Numerical History Matching – SCAL Data

Why is it necessary?

SCA 2019 - Pau

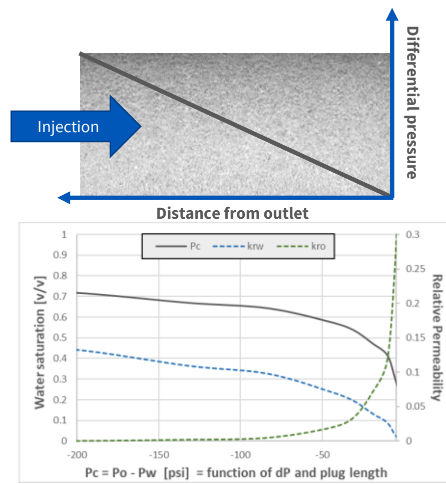
Right-click, select Format Background and change the Picture fill, File

Overview

- Boundary effects resulting in relative permeability errors
- Field implications
- QC checks prior simulation

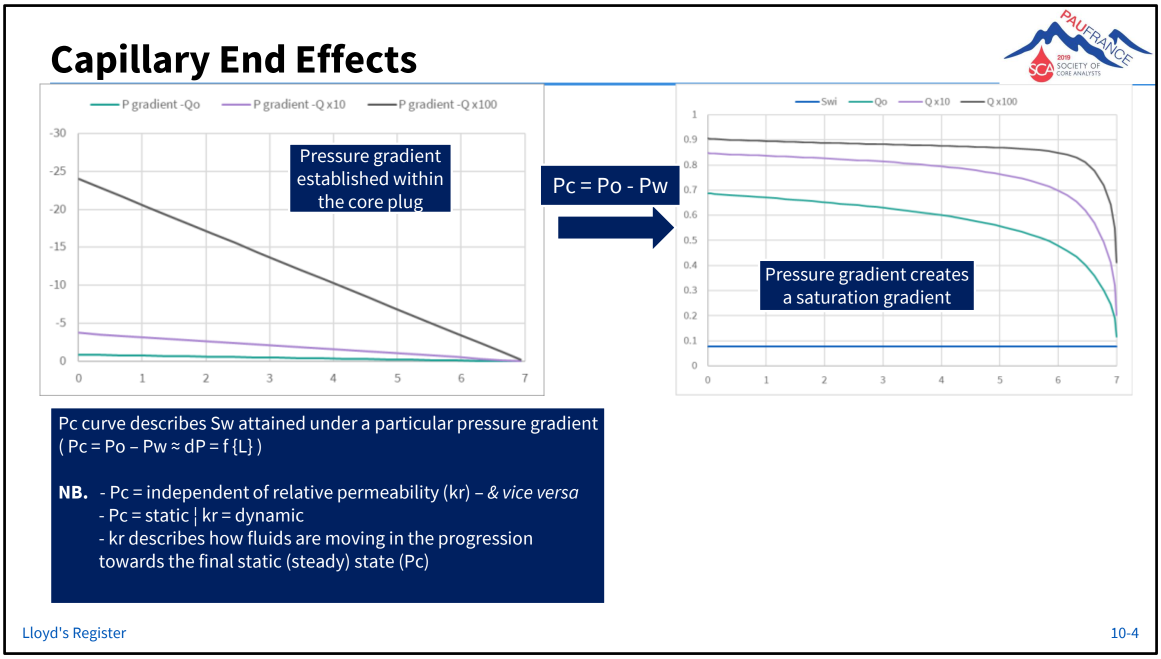
Capillary interference (simplified)

- Saturation is a function of capillary pressure (wettability), distance from Pc=0 and fluid pressure gradient
- In a coreflood, a fluid pressure gradient is applied across the plug, creating:
  - saturation gradient as a function of Pc
  - relative permeability gradient as a function of Sw
- Gradients produce error in direct calculation, since equations assume equal properties throughout the core



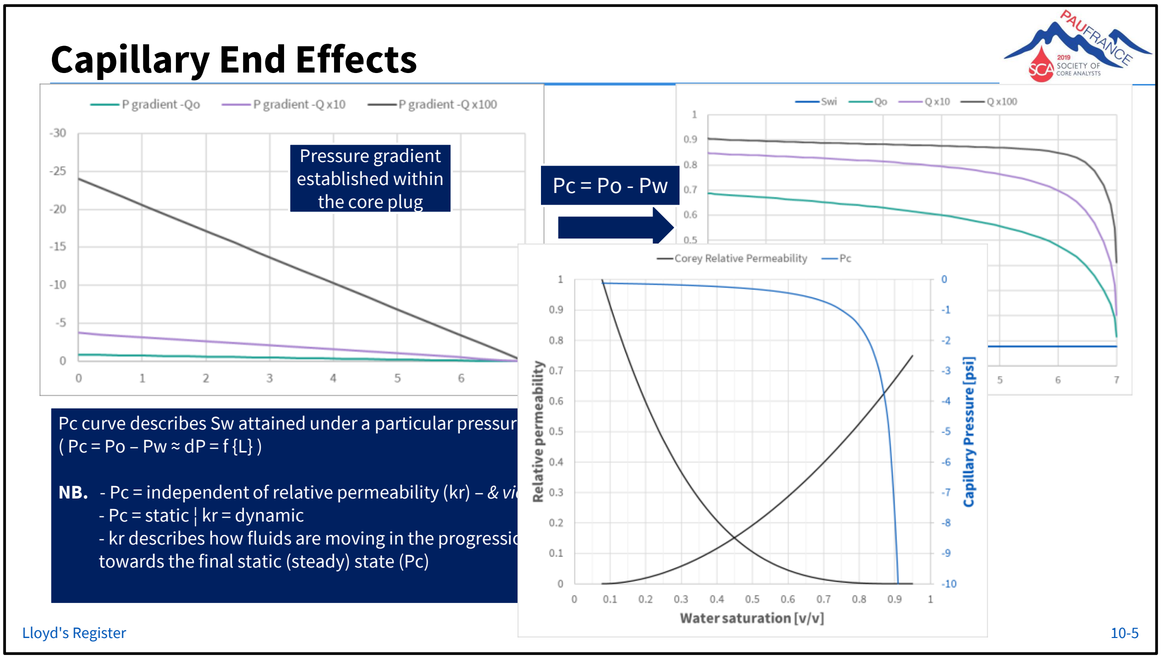
Saturation is a function of the balance of forces within a coreflood. Coreflooding is performed either using constant rate or constant differential pressure as the displacement process. In both cases, a pressure gradient will be established between the fluid phases. The pressure gradient will be a function of the distance from the point of Pc=0.

Saturation therefore becomes a function of distance from Pc=0 and the pressure gradient – since a Pc-Sw correlation can be given for a particular height above free water level (HAFWL), hence distance from Pc=0 (in a water-oil system).



These plots show a simplification of the pressure gradient during coreflooding. Assuming a homogeneous core plug and assuming that the point of Pc=0 is found at the production face of the sample (in reality it is never quite Pc=0 at the production face, but sometimes it can be).

Considering the case of an unsteady state (USS) coreflood at a particular, original flow rate (Qo – turquoise lines), a differential pressure (dP) forms and a pressure gradient builds between the two fluid phases (NB. not equal to differential pressure). At the end of the original coreflood (steady state) a saturation gradient will be established as a function of the pressure gradient and the capillary pressure-saturation distribution for the fluid pair. If a bump flood is performed (increased flow rate – for instance, 10x original flow rate) a new differential pressure and new pressure gradient will be established, leading to a new saturation distribution.

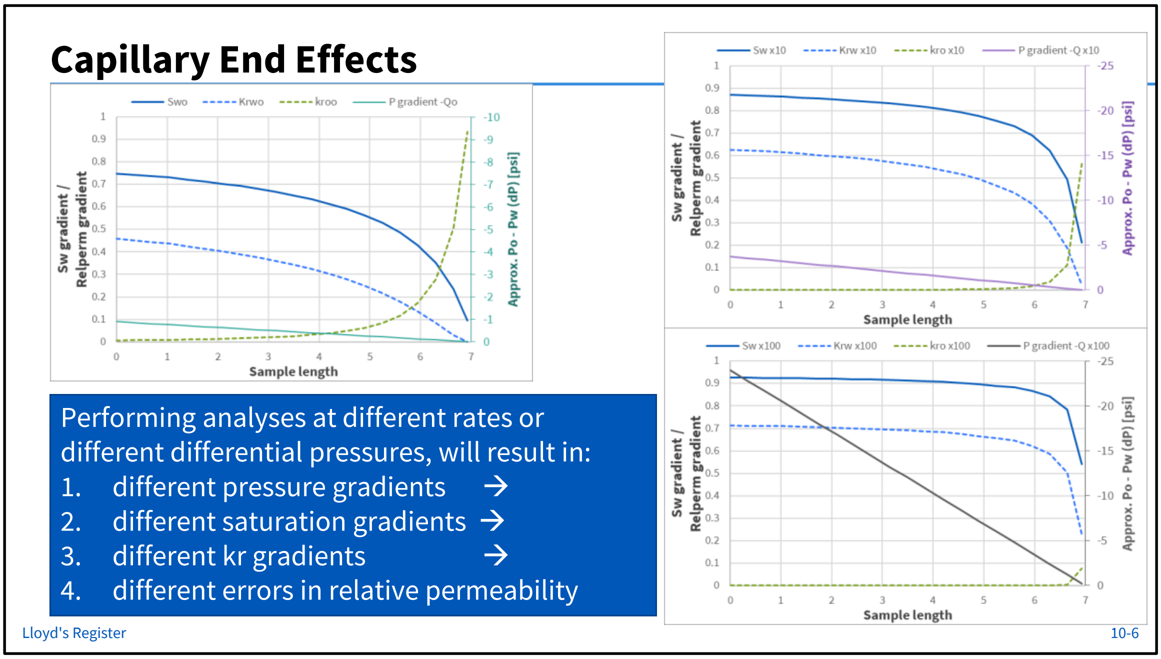


Relative permeability does not change but, since relative permeability is a function of saturation, the changing saturation at various length-scales across the core means that permeability at different parts of the core will be different, since different saturation will entail a different part of the relative permeability curve.

For instance,

- in the case of the original flow rate, above turquoise lines,
    - at 4cm from the injection end, Sw = approx. 0.60
        - Krw = approx. 0.30, Kro = approx. 0.05
    - At 6cm, Sw = approx. 0.48
        - Krw = 0.18, kro = 0.12
    - At 6.9 cm, Sw = 0.20
        - Krw = 0.02, kro = 0.60

Thus, the saturation gradient instigates a relative permeability gradient. The relative permeability curve is unchanged but changing saturation properties through the sample lead to changing relative permeability through the sample.



These plots exhibit the relative permeability gradient for the three different flow rate cases (Qo, Qx10, Qx100) The dotted lines show the changing relative (hence effective) permeability as a function of saturation.

Laboratory measurements of saturation (for input to relative permeability curves) are an average saturation, either obtained from volumetric or gravimetric production or the average of in-situ saturation monitoring (ISSM) scans. Differentiation of injection volumes versus changes in average saturation are performed to derive the expected saturation at the production face of the sample (Johnson-Bossler-Nauman [JBN], or Jones-Roszelle calculations). Obviously, since the average saturation is heterogeneous (whilst homogeneity is assumed), there will be errors in the differential saturation derivation.

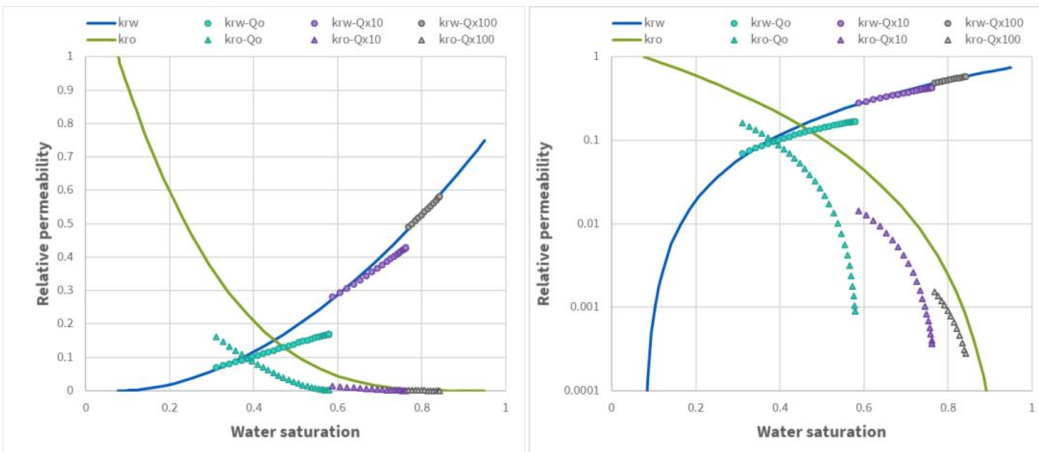
Laboratory determination of permeability is performed using differential pressure – which is intrinsically an average permeability between the locations where the pressure lines connect with the sample.

The relationship between saturation and permeability is not a mean average – it is a harmonic average - thus the mean average measurements and derivation produce wrong results.

In order to resolve a correct correlation, numerical history matching is necessary.

Capillary end effect

- Effect on analytical USS relative permeability (assumes Pc = 0)



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These plots show the potential error of analytical (JBN or Jones-Roszelle) calculations.

These relative permeability data are from a real case coreflood history, performed at 3 different flow rates, with sufficient available production data to calculate relative permeability by Jones-Roszelle method. Flow rates used were 4 ml/h (turquoise), 40 ml/h (purple) and 400 ml/h (grey).

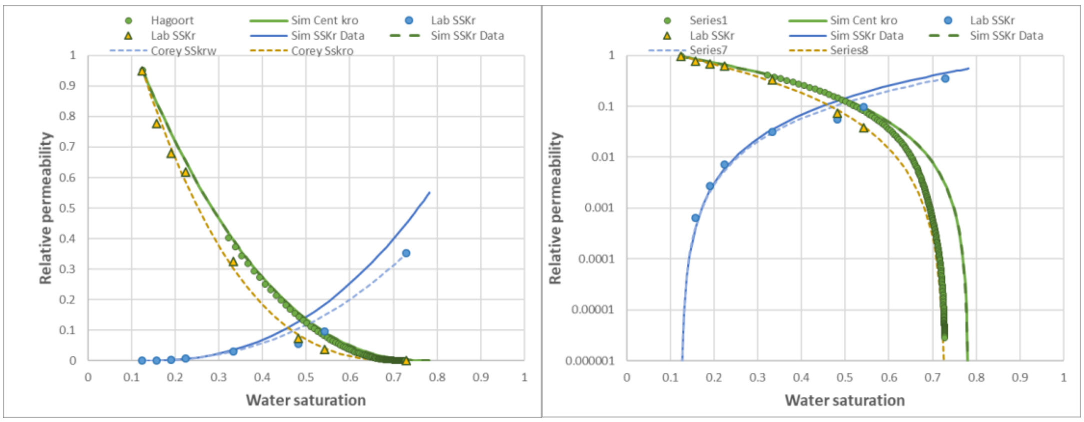
It can be clearly seen that the low rate coreflood (4 ml/h, approx. equivalent to 0.3 m/day reservoir advancement rate – capillary number approx. 10^{-7}) produces significantly erroneous data. Both kro and krw and massively suppressed and residual oil saturation (Sor) is 35% higher than the true residual.

The error is decreased by subsequent higher rate floods (Nc = 10^{-6} & 10^{-5}), but it is not negated, particularly in kro and Sor. Even at the highest rate (close to the maximum rate of the labs equipment), Sor remains 10% higher than true Sor.

It must be noted that, in the reservoir, the regions around injectors and in well swept layers, true Sor will be observed; since the capillary artefacts which create these laboratory errors are not present in the reservoir.

Capillary end effect

- Effect on SS & centrifuge relative permeability (assumes Pc =0)



This is further real case data showing relative permeability derