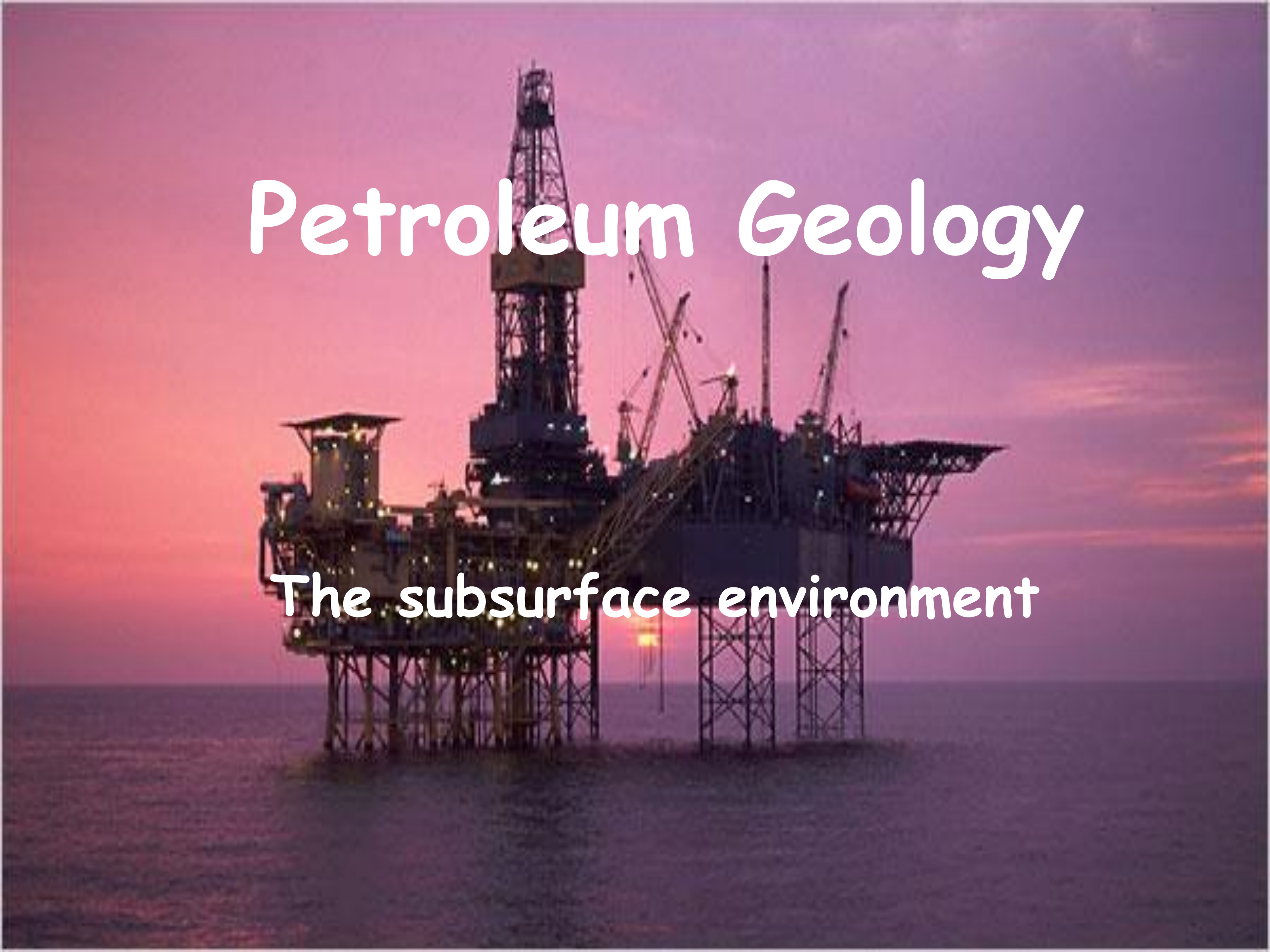
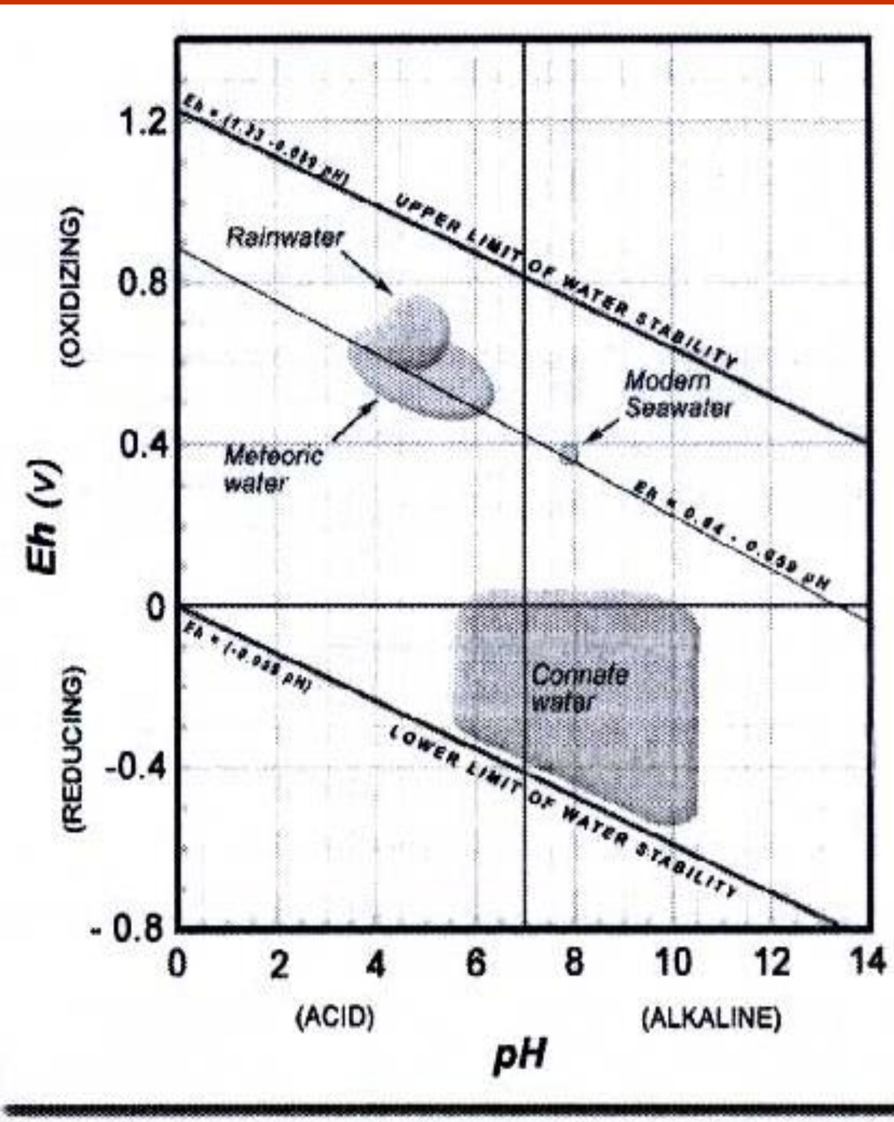
Petroleum Geology

The subsurface environment



Water in subsurface



water in subsurface can be:

Free water

Free to move in and out of pores

Interstitiale(irreducible) water

Bonded to minerals grain can not be removed from a reservoir during production of oil and gas

According to genesis 4 types of water exist:

Meteoric

mixed

juvenile

Connate

Meteoric: near the surface.infiltration of rain waters. Often acid,Low salinity

Connate:waters buried in a close hydraulic system and have not formed part of hydraulic cycle for a long time. Alkaline, High salinity

Water in subsurface

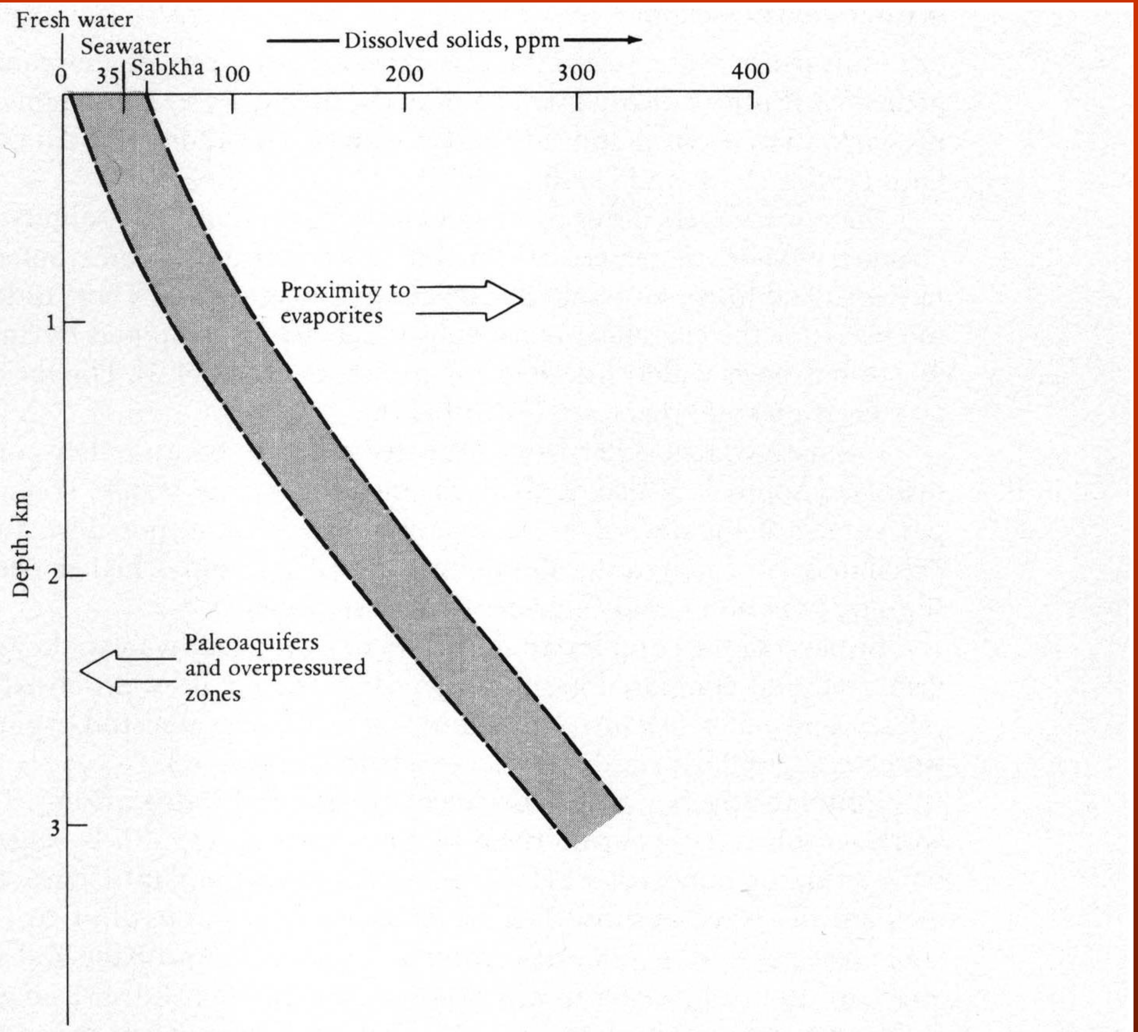


FIGURE 4.2 Graph of salinity against depth for subsurface waters. (After Dickey, 1966,1969; Russell, 1951.)

Normal seawater contain 35000 ppm of TDS mostly as NaCl. Connate waters contain up to 300000 ppm of TDS. Suvsurface water with >100000 ppm TDS is considered brine

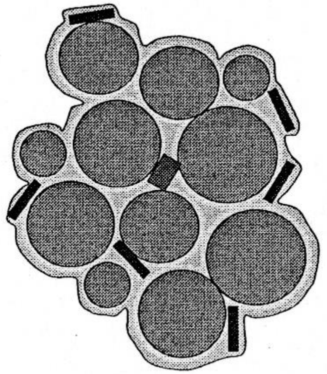
Types of Water in the Reservoir

Structural water and OH (chemically bound)

Hydration water (chemically bound)

Bound water, immobile water, irreducible water

Capillary water



Bound to the grains by capillary force

Water … and what to do about it !

Structural water (chemically bound)

Hydration water (chemically bound)

Bound water, immobile water, irreducible water ("Haftwasser")

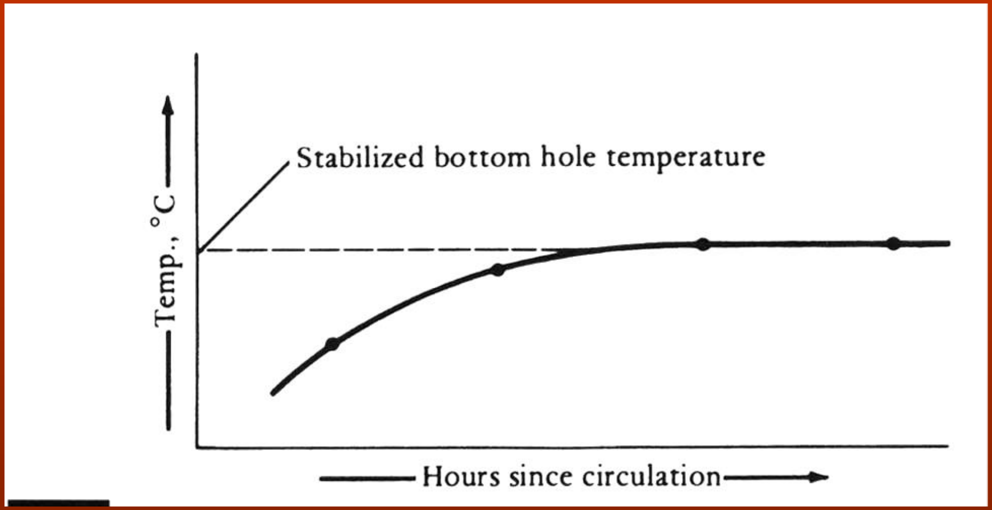
Can't do much about them !

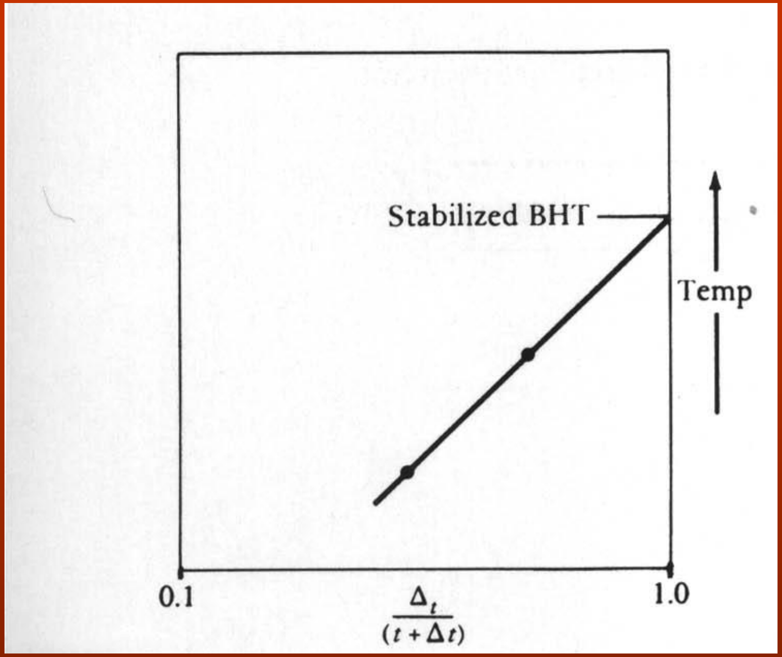
Capillary water

Displace as much as possible !

Temperature in the subsurface

How we measure it





Bottom hole (BHTs) are recorded from wells. Mud takes hours to warm up to T of adjacent strata

Horner plot
T= circulation time
Dt= elapsed time after circulation has ceased

This method is easy to utilize even in the field, however on the other hand, it requires relatively long period of temperature recover data up to 120 hours to estimate correctly.

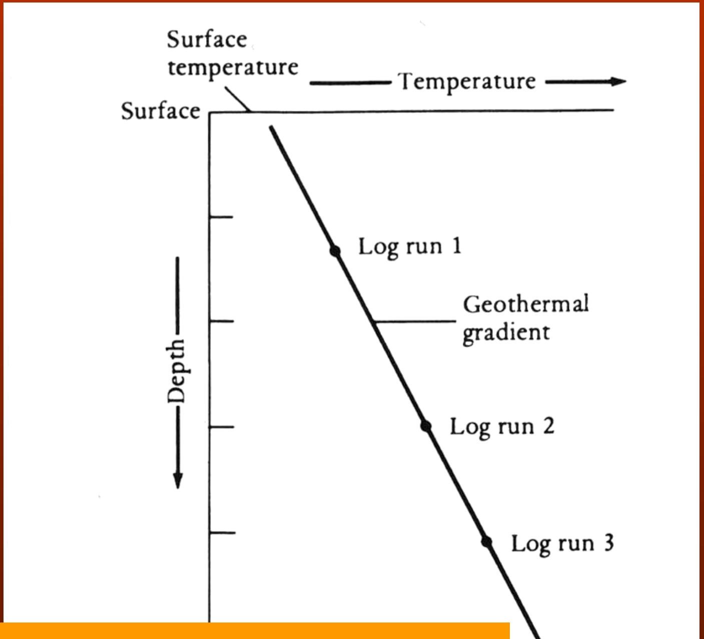
Temperature in the subsurface

- Increases towards the earth's core: geothermal gradient
  - Different lithologies will conduct heat differently: thermal conductivity
  - Additional heat added by decay of radioactive species
  - Heat Flow = Geothermal gradient x thermal conductivity

Change of T with depth

25°C/Km

Varies with tectonic setting



Geothermal gradient

…but

Sometimes BHTs data plotted against depth may show that the geothermal gradient is not constant with depth…..WHY?

variation on thermal conductivity of penetrated strata

Thermal conductivity

Thermal gradient

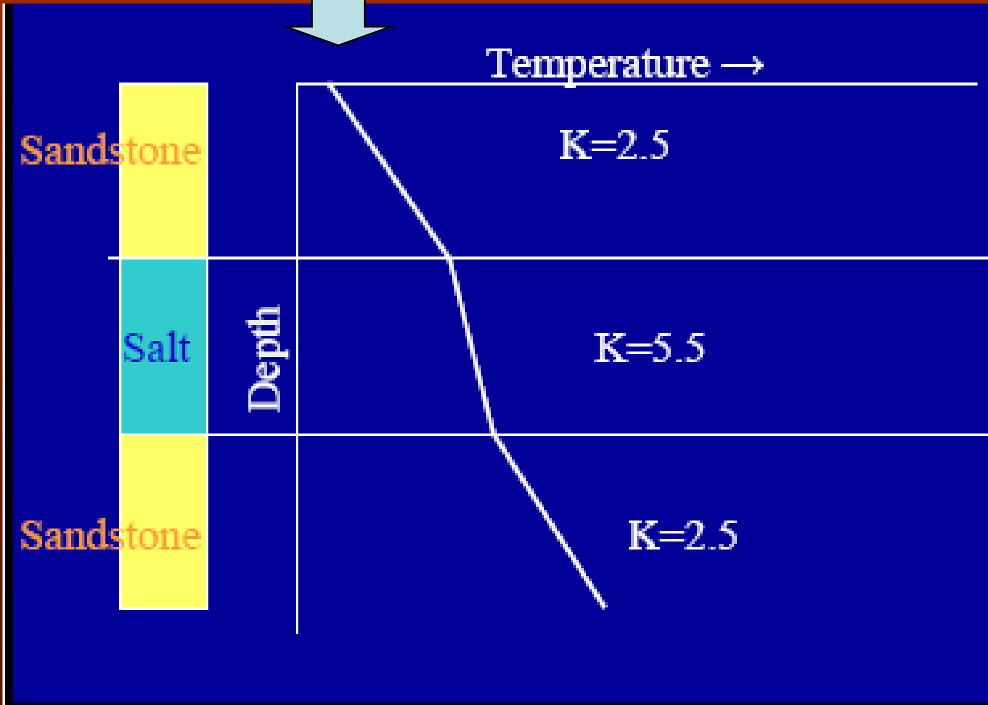
Heat flow → $q=k*dT/dz$

Geothermal gradient differs because sediment with different k are interbedded

Role of Thermal Conductivity

- K (conductivity) W/m°C
- Rock Type / K

Rock Type	K
Salt	5.5
Dolomite	5.5
Granite	3.5
Limestone	2.8 - 3.5
Sandstone	2.6 - 4.0
Shale	1.5 – 3.0
Coal	0.3
Water	0.6



Heat flow

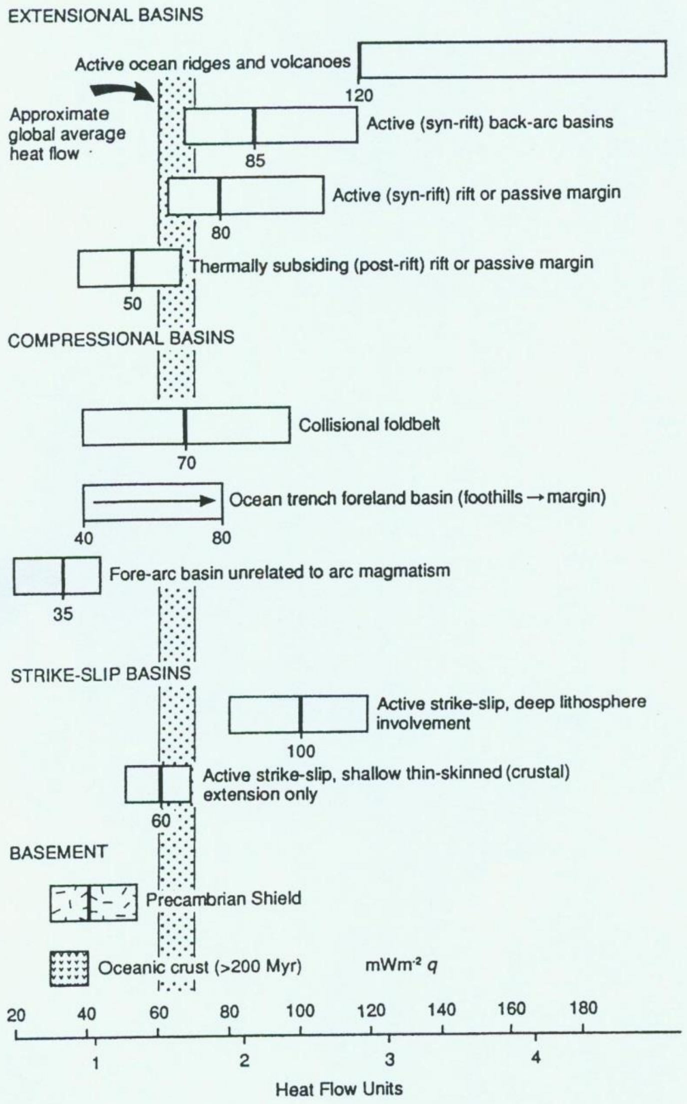


Figure 4.1: Summary of the typical heat flows associated with sedimentary basins of various types (from Allen and Allen, 1990).

