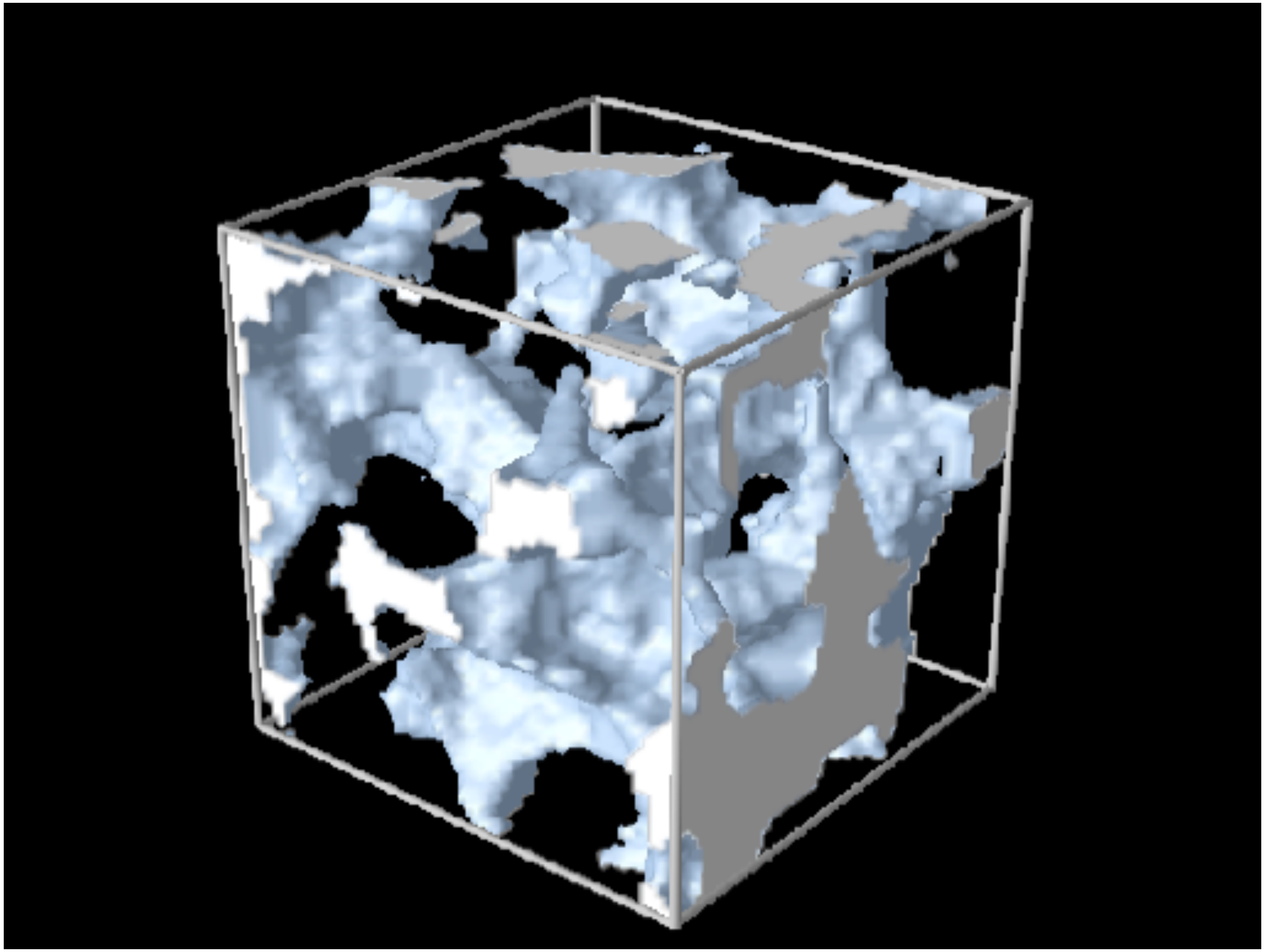
Navajo Sandstone, porosity 13%, permeability ~200 mD

Real Rocks Are Three-Dimensional



Pore Network of a Sandstone in 3-D

Courtesy Schlumberger-Doll Research/Brookhaven National Laboratory



Synchrotron tomography of sandstone.
Volume is one cubic millimeter and resolution 1 micrometer

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Major Factors Affecting k

In clastic rocks, the three-dimensional pore network is a function of the grain properties (the texture).

Grain size is probably the most important factor affecting permeability. Small grains generally have smaller pores and smaller pore throats than larger ones; fine-grained sandstones are therefore usually lower in permeability than coarse-grained ones.

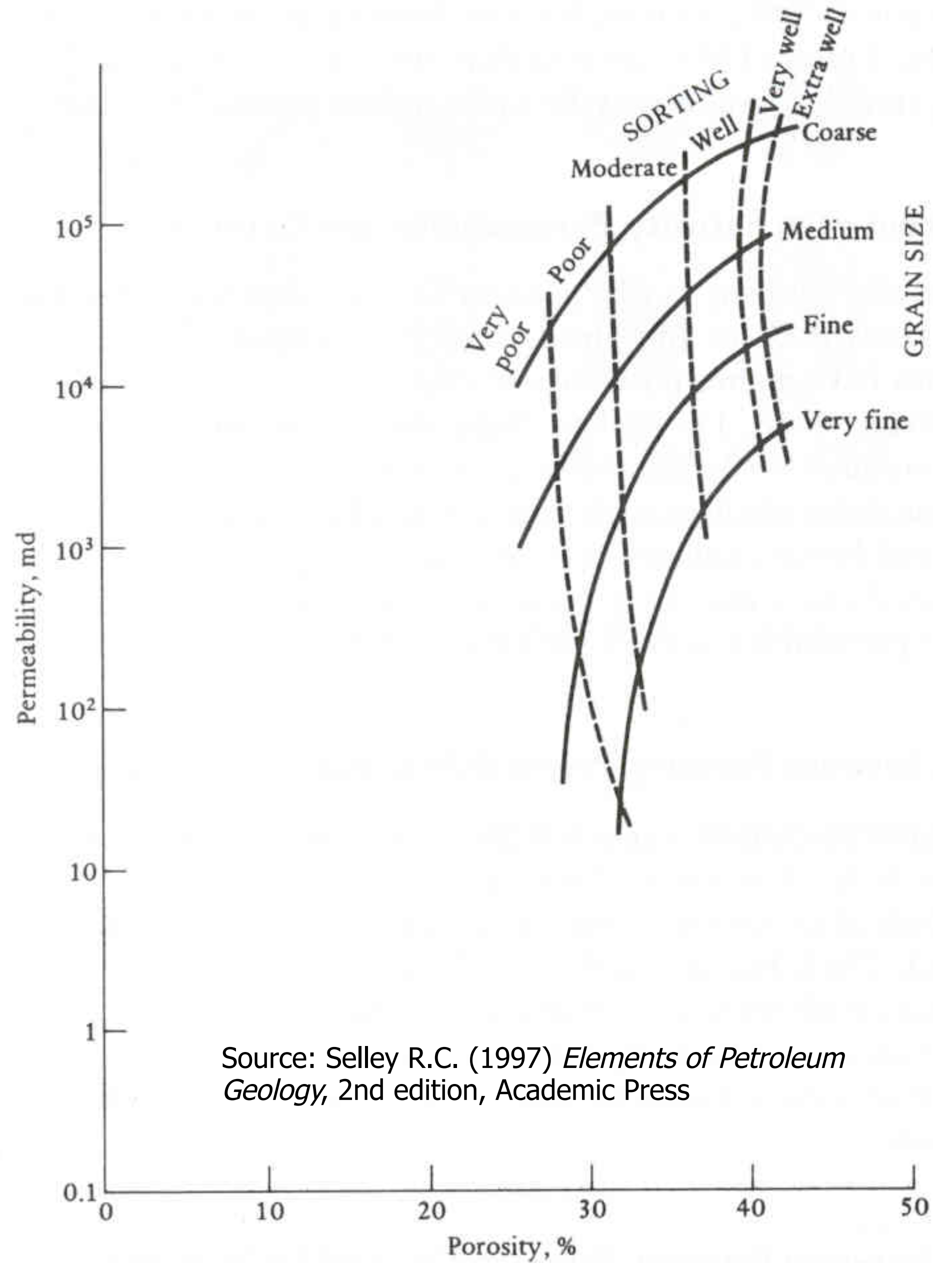
Grain sorting is another important factor controlling permeability. If the grain distribution is very wide, the smaller pores can more easily block the pore throats and therefore reduce permeability.

Grain roundness is of secondary importance.

Factors Affecting k/2

The general relationships shown on the right have been established experimentally and theoretically. They control to a large degree the porosity-permeability relationships in sandstones.

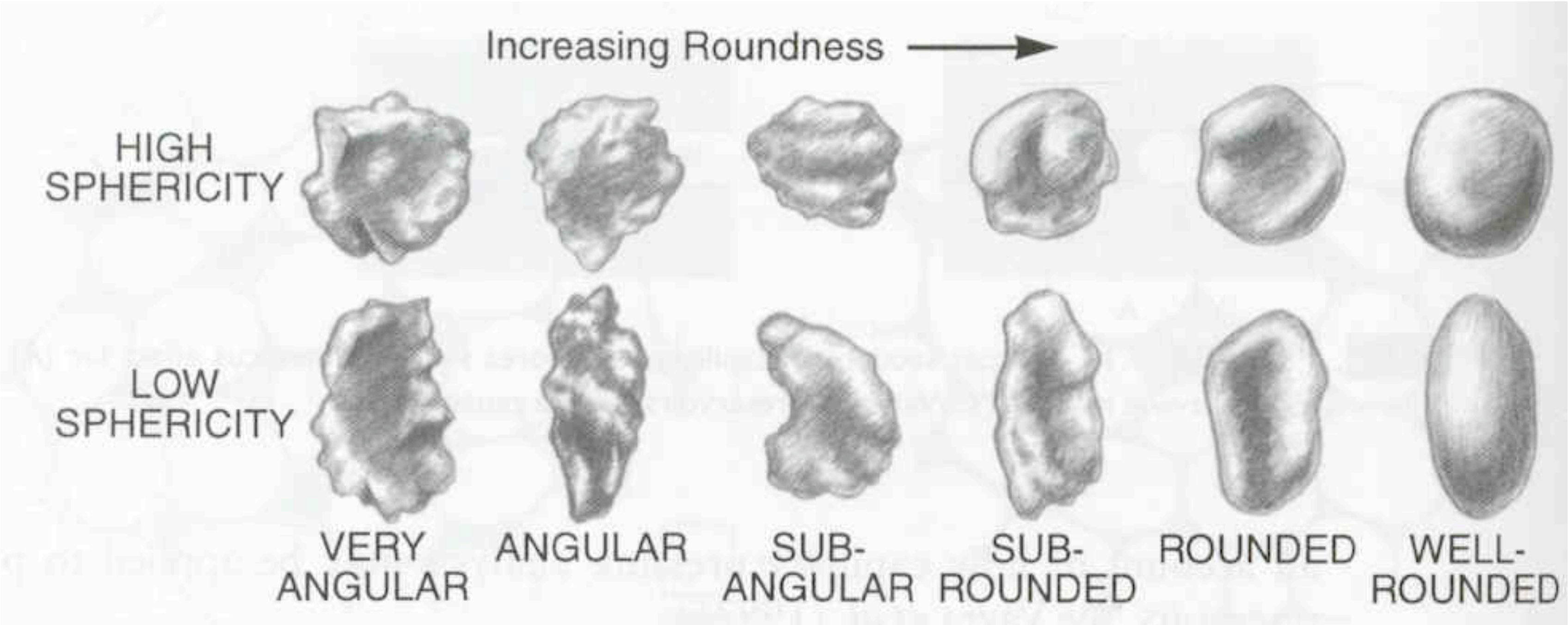
However, clay-rich sandstones, carbonates, and other reservoir rocks may behave very differently!



Source: Selley R.C. (1997) *Elements of Petroleum Geology*, 2nd edition, Academic Press

Texture Affecting Permeability

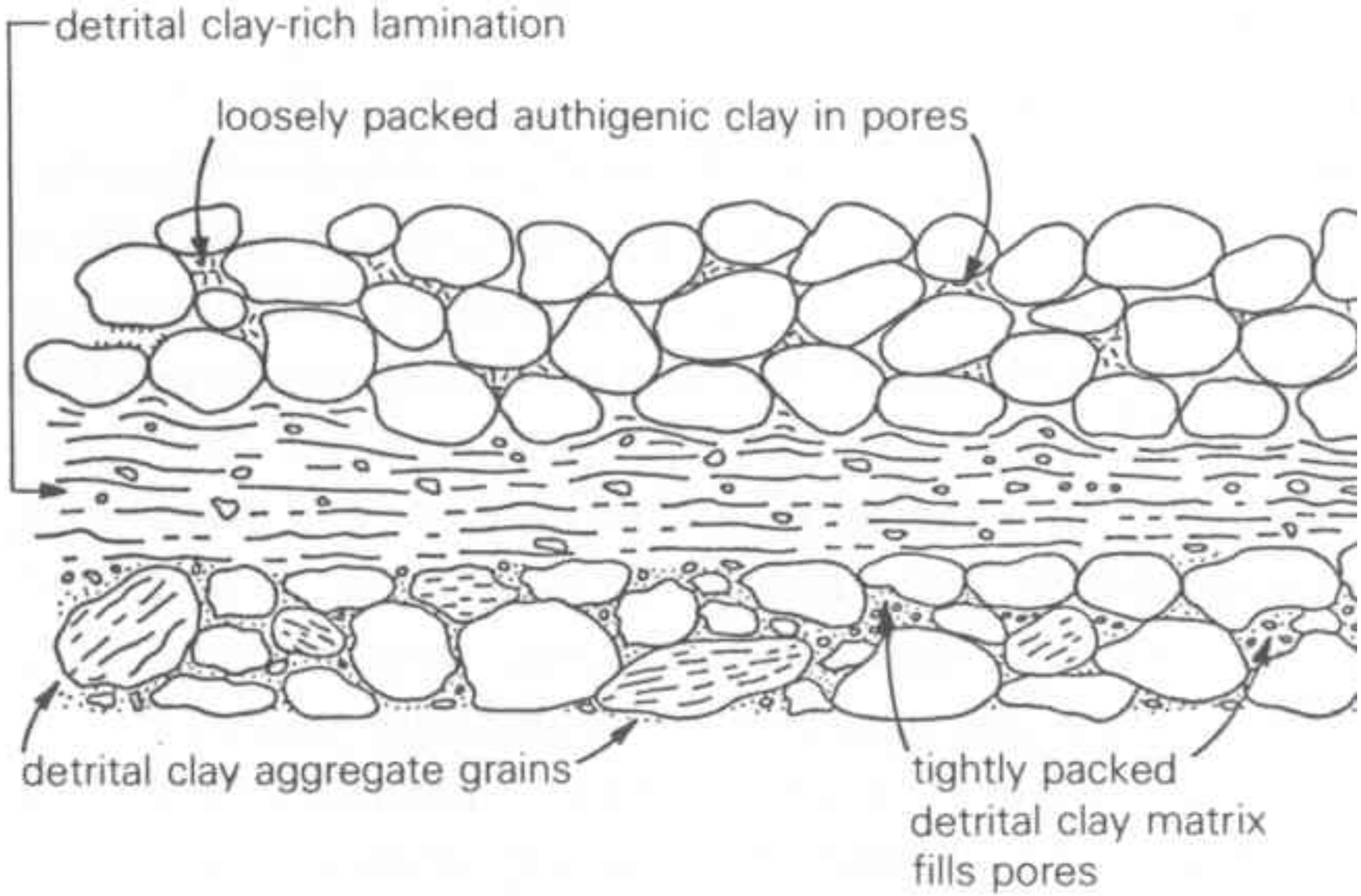
Source: Selley R.C. (1997) *Elements of Petroleum Geology*, 2nd edition, Academic Press



Increased roundness and sphericity lead to higher permeabilities. In what depositional settings do we find the different grains shown here?

