Detecting Reservoir Compartmentalization from the Mixing Time-Scales of $^{87}Sr/^{86}Sr$ Isotope Ratio Variations in Oilfield Formation Waters*

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Search and Discovery Article #40967 (2012)**
Posted July 3, 2012

*Adapted from oral presentation at AAPG Annual Convention and Exhibition, Long Beach, California, USA, April 22-25, 2012

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Abstract

Vertical and lateral changes in the $^{87}Sr/^{86}Sr$ isotope ratio in formation water are sometimes used during appraisal as indications of reservoir compartmentalization. These variations will tend to homogenize slowly over time by diffusion and flow. They will only be robust indications of compartmentalization if their mixing time in the absence of a flow barrier is less than the time since the process causing those variations stopped.

Improved analytical solutions that estimate mixing times of $^{87}Sr/^{86}Sr$ isotope ratio variations in formation water are presented. Whereas previous solutions have only modeled the mixing of $^{87}Sr/^{86}Sr$ isotopic ratios in a homogeneous reservoir, the new solutions evaluate the diffusive mixing of formation waters between two formations with different properties (adsorption, porosity, permeability and connate water saturation). These formations may be separated by a low-permeability baffle, a discontinuous shale or be in good communication. The increase in diffusion time resulting from prevailing high tortuosities of irreducible water films in hydrocarbon columns are also captured in the analytical solutions.

The analytical-solution predictions are shown to compare well with results from an existing numerical simulator developed to predict contaminant transport in groundwater flows. The time for diffusive mixing over a typical reservoir thickness (i.e., < 100m) is typically ~ 10 m.y. As expected, this time reduces when formation porosity and/or water saturation is higher. For heterogeneous formations separated by a discontinuous "impermeable" shale, formation water mixes around the barrier faster than through it due to the low- porosity, high-tortuosity and high-adsorption characteristics of the shale barrier despite being fully saturated with pore water. The equations can be used to estimate a critical shale length to thickness ratio where formation water diffuses around the shale at the same rate as through the shale barrier.

The equations can also be used to constrain the barrier or baffle properties (e.g., the shale length) based on the time at which the initial perturbation to the fluid properties took place. These improved analytical solutions are thus a significant addition to the suite of published expressions for evaluating reservoir compartmentalization during appraisal, using reservoir fluid mixing.

Selected References

Li Y-C, Cleall PJ. Analytical solutions for contaminant diffusion in double-layered porous media: Journal of Geotechnical and Geoenvironmental Engineering-ASCE 2010, v. 136/11, p. 1542-1554.

Rahimpour-Bonab, H., 2007, A procedure for appraisal of a hydrocarbon reservoir continuity and quanitification of its heterogeneity: Journal of Petroleum Science and Engineering, v. 58/1-2, p. 1-12.

Smalley, P.C., T.A. Dodd, I.L. Stockden, A. Raheim, and E.W. Mearns, 1995, Commpositional heterogeneities in oilfield formation waters; identifying them, using them, *in* J.M. Cubitt, and W.A. England, (eds.), The geochemistry of reservoirs: Geological Society of London, Special Publications, v. 86, p. 59-69.

Worden, R.H., N.H. Oxtoby, and P.C. Smalley, 1998, Can oil emplacement prevent quartz cementation in sandstones? Petroleum Geoscience, v. 4/2, p. 129-137.

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Outline

1. What is reservoir compartmentalization?
2. $^{87}Sr/^{86}Sr$ isotope ratio variations in oilfield formation waters
3. Mixing of $^{87}Sr/^{86}Sr$ isotopic ratios
    a. in a homogeneous reservoir to identify fluid flow barriers
    b. between two formations with different properties
        » adsorption, porosity, permeability and connate-water saturation
4. Implications for reservoir compartmentalization
5. Case study: South Pars gas field
6. Conclusions

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What is reservoir compartmentalization?

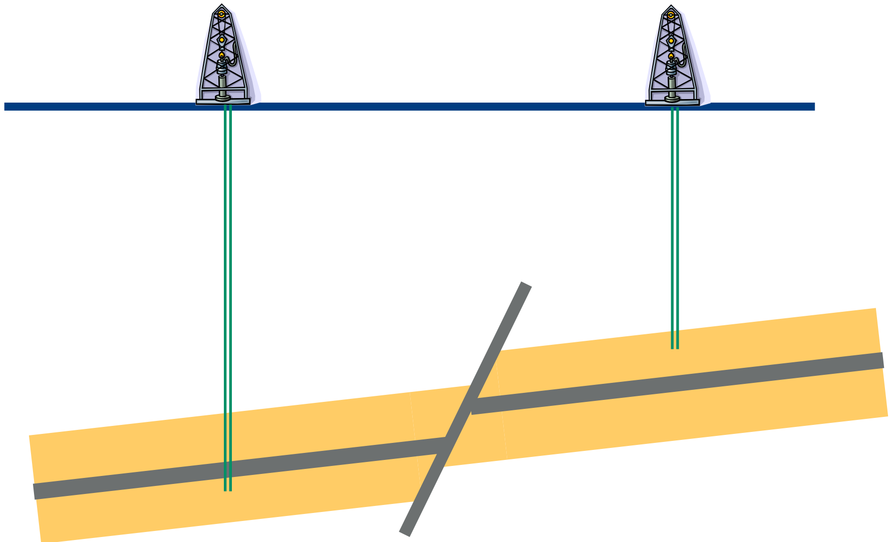
*A field is compartmentalized if **fluids do not flow freely** from one part of the field to another over **production time-scales**.*

Reservoirs may be compartmentalized by

- Continuous shale layers (stratigraphy)
- Faults (structure)
- Depositional or diagenetic changes

Compartmentalization affects the drainage volume of each well

- Reducing recovery or
- Increasing the number and/or complexity of wells



What is reservoir compartmentalization?

- If we know about compartmentalization beforehand, **we can adapt**
  - by changing a field development (e.g., Number or location of wells)
  - or (in extreme cases) by not developing the field

- Barriers and baffles can be interpreted from production data
  - but such data are only available once the field has been developed - **too late**

- Detecting reservoir compartmentalization at appraisal:
  - Extract dynamic signal from **natural fluid variations**
    - e.g., Pressure, hydrocarbon density, composition, pore-water composition
    - only likely to provide an accurate indication of compartmentalization **if the variations have existed for longer than the time needed for them to equilibrate.**

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Vertical and lateral changes in the $^{87}Sr/^{86}Sr$ isotope ratio in formation water

- Strontium isotope residual salt analysis (SrRSA) is used to measure “frozen” $^{87}Sr/^{86}Sr$ isotope ratio at the time of filling, with **no subsequent mixing**

- smooth SrRSA profiles ⇒ uninterrupted filling and absence of sealed barriers

- step change in SrRSA profiles ⇒ indicates barrier sealed updip from well penetration

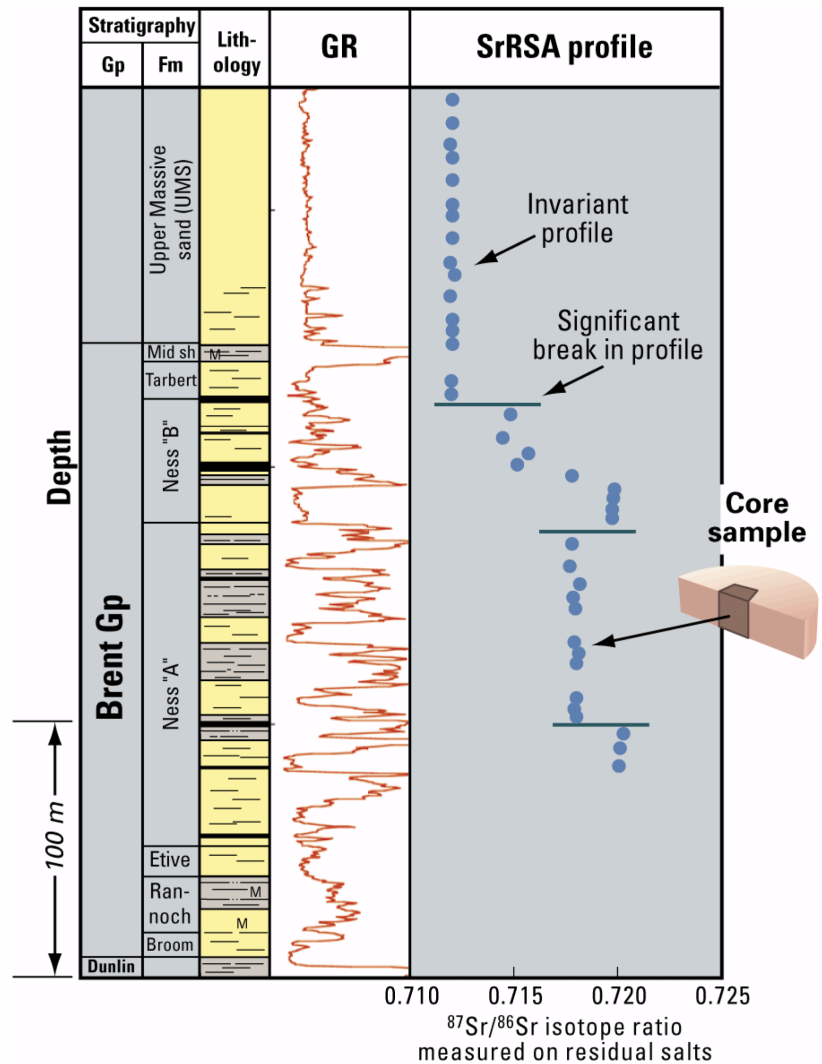

Figure from Mearns and McBride, 1999. Petroleum Geoscience 5:17-27.

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Vertical and lateral changes in the $^{87}Sr/^{86}Sr$ isotope ratio in formation water - 100% water-saturated sand

- Smalley et al. (1995) estimated diffusional mixing times for Sr **around a shale** barrier in a fully water-saturated sand using

$$t = \frac{0.1L^2}{(D/\tau R)}$$

where $$R = 1 + \frac{(1-\varphi)}{\varphi}\rho_B K_D$$

D – tracer diffusion coefficient

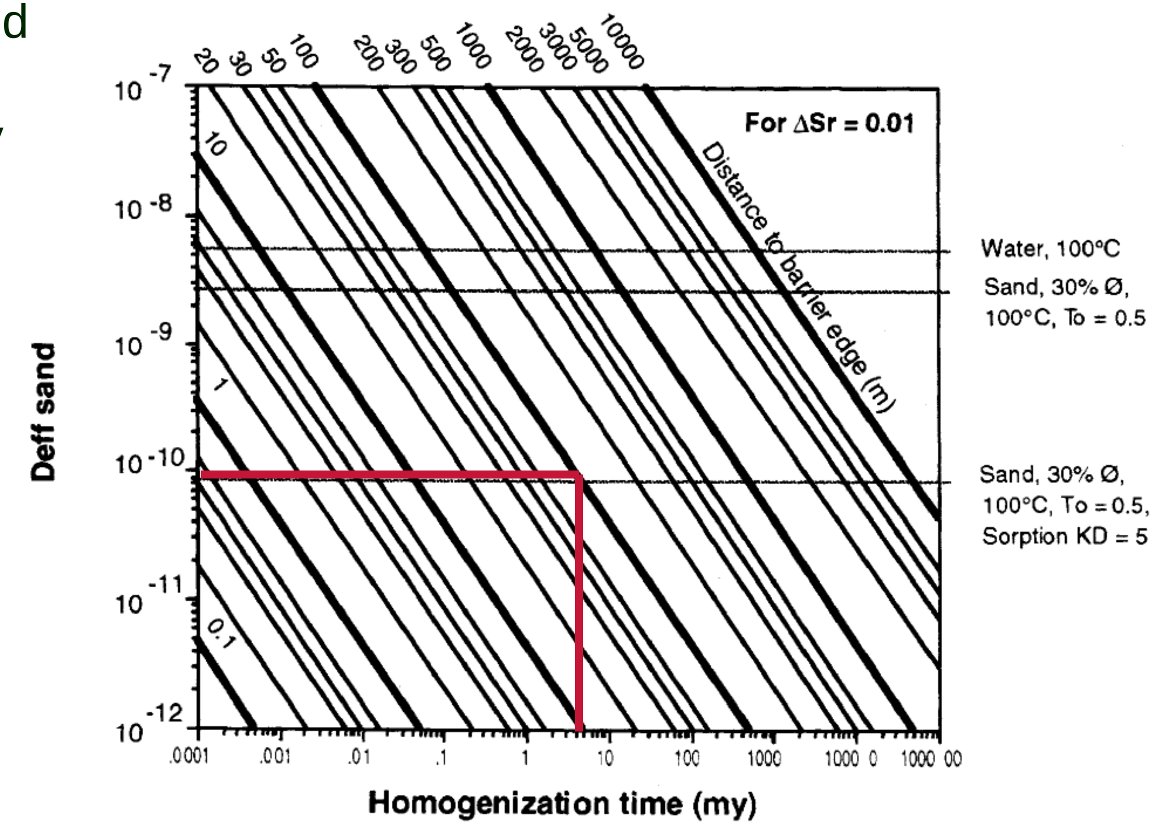
τ – tortuosity

R – retardation factor

φ – porosity

ρ_B – bulk rock density

K_D – partitioning coefficient



Sr in two 50-m-thick sands would homogenize in 3 m.y. in the absence of a barrier

Figure from Smalley et al. 1995. Geological Society, London, Special Publications 86:59-69.