Temperature in the subsurface

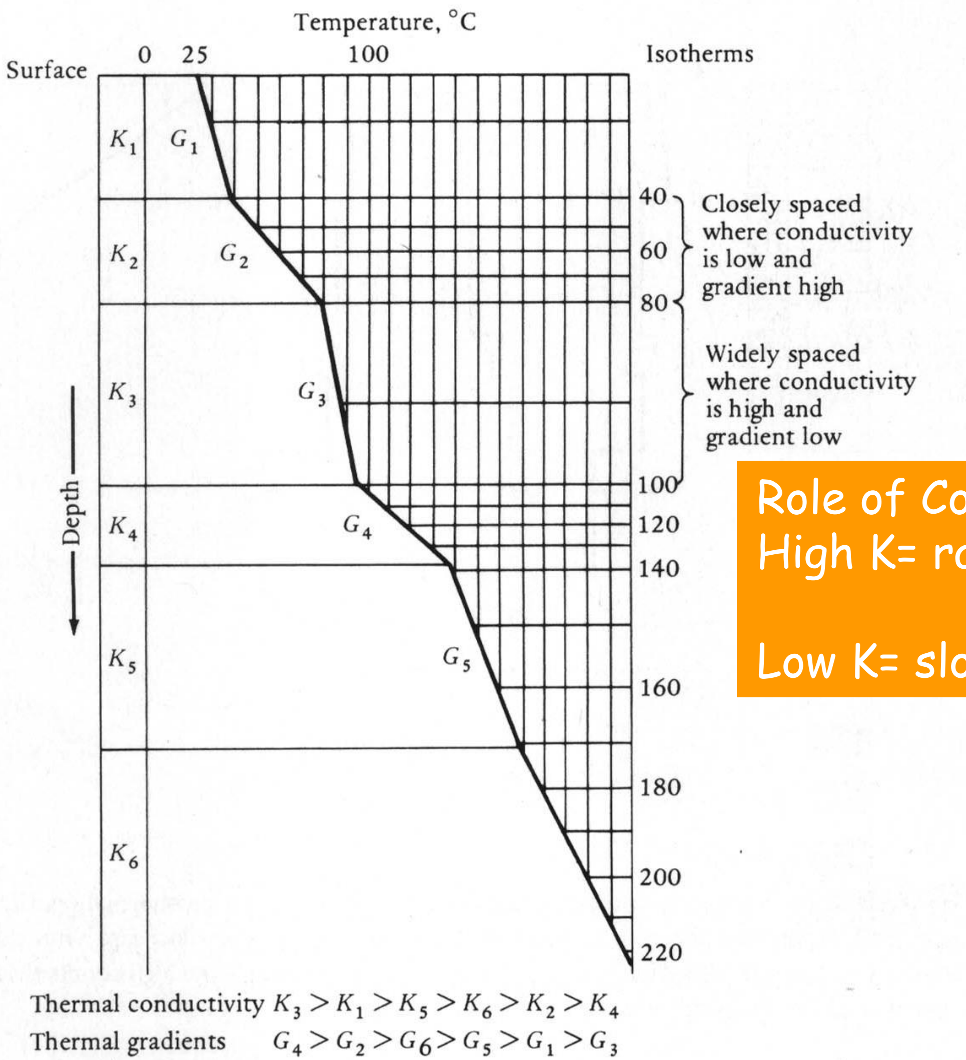


FIGURE 4.8 Depth–temperature plot showing the effect of rocks of differing thermal conductivity (K) on geothermal gradient (G) and the vertical spacing of isotherms.

Now we can draw the isotherms

Role of Conductivity

High K= rapid heat transfer =Low Thermal Gradient

Low K= slow heat transfer = HighThermal Gradient

Temperature in the subsurface

Anomalies on isotherm geometries are likely to occur when strata are folded or where formations are lenticular

Isotherms dome up over a salt diapir and are depressed beneath it because of the high thermal conductivity of evaporites.

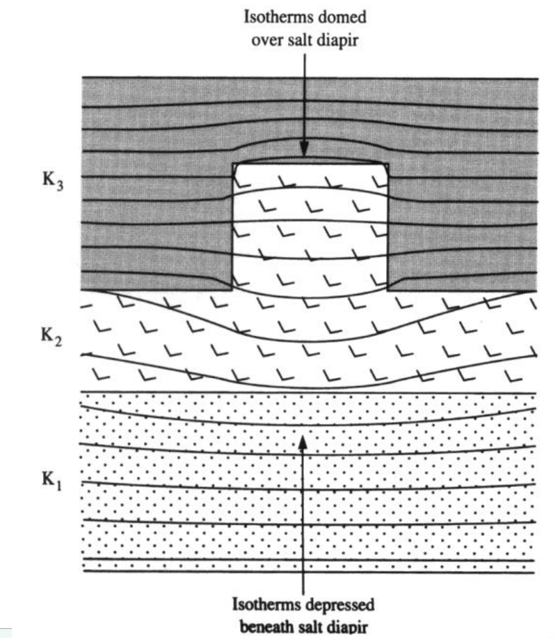


FIGURE 4.9 Isotherms modelled for a salt dome. Contours at 20°C. Conductivities as follows: postsalt sediments, K_3 = 1.74 W·m^{-1}·°C^{-1}. Zechstein (Permian) salt, K_2 = 4.22 W·m^{-1}·°C^{-1}. Pre-Permian Carboniferous clastics, K_1 = 2.82 W·m^{-1}·°C^{-1}. Note how source rocks will be abnormally mature above a salt dome and abnormally immature beneath one. Conversely, reservoir sands may be abnormally cemented above and abnormally porous beneath a diapir. (Developed from Evans, 1977.)

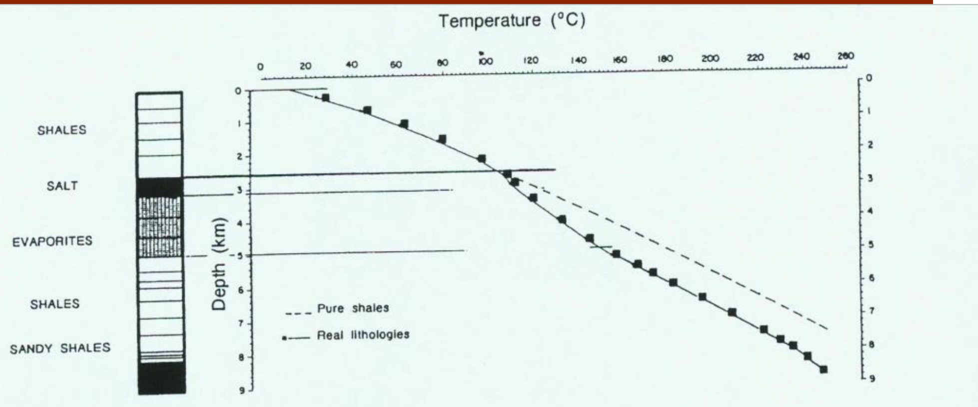


Figure 4.5. Temperature profile through a section containing an evaporite (from Burrus and Audebert, 1990).

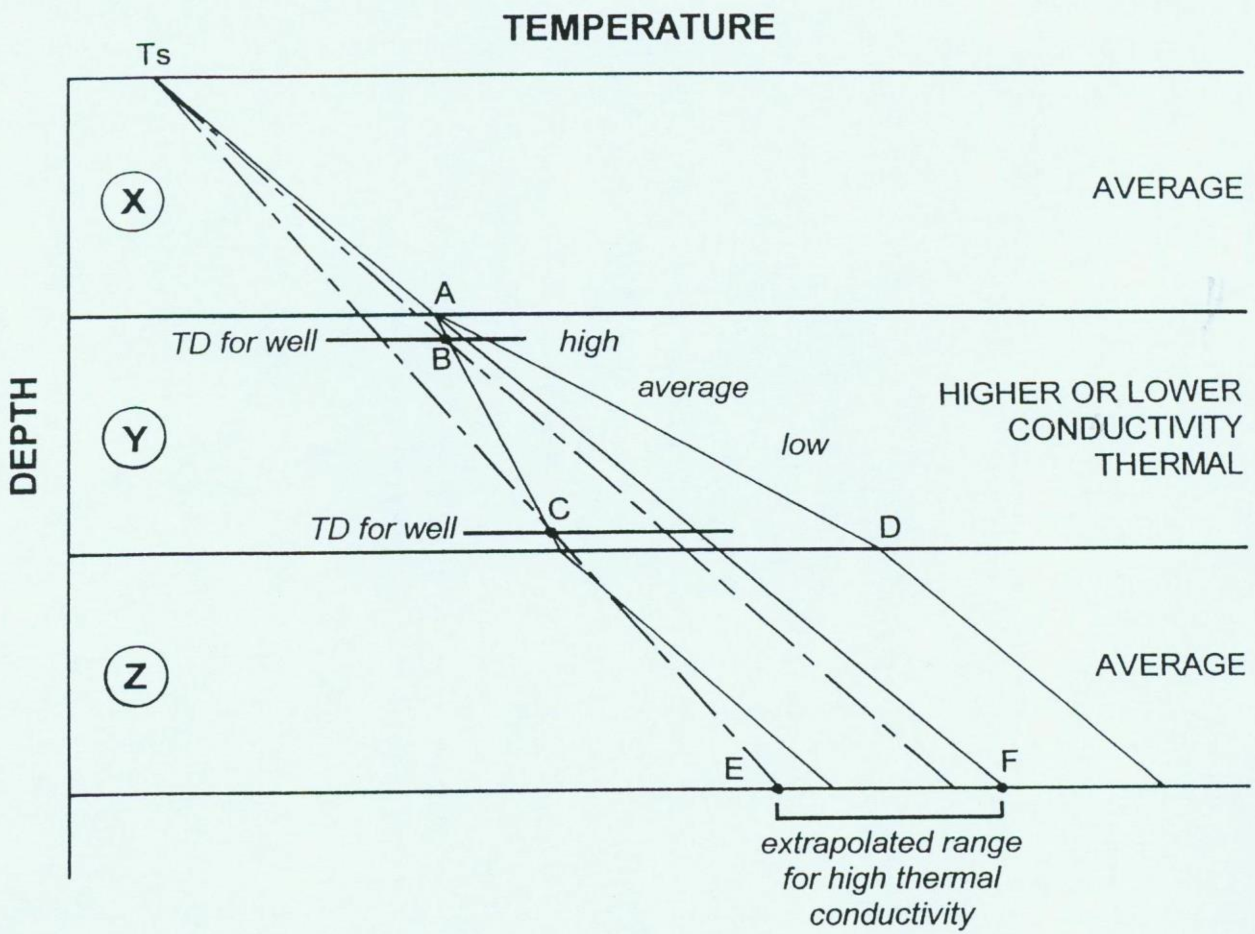
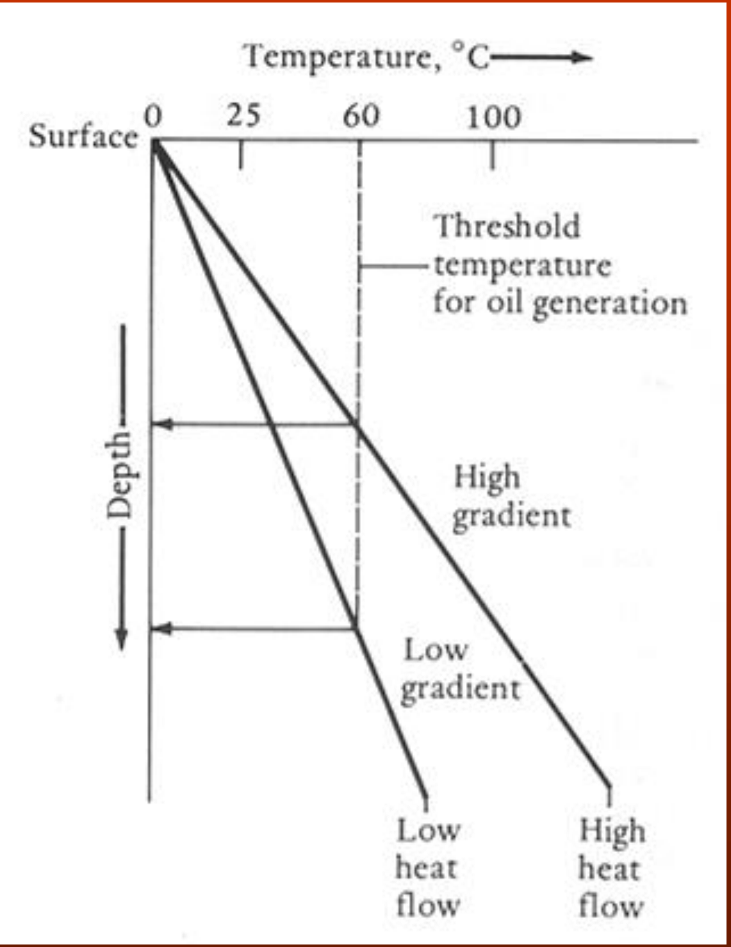


Figure 4.8. Schematic temperature versus depth profiles for a 3-layer system illustrating situations where Layers X and Z always have an average thermal conductivity, but where the conductivity of Layer Y may be higher or lower than average. Dashed lines show possible extrapolated geothermal gradients when drilling stops at different depths in Layer Y. Ts is the surface temperature.

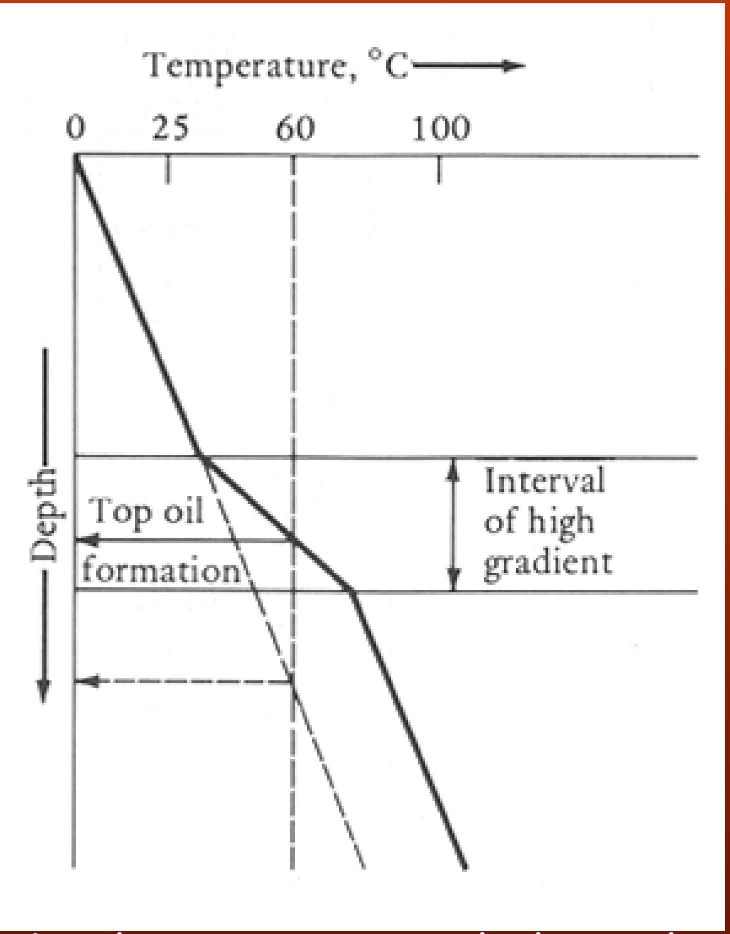
Temperature in the subsurface

The Oil Window

Range of temperature where maturation occurs:60°-120°C



Depth-temperature graph showing how the top of the oil generation zone rises with increasing geothermal gradient



Depth-temperature graph showing how a formation with a low conductivity and high gradient raises the threshold depth of oil generation.

Pressure in the subsurface

PRESSURE: *The force per unit area acting on a surface*

Overburden pressure **(S)** =
lithostatic pressure **(p)** + fluid pressure **(f)**

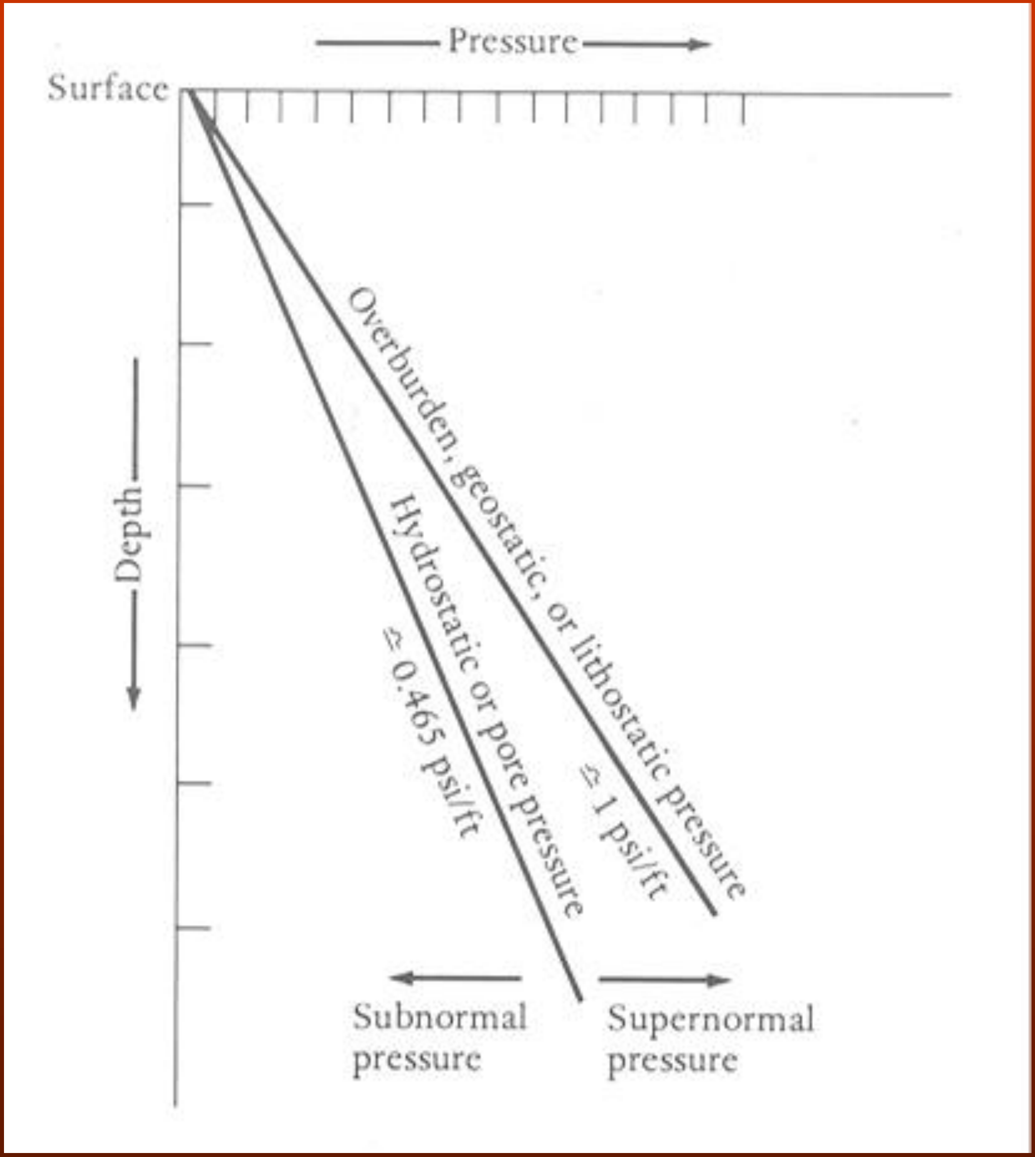
Grain-grain contact (weight of the solid portion)

Hydrostatic (imposed by a column of fluid at rest)
Hydrodynamic (fluid potential gradient caused by fluid flow)

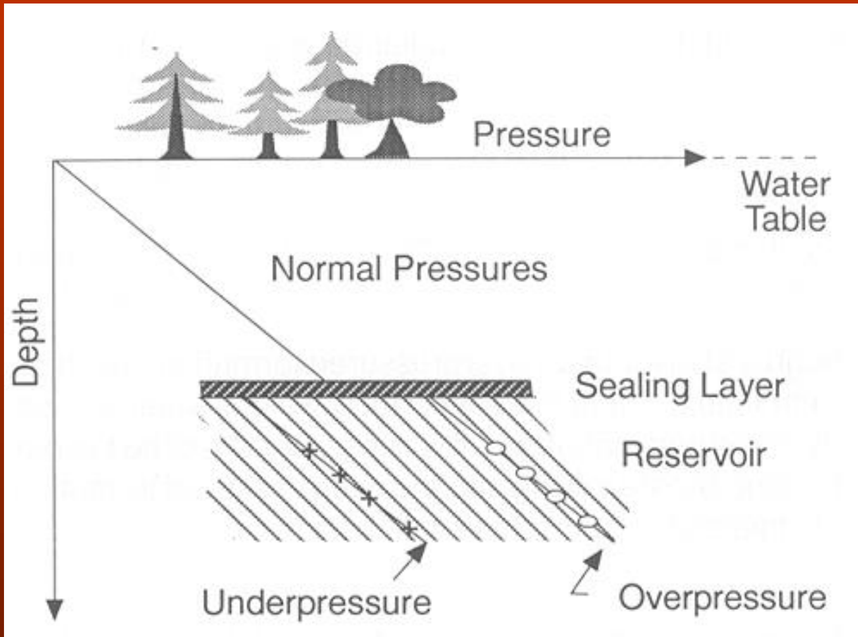
Column of freshwater = 0.43 psi/ft : normal
Abnormal (overpressured) = >0.43 psi/ft
Abnormal (underpressured-subnormal) = <0.43 psi/ft

When fluid P increase forces acting at sediment grain contacts diminish and lithostatic P decrease

Pressure in the subsurface



Depth-pressure graph illustrating hydrostatic and geostatic pressures and concepts.



Pressure in the subsurface

Fluid density changes with depth as a result of changes in:

- T
- P
- Fluid composition (including dissolved gas and solids)
- Fluid phase-gaseous or liquid

Ranges of fluid density and gradient variation

Oil-field liquids and gases occur in a wide range of compositions. The table below shows typical density ranges and gradients for gas, oil, and water. However, because exceptions occur, have some idea of the type of fluid(s) expected in the area being studied and use appropriate values.