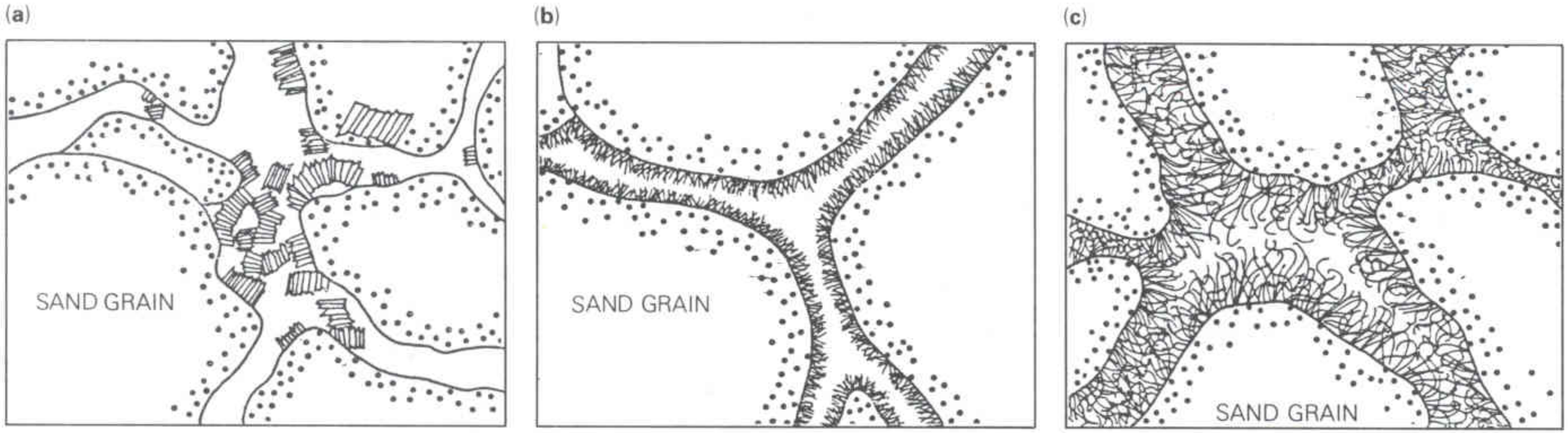
Texture Affecting Permeability ctd.

Source: North, F.K. (1985) *Petroleum Geology*, Allen & Unwin



Typical occurrences of clay minerals in sandstones

Texture Affecting Permeability ctd.



Source: North, F.K. (1985) *Petroleum Geology*, Allen & Unwin

The clay type can also have a great influence on permeability. Shown are kaolinite (a), chlorite (b), and fibrous illite (c).

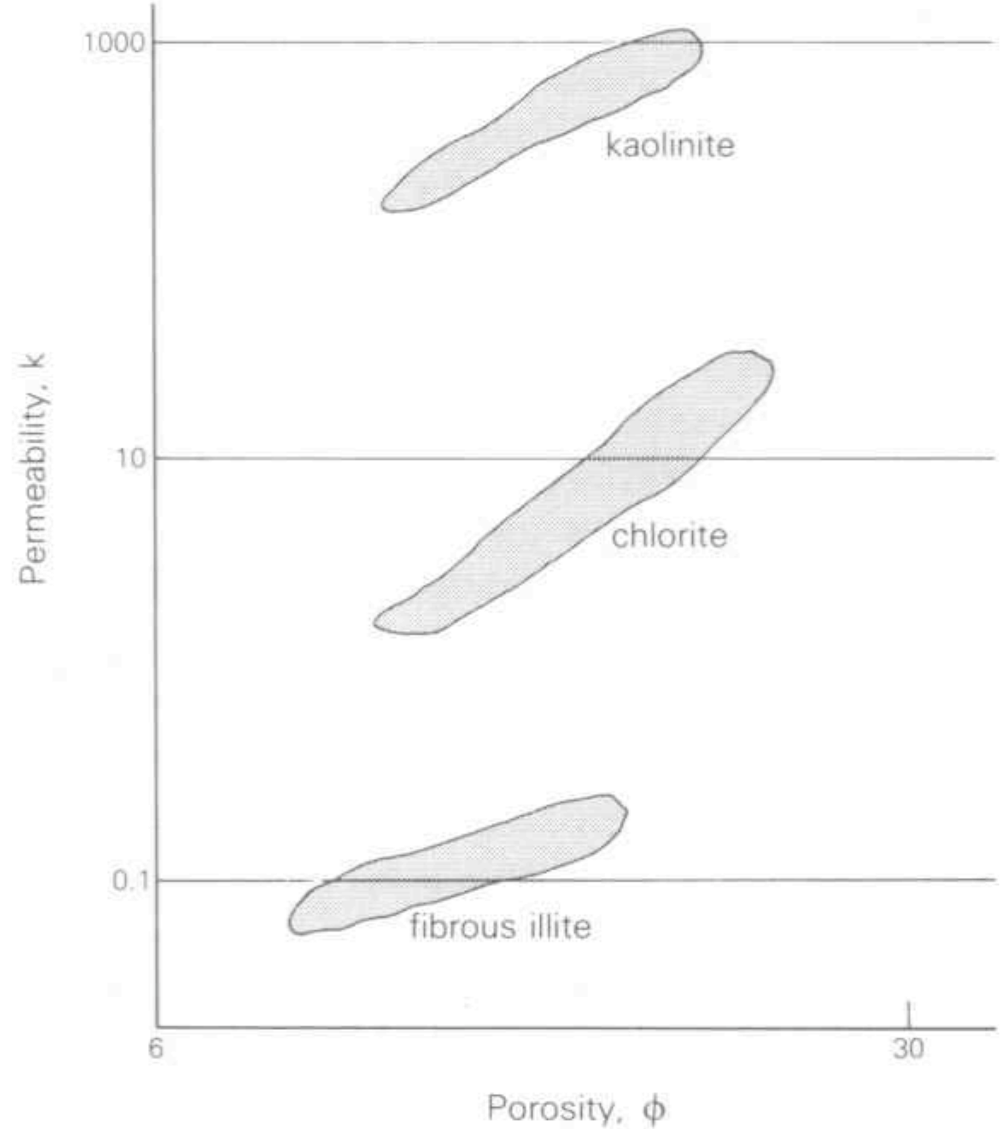
How do their distributions and shapes affect permeabilities?

Texture Affecting Permeability ctd.

Source: North, F.K. (1985) *Petroleum Geology*, Allen & Unwin

The different clay textures on the previous slide lead to dramatically different porosity/permeability relationships.

How does this relate to the maturation and compaction process discussed earlier in the course?



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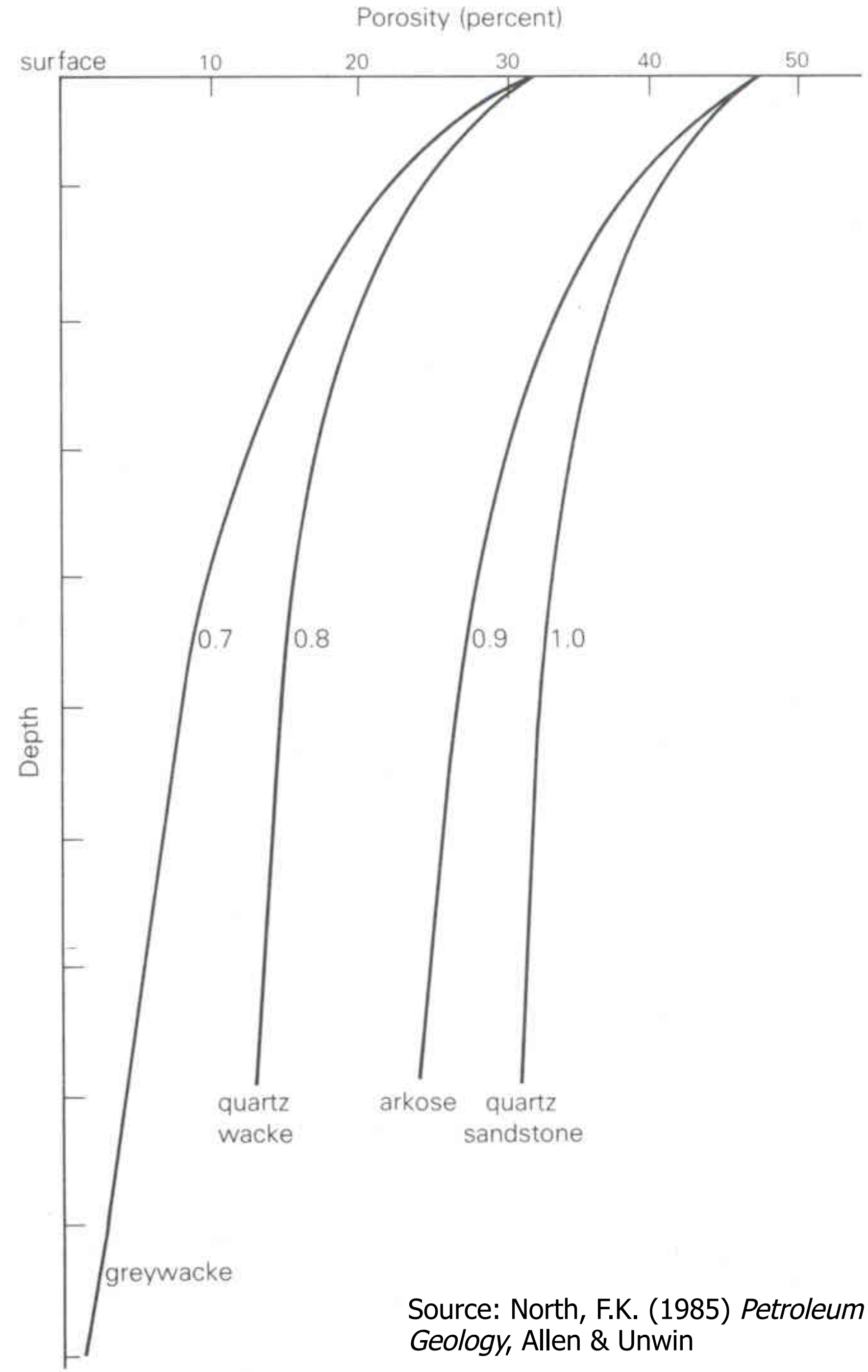
Compaction

Compaction is particularly strong in rocks with lower grain fractions (the amount that grains constitute of the total solid volume, shown here in fractions of unity, with the rest being fine-grained matrix minerals).

Clays and other matrix minerals move under pressure into the pore spaces. The softer grains in greywackes crumble and dislocate to clog the pores.

Cementation additionally leads to porosity reduction.



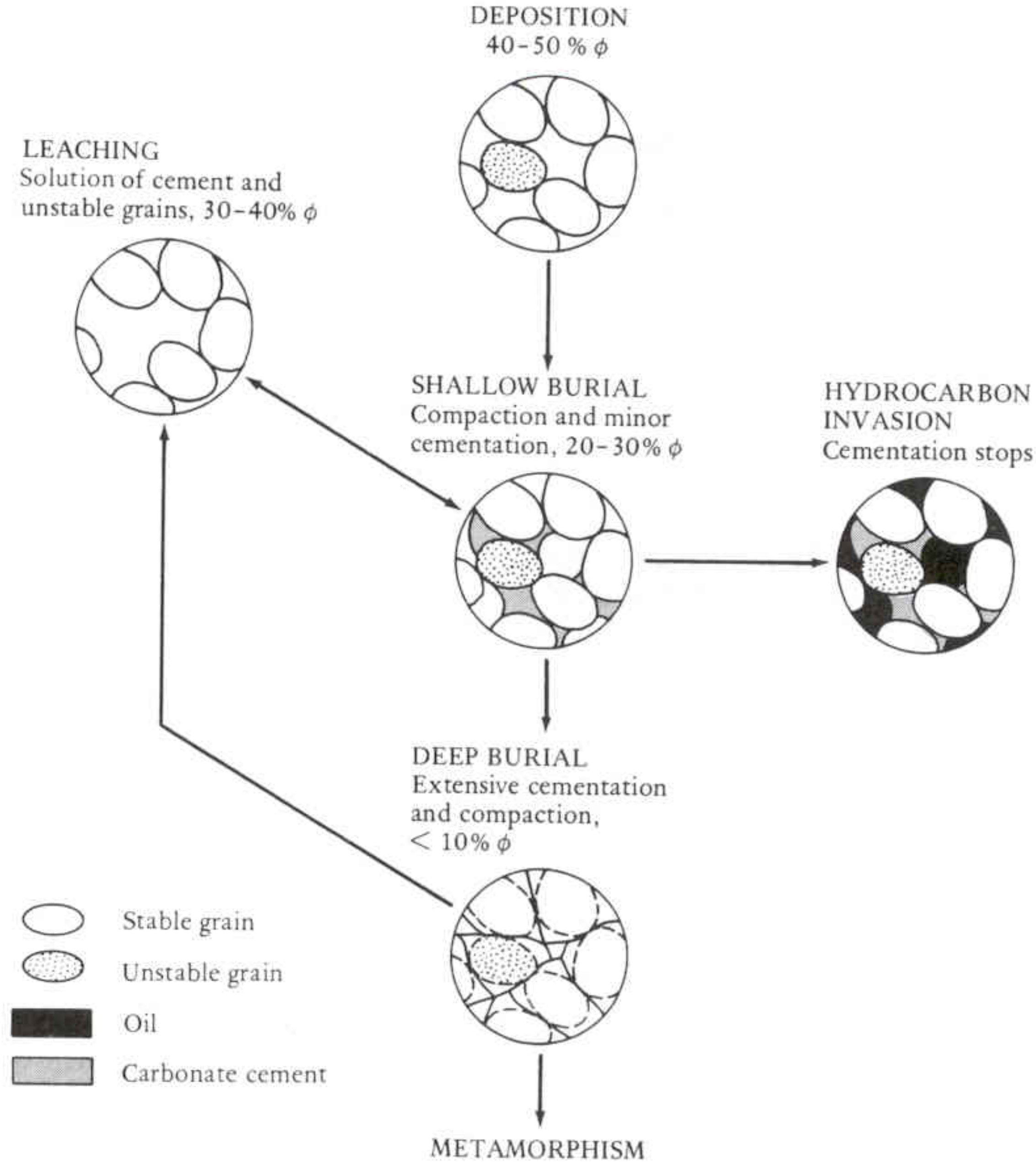
Source: North, F.K. (1985) *Petroleum Geology*, Allen & Unwin

Diagenesis Summary

This graph shows in a summary fashion the main changes a potential reservoir rock undergoes with burial.

The example shown is a sandstone. Diagenesis in carbonates is significantly more complex.

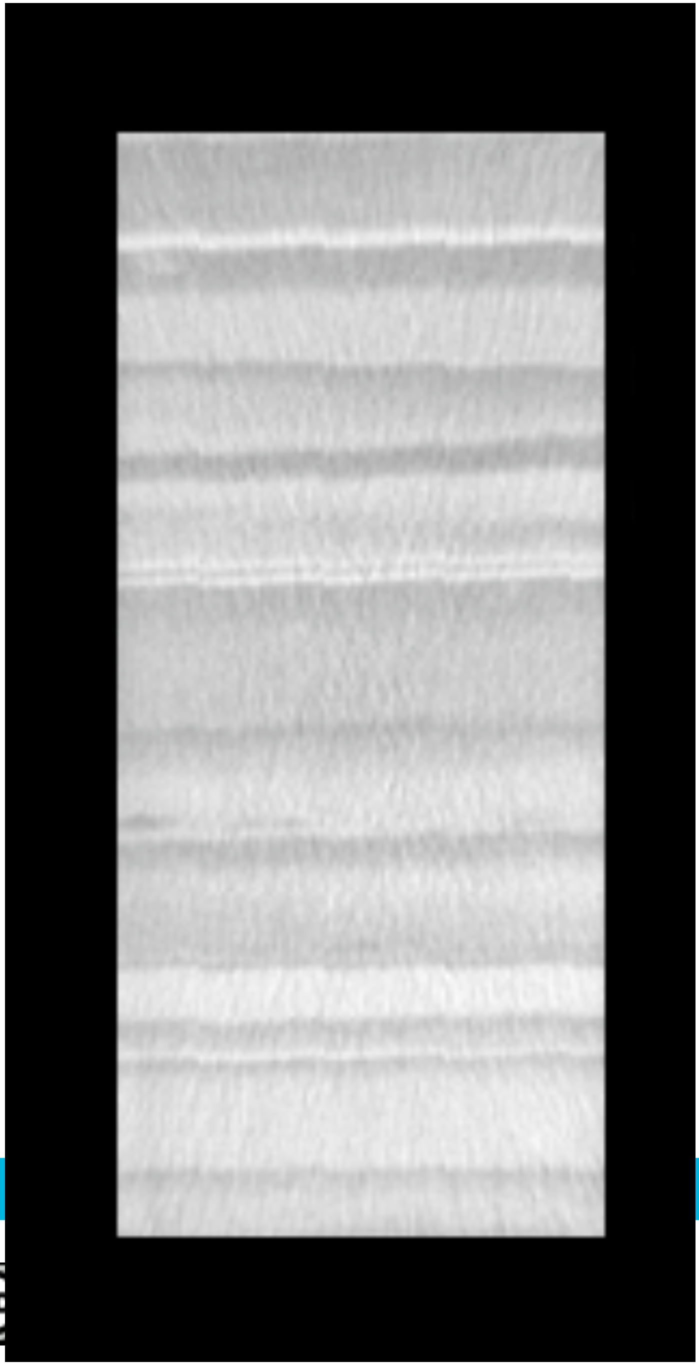
Source: Selley R.C. (1997) *Elements of Petroleum Geology*, 2nd edition, Academic Press



Heterogeneity and Anisotropy

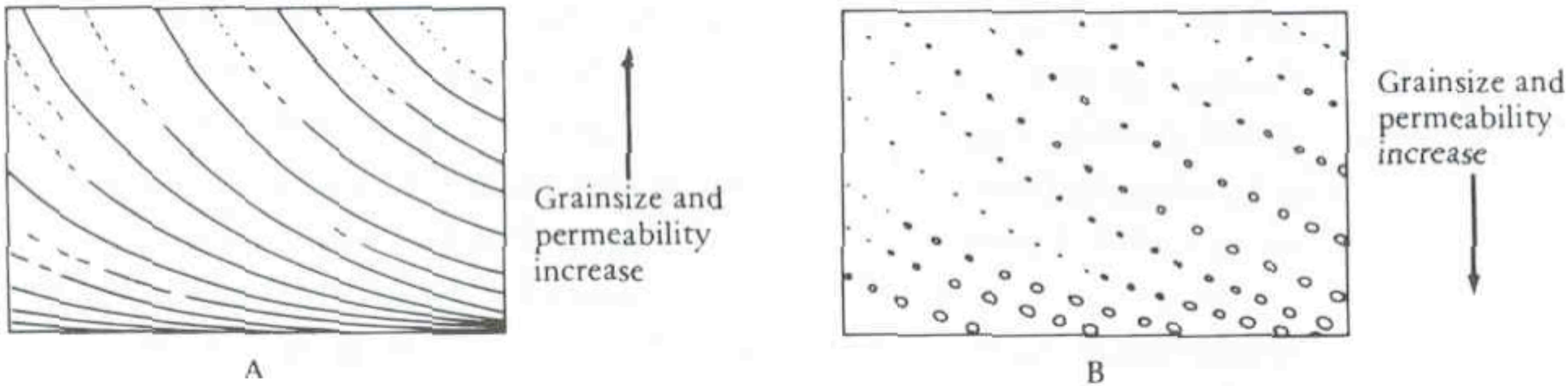
This is a CT Scan density image of an eolian sandstone. It measure a few cm across and about 20 cm in height. The darker layers are more porous (~20%), while the brighter streaks are tighter (~ 5%). These differences are due to initial sorting, differential packing and cementation.

Lateral and vertical changes in rock properties are called heterogeneities. The resulting difference in physical properties in different directions is referred to as anisotropy.



Lateral and Vertical Porosity Changes

Source: Selley R.C. (1997) *Elements of Petroleum Geology*, 2nd edition, Academic Press



The situation on the left is often found in marine barrier bars, while the one on the right is common in fluvial and marine channel deposits. They are referred to as upward-coarsening and downward-coarsening respectively and lead to anisotropy.

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Layering and Porosity Changes

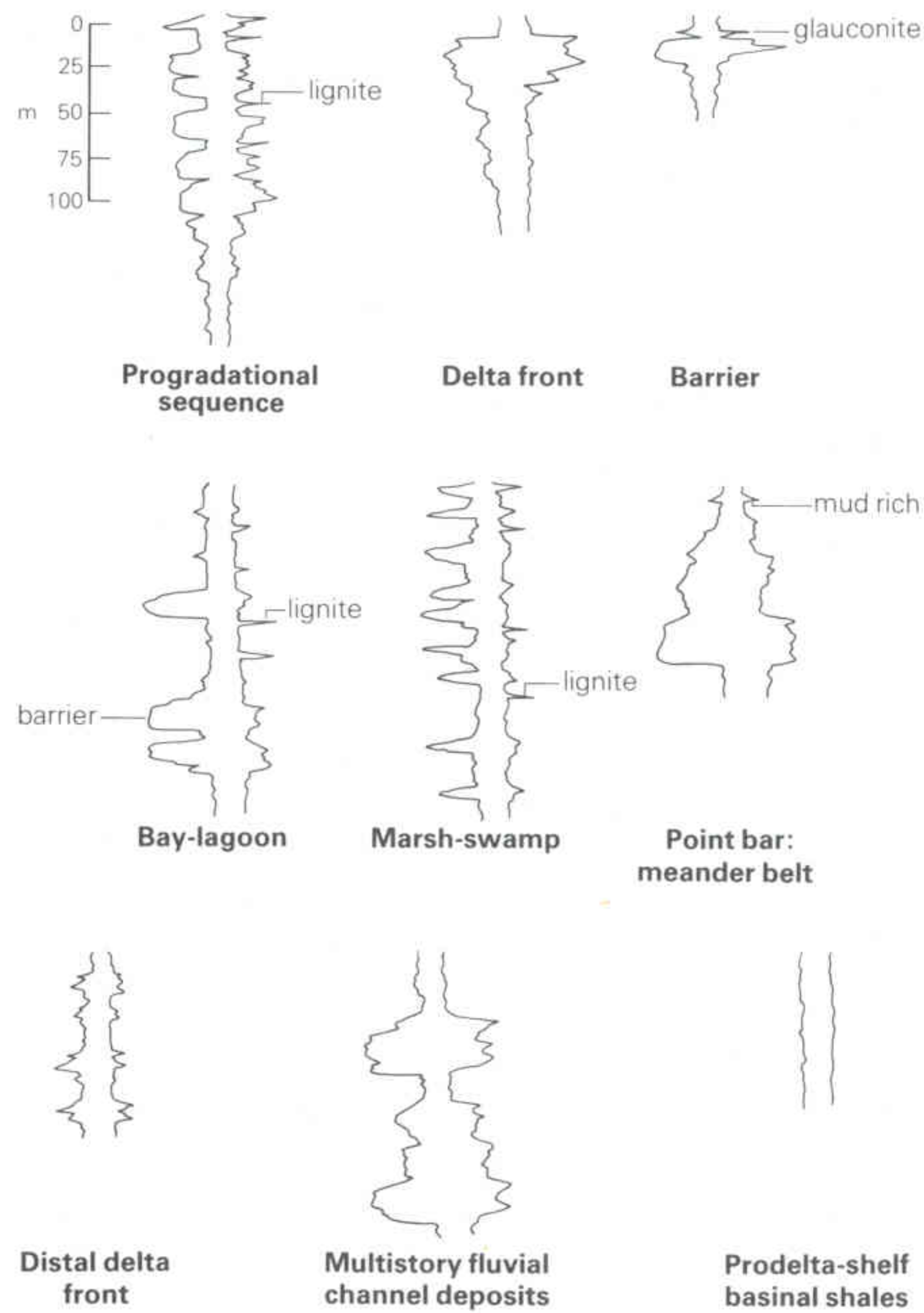
This outcrop photograph from Huesca, Spain, shows thick, coarse-grained channel sandstones, thin, finer-grain overbank deposits, and floodplain shales. They have all different porosities and permeabilities, caused by differences in grain sizes.

Well Logs

Source: North, F.K. (1985) *Petroleum Geology*, Allen & Unwin

Well logs are useful to identify layering and, therefore, differences in reservoir quality.

Skilled interpreters can relate typical log shapes to depositional sequences, as shown on the right. The logs shown are a gamma ray log on the left and a resistivity log on the right.

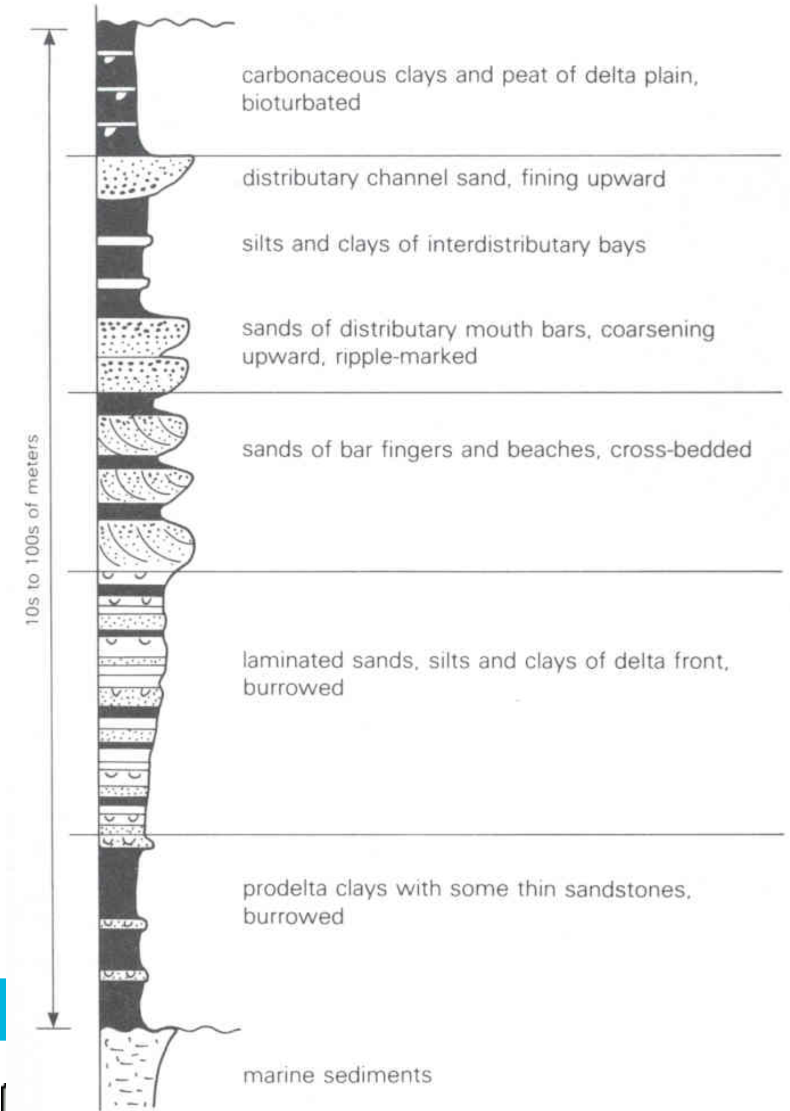


3-D Reservoir Architecture

Reservoirs in fact consist of complex arrangements of three-dimensional bodies. Understanding this 3-D architecture is often difficult because of the sparse data available. Wells only provide one-dimensional information, such as the examples shown on the previous slide, or the one shown here - which comes from a deltaic sequence.