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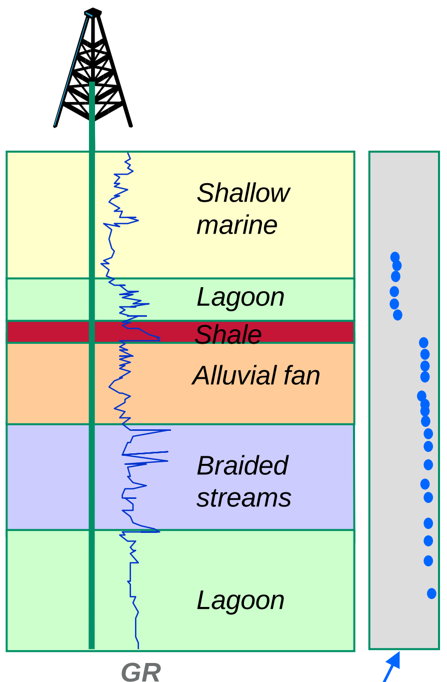
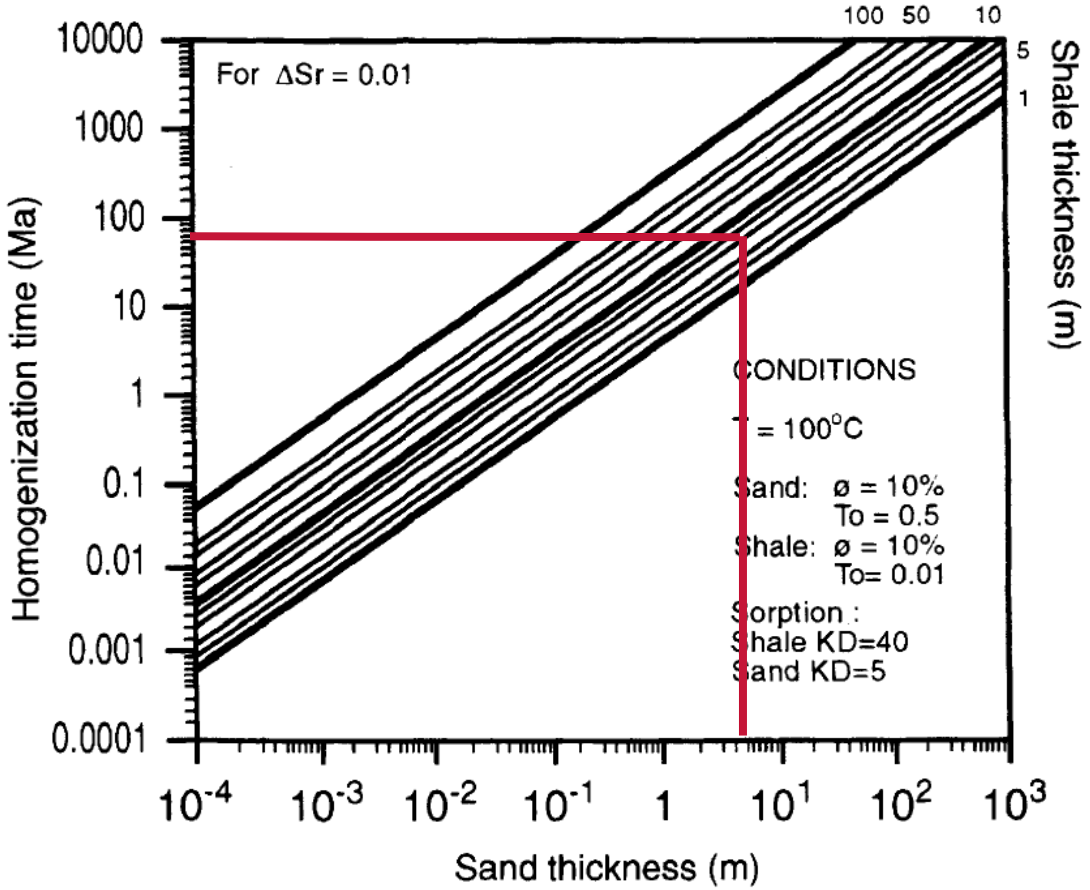
Vertical and lateral changes in the $^{87}Sr/^{86}Sr$ isotope ratio in formation water - 100% water-saturated sand





- With a 5-m-thick shale between the sands (100% saturation), **homogenization time (through the shale) is increased to 50 m.y.**

Figure from Smalley et al. 1995. Geological Society, London, Special Publications 86:59-69.

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What if mixing continues in the oil leg?

- Diffusion → rate limiting step
  - Transport would be through the water film adjacent to grains.
  - Limited to tens to hundreds of meters

- Mixing rate will depend on:
  - Porosity
  - Oil saturation
  - Wettability

- Tortuousity will be higher compared to that in the water leg

(Attia et al., 2008)

$$\tau = 1 + \frac{\varphi - \varphi^m}{\varphi^m (Sw - Sw_{ir})}$$

φ – porosity m – cementation factor
Sw – water saturation Sw_{ir} – irreducible water saturation