Fluid	Normal density range (g/cm^3)	Gradient range (psi/ft)
Gas (gaseous*)	0.007–0.30	0.003–1.130
Gas (liquid)	0.200–0.40	0.090–0.174
Oil	0.400–1.12	0.174–0.486
Water	1.000–1.15	0.433–0.500

*Varies with pressure, temperature, and composition. The composition used for this table is for an average gas composed of 84.3% methane, 14.4% ethane, 0.5% carbon dioxide, and 0.8% nitrogen (GO Log Interpretation Reference Data Handbook, 1972).

Pressure in the subsurface

Calculating geostatic pressure

$$P_G = [\text{weight of rock column}] + [\text{weight of water column}]$$

$$P_G = [\rho_m \times (1 - \phi) \times d\,] + [\rho_w \times \phi \times d]$$

where:

P_G = geostatic pressure (psi)
ρ_m = weighted average of grain (mineral) density (sandstone and shale = 2.65 g/cm^3, limestone = 2.71 g/cm^3)
ρ_w = weighted average of pore-water density (g/cm^3)
ϕ = weighted average of rock porosity
d = depth (ft)

To calculate weighted averages, use 1000-ft (300-m) increments.

Geostatic gradient is the rate of change of geostatic pressure with depth. A geostatic gradient of 1 psi/ft results from an average density of 2.3 g/cm^3.

Three variables determine the geostatic pressure

Densities of formation waters as related to salinities (fresh water ~0.435 psi/ft, water with 88000 TDS ~ 0.465 psi/ft)
Net thickness of different lithologies, e.g SS, Sh, Lmst
Porosities of different lithologies

Geostatic gradients vary with depth and location
The gradient increase with depth for 2 reasons:

Bulk density increase with increasing compaction
Formation water density increase beacuse the amount of TDS in water increase with depth.
Cenozoic of lousiana- geost. Grad. 0.85psi/ft at 1000 ft and 0.95psi/ft at 14000 ft

Pressure in the subsurface

Sub surface P are important on driving fluid flow, influencing petroleum expulsion controlling migration pathway and if present today causing drilling problems. They may also influence compaction

Hydrostatic or normal subsurface fluid pressure at any depth is equal to the pressure exerted by a column of water reaching the surface

Abnormal pressures =upper limiting value of 1.0 psi/ft.In fact this is equivalent to the pressure exerted by the rock column.

Pressure in the subsurface

Hydrodinamic pressure. Fluid flow
P of fluids is given by hydrostatic+hydrodinamic component

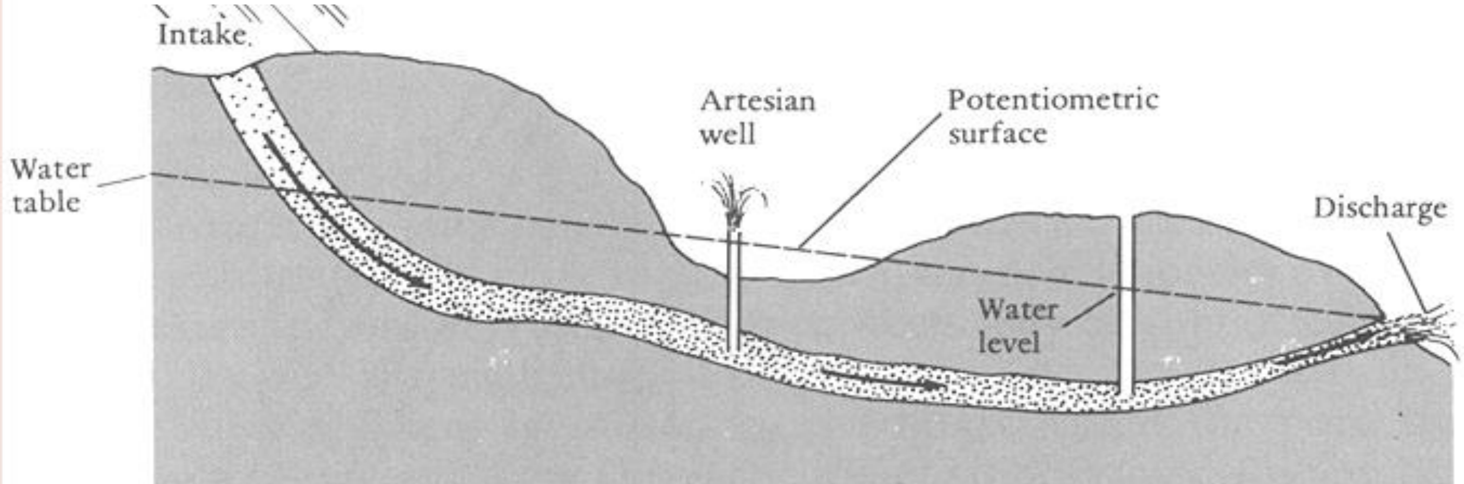
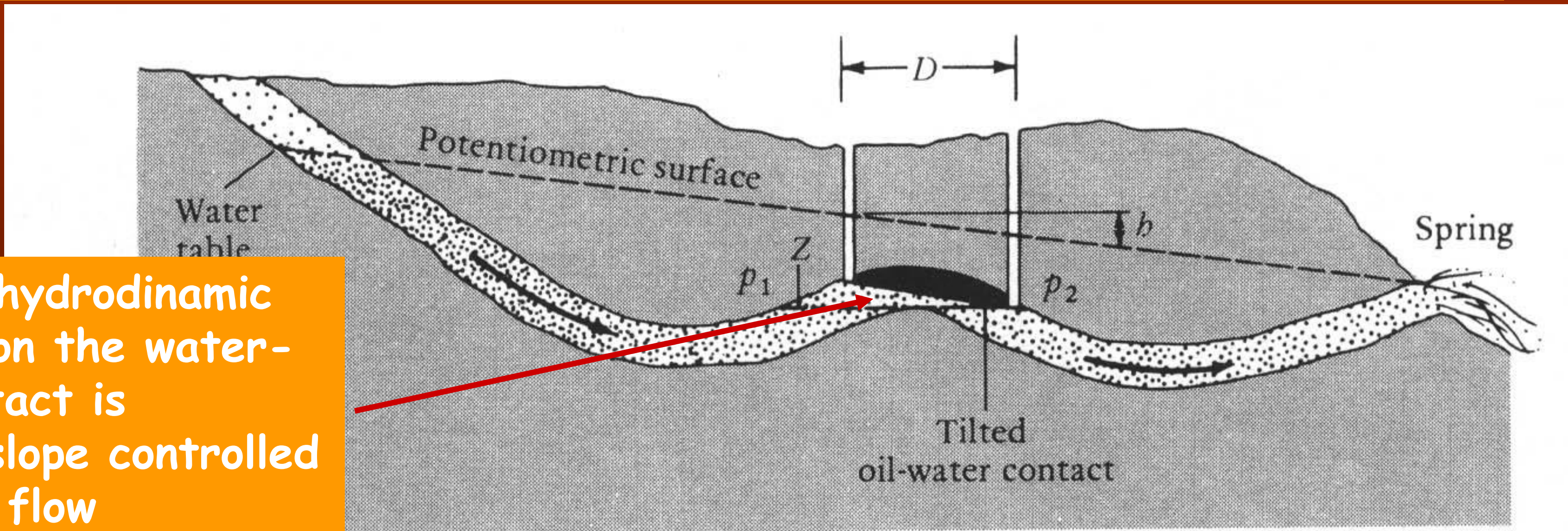


Diagram illustrating the concept of potentiometric or piezometric surface.



Under hydrodinamic condition the water-oil contact is tilted.slope controlled by the flow

Pressure in the subsurface

Whitin any formation with an open pore spase system,P will increase linearly with depth.When separate pressure are encountered in a well it indicates that impermeable barries separate formations

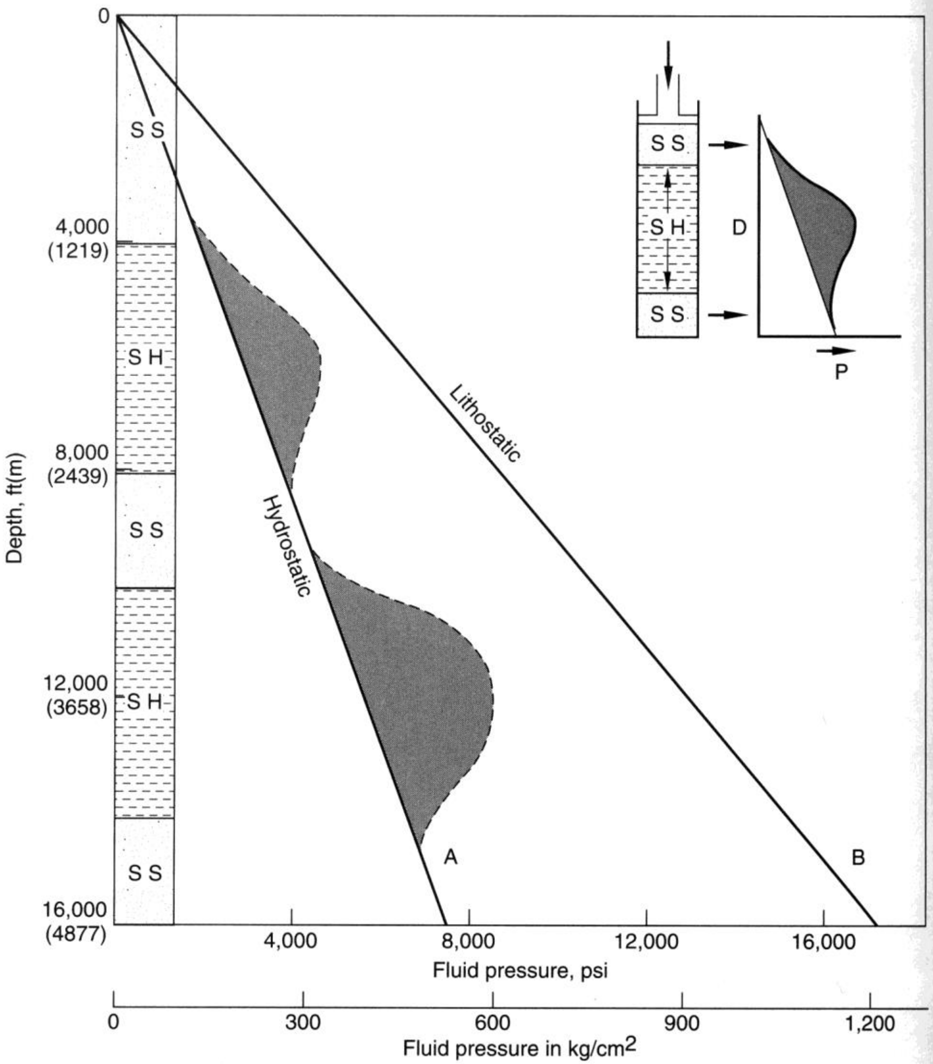
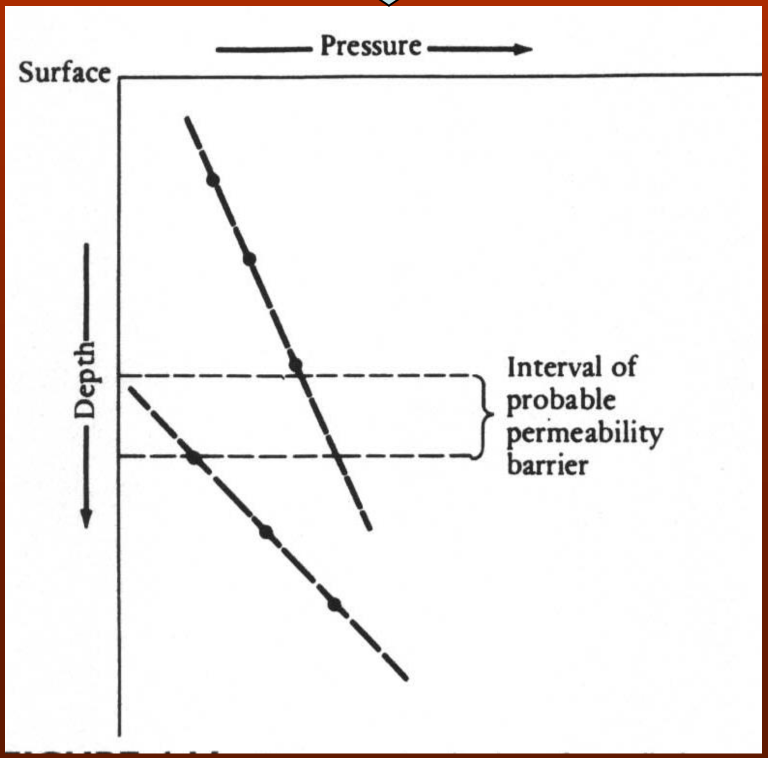


Figure 9-1

Increase in fluid pressure with depth. Line A is the hydrostatic gradient for most petroleum basins, 0.46 psi/ft (10.4 kPa/m). Line B is the lithostatic gradient, 1.08 psi/ft (24.4 kPa/m). The dashed line shows fluid pressures in the sandstone–shale sequence to the left. The diagram in the upper right shows the change in fluid pressure when pressure is applied to layers of sand and clay mud. The center of the shale is a pressure barrier to fluid movement. Fluids are escaping upward and downward to sand beds which are in contact with the surface.



Abnormal Pressure Regimes

Supernormal pressures → Pressures greater than hydrostatic

Overpressuring occurs in close-pore fluid environments where fluid pressure can not be trasmitted through permeable beds to the surface

DANGER FOR DRILLING

Permeability barrier:

lithological

structural

Evaporites ,shales

Fault,folds

The most common cause for overpressure is compaction or better the lack of it

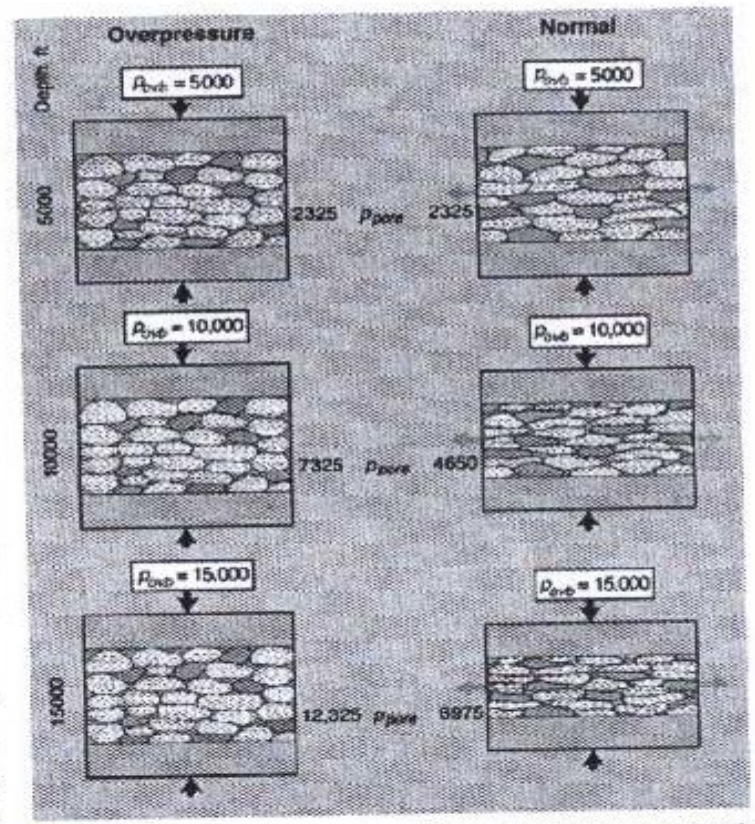
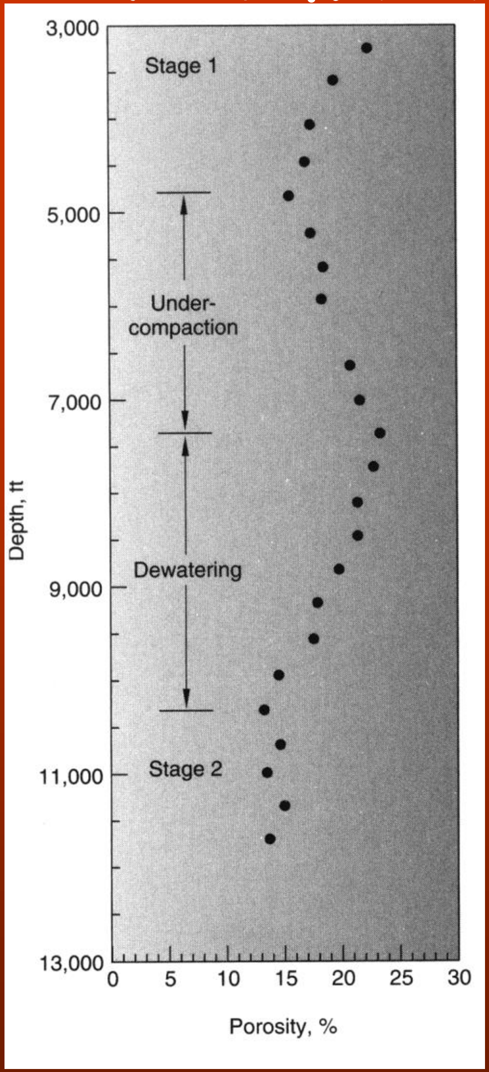


Figure 103. Overpressure. When sediment burial is rapid and permeability poor, pore fluid cannot escape and supports the ever-increasing overburden stress (left). Permeable lithologies undergo 'dewatering' (right). P_{ovb} = overburden pressure (psi); P_{pore} = pore pressure (psi) (image © 2007 Schlumberger, Ltd. Used with permission).

Normal and Abnormal Pressure Regimes



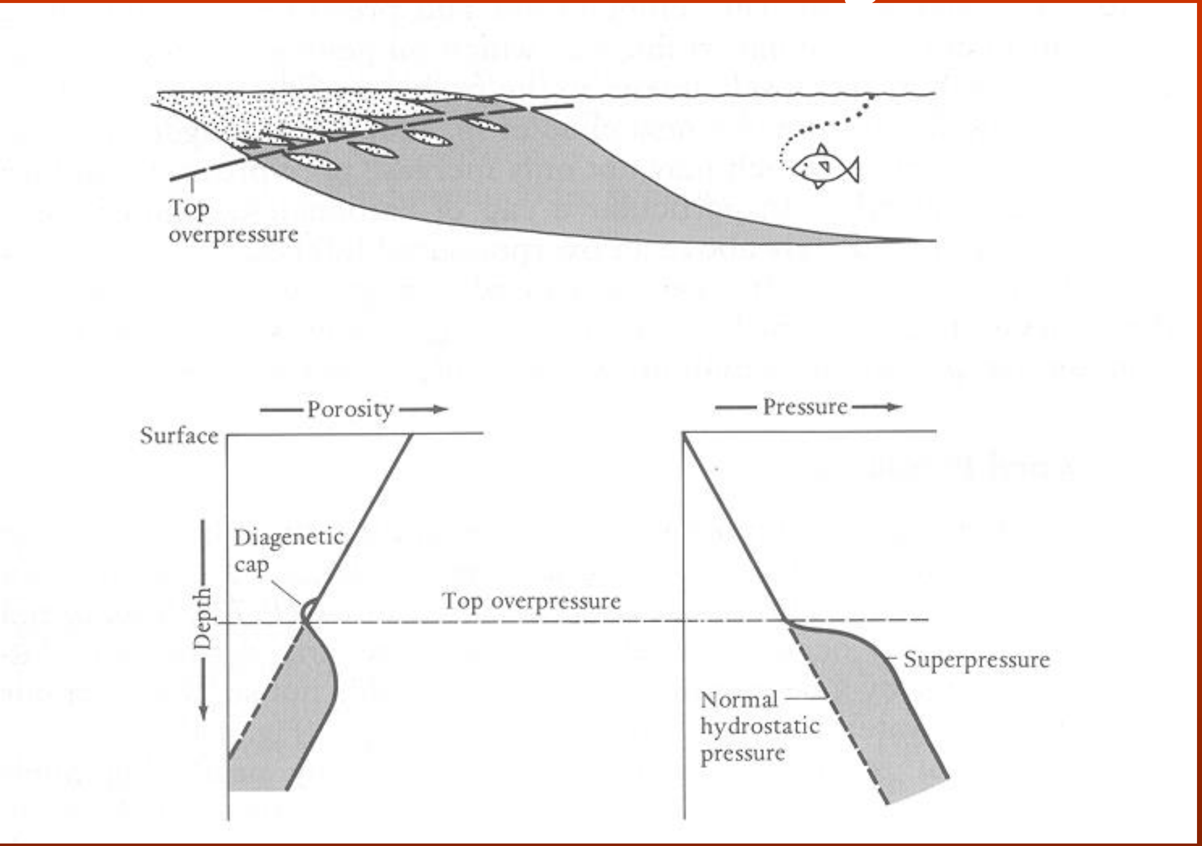


Figure 9-2
Porosity/depth profile showing under-compaction in a thick shale at Mustang Island, at 27° 8′S, 96° 8′W offshore the south Texas Gulf Coast.

A) Cross section through a delta. B) depth-porosity and depth-pressure curves, indicating overpressuring due to undercompaction.

Overburden pressure (S) = lithostatic pressure (p) + fluid pressure (f)

Normal and Abnormal Pressure Regimes

Overpressures on fluid compartments at great depth (>3000m) surrounded by impermeable rocks

In this case
No undercompaction

Permeability barriers created by cementation of fractures

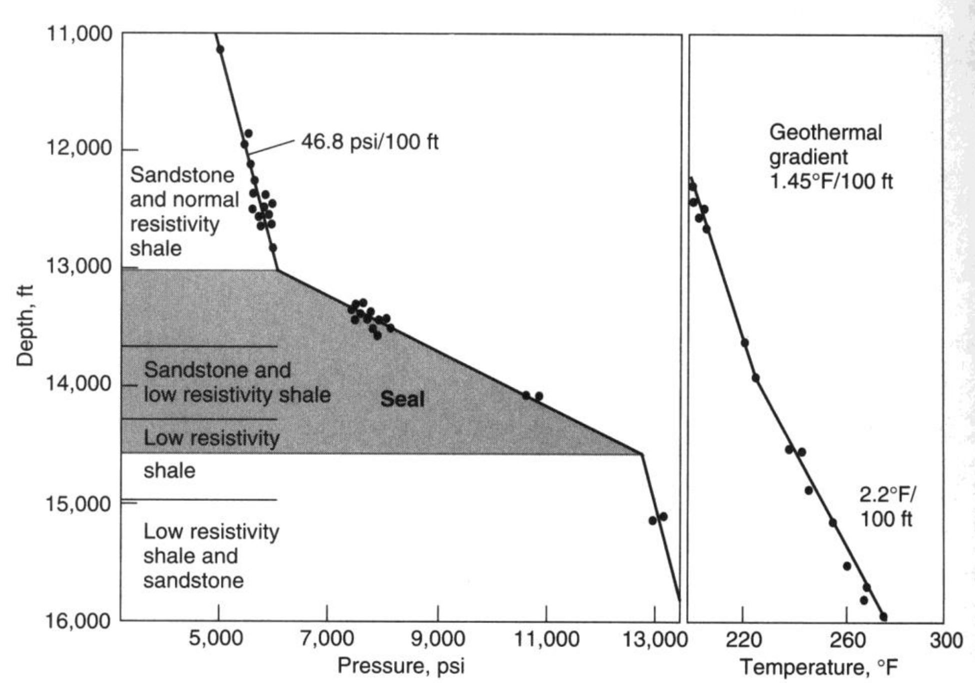


Figure 9-6

Pressure/depth gradient in Lower Miocene formations, Vermilion area, offshore Louisiana. Data points are DST measurement from six wells in Blocks 14 and 15. Geothermal gradients decrease to 1.8°C/100 m (1.0°F/100 ft) in shallower beds located above the areas shown. [Powley 1985]

In overpressured zones the Geothermal gradient could increases. Overpressures could be find using Vitrinite reflectance studies

Subnormal pressures

Subnormal reservoir pressures (P less than 0.43 psi/ft of depth) are very common.

Causes non well understood. If a reservoir containing either gas or oil is isolated and then subjected to uplift and erosion, the removal of overburden causes an elastic rebound of the solids and an increase in volume of the pores.. The pressure of the pore water in the acquifer and shales will drop.

Most low pressure reservoirs in area where there has been uplift and erosion since the sediment forming the reservoir were deposited and lithified.

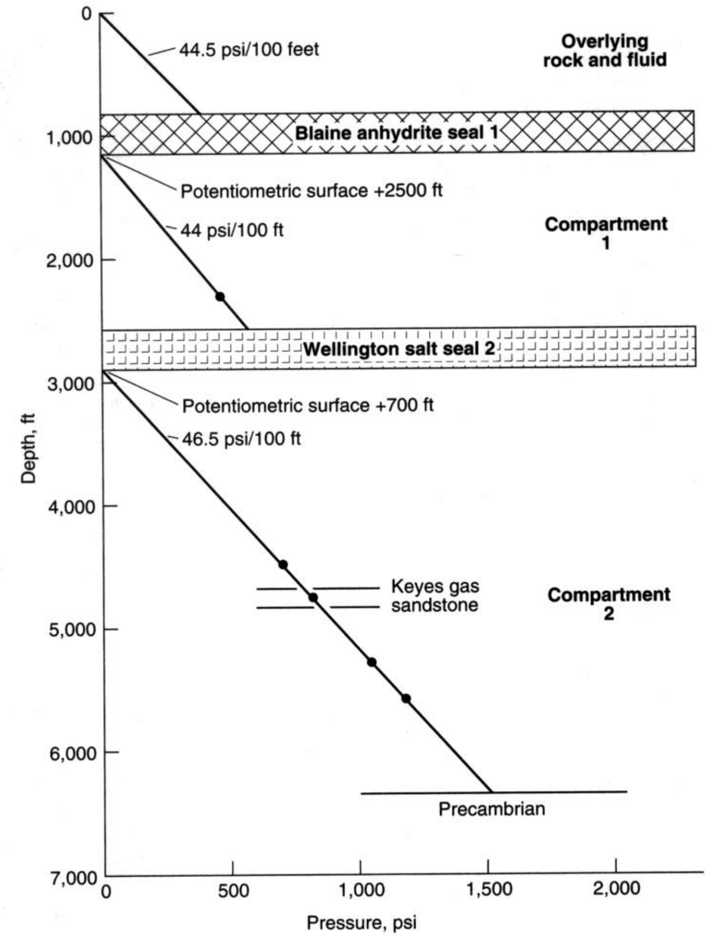


Figure 9-5
Pressure/depth gradient, Keyes field, Cimarron and Texas counties, Oklahoma, based on information from Dwight Energy Data Company. [Powley 1980]

Determining formation fluid P with DST

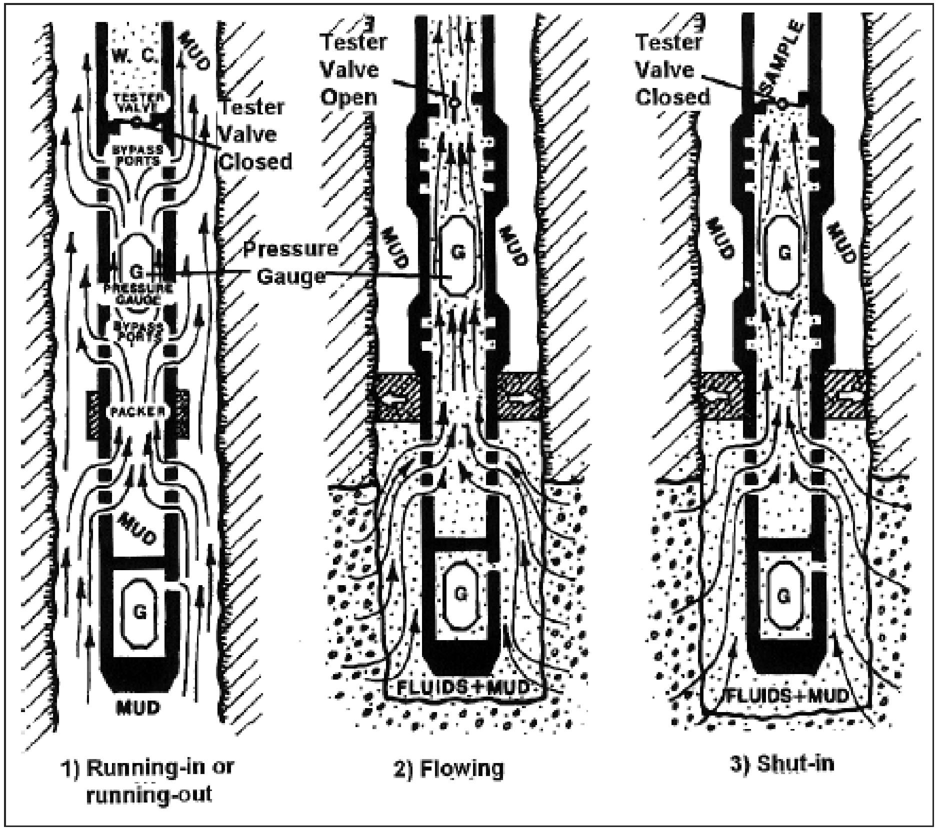
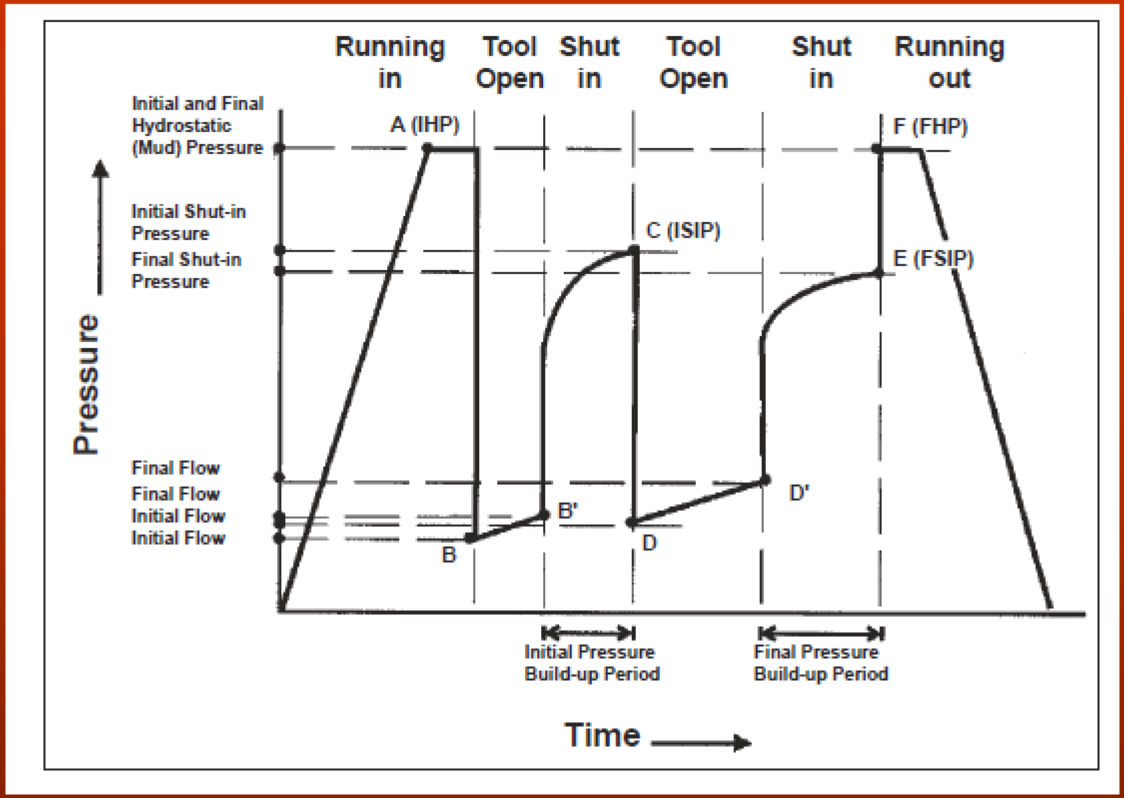


Figure 5–13. Modified from Dalhberg, 1994; courtesy Springer-Verlag.

Run in run out period= Tester valve is closed. Drilling fluids flow through the ports
The P gauges respond to the weight of the drilling mud column
Flowing period= an interval of the borehole is sealed off from the rest of the borehole.tester valve opened creating a P drop in the tool which sucks fluids into the tool. Recovered volumes of oil,gas,water, mud are recorded
Shut in period= Tester valve closed.interval sealed off. P increase in the closed tool gradually until it reaches an equilibrium with the P of the isolated fm

Determining formation fluid P



A= initial Hydrost. P exerted by the mud column in the borehole
B & B1= P recorded when the tool is opened up to the fm and fluids flow
C= initial shut-in pressure measured when the tool is closed. It is the P in the reservoir
D & D1= P recorded during the next flow period
E= final shut-in period. Record the P in the reservoir
F= final Hydrost pressure of mud column. It should match P of point A within 5 psi

Prediction of overpressure while drilling

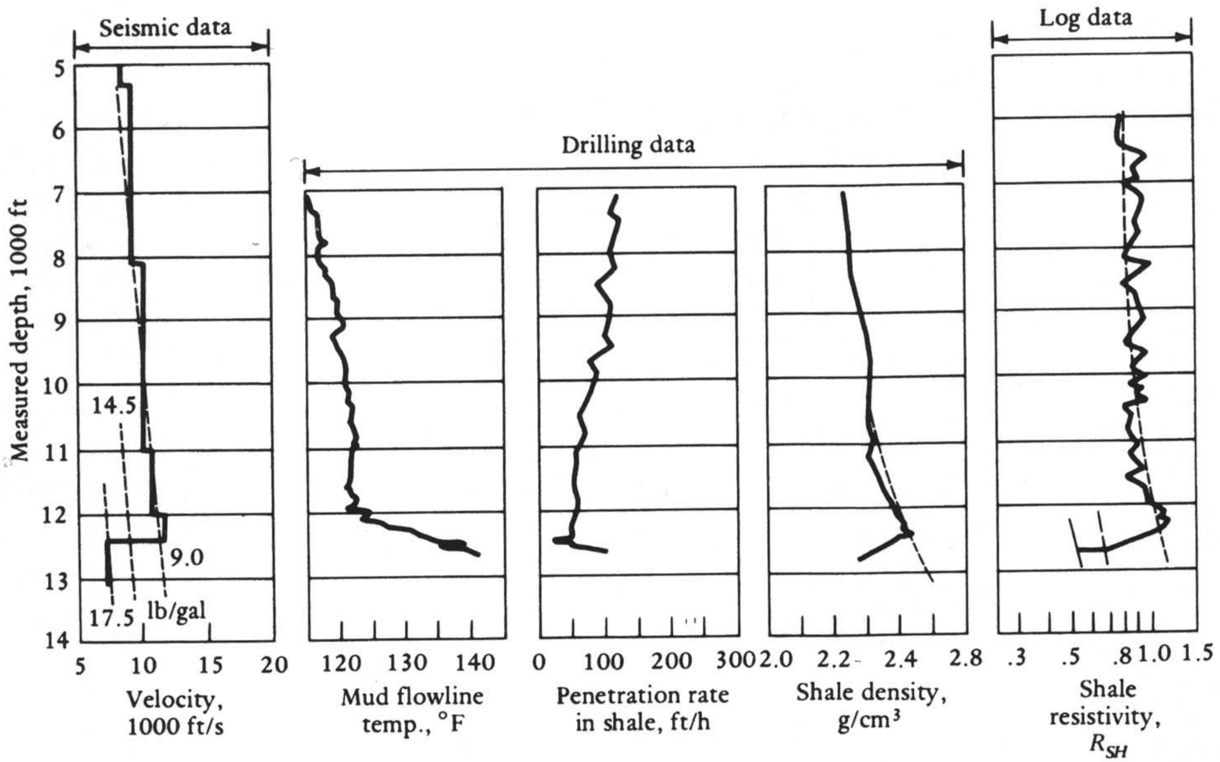


FIGURE 4.11 Various indicators of overpressure detection. In this well a zone of overpressure is present below 12,400 ft. (After Fertl and Chilingarian, 1976 © SPE-AIME.)

Drilling rate usually increase- Normal pressure:DR increase as sediment compact

Undercompacted shales usually have a much lower elctrical resistivity than normally compacted

Undercompacted shales have low seismic velocity and low density

Drilling problems with overpressured reservoirs

Blowouts- uncontrolled production of formation fluids

Caving-high pore pressure in low K rocks causes them to stress relieve or cave into the borehole

Stuck pipe- the drill pipe adheres to the side of the borehole due to swelling (stress relief) of the borehole walls behind it

Lost circulation- by raising the mud weight to control the formation P at the bit, the formation may rupture. The mud will then run out into a cavity of its own making

Important to know both the pressure of the fluids in the pores and the pressure at witch the formations will fracture. Pumping just heavy mud is not a solution!

Normal and Abnormal Pressure Regimes

Causes of abnormally pressured reservoirs.

Uplift/burial of rocks: whereby permeable rock, encapsulated by thick layers of shale or salt, is either uplifted or down thrown. The overburden pressure is altered, but the fluid pressure cannot vary, because the reservoir is isolated, and therefore pore fluids absorb the change in the overburden stress.

Thermal Effect: causing expansion or contraction of fluids which are unable to escape from an isolated reservoir.

Rapid burial of sediments: in sedimentary environments where sand bodies are deposited within shale deposits at a high rate the fluid cannot escape from the pores as the rock is burried under younger sediments and compacted. This leads to overpressure.

Rapid erosion: in the case of isolated reservoirs where the overburden is reduced through erosion.

Depletion of a sealed or low permeability reservoir through production.

Depletion due to production in adjacent field in pressure communication via a common aquifer.

Phases changes e.g. anydrite into gypsum (absorbs water) or alteration in clay mineralogy.

Overpressures as result of hydrocarbon charge (displacement pressure > pore fluid pressure)

Inflation of pressure due to seal failure (e.g. faulting) . Uncontrolled cross flow between reservoirs.

Oil generation expulsion and Migration

Present day maturity (for mature or post mature rocks) gives no information about the actual time when they become mature

OM in a rock may be made up of several different kerogen types that have different generating abilities and different thermal stabilities

The time of generation is important because it is the migration pathway at that time that will control where the oil goes

Quantities generated

The progress of generation is reported as TR (or PI if no migration occurred):

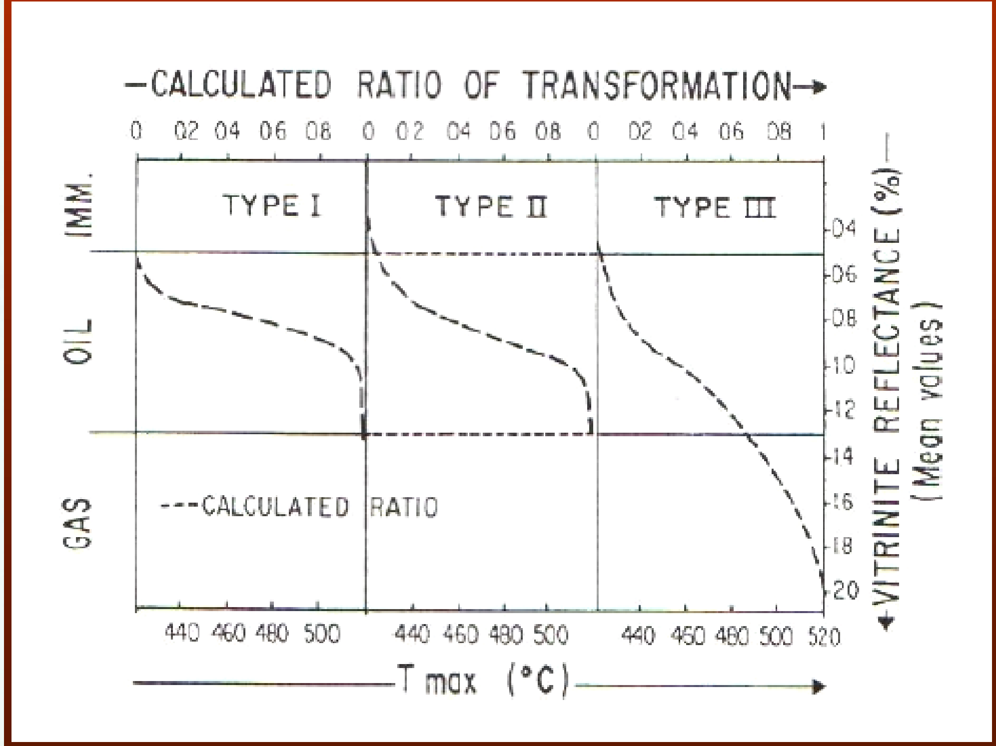
TR=amount generated/total potential for generation=peak1/peak1+peak2
Transformation ratio (TR) is ratio of generated petroleum to potential petroleum. In other words it is ratio of organic matter which is transformed to oil and gas. The transformation ratio is related to organic matter maturation, the more maturity is increased, the more oil is generated.

Geochemical parameters and pyrolysis information used to establish source rock maturity, generating potential, and type of hydrocarbon product. Values are from Peters (1986) but there are variations among values quoted by other authors.

GENERATING POTENTIAL	TOC (wt%)	S1 mg HC/g rock	S2 mg HC/g rock
Poor	0.0 - 0.5	0.0 - 0.5	0.0 - 2.5
Fair	0.5 - 1.0	0.5 - 1.0	2.5 - 5.0
Good	1.0 - 2.0	1.0 - 2.0	5.0 - 10
Very good	>2.0	>2.0	>10

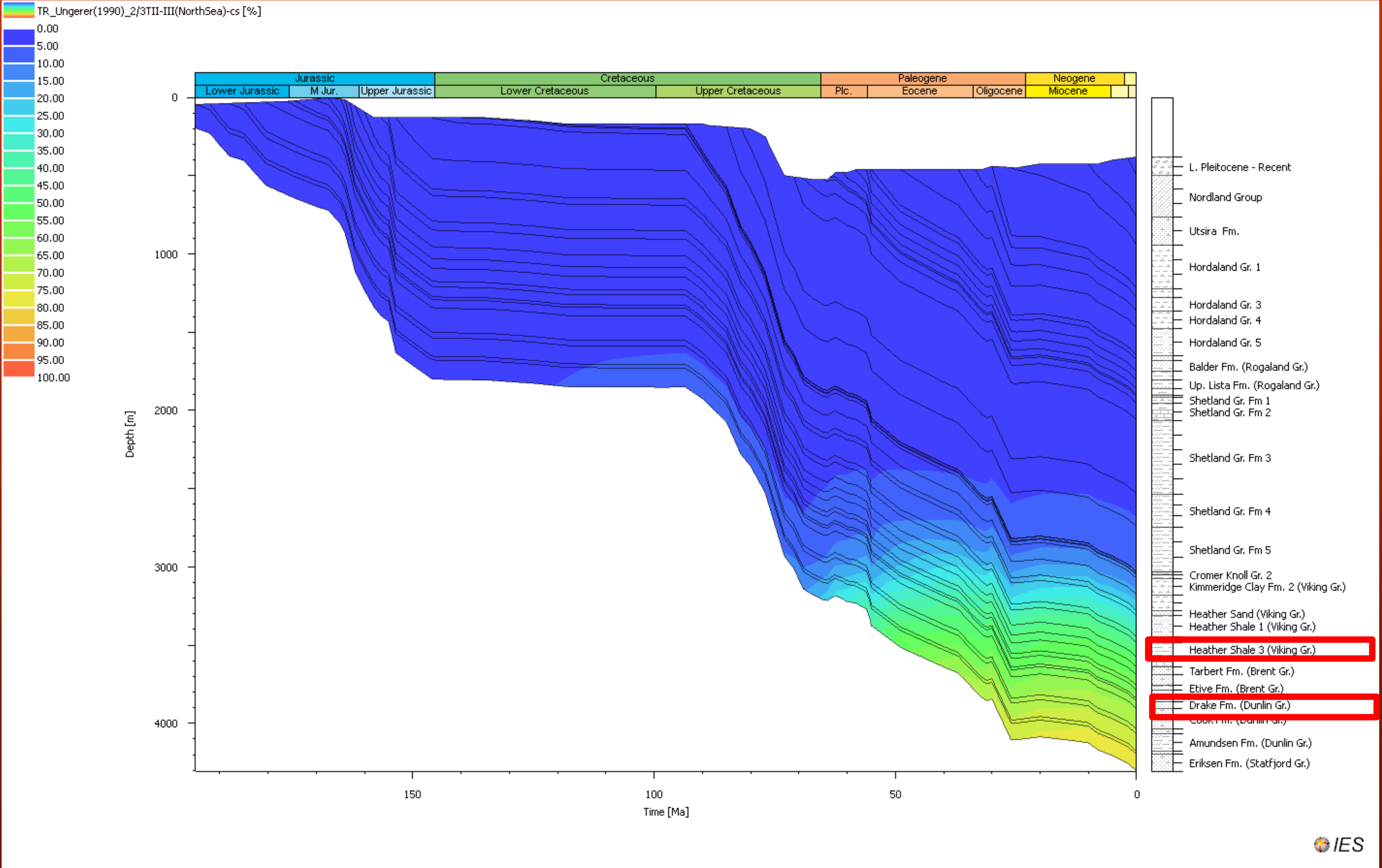
TYPE	HI	S2 / S3
Gas	0 - 150	0 - 3
Gas and oil	150 - 300	3 - 5
Oil	>300	>5