The geologist's task is to use well and seismic data, and geological knowledge to build a three-dimensional reservoir model.

Source: North, F.K. (1985) *Petroleum Geology*, Allen & Unwin



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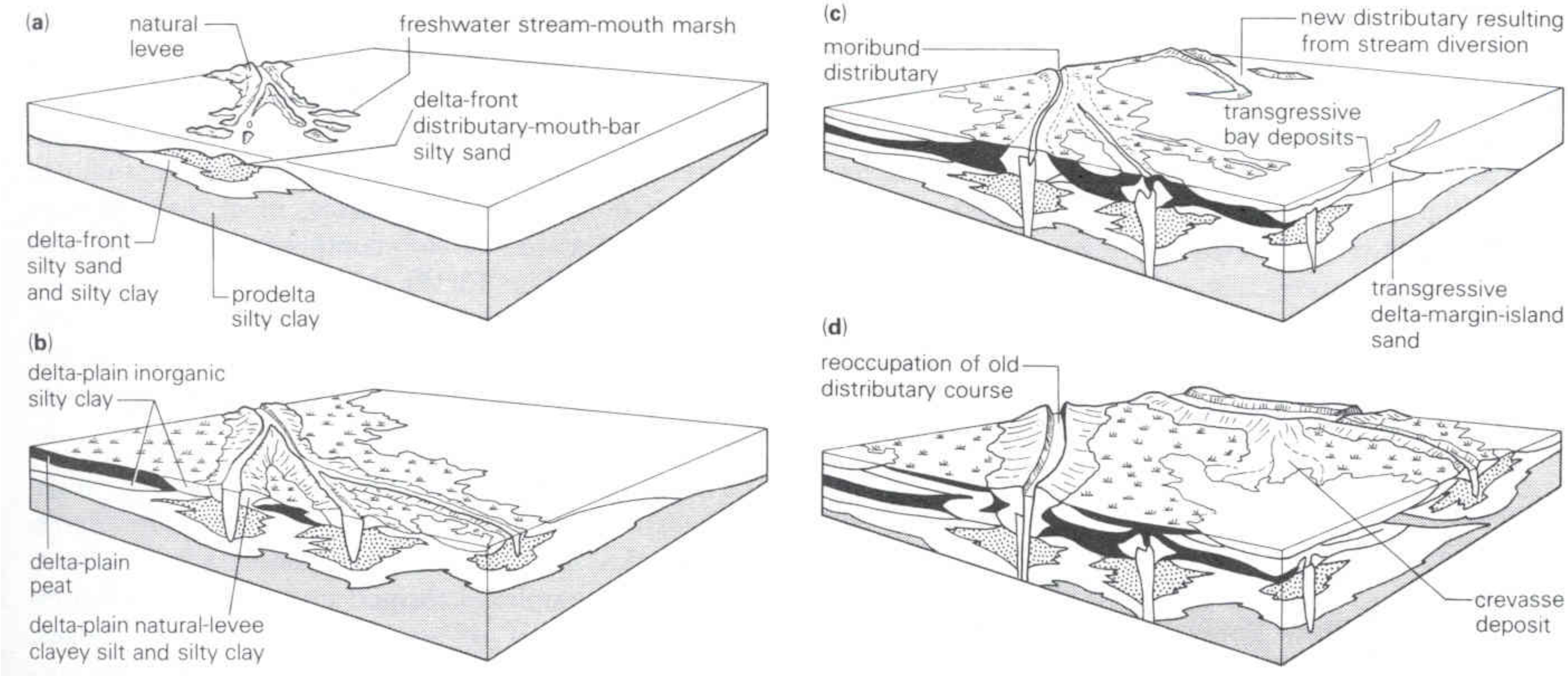
Sedimentological Models

Source: North, F.K. (1985) *Petroleum Geology*, Allen & Unwin

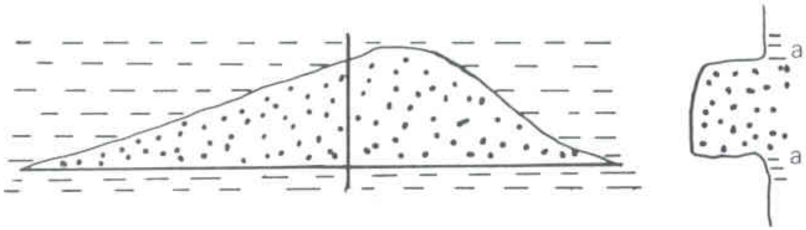


Conceptual depositional models are important in helping to relate well data to a 3-D reservoir model. Shown here are four stages in the formation of a bird-foot delta, such as the Mississippi delta, where rivers dominate sediment distribution.

Geological Knowledge: Sedimentology

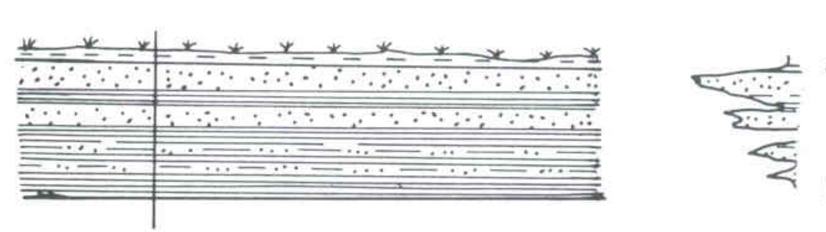
Source: North, F.K. (1985) *Petroleum Geology*, Allen & Unwin

Chenier beach



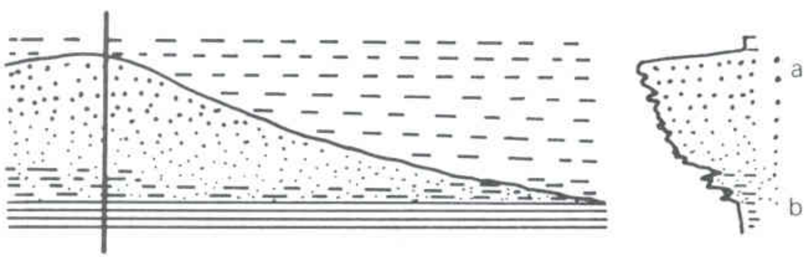
a/a contact: abrupt upper and lower contact; sands generally are well sorted by wave action

Deltaic sequence



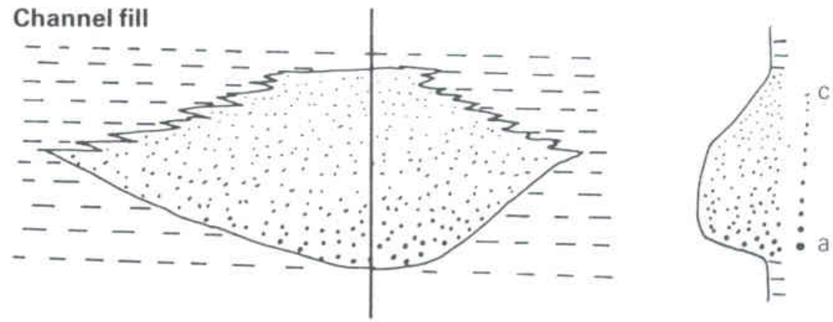
a/b contact: interbedded sand–shale sequence; the sands are fine grained

Barrier bar



a/c or a/b: grain size increases upward in section; graduation in grain size is probably related to increasing wave energy with decreasing water depth as the bar is built up

Channel fill

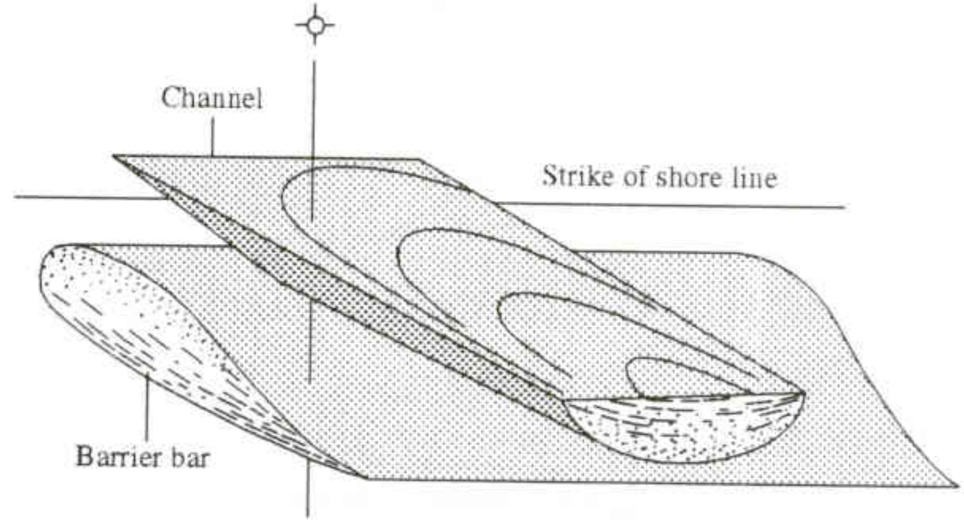


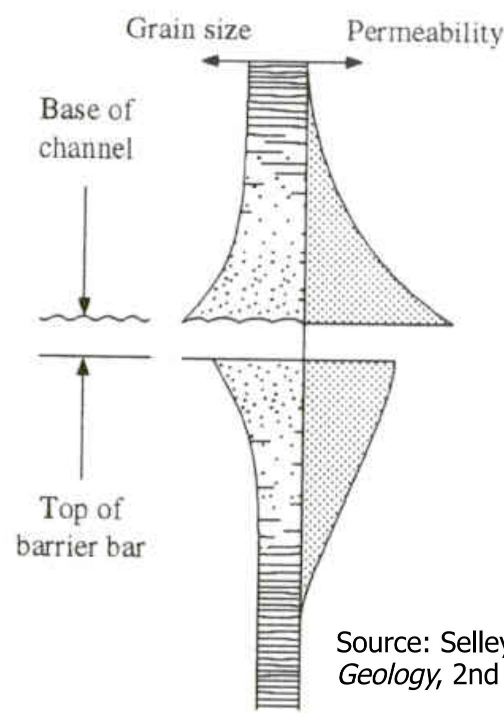
c/a contact: characterized by an abrupt lower contact and gradual upward decrease in grain size

Simple cross-sections of sedimentary bodies can be used to construct vertical sequences that would be expected in a well. These type logs can then be used to predict the lateral extents of the various layers, and to help in identifying depositional environments.

Example of 3-D Sedimentary Bodies

This example shows a simple 3-D reconstruction. The well data (below) suggest that a barrier bar deposit is overlain by a channel deposit. Directional information, such as obtained from dipmeters or borehole images, help orient the sand bodies in a qualitative way in three dimensions. The resulting local model is shown at the top.



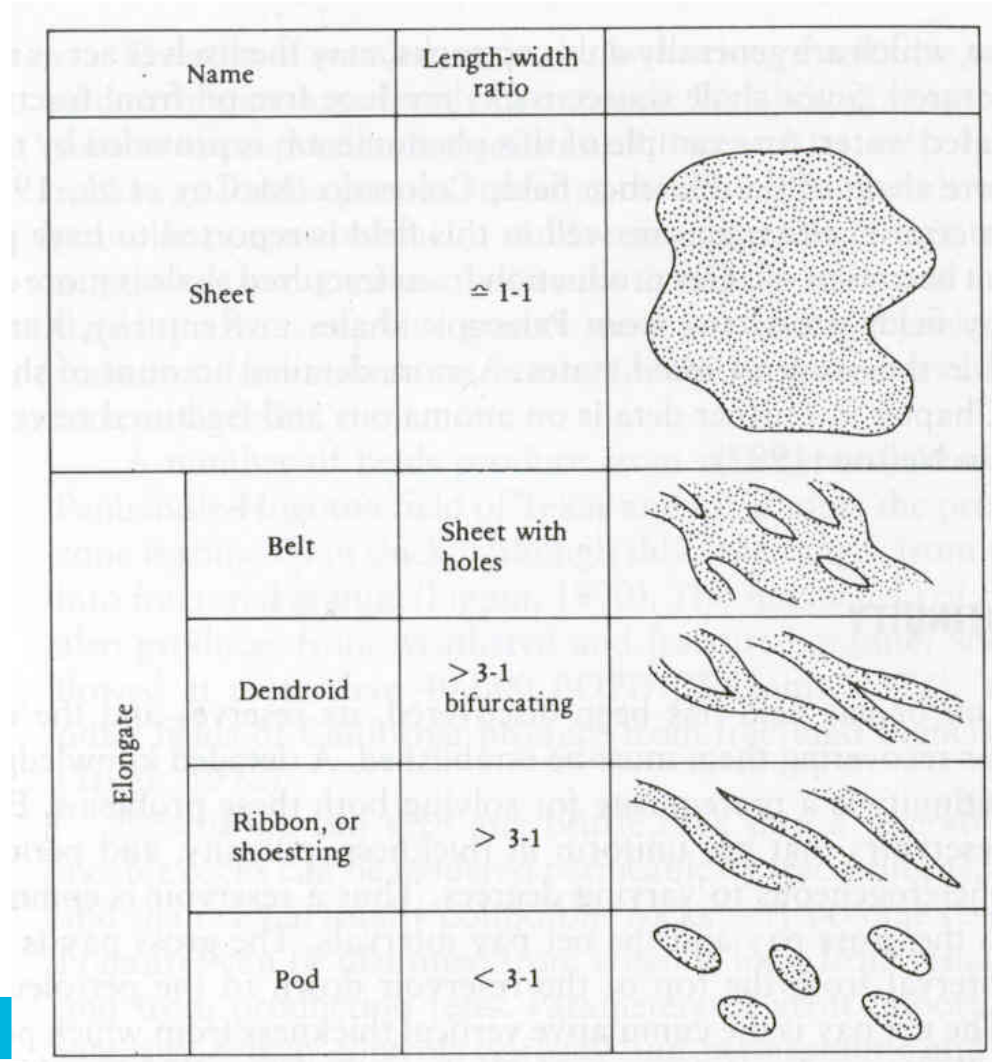


Source: Selley R.C. (1997) *Elements of Petroleum Geology*, 2nd edition, Academic Press