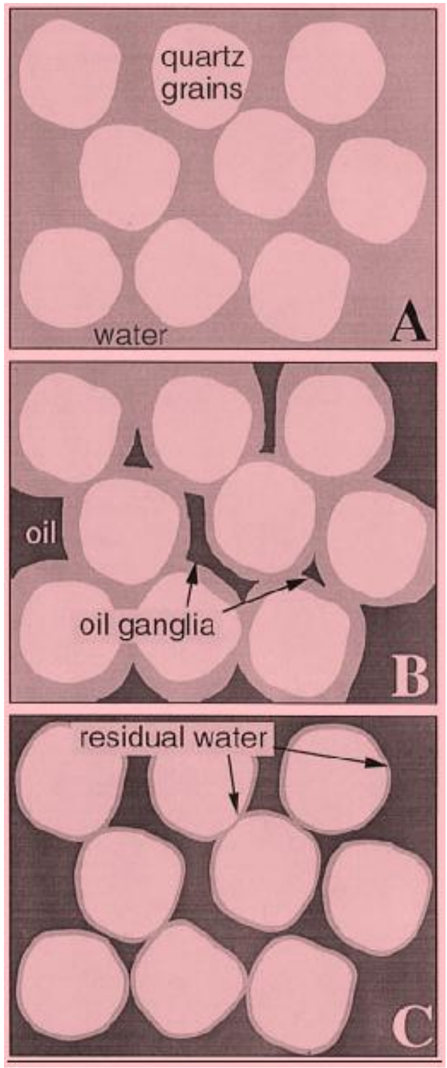
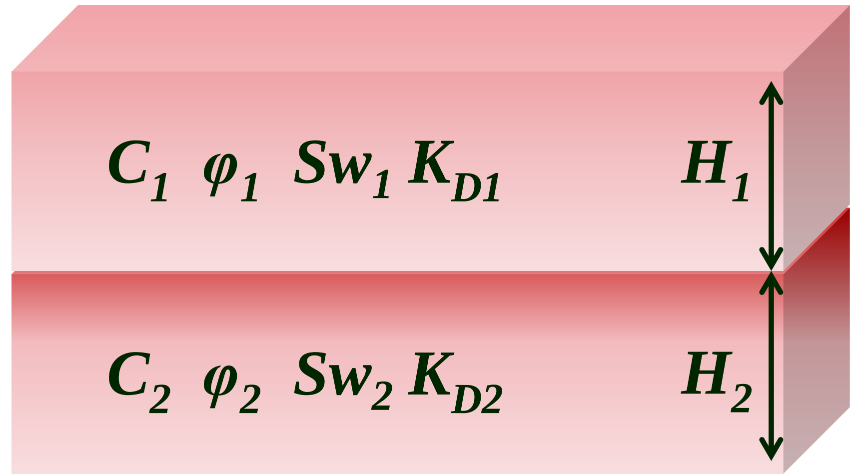


Figure from Worden et al. 1998. Petroleum Geoscience 4:129-137.

What if reservoir is heterogeneous?

- Consider two formations with different properties (adsorption, porosity, permeability and connate-water saturation)
  - *May be separated by a low-permeability baffle, a discontinuous shale or be in good communication*
- From Li and Cleall (2010):



$$C_1 = C_o \frac{\rho\nu\theta}{1+\rho\nu\theta} + \sum_{m=1}^{\infty} B_m \cos\left(\lambda_m \frac{z}{H_1}\right)\exp(-\beta_m t)$$

$$C_2 = C_o \frac{\rho\nu\theta}{1+\rho\nu\theta} + \sum_{m=1}^{\infty} A_m B_m \cos\left(\mu\lambda_m \frac{H-z}{H_1}\right)\exp(-\beta_m t)$$

where:

$$\delta = \frac{\tau_1}{\tau_2} \quad \rho = \frac{R_2}{R_1} \quad \nu = \frac{\varphi_2}{\varphi_1} \quad \theta = \frac{H_2}{H_1}$$

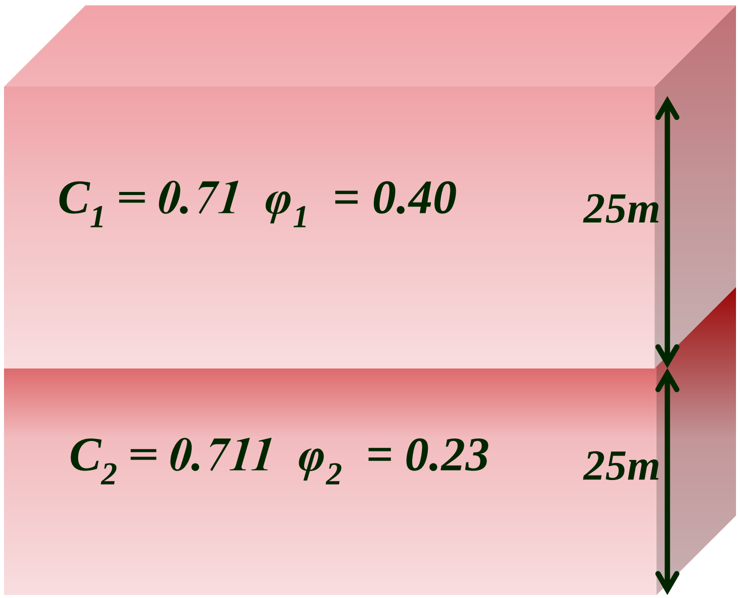
$$A_m = \cos\lambda_m / \cos(\mu\theta\lambda_m)$$

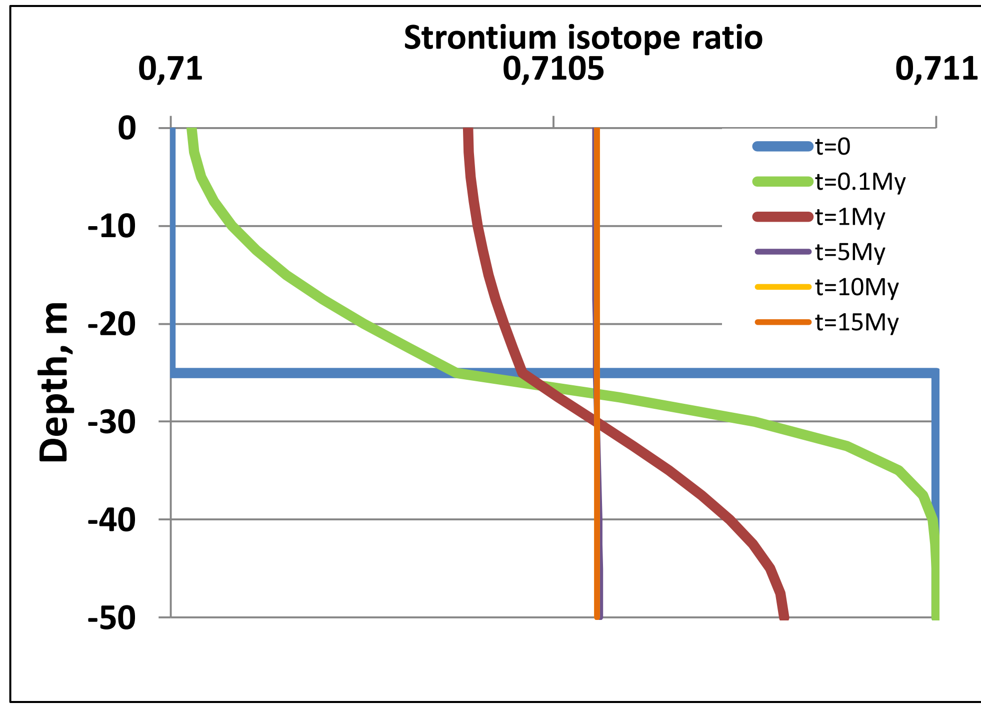
$$\sin\lambda_m \cos(\mu\theta\lambda_m) + \delta\nu\mu\cos\lambda_m \sin(\mu\theta\lambda_m) = 0$$

$$B_m = C_o \frac{-\rho\nu\theta\sin\lambda_m + \nu\sqrt{\delta\rho}A_m \sin(\mu\theta\lambda_m)}{\lambda_m(1+\rho\nu\theta)(1+\rho\nu\theta A_m^2)/2}$$

Li and Cleall. 2010. J Geotech Geoenviron Eng. 1542-1554.