MATURATION	TR	Tmax	Ro
Top of oil window	~0.1	~435 - 445	~0.6
Bottom of oil window	~0.4	~470	~1.4



Quantities generated

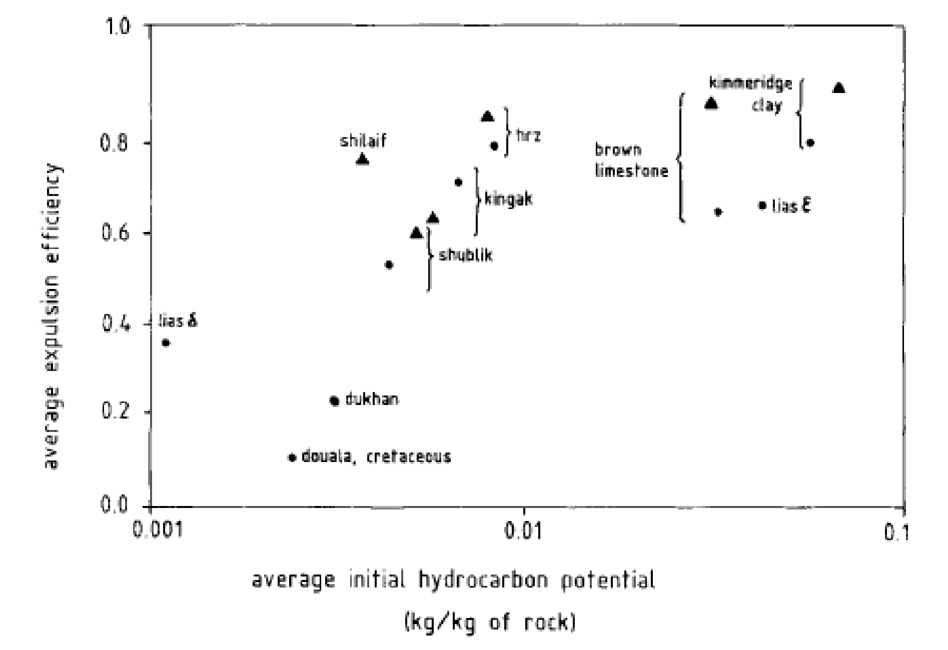
1-D model basin history



Transformation-Ratio: Heather FM. Shale: 25 – 45%
DrakeFM. Shale: 60 – 65%

Petroleum generated and expelled

Po =initial petroleum potential=inizial oil+initial reactive kerogen



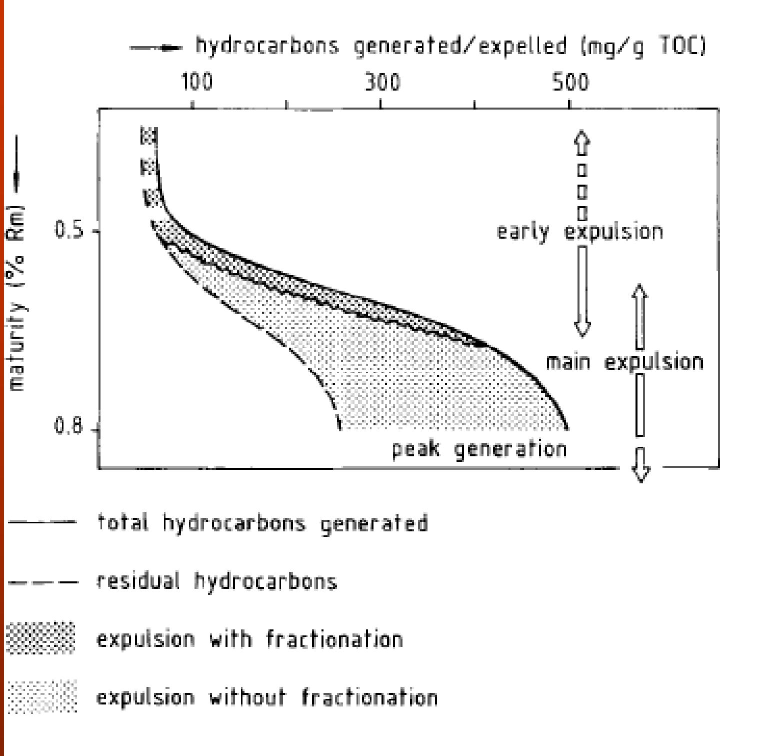


Figure 3.16 Schematic representation of amount of hydrocarbons generated in, and expelled from a type II kerogen-bearing source rock as a function of organic matter maturity for the initial part of the oil window (after Leythaeuser et al., 1987. Reprinted with permission from the Proceedings 12th World Petroleum Congress, Houston, Vol. 2, Fig. 2a, p. 229).

Po =initial petroleum potential=inizial oil+initial reactive kerogen

Maturity and petroleum generation

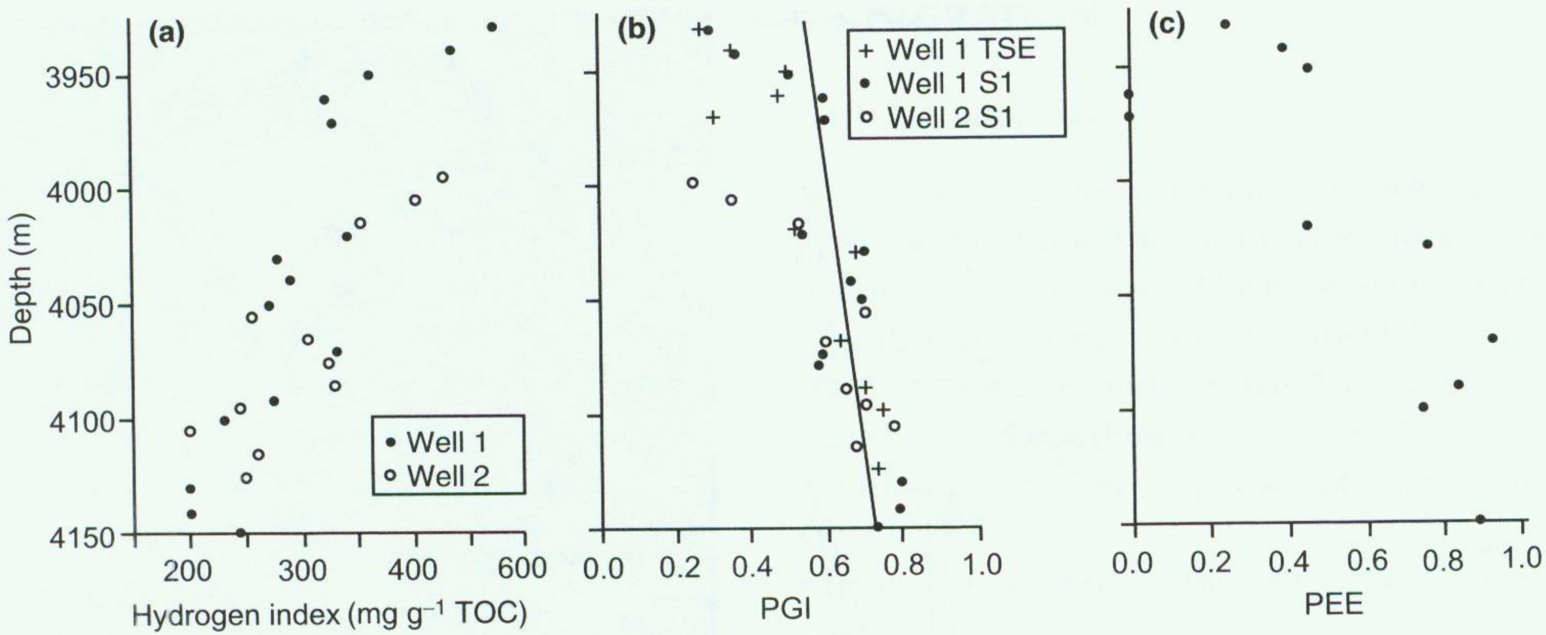
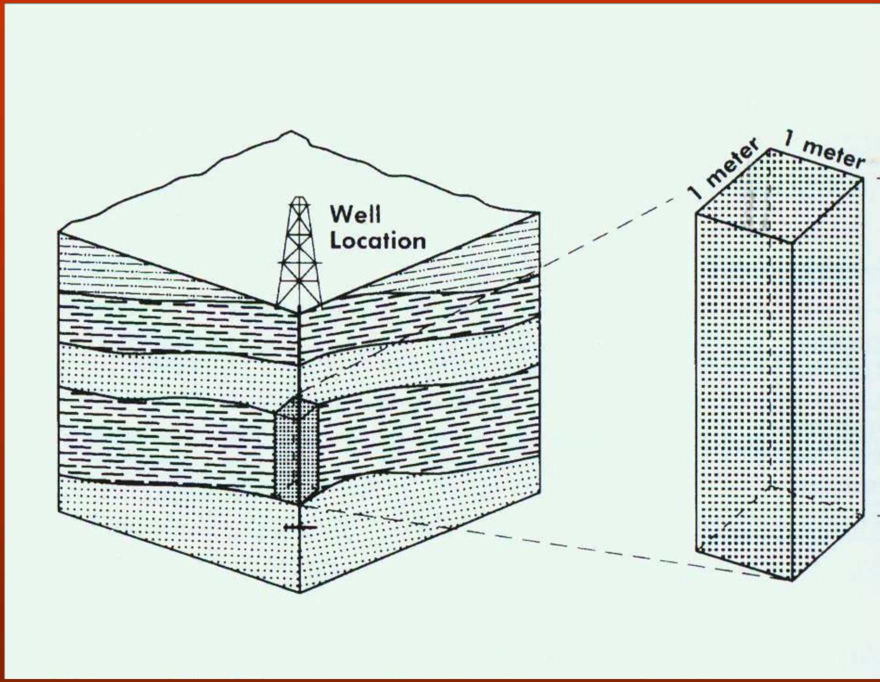


Fig.4.28 (a) The average hydrogen index (mg g^{-1} TOC) as a function of depth, Kimmeridge Clay Formation, Miller Field, UK continental shelf. The hydrogen index was measured every 2 m: the points shown are averages for each 10 m interval (five samples), plotted at the mid-point of the range. (b) The average petroleum generation index as a function of depth (calculated using both S_1 pyrolysis and TSE methods for well 1). (c) Average petroleum expulsion efficiency (PEE) as a function of depth for well 1, calculated using TSE data. (From Mackenzie et al. 1987.)

Quantities generated

But is better to combine net source rock thickness and richness



The source potential index (SPI) or cumulative HC potential is the maximum quantity of HC (in metric tons) that can be generated within a column of source rock under 1 m2 of surface area

$$SPI=h(S1+S2)\rho/1000$$

Oil Migration

Migration is the movement of oil and gas within the subsurface.

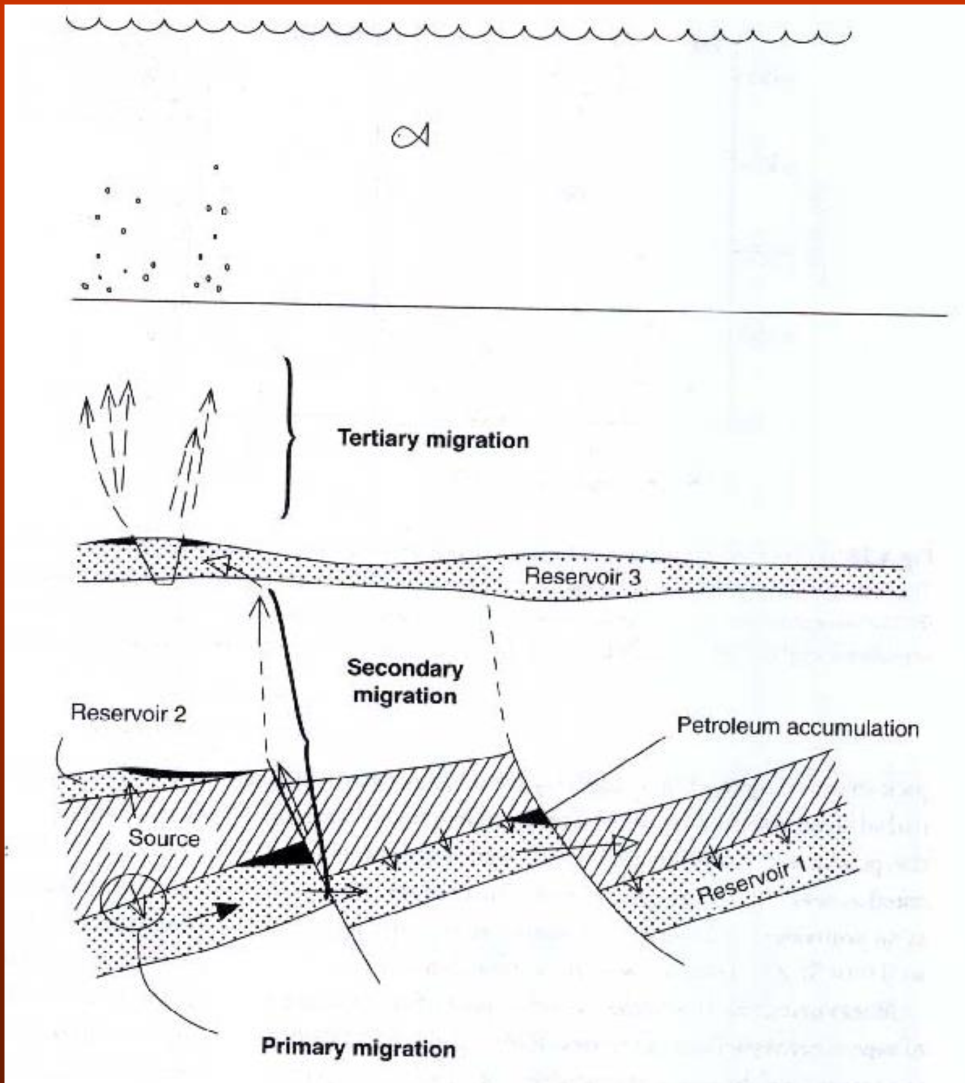
Primary migration is the first phase of the migration process; it involves expulsion of hydrocarbons from their fine-grained, lowpermeability source rock into a carrier bed having much greater permeability.

Secondary migration is the movement of oil and gas within this carrier bed. *Accumulation is* the concentration of migrated hydrocarbons in a relatively immobile configuration, where they can be preserved over long periods of time.

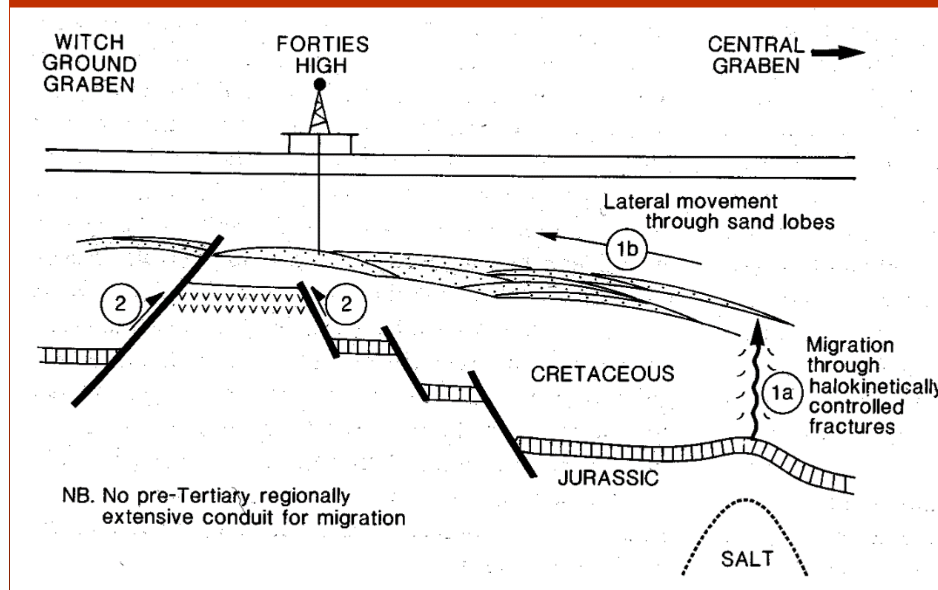
Tertiary migration is the movement of petroleum from a previous accummulation to eithr the earth's surface or a shallower trap

This processes progres until the oil column reaches a rock whose pores are so small that the oil column pressure cannot force further movement: the oil is trapped against a CAP ROCK (seal)

Oil Migration



Secondary Migration

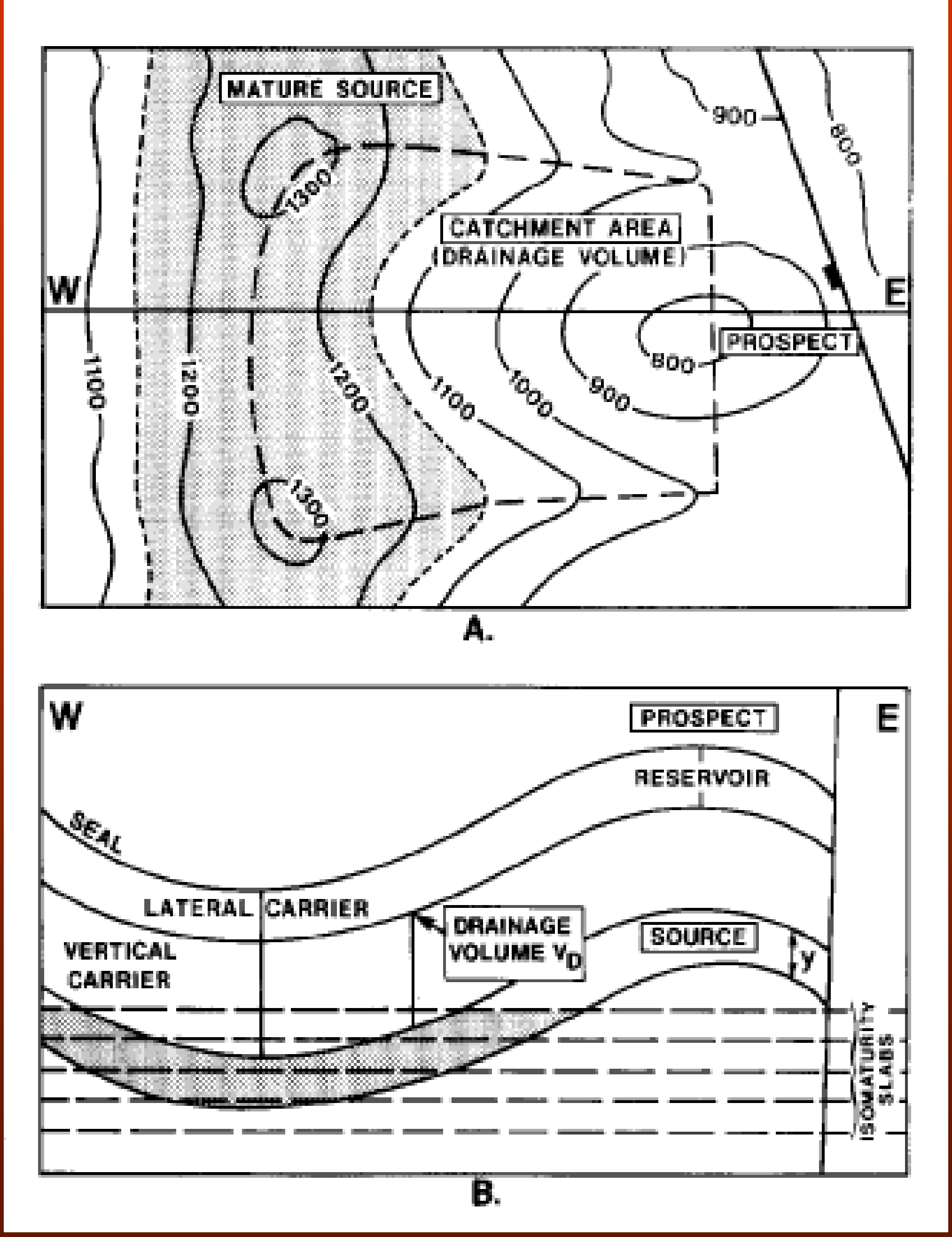


The volume of rock that constitutes the migration pathway is called drainage volume

The volume of Petroleum lost along the migration is proportional to the pore volume through which the petroleum flows.

Volume of petroleum charge=

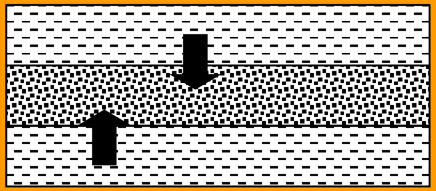
Vc=Ve-Vl



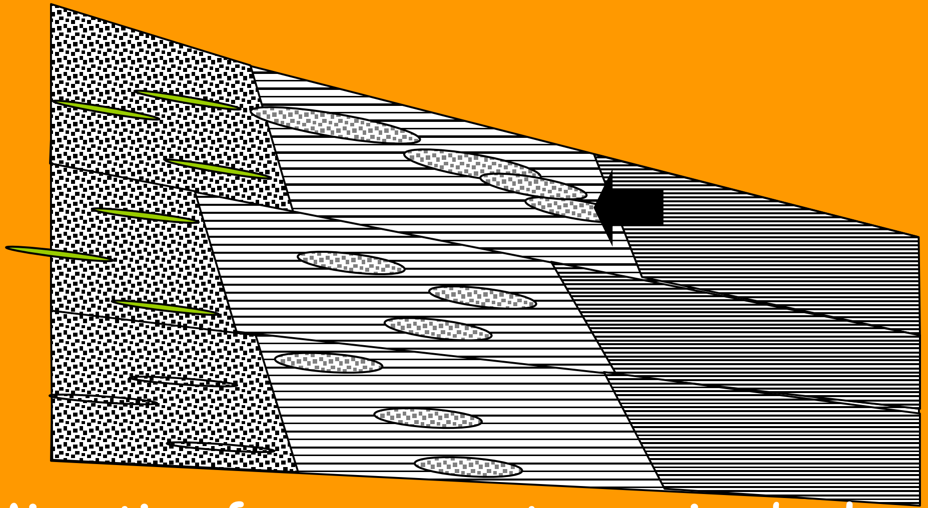
Primary Migration

Primary migration is the process by which hydrocarbons are expelled from the source rock into an adjacent permeable carrier bed.

Paradox: Most source rocks are black shales which have very low permeabilities. How can the hydrocarbons move through these rocks? Processes that have been proposed involve either the transport of hydrocarbons in solution, or their diffusion through shales, or migration of an independent hydrocarbon phase either as oil or gas.



1) Migration from kerogen to porosity



2) Migration from source to carrier bed

Represented by Expulsion efficiency

Oil expulsion

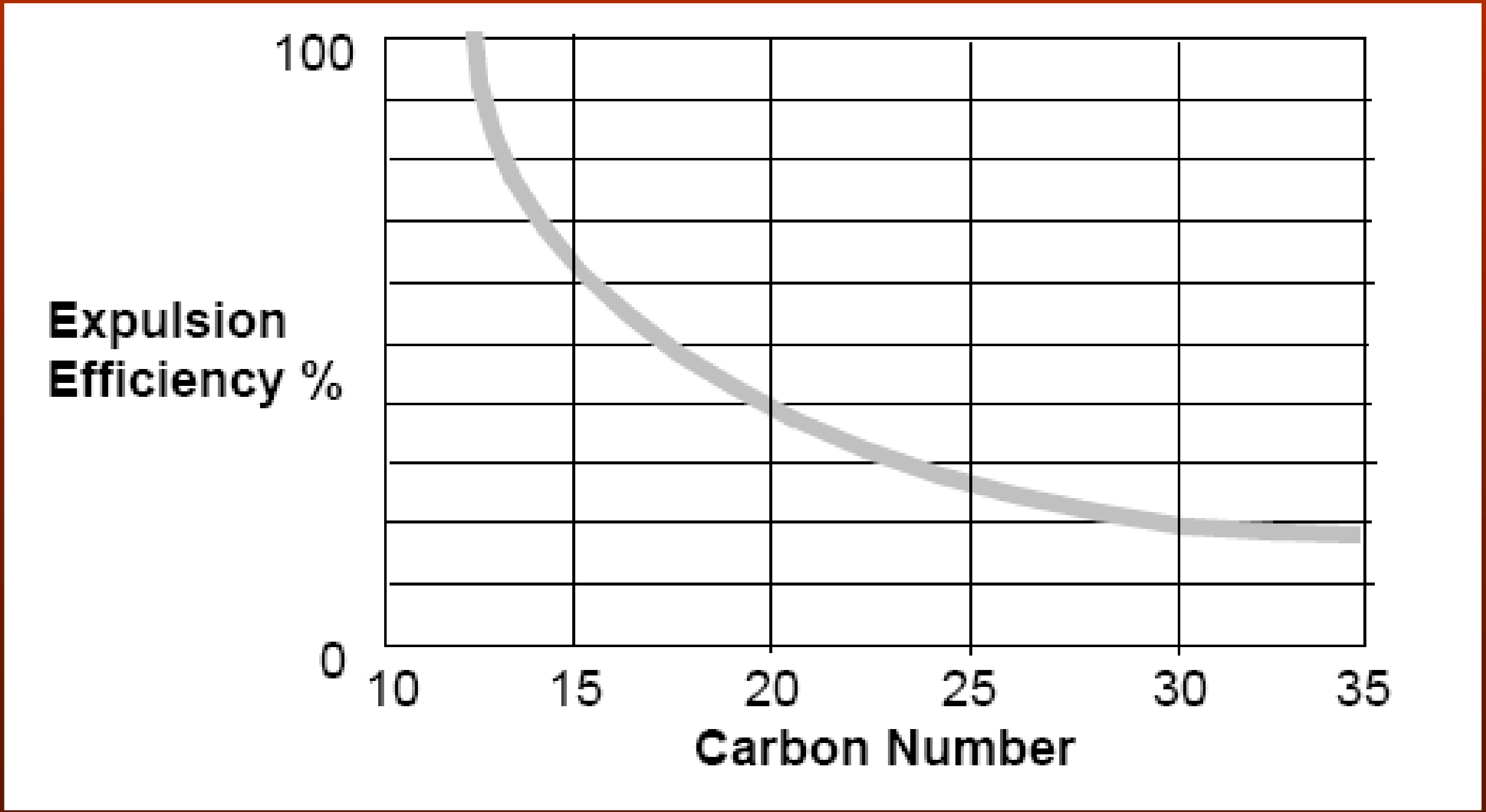
Expulsion efficiency is a measure of the percentage of a particular hydrocarbon that can escape from the source bed during primary migration.

Efficiency is strongly dependent on the original richness of the Source rock.

Oil expulsion can be in some rich source 60-90% oil generated

Leaner source rock most of oil remains in the rock..but if raised to higher maturity it may be cracked to gas

Expulsion appears to be very efficient for gas irrispective of original source richness



Expulsion(primary migration) from the source rock

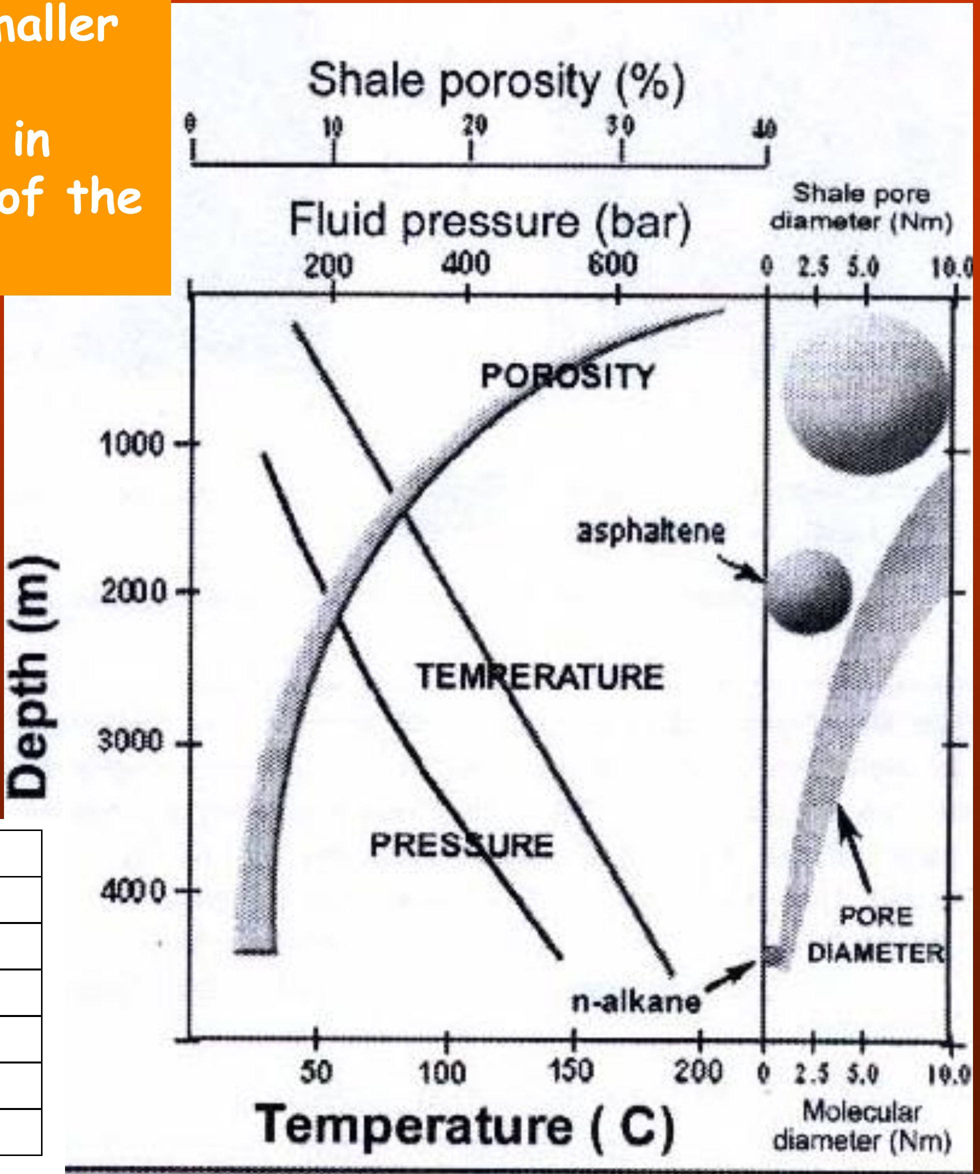
As result of the compaction of source rock during burial,pore size may become smaller than the size of some petroleum molecules.This present a difficulty in explaining how petroleum migrates out of the source rock

2 Median Pore Diameters and Porosities of Shale Source Rocks

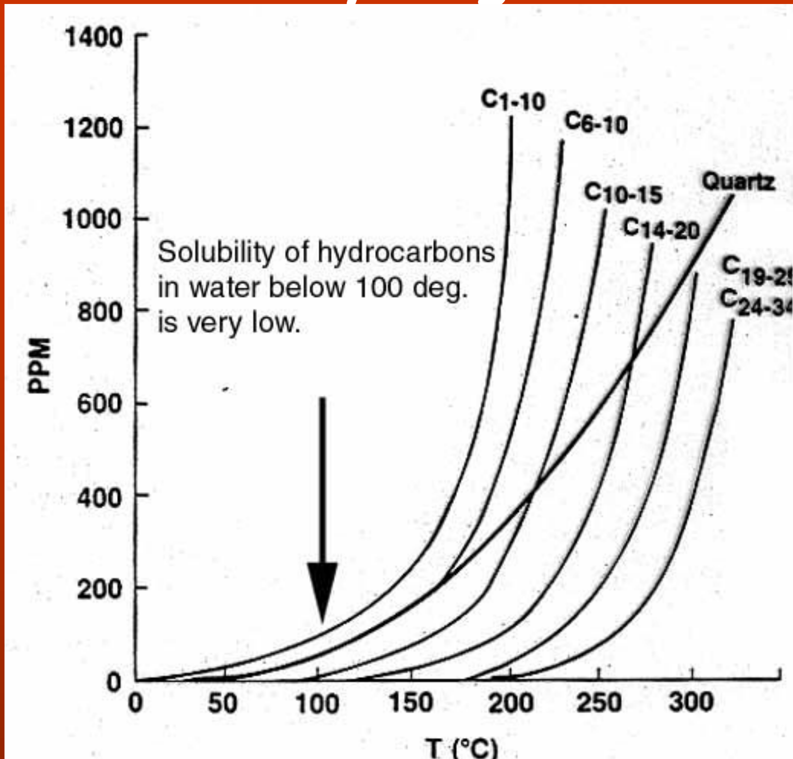
Shale	*Diameter, nm*	*Porosity, %*
Bakken, North Dakota[a]	5	4.3
Cherokee, Oklahoma	7	5.2
Monterey, California[b]	10	8.5
Monterey, California[b]	16	12.7
Tertiary, U.S. Gulf Coast[b]	20	15

Sources: [a]Hall et al. 1986; [b]J. Popek, personal communication.

Molecule	Diameter (nm)
Water	0.30
Methane	0.38
n-Alkanes	0.47
Cyclohexane	0.48
Complex aromatics	1-3
Asphaltenes	5-10



Primary Migration and possible mechanisms:solution

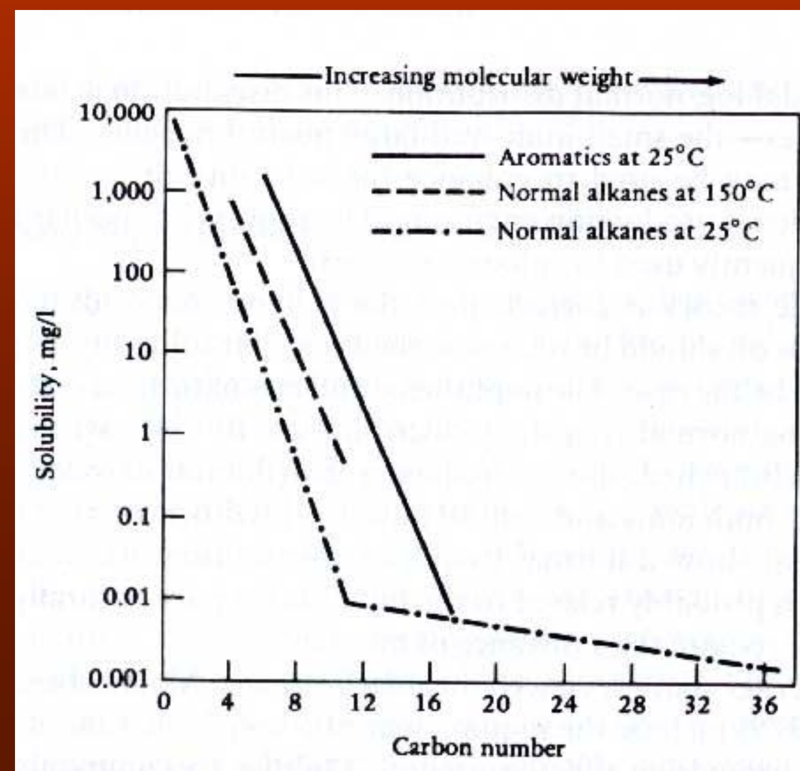


Solubilities are negligible below 150°

"optimum oil generation about 120°"

=Solubility no good mechanism?

It is not true: looking more in detail



Solubility decrease with increasing molecular weight

Easy for paraffin gases to emigrate dissolved in pore water

Also heavy oils are advocates for primary migration by solution in water

Primary Migration:possible mechanisms

Max water loss from surface to 2 Km

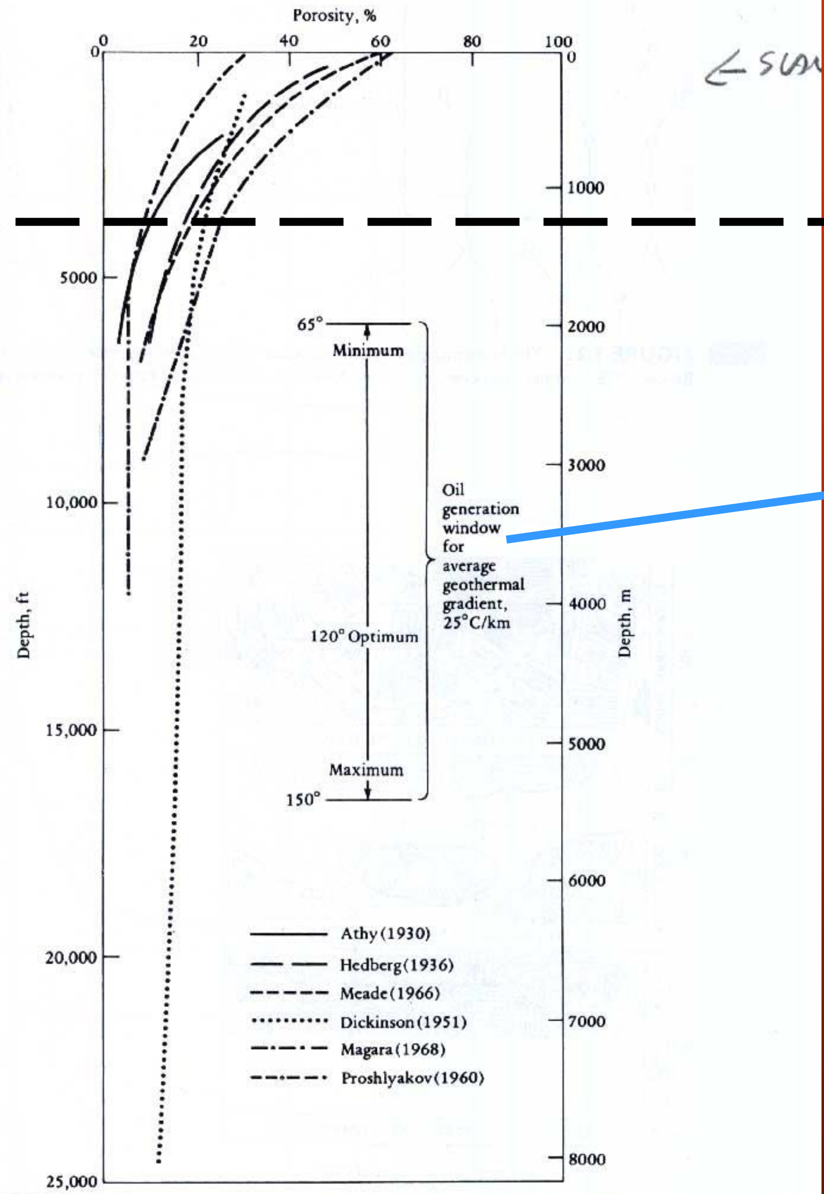


FIGURE 5.20 Shale compaction curves from various sources. Note that there is minimal water loss through compaction over the depth range of the oil window.

Oil pruduction begins below the depth at which most of the compactional pore water has been expelled.

Therefore the migration of oil by flushing of pore waters is not a viable proposition

Primary Migration:possible mechanisms

Migration as Hydrocarbon Phases

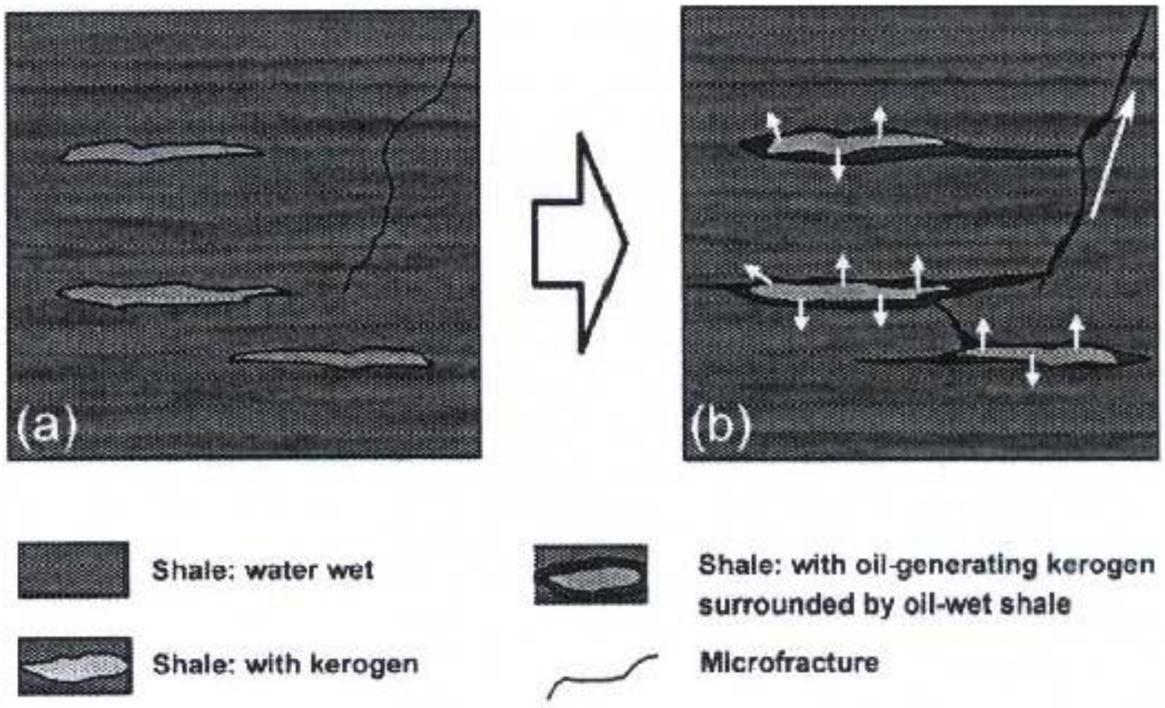


Figure 36. Microfracture-induced hydrocarbon-phase migration during oil generation. (A) Represents the initial stage prior to oil generation, in which the bulk of the source rock is water-wet. (B) Oil generation has occurred with the creation of an oil-wet pore network around the kerogen. The generation of oil creates an increase in pore pressure that either opens existing fractures or creates new ones. The oil is then expelled along oil-wet microfractures (modified and redrawn from Ungerer *et al.*, 1983).

Most migration of petroleum takes place by flow of a hydrocarbon liquid or gaseous phase through microfractures in the source rock.

Microfractures in organic rich shale. Hunt, 1995.

Driven by volume change during creation of petroleum

Secondary Migration

is any movement in carrier rocks or reservoir rocks outside the source rock or movement through fractures within the source rock concentrating petroleum in specific sites (traps) where it may be commercially extracted. It is teh movement of HC as a single continuous phase throguh a water saturated rocks.