Simple 2-D Shapes

Source: Selley R.C. (1997) *Elements of Petroleum Geology*, 2nd edition, Academic Press

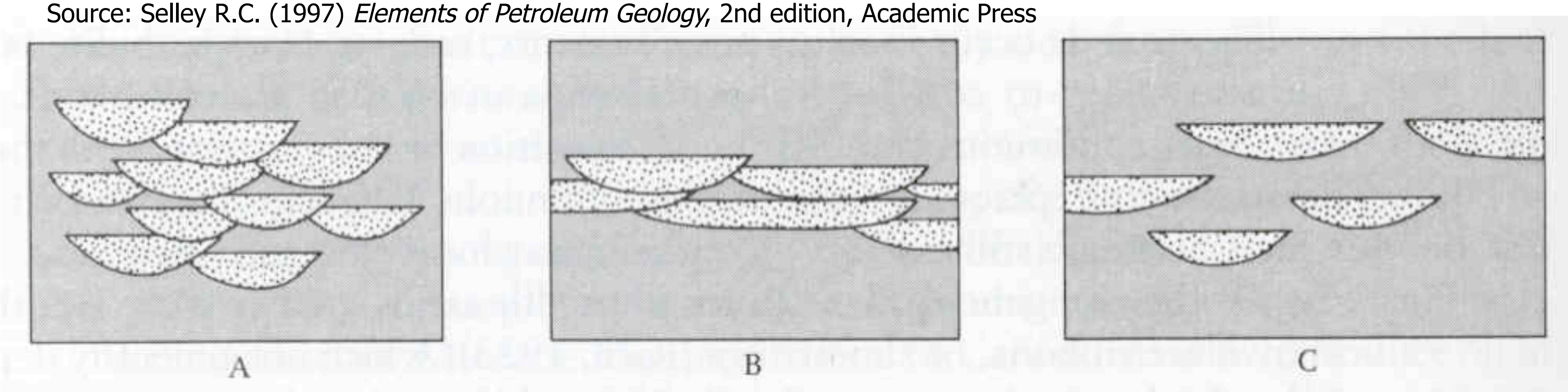
These 2-D shapes have been proposed by E. Potter as simple descriptors of the extent of typical sandstone bodies. They can be applied in stochastic reservoir models, i.e. where the exact shape and position can only be known statistically, not deterministically.



	Name	Length-width ratio	
	Sheet	≃ 1-1	
Elongate	Belt	Sheet with holes	
	Dendroid	> 3-1 bifurcating	
	Ribbon, or shoestring	> 3-1	
	Pod	< 3-1	

Reservoir Connectivity

Source: Selley R.C. (1997) *Elements of Petroleum Geology*, 2nd edition, Academic Press



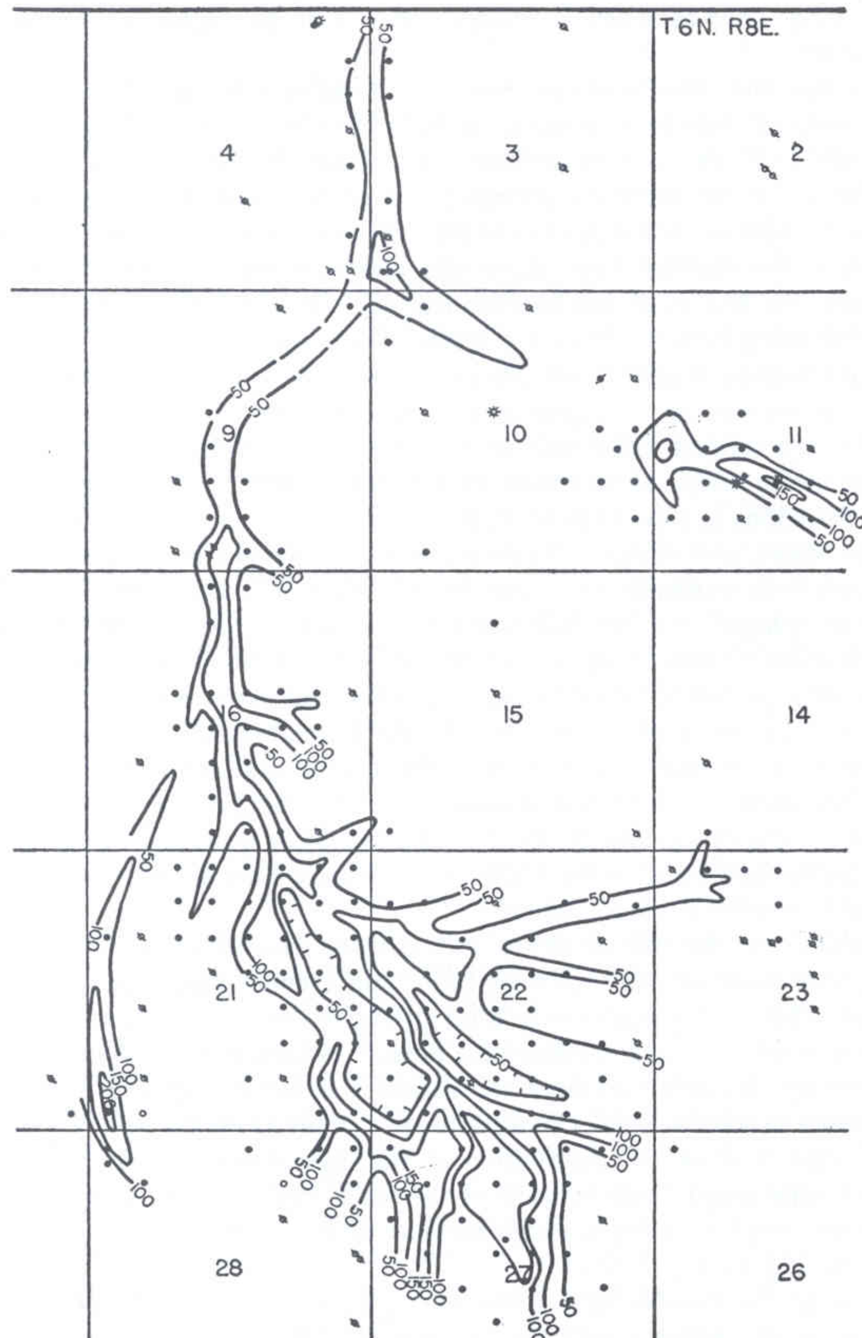
These three sketches show sand bodies with different lateral and horizontal connectivities. A: Vertically stacked (multistorey); B: Laterally stacked; C: Isolated.

Sand body connectivity is important in fluid flow simulations. It results from depositional system that laid the sand bodies down in a “matrix” of finer-grained rocks such as shales.

3-D Reservoir Shapes

This map shows the initial production of wells in the Hawkings field, Oklahoma (in barrels per day). The contours follow almost precisely the isopach map of the net reservoir sands.

Try to interpret the nature of this reservoir. How could the dry wells (single dots outside the contoured areas) have been avoided?



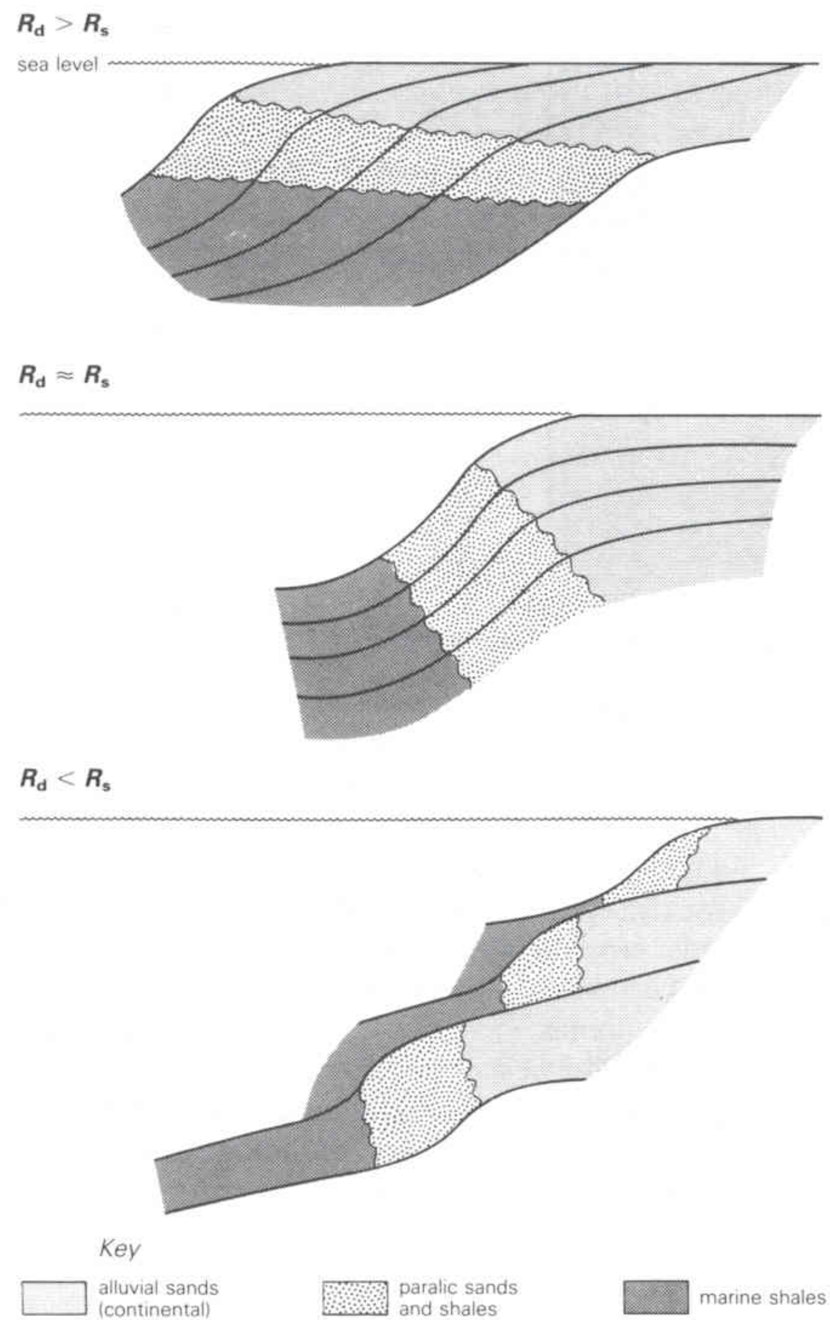
Source: Levorsen, A.I. (1967) *Geology of Petroleum*, W.H. Freeman and Co

Depositional Systems through Time

As depositional system evolve through time, they shift in space. Lateral shifting is called accretion, while vertical stacking is called aggradation.

These shifts are controlled by the relative rates of deposition and subsidence. Shown here is a simple deltaic system with three different relationships of these rates.

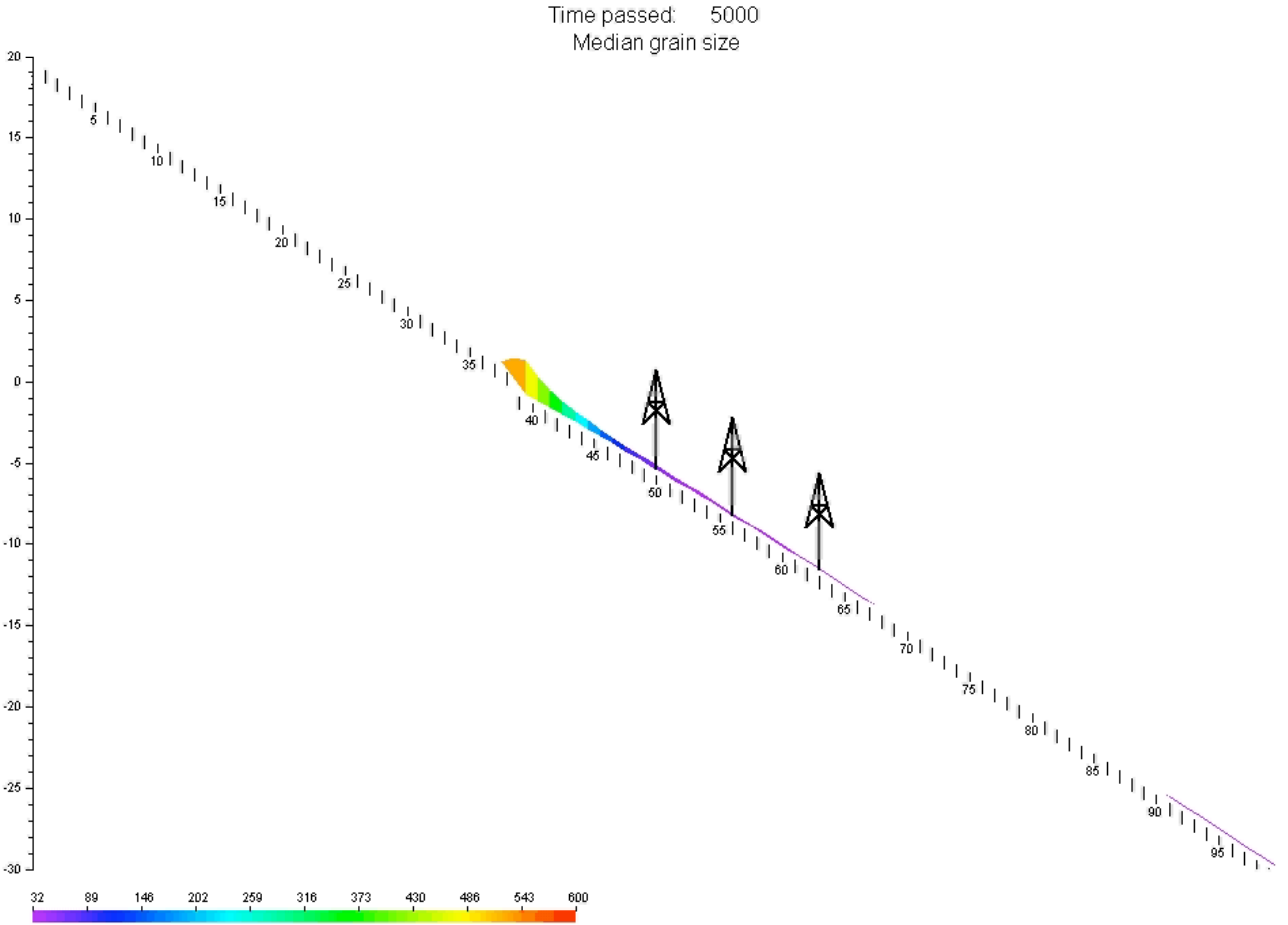
Source: North, F.K. (1985) *Petroleum Geology*, Allen & Unwin



BarSim

At the TU Delft we have a group that models such time-dependent sedimentary systems. BarSim is a process-based simulation of barrier bar development as a function of fluctuating sea levels.

Authors: Joep Storms, Gert Jan Weltje and Kees Geel.


Time passed: 5000
Median grain size
32 89 146 202 259 316 373 430 486 543 600

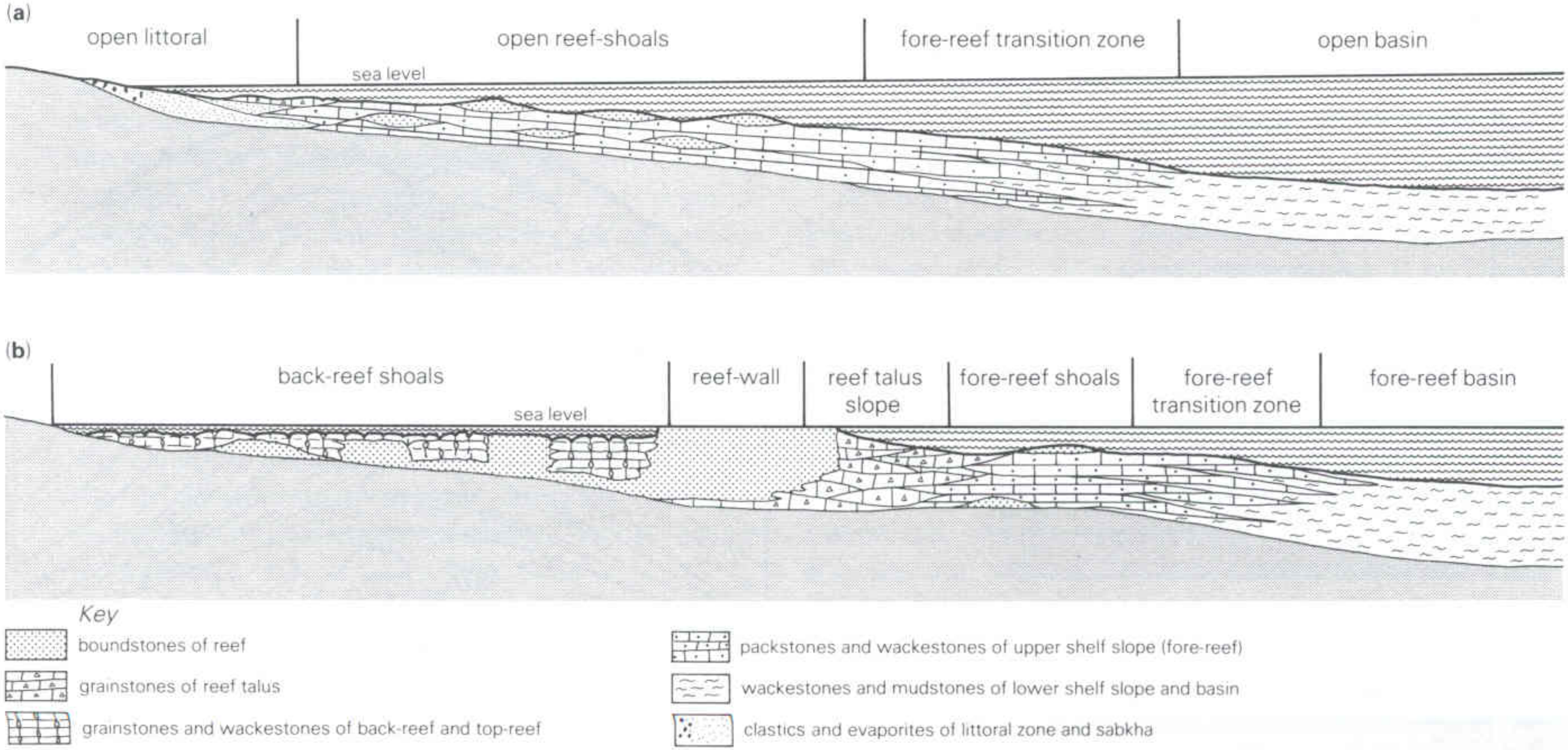
And Now to Carbonates....

We have left carbonates out so far, because in the petroleum geology world they are quite another matter. Their depositional mechanisms, their diagenesis, and their response to structural deformation all differ significantly from clastic reservoir rocks (i.e. sandstones).

One of the most important aspects of carbonate deposition is that much of the material is biogenic. Reservoir carbonates are often deposited on shelves, and quite often in waters that do not have high mud supplies. As a consequence, carbonate reservoirs have generally lower clay contents than sandstones. There is also organic matter in such environments, much of which will get oxidized and will disappear. However, it is not uncommon for carbonates reservoirs to be at least partly self-sourced (i.e. they are both source and reservoir rock)

Carbonate Depositional Settings

Source: North, F.K. (1985) *Petroleum Geology*, Allen & Unwin



The carbonate ramp model (above) and the differentiated shelf model (below) apply to many carbonate reservoir provinces. With a source rock in the deeper waters, any of the various facies shown can become a productive reservoir rock under the right conditions.

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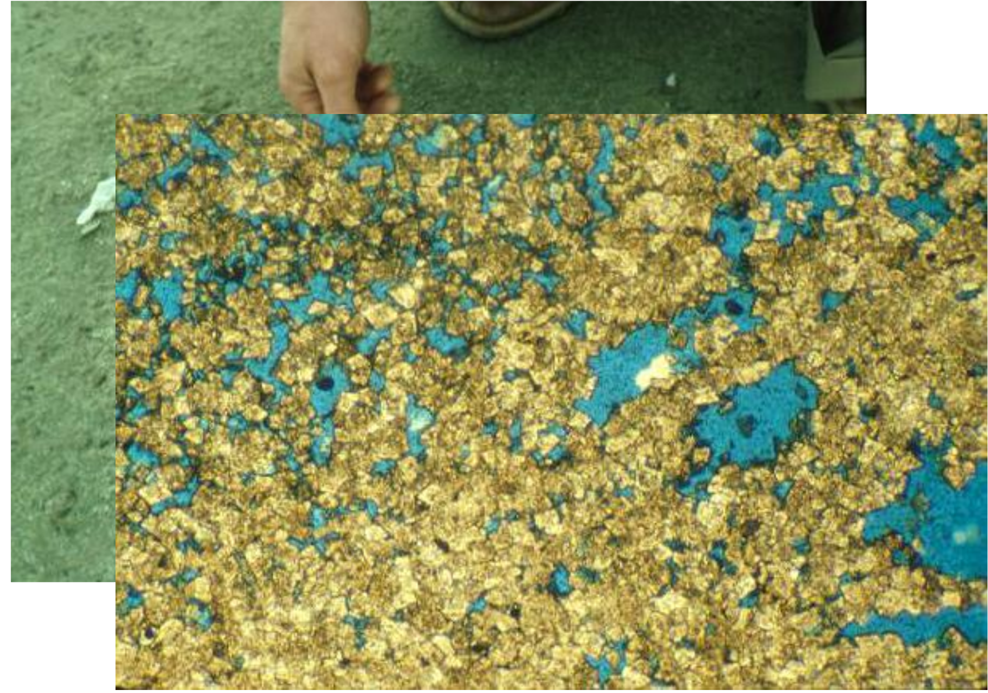
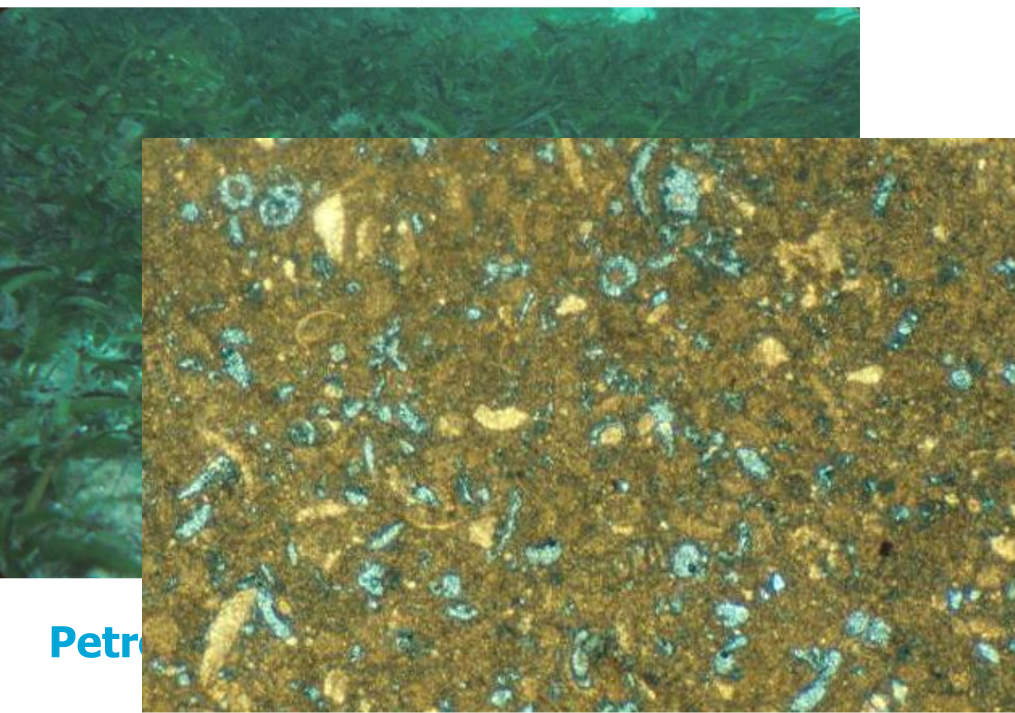
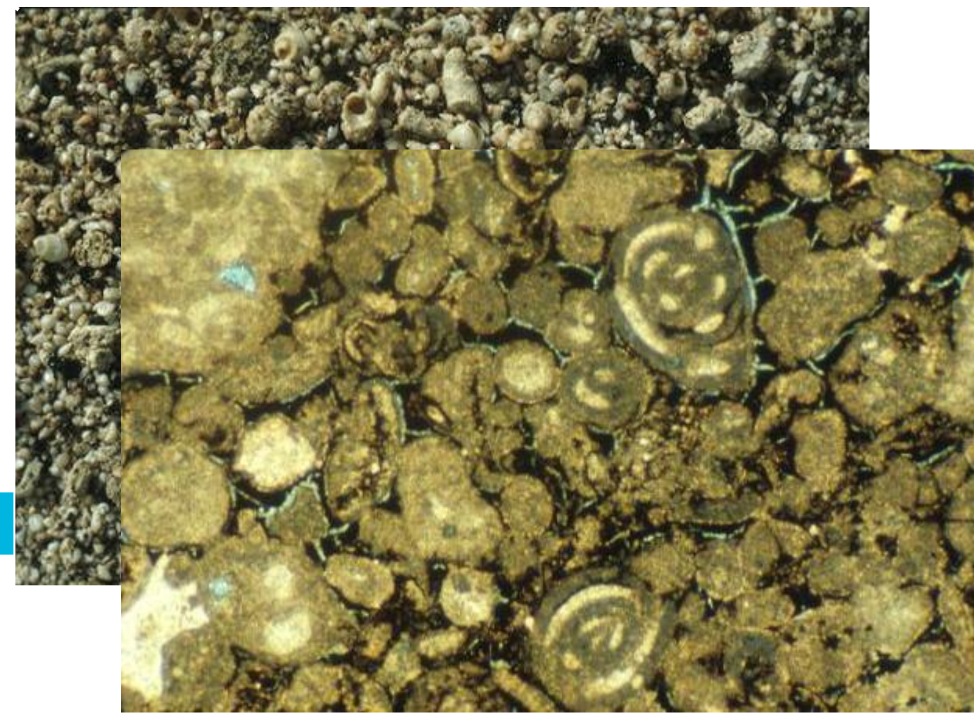
Berry Islands, Bahamas, a large differentiated carbonate platform







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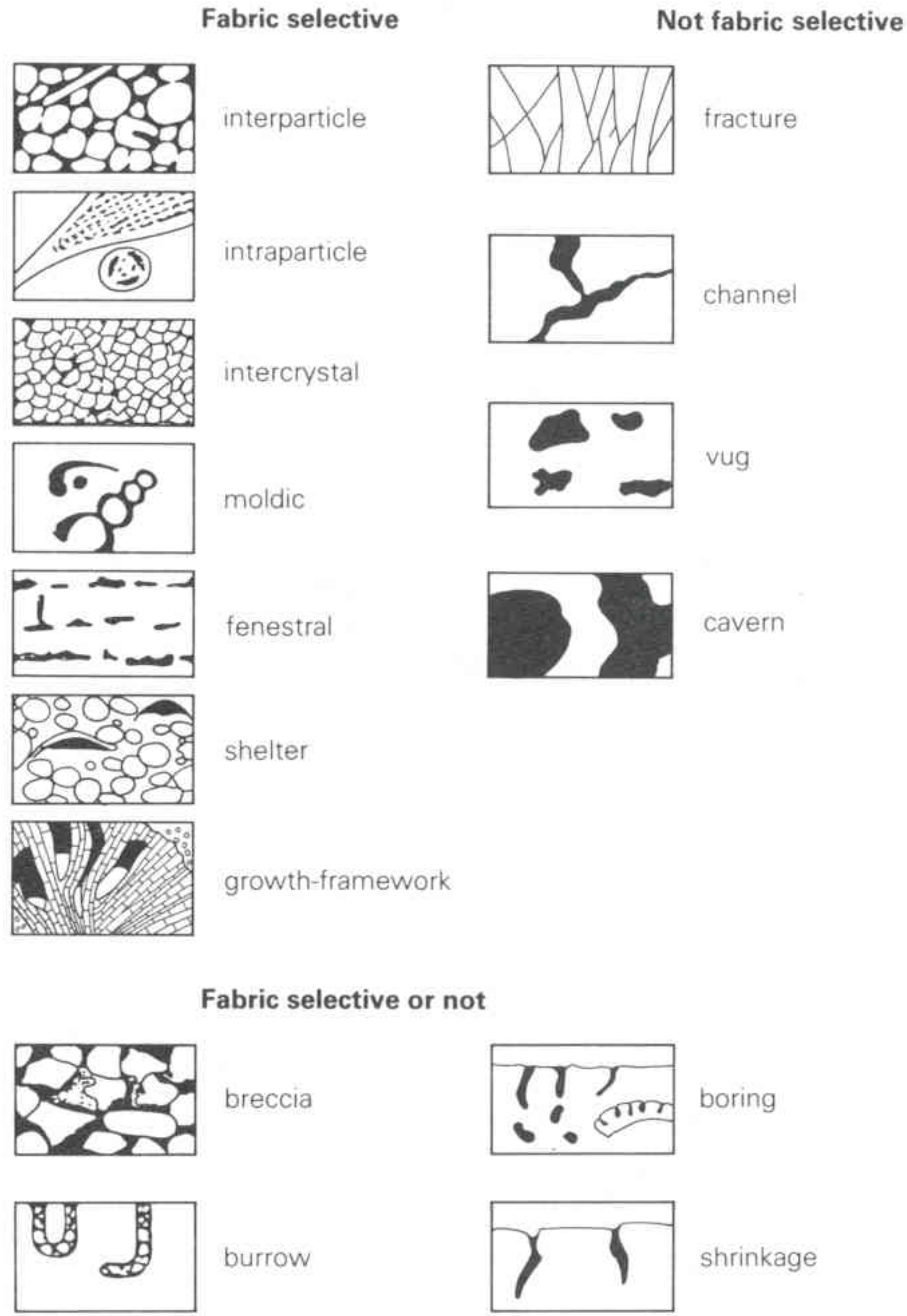
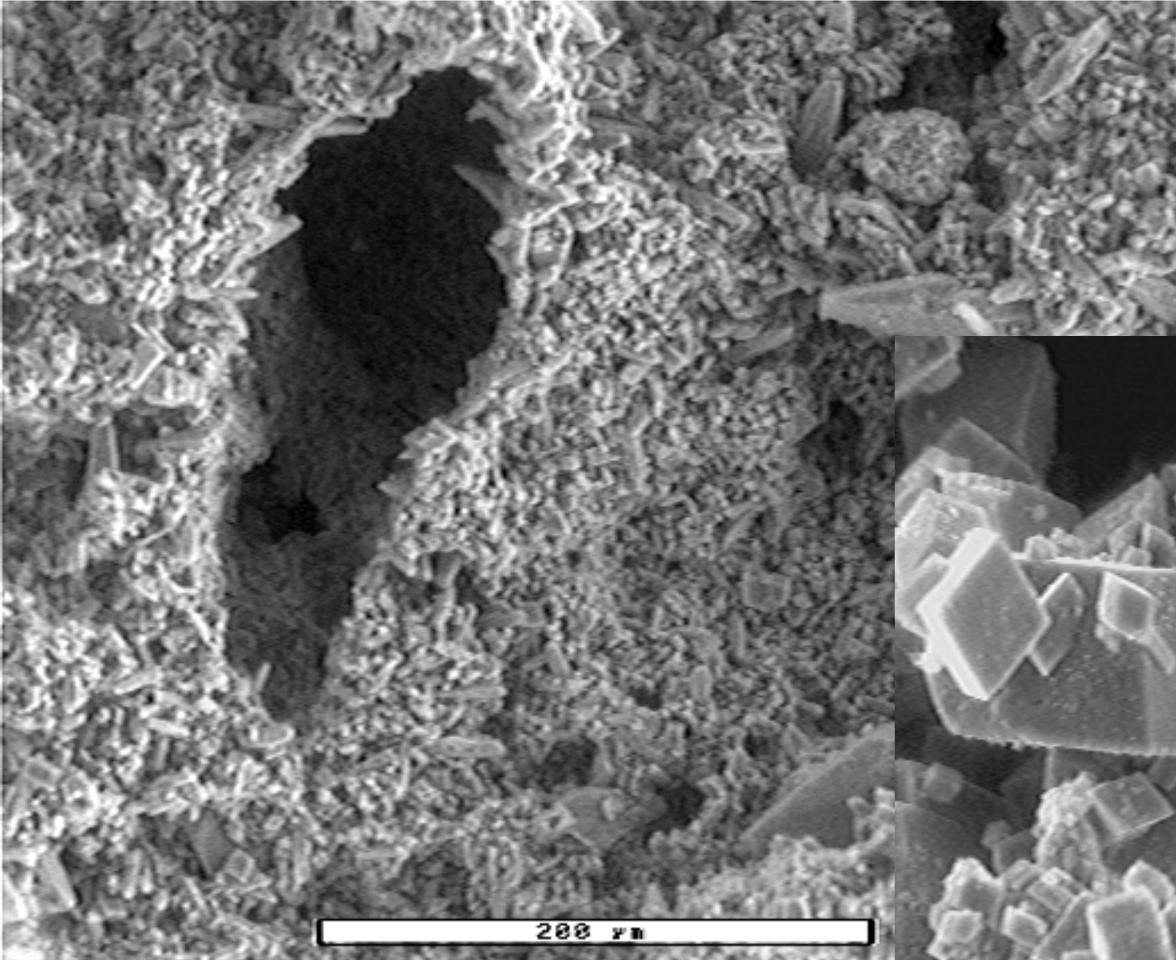
Carbonate Pore Types

Because of the higher solubility and different geomechanical properties of carbonates compared to sandstones, a much greater variety of pore types is found in them.
This classification by Choquette and Pray (1970) is directly related to the depositional origin, the diagenesis and in some cases to tectonics. Often, several types of porosities coexist. Unraveling the development of porosities in carbonates is an important but difficult task. It can improve prediction of production behavior.

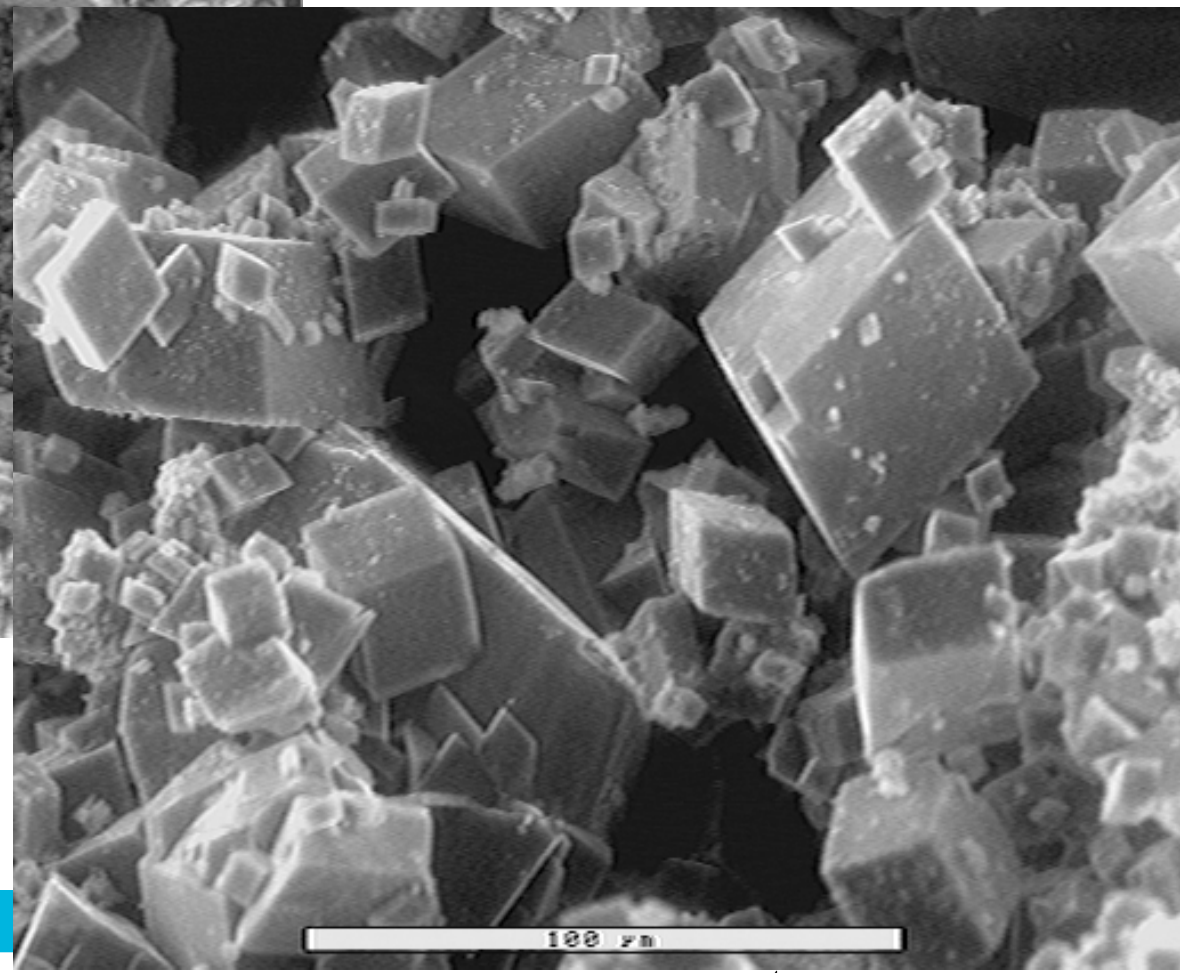


Source: North, F.K. (1985) *Petroleum Geology*, Allen & Unwin

Influence of Pore Types on k/ϕ



Bioclastic, moldic limestone
$m = 3.27$, $\phi = 36\%$, $k = 7.7$ mD



Crystalline dolomite
$m = 1.95$, $\phi = 47\%$, $k = 3160$ mD

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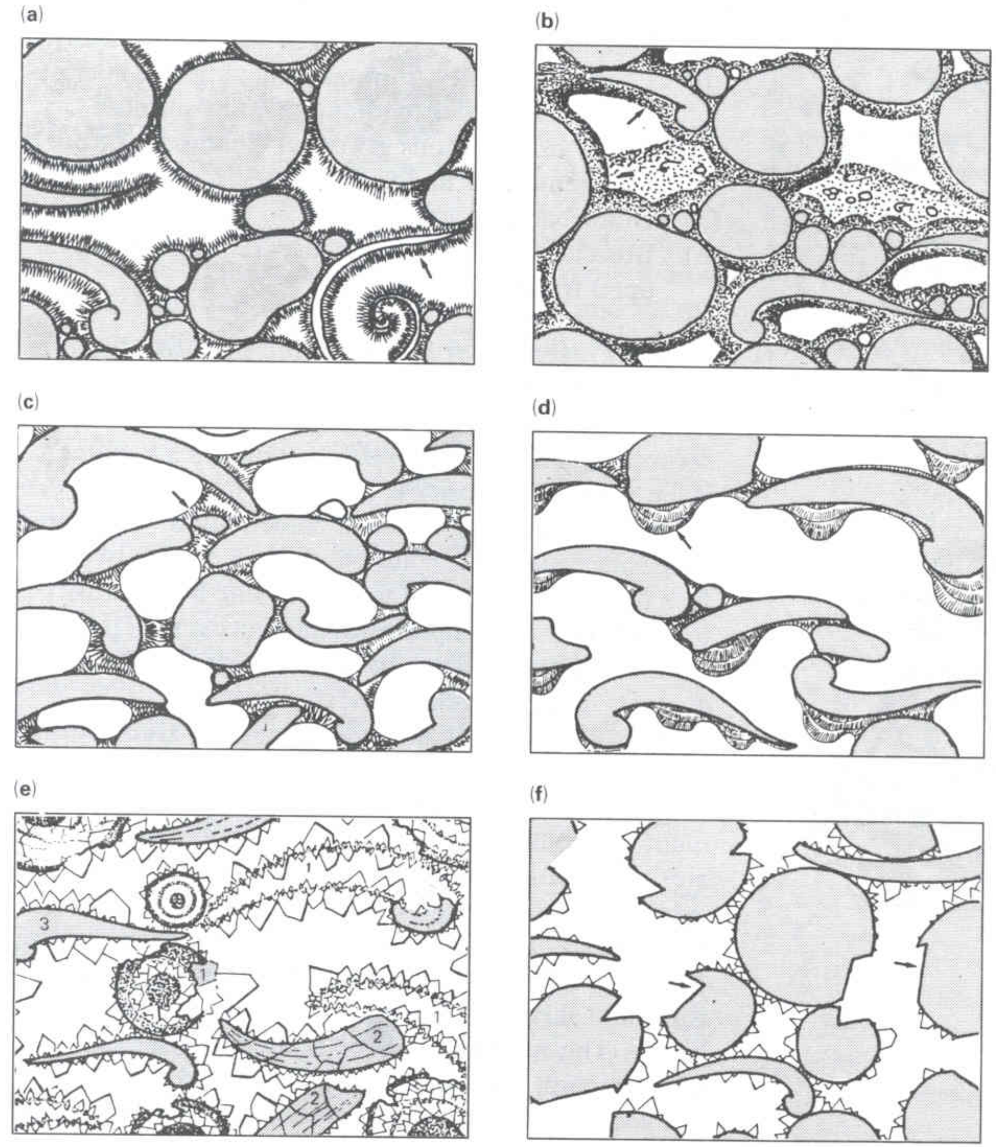
Carbonate Diagenesis

This slide shows some important early diagenetic processes.

a,b: submarine cements;
c,d: inter- and supratidal cements;
e,f: continental diagenesis with dissolution and recrystallization of calcite and aragonite grains, as well as calcite cementation.

Drawings from petrographic thin sections a few mm wide by Purser, 1978.



Source: North, F.K. (1985) *Petroleum Geology*, Allen & Unwin

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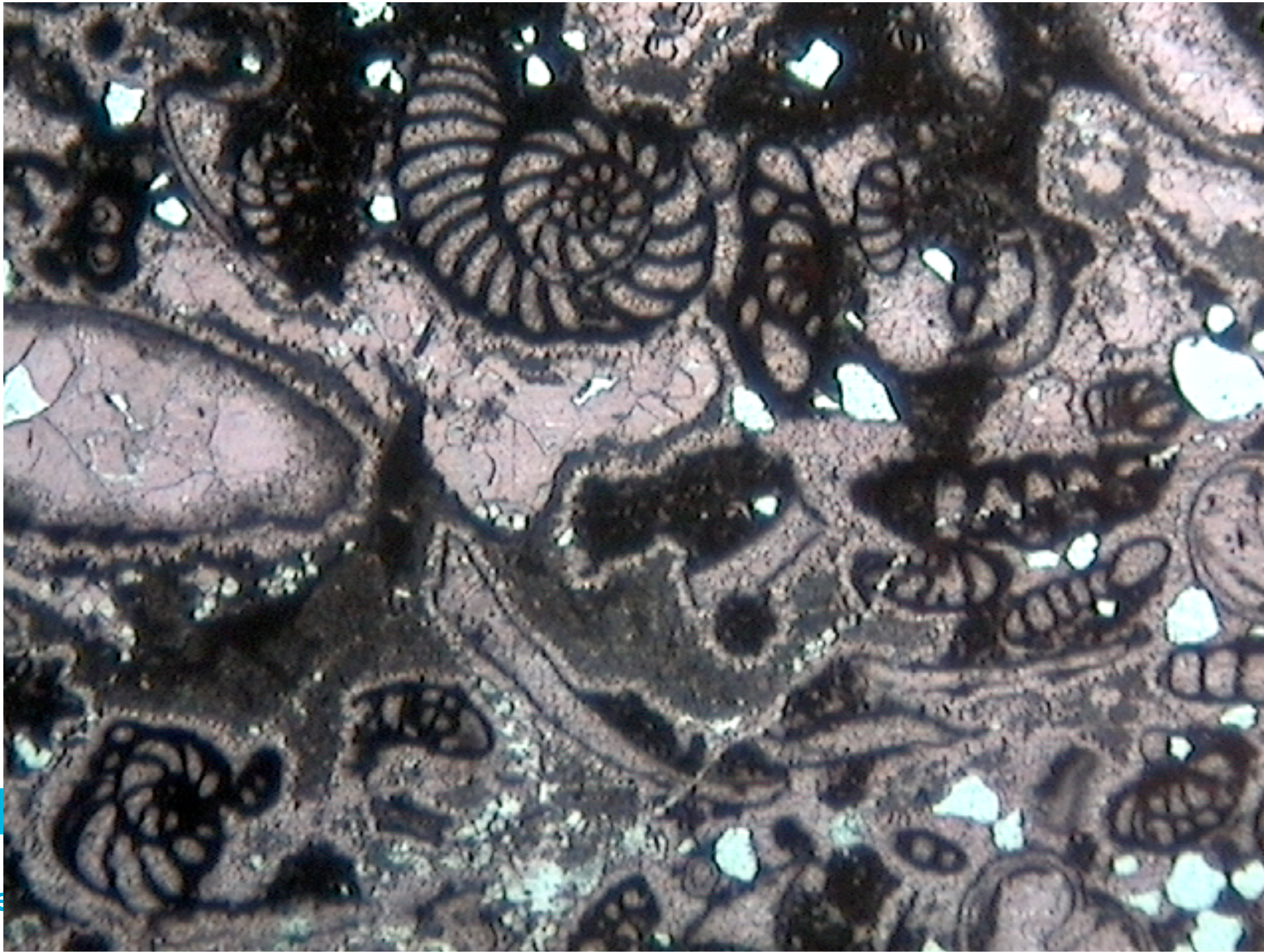
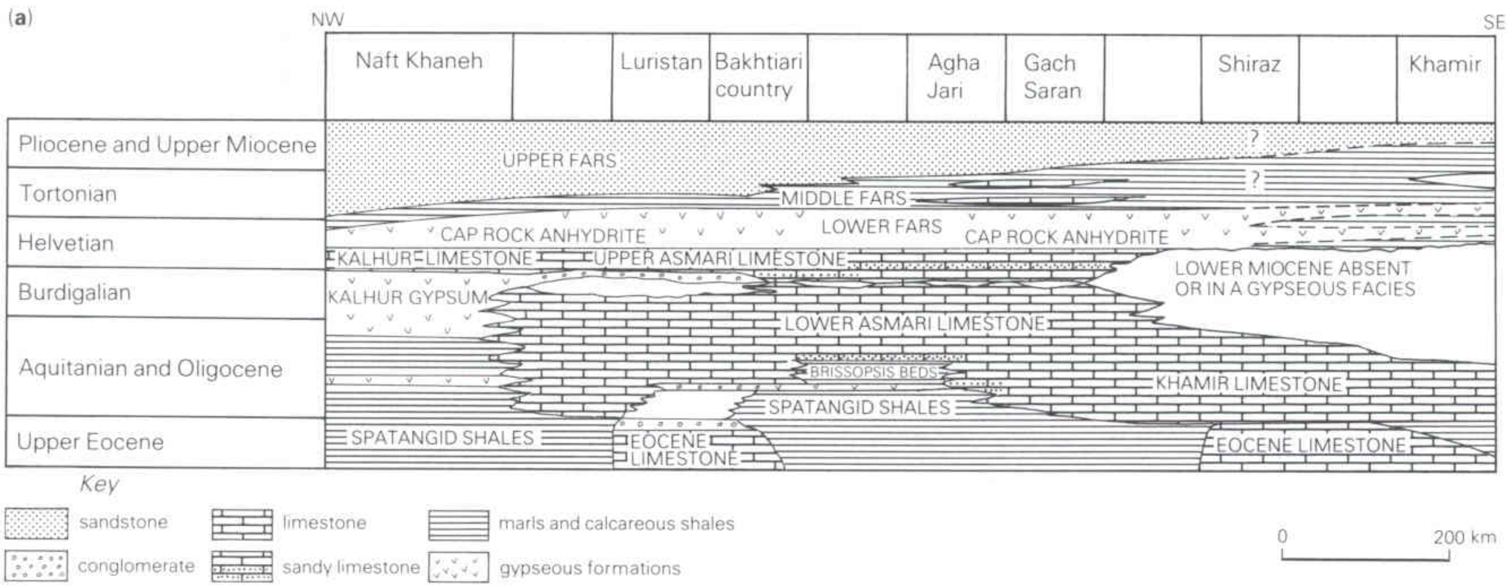
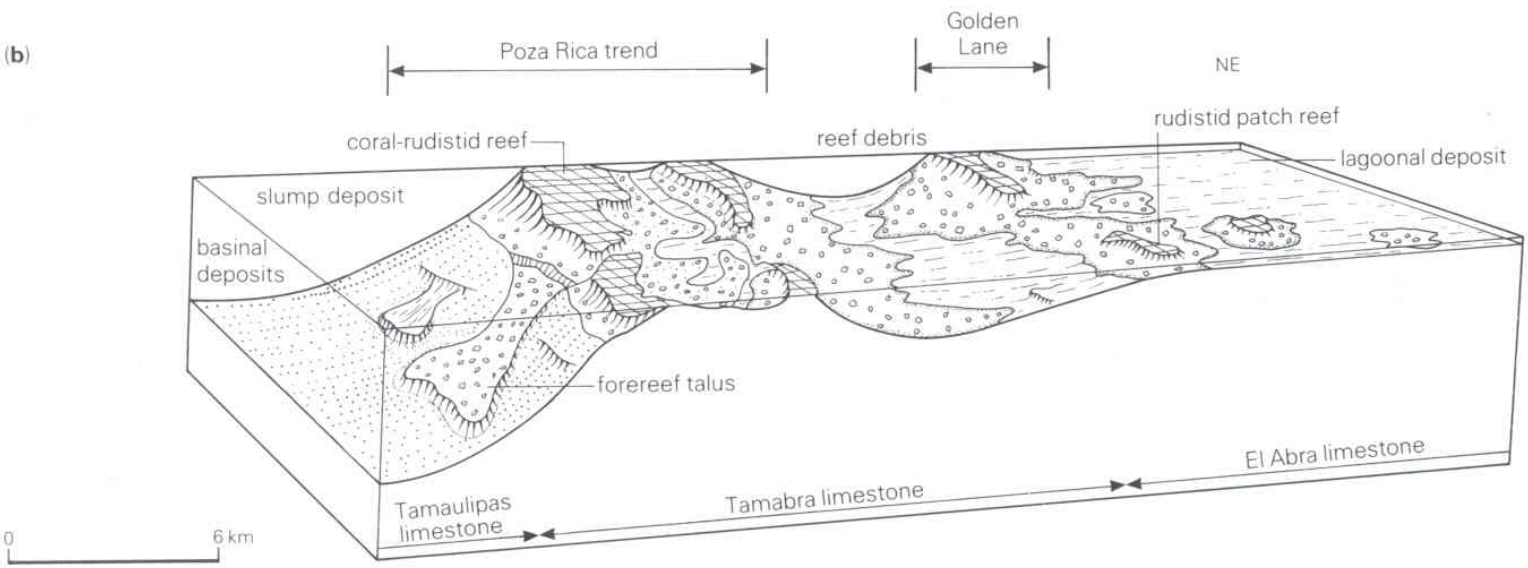
Asmari Limestone, Iran



Asmari Sedimentation and Facies

Source: North, F.K. (1985) *Petroleum Geology*, Allen & Unwin





Petroleum

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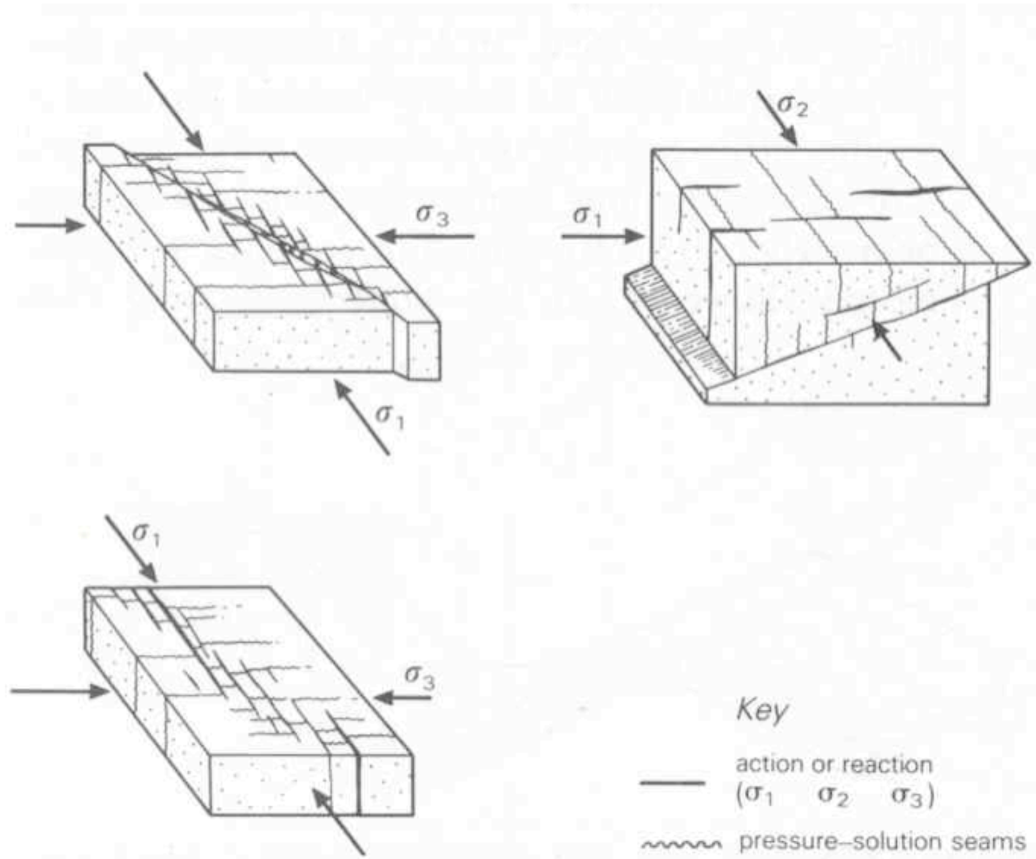
Large-Scale Dissolution

These large-scale dissolution features are called karst and are caused by meteoric water. The dissolution generally follows preexisting cracks or other weaknesses.

The large-scale porosity thus formed is very difficult to evaluate from wells. Fields in Turkey, among others, are known to produce from such porosity.

Fractured Reservoirs



Source: North, F.K. (1985) *Petroleum Geology*, Allen & Unwin

Fractures are essential in creating permeable paths in tight carbonate rocks like the Asmari limestone. They can create high permeabilities but low porosities. If the matrix porosity is sufficient, such “dual porosity” systems can be very good, sustained producers.

Analogue Studies of Fractured Reservoirs

TU Delft fieldwork site in Cambrian Umm Ishrin Formation, Jordan