What if reservoir is heterogeneous?





Assume:

D = 2.06 x 10^{-5} cm^2/s (T = 100ºC)

K_D = 5 g/cm^3

ρ = 2.6 g/cm^3

Sw_{ir} = 50%

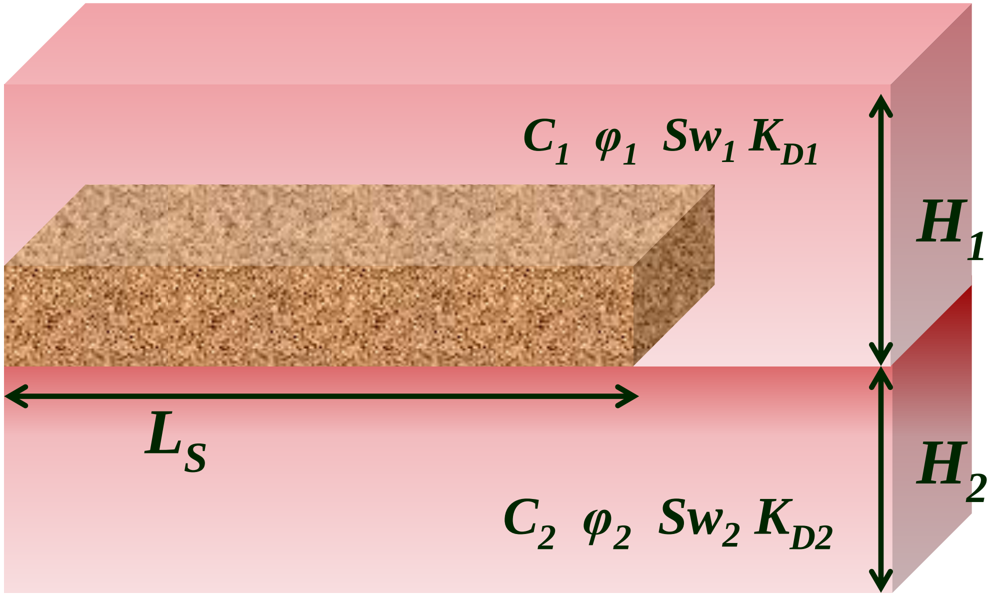
Sw_{ir} = 0.05

m (sand) = 2

- an initial step $^{87}Sr/^{86}Sr$ isotope ratio in two 25-m-thick sands with different porosities will homogenize in 15 m.y.

Mixing around a barrier

- Consider a thin, impermeable but discontinuous barrier layer separating the two sand compartments
  - *barrier length L_S >> H*
  - *diffusion is still in 1D*



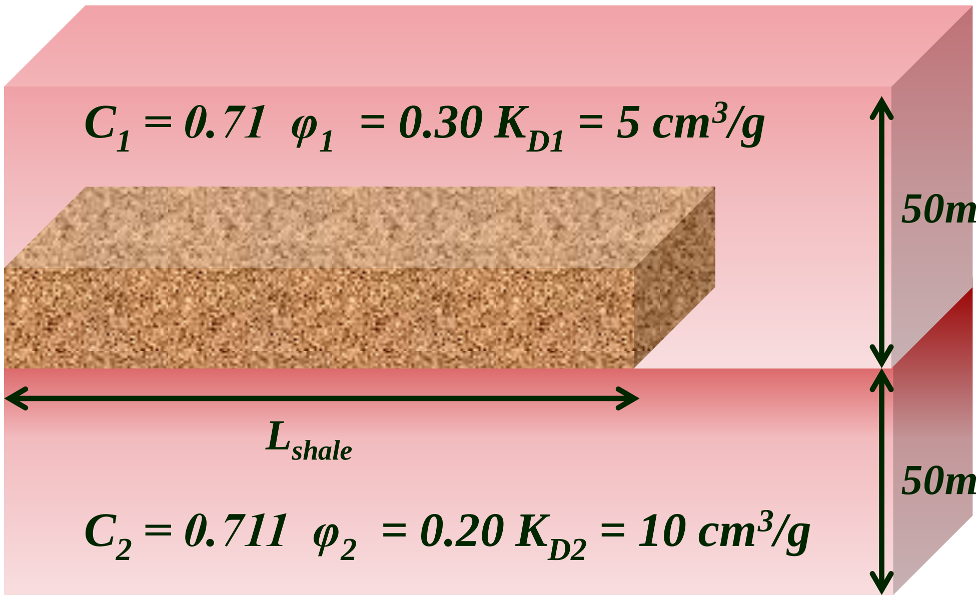
- time-scale for Sr to homogenize around the shale barrier is given by

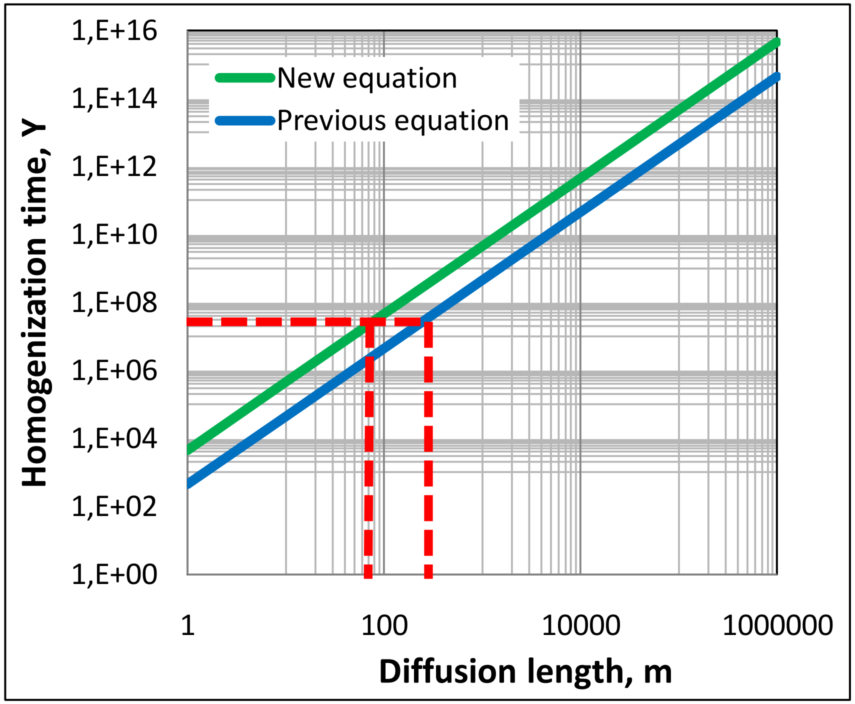
$$\boxed{t = \frac{1}{\beta_1} \ln\left(\frac{0.001}{\beta_1 B_1}\right)}$$

Where: $$\beta_1 = \frac{D_{e1}}{R_{d1}} \frac{\lambda_i^2}{L_S^2}$$

Note: this equation relates to/deals with water saturation (De)

Implications for compartmentalization





Assume:

D = 2.06 x 10^{-5} cm^2/s (T = 100°C)

ρ = 2.6 g/cm^3

Sw_{ir} = 0.05

m (sand) = 2

- **previous equation over-predicts diffusive lengths**
  - ✓ if t = 30 m.y. L_{shale} ~ 260 m (previous equation)
    L_{shale} ~ 80 m (new equation)

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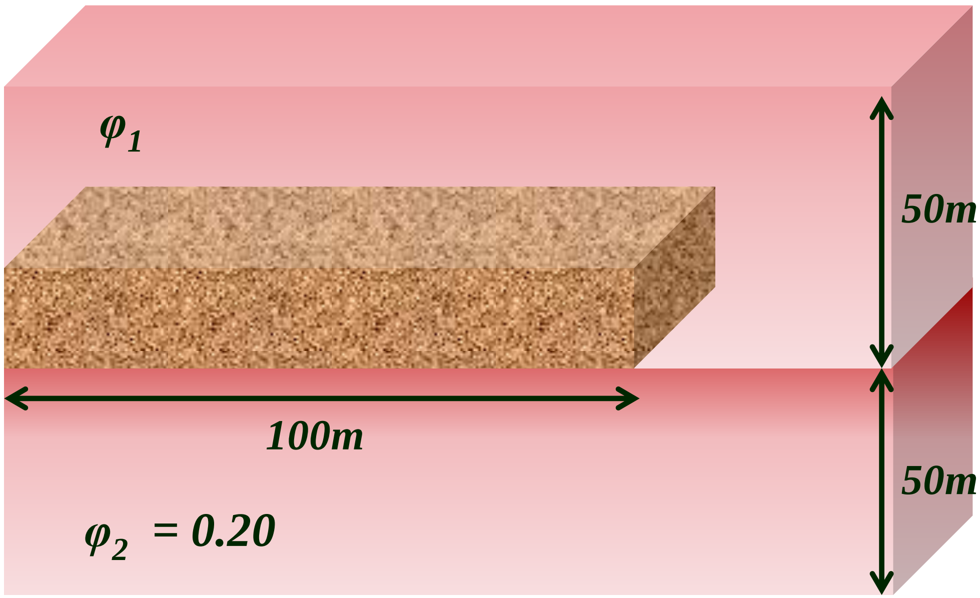
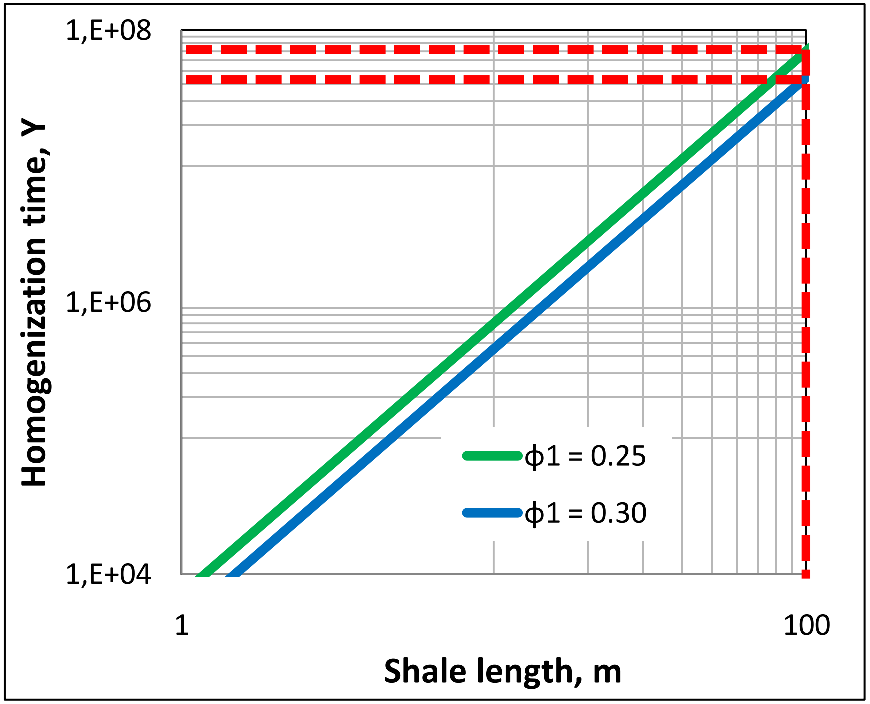
Implications for compartmentalization





Assume:

D = 2.06 x 10^{-5} cm^2/s (T = 100ºC)