Main different with Primary migration is the Porosity,Permeability and Pore size distribution of the roch through which migration take place

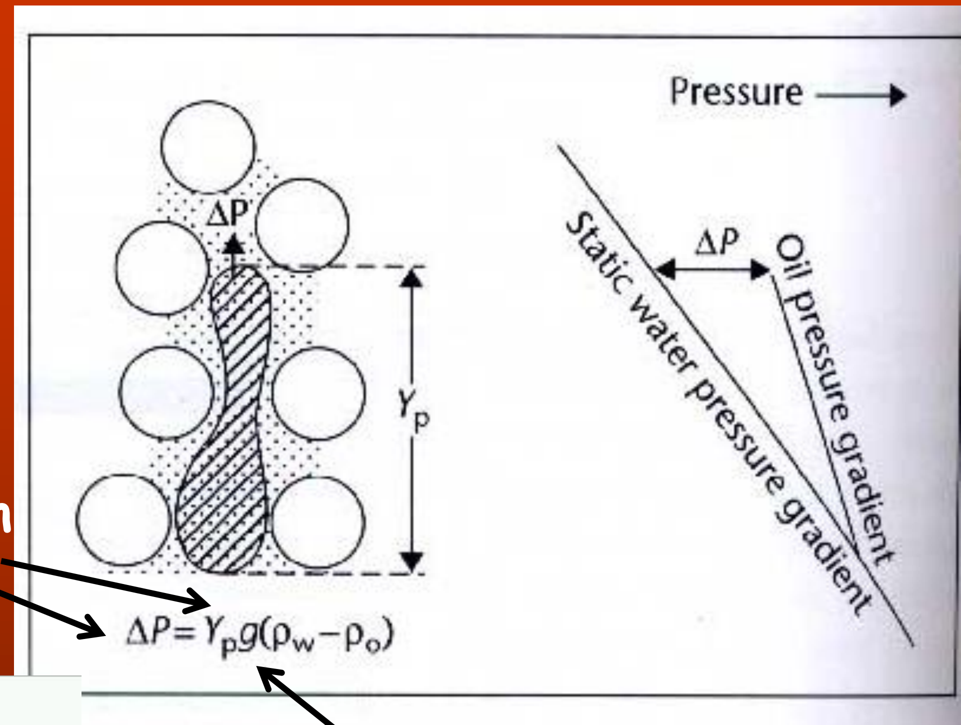
Driving forces for migration:
Buoyancy (force which due to the density difference between water and the hydrocarbon)
Hydrodynamic flow (water potential deflect the direction of oil migration, the effect is usually minor except in over pressured zones (primary migration)

Resisting forces:
Capillary pressure (opposes movement of fluid from coarse-grain to fine-grain rock, also the capillary pressure of the water in the reservoir resists the movement of oil)

Secondary migration:mechanisms

Driving forces for migration:

Buoyancy :is a vertically directed force which is proportional to the density difference between water and the hydrocarbon so it is stronger for gas than heavier oil



Height of petroleum column

Buoyancy force

Acceleration due to the gravity

The formula can also be written

$H(\gamma) = \Delta P / (\rho w - \rho hc) \times 0.433$

ρw= 1-1.2 g/gm3

ρo= 0.5-1 g/cm3

ρg= <0.5 g/cm3

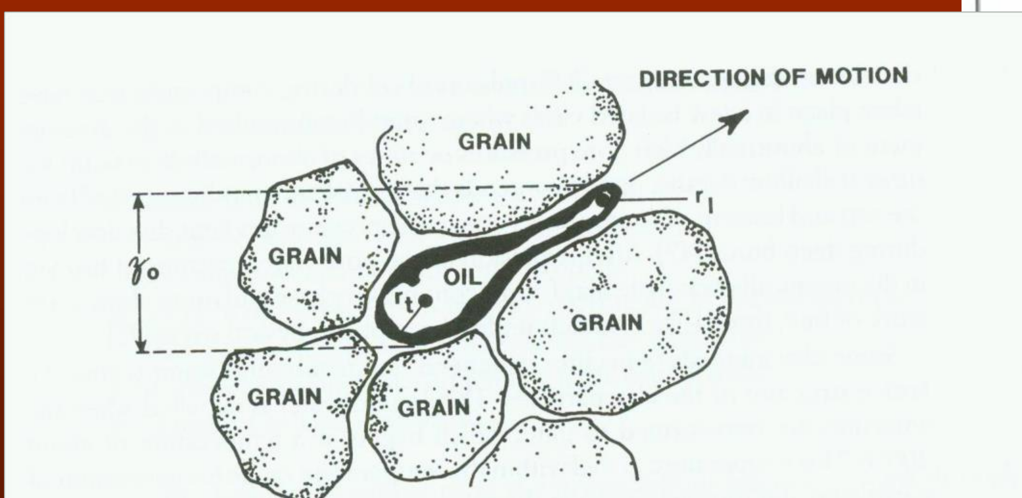
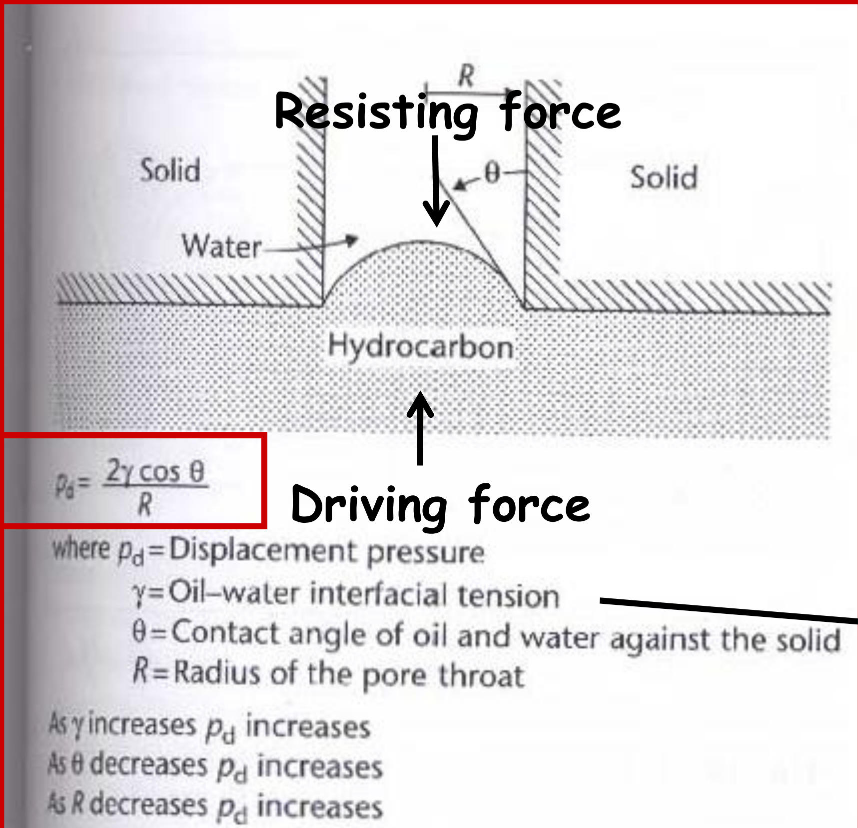


Figure 2.9. *Displacement of an oil droplet through a pore throat in a water-wet rock.*

Secondary migration:mechanisms

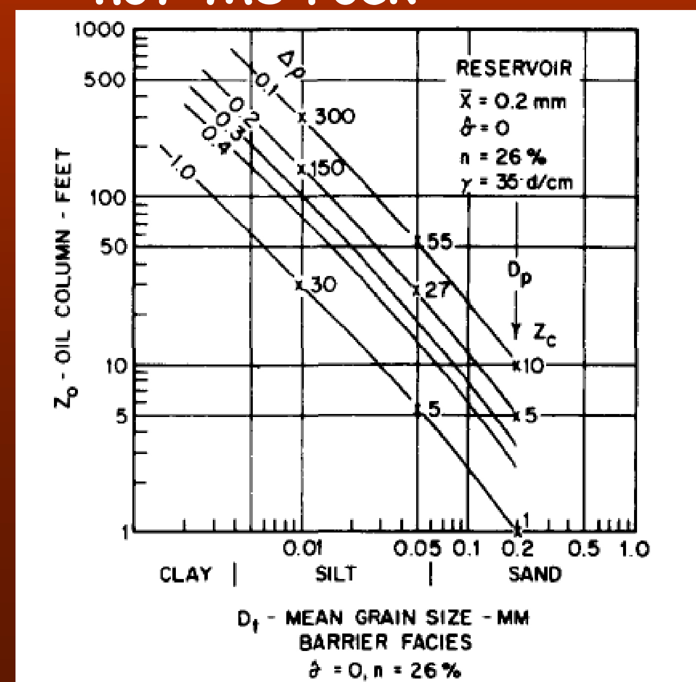


Resisting forces:

Capillary pressure :the force required for distorting and aqueezing a petroleum globule thorough the pore throats

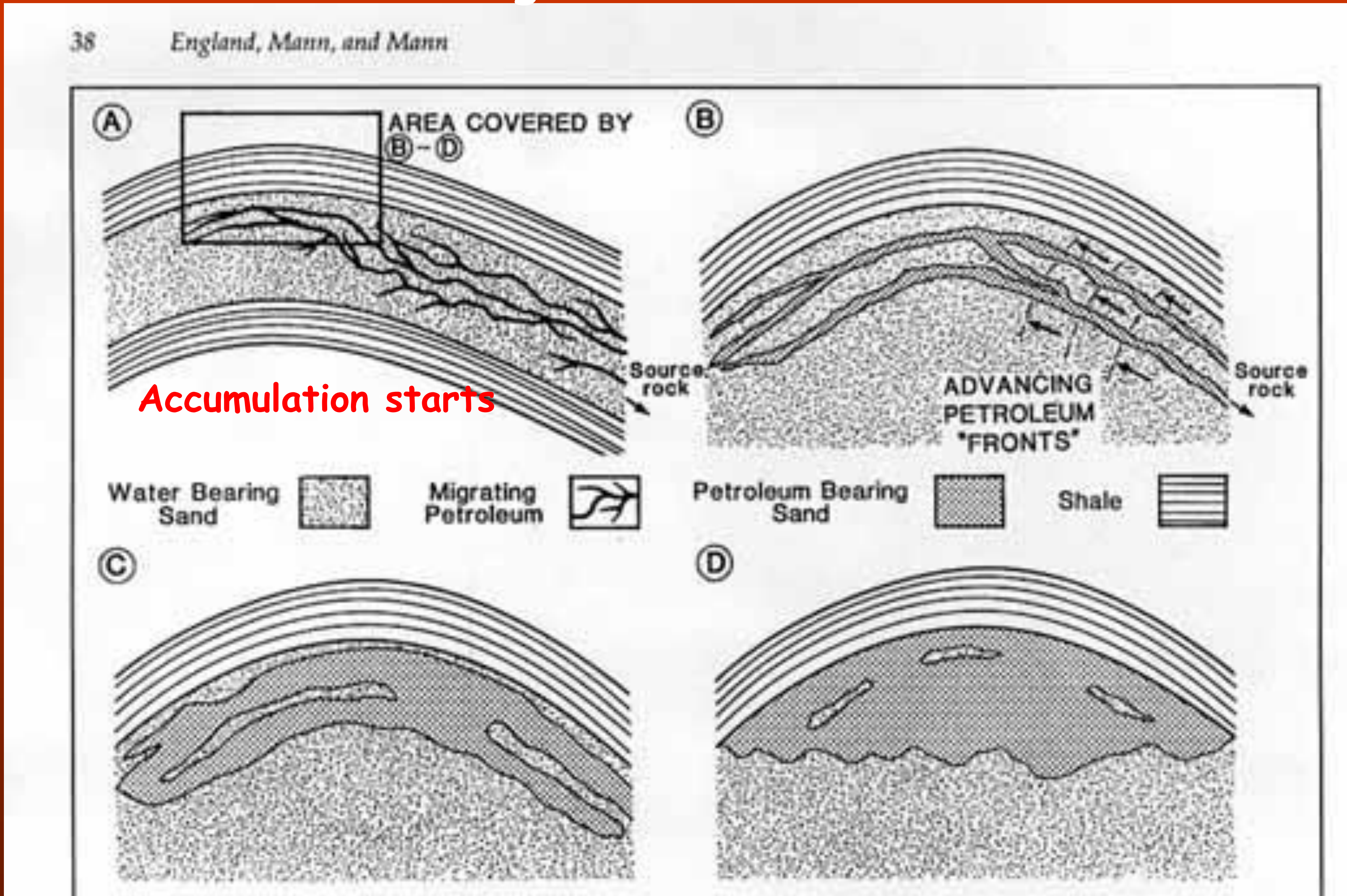
$$Pd=2\gamma\cos\tau/R$$

Function of the composition of water and petroleum not the rock



The height of the column necessary to overcome displacement pressure is:

Oil migration and accumulation



The traps are usually filled from one direction and therefore the accumulation reflect the compositional gradient of the maturation process. The last expelled products are located in the area of the trap closest to the SR

Oil migration and accumulation

Vetical migration= <1000 m (only along fault and fracture plane this increase)
Lateral migration= hundreds of Km
But..lateral migration less effective than vertical (to overcome the Pc there is need of large volume of oil). Lateral migration has also more HC lost than vertical

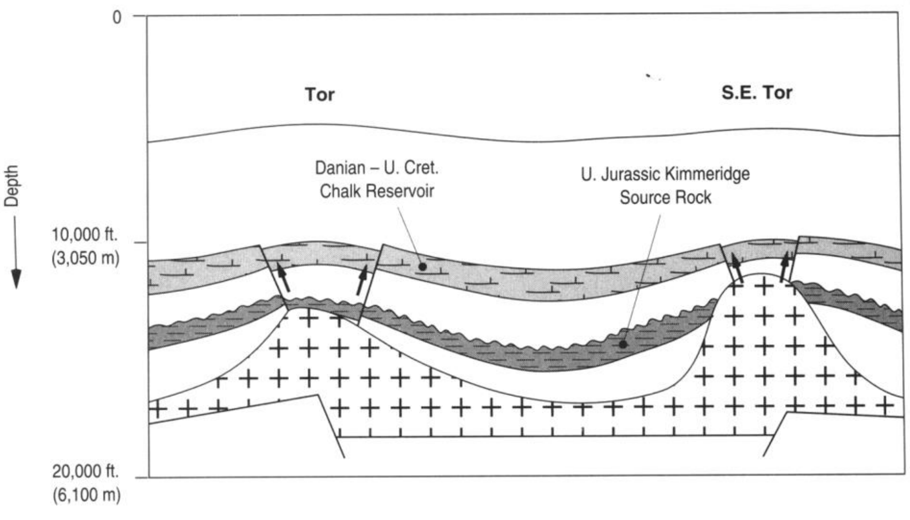


Figure 8-17
Vertical migration at the Tor and Southeast Tor fields in the Central Graben of the southern Norwegian North Sea. [Courtesy of R. C. Leonard]

In Vertical drained petroleum systems:
Almost all the accumulations are above the source rock with lateral migration within 30Km
Multiple levels of reservoirs of different ages contain the same (genetically) oil
Superficial seeps and/or Hc shows are abundant if tectonic activity recent affected the regional seal

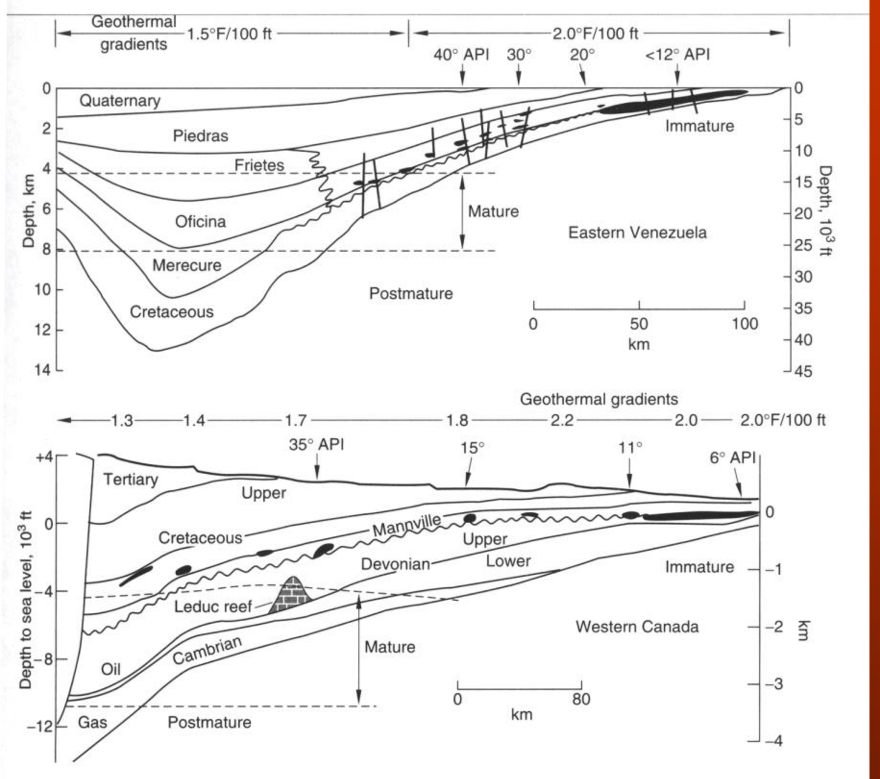
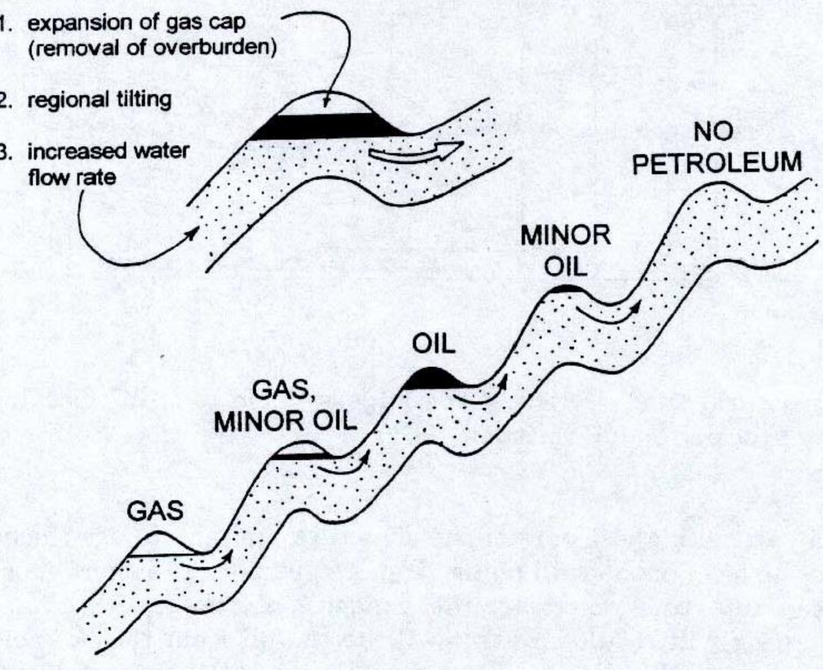


Figure 8-18
Long-distance lateral migration in the Eastern Venezuelan and Western Canada Basins. The oil-generation windows are labeled mature. [Demaison 1977; Roadifer 1987]

In laterally drained petroleum systems:
HC accumulations very far from SR
Usually one reservoir capped by the most effective seal contain most of the HC generated by the SR

Migration pathways and differential entrapment



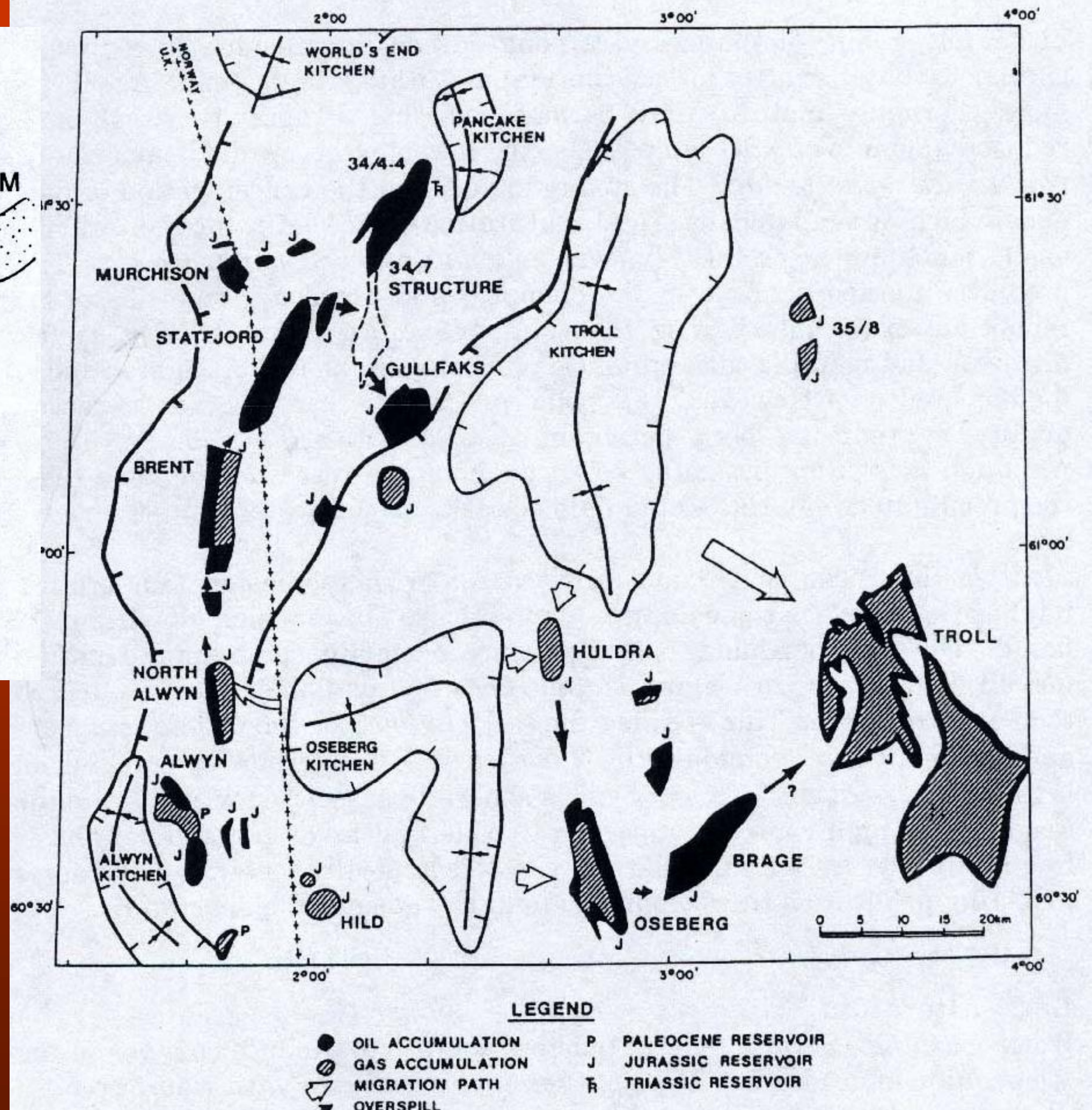
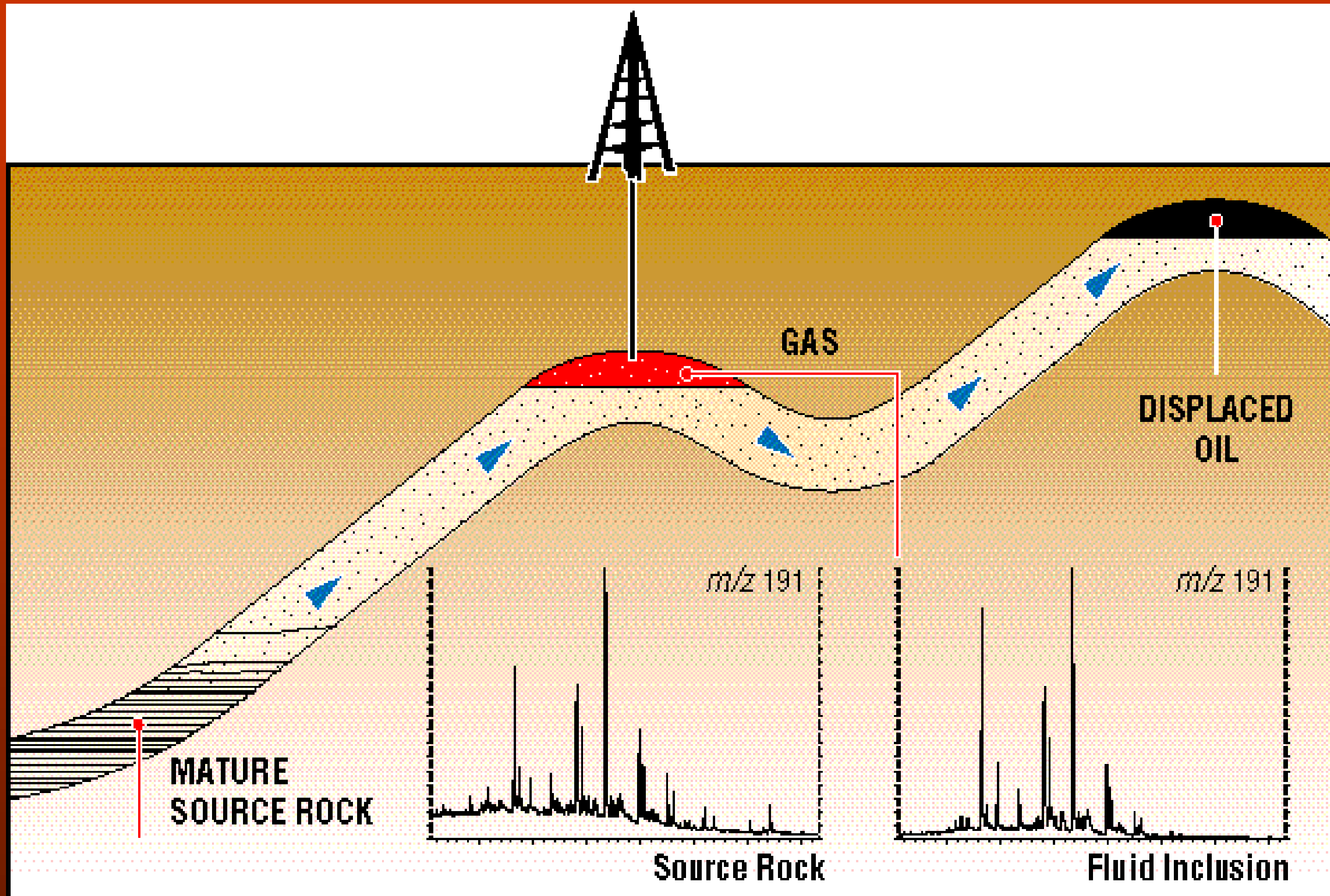


Figure 1.28. Inferred migration pathways in part of the North Sea showing the effects of differential entrapment (Thomas et al, 1985).

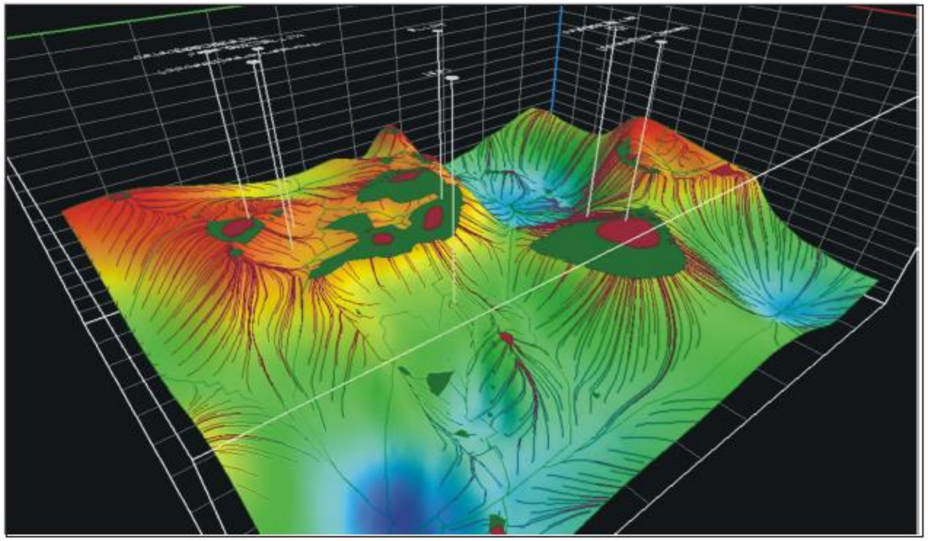
Petroleum Charge System

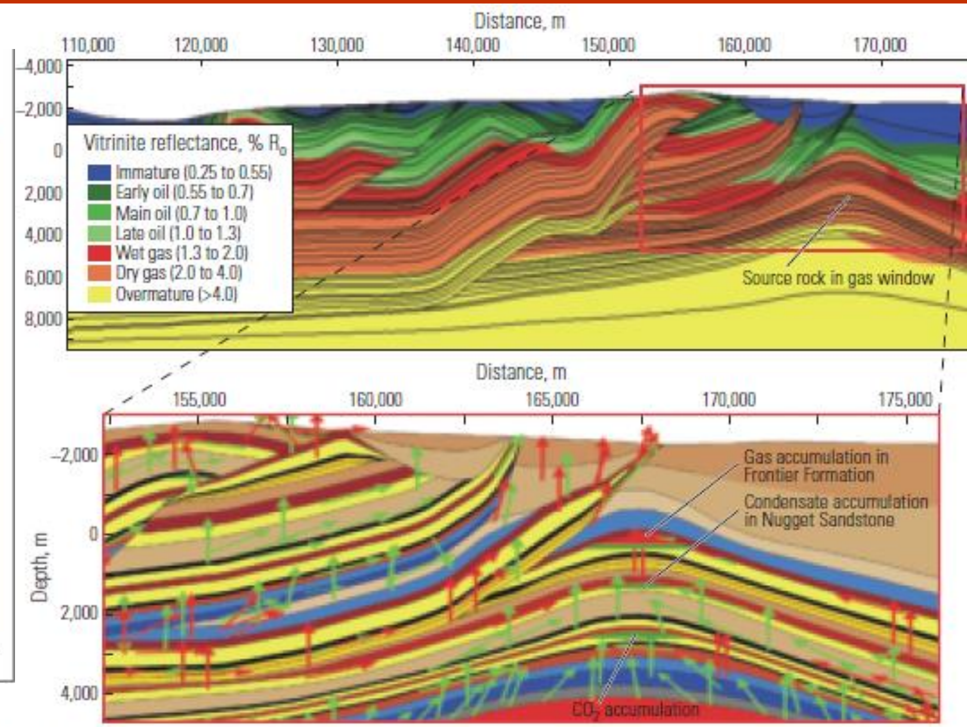


Correlations and New Plays: MCI analysis of palaeo oil in a gas zone enables source rock correlation and suggests updip displacement of oil into a new play.

To the models

Oil and Gas traps with migration from BasinView's 3D Model Viewer





^ Modeling maturity and migration. PetroMod software modeled the products of maturation from multiple source rocks in a complex thrust zone (*top*). Migration calculations over a portion of the section (*bottom*) predicted accumulation of CO_2 in a deep Paleozoic reservoir, condensate in the Nugget Sandstone and gas in the Frontier Formation. Green and red arrows represent flowpaths taken by liquid and vapor phases, respectively. Results matched published fluid data from the field. (Adapted from Kemna et al, reference 26.)

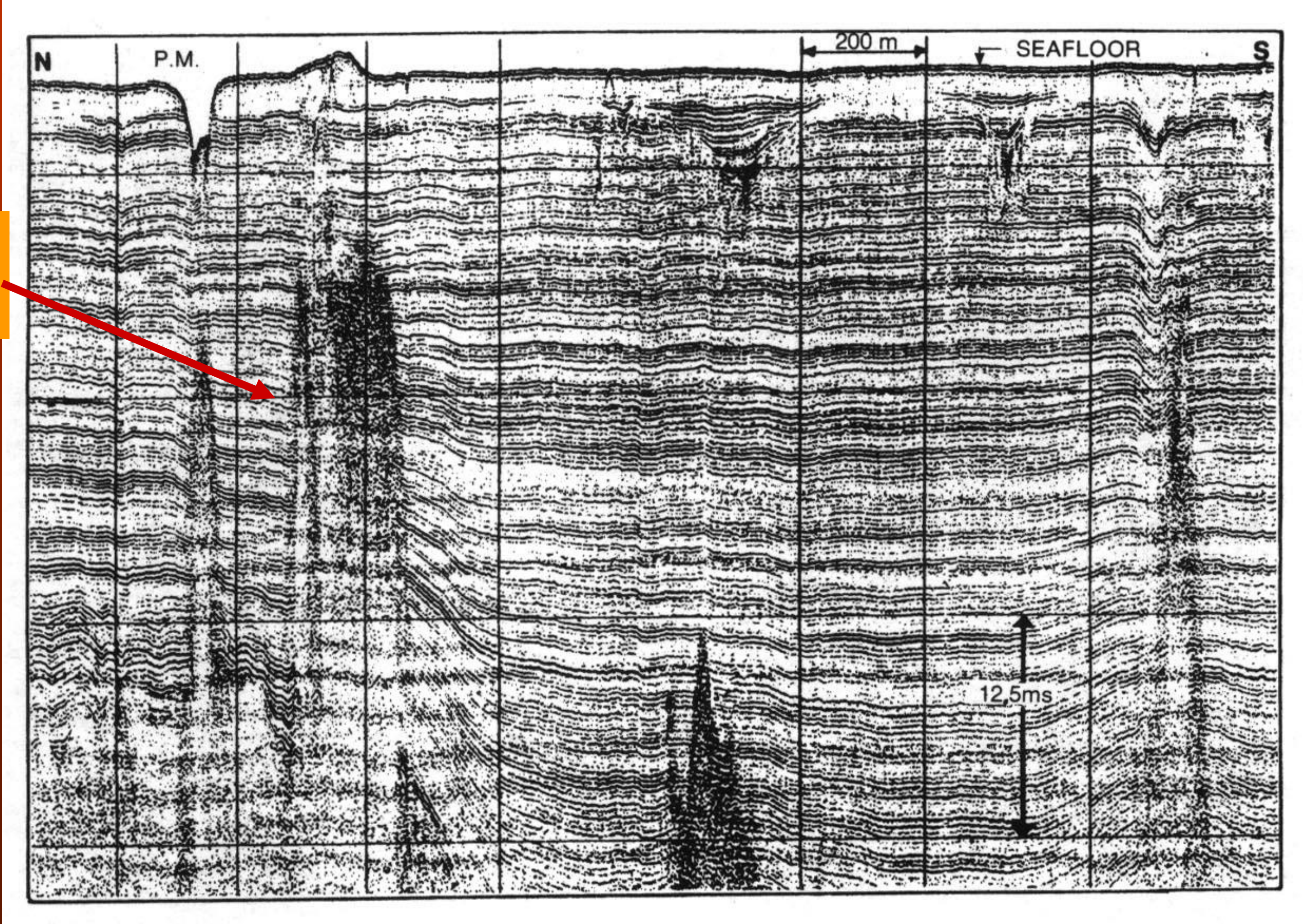
Tertiary Migration

Migration from reservoir – pressure but also slowly by buoyancy

•Mechanisms:

spilling (due to excessive gas charge) ,seal compromise,slow leaking

Mound due to gas seepage



Seal failure

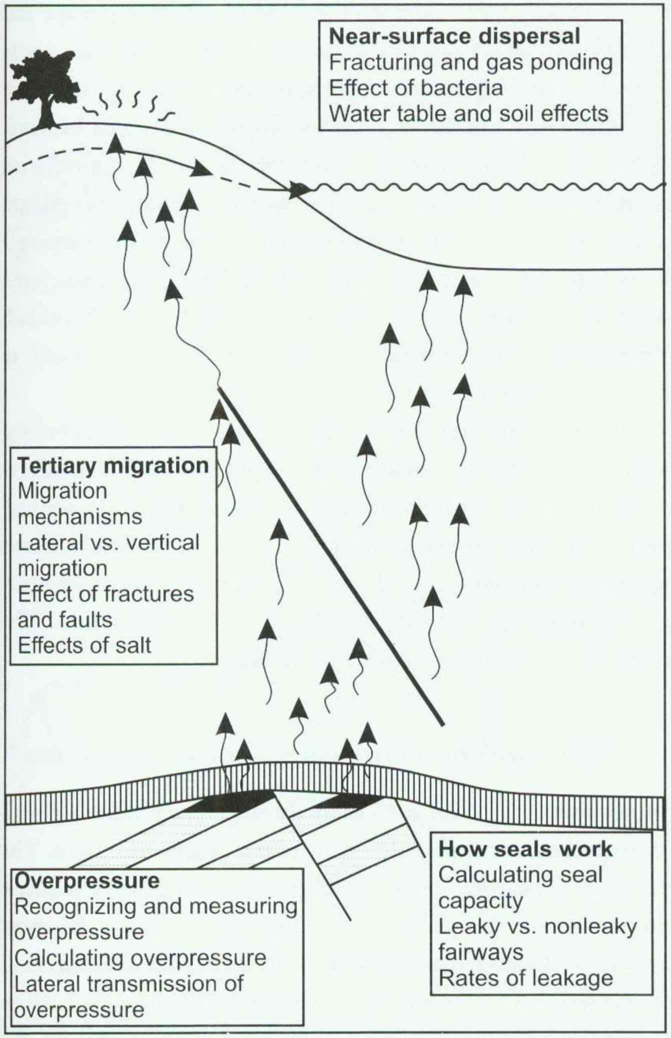


Fig.3.3 Seal failure, tertiary migration, and dissipation. (Reproduced

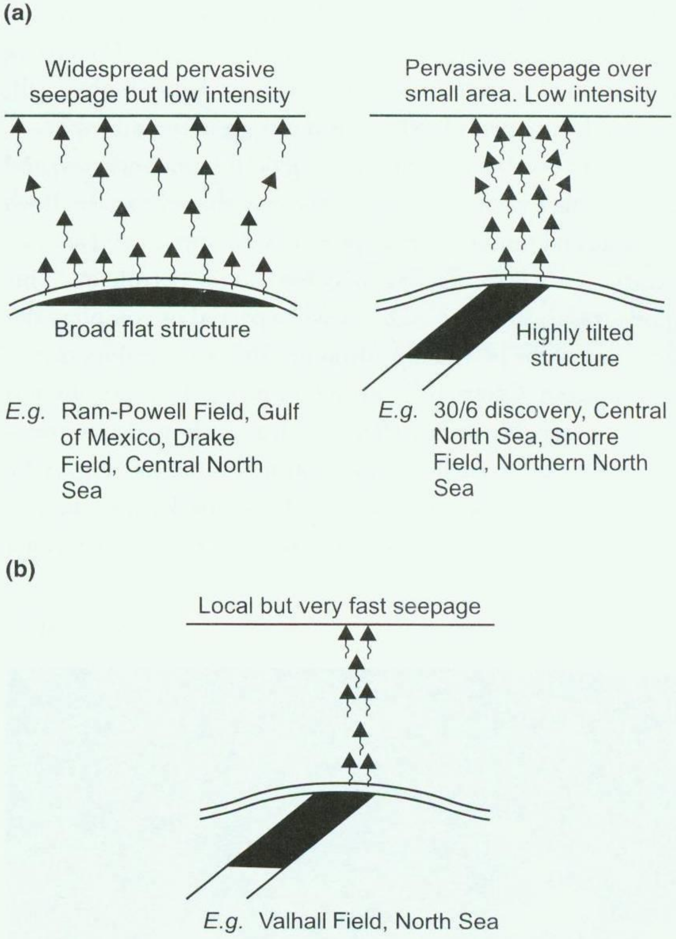


Fig.3.4 Capillary failure (a) and fracture failure (b) of a seal. Active faulting will focus flow; lateral migration will focus flow. (Reproduced courtesy of BP Amoco.)

Secondary migration losses

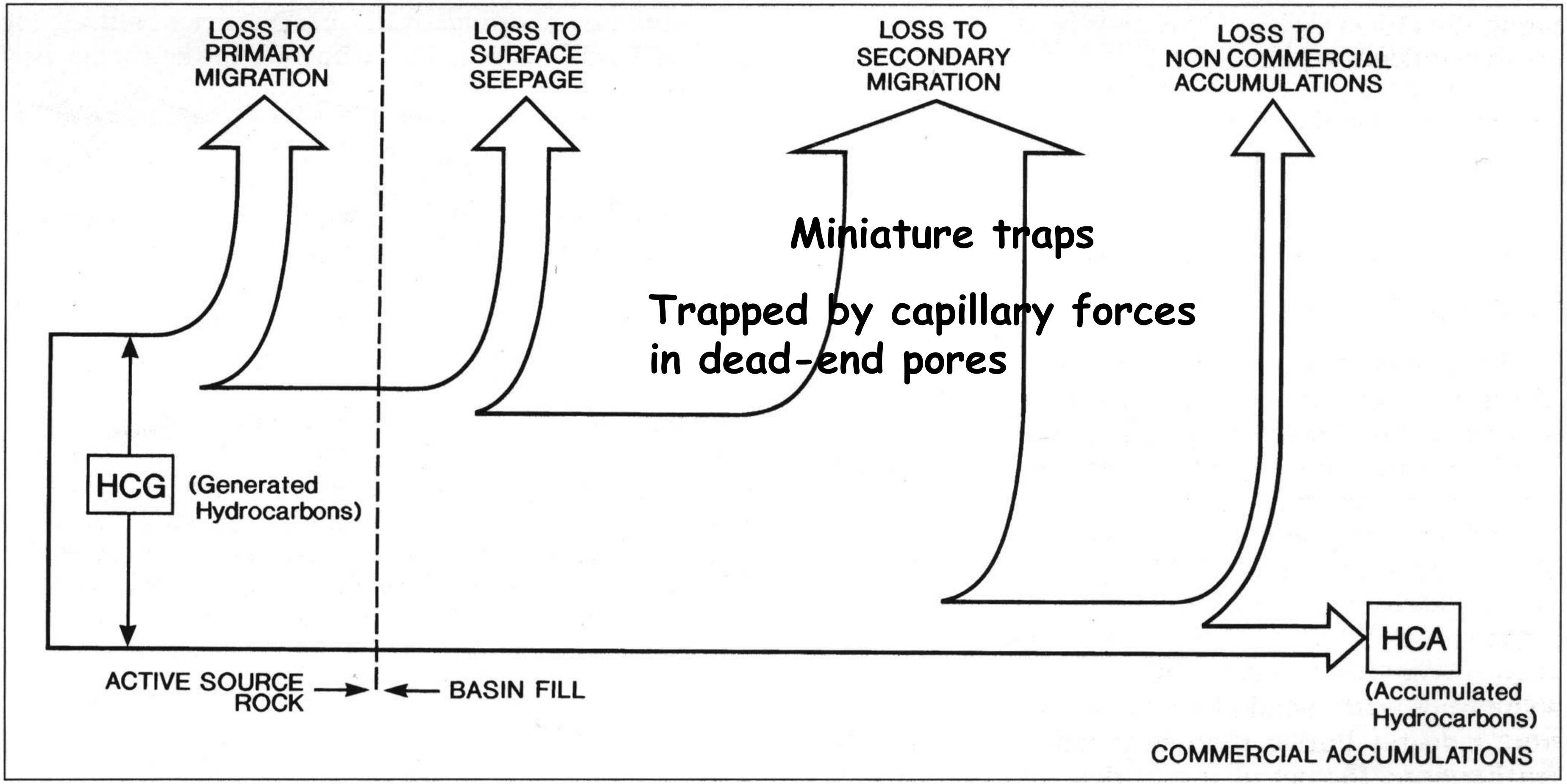


Figure 12.2. Hydrocarbon loss during migration from an active source rock through basin fill. Only a portion of the hydrocarbons generated (HCG) form commercial accumulations (HCA), of which only some is recoverable. The relative magnitudes of hydrocarbon loss change greatly from case to case.

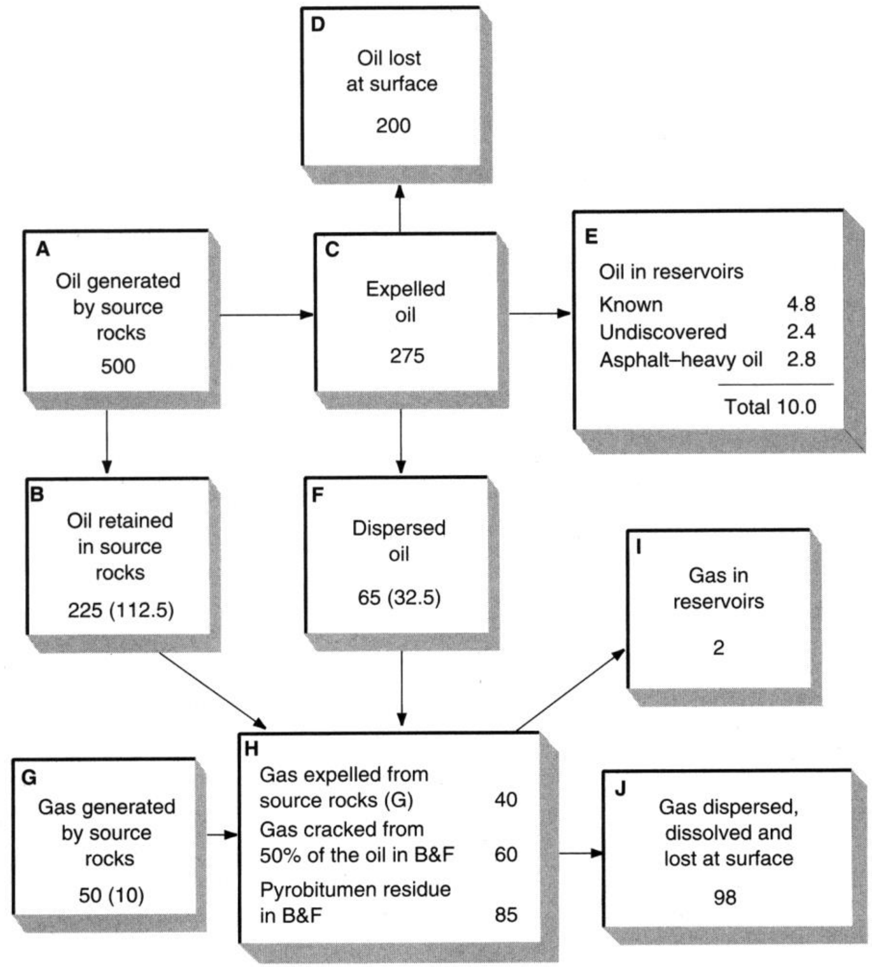


Figure 16-2

Flow chart showing the ultimate sinks for an estimated 550×10^{12} BOE of oil and gas generated in the last 100 million years (Boxes A plus G). The numbers shown are the original BOE for each box. The numbers in parentheses in Boxes B and F represent the residual oil after 50% of the oil cracks to gas and the gas moves to Box H. The number in parenthesis in Box G is the residual gas left adsorbed on the source rocks after primary migration. The 550×10^{12} BOE generated is estimated to be distributed at present as follows: B(112.5), D(200), E(10), F(32.5), G(10), H(85), I(2), and J(98).