ρ = 2.6 g/cm^3

Sw_{ir} = 0.05

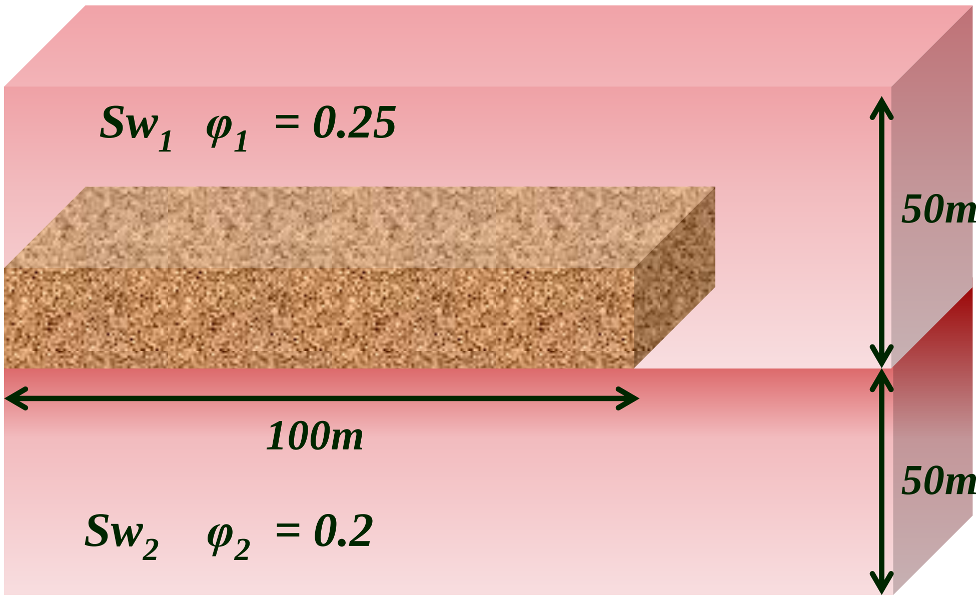
m (sand) = 2

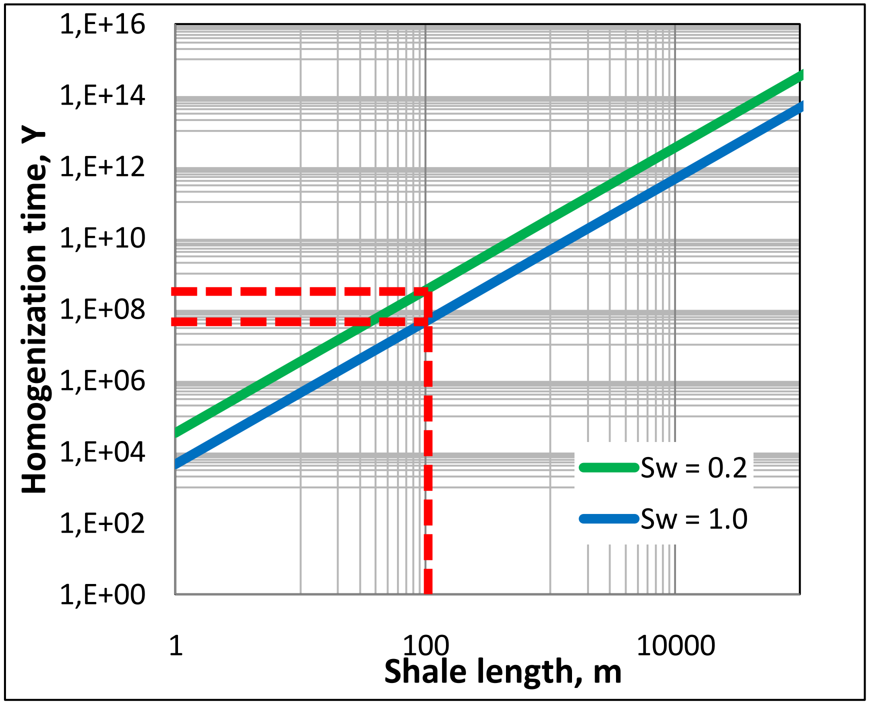
- **the larger the porosity contrast between 2 sand formations, the shorter is the mixing time**

  ✓ if $\Delta\varphi$ **= 0.05** t = 70 My

  ✓ If $\Delta\varphi$ **= 0.10** t = 45 My

Implications for compartmentalization





Assume:

D = 2.06 x 10^{-5} cm^2/s (T = 100°C)

ρ = 2.6 g/cm^3

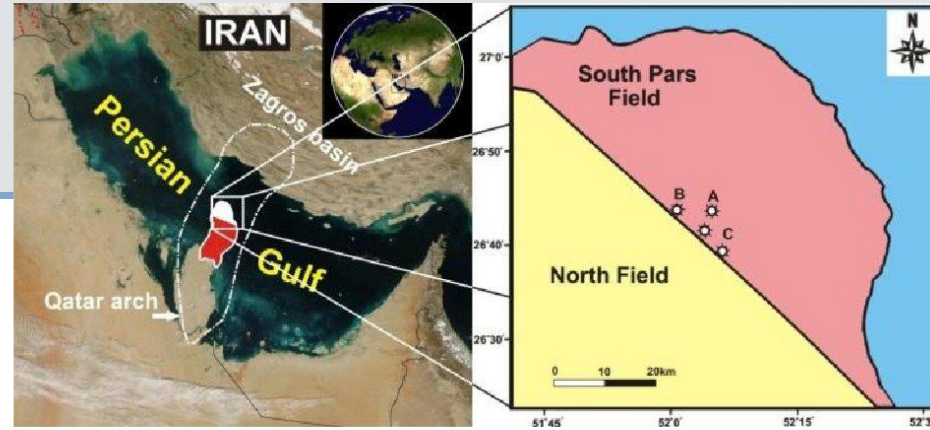
Sw_{ir} = 0.05

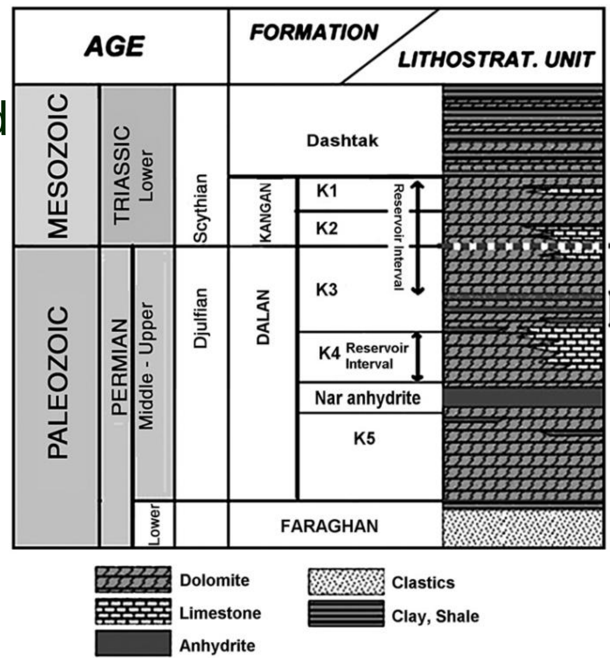
m (sand) = 2

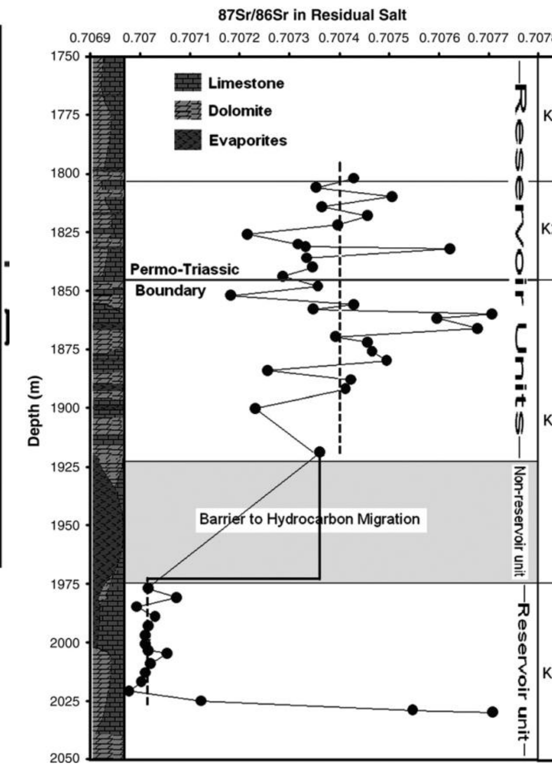
- **the lower the degree of saturation, the longer is the mixing time**
  - ✓ if Sw = 100% (aquifer) t = 45 My
  - ✓ If Sw = 20% (oil leg) t = 340 My
  - ✓ If Sw_1 = 20%, Sw_2 = 100% t = 160 My

Case study: South Pars gas field

- South Pars field is located in the Persian Gulf, discovered in 1990.
- 2nd biggest gas field – accumulation is mostly limited to the Permian-Triassic stratigraphic units.
- Two reservoir compartments – lower (K4) and upper (K3 through K1).
- Source rock: Lower Silurian shales







Reference: Rahimpour-Bonab, 2007. J Petrol Sci Eng. 58: 1-12.

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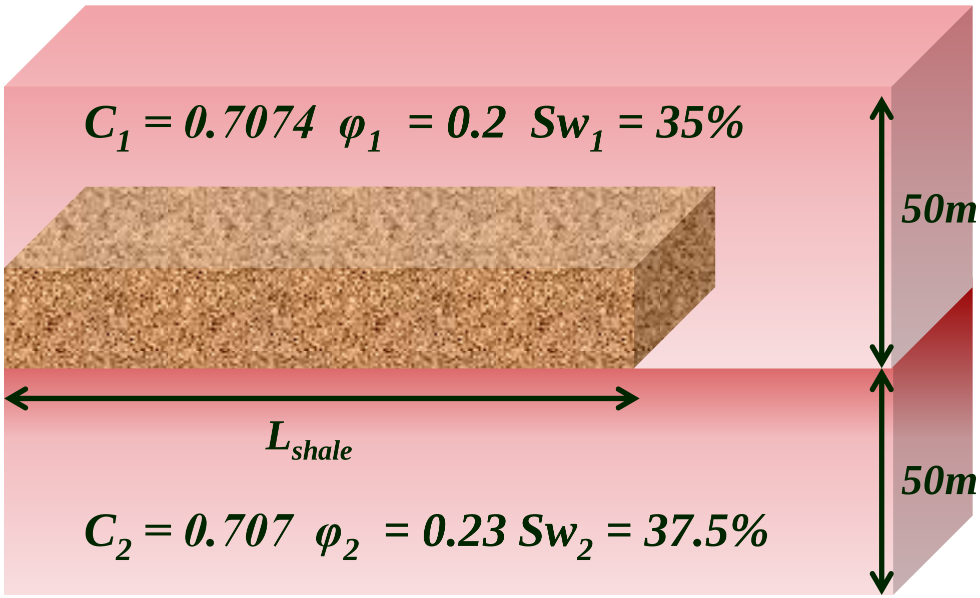
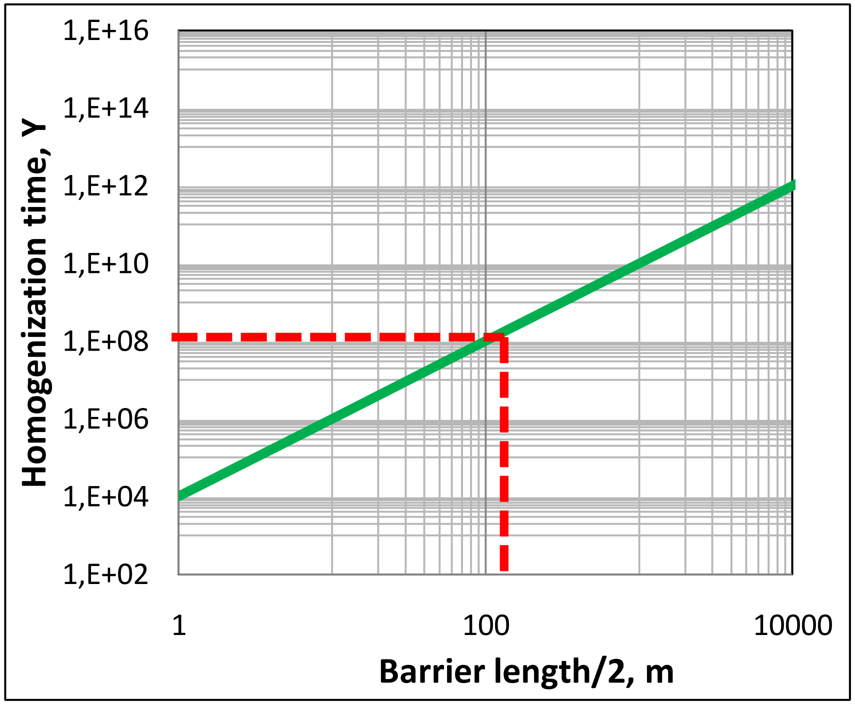
Case study: South Pars gas field





Assume:

D = 2.06 x 10^{-5} cm^2/s (T = 100^oC)

K_D = 10 cm^3/g

ρ = 2.6 g/cm^3

Sw_{ir} = 0.05

m = 2

- No barrier (base case) t ~ 100 m.y.
- With discontinuous barrier,
  - ✓ $t_{perturbation}$ = 200 m.y. (oil filling stopped), $L_{barrier}$ ~ 280 m

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Conclusions

- **Compartmentalization can be identified using vertical and lateral changes in the $^{87}Sr/^{86}Sr$ isotope ratio in formation water**
  - Caveat: concentration step-changes are not necessarily clear indications of compartmentalization → may take a long time to mix.
  - 0.001 isotopic ratio difference may take 15m.y. to homogenize between 2 25-m-thick sands with different porosities (0.4 and 0.23).

- **Barrier/baffle properties and effect of reservoir heterogeneity can be estimated using new equation**
  - barrier lengths
  - effect of water saturation on time-scale
  - effect of heterogeneity on time-scale

- **Non-reservoir interval layer identified within the South Pars gas field serve as barrier**
  - Validation of new equation
  - Now ready to be applied to fields under appraisal

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Acknowledgements

We thank

for supporting this research and for permission to publish this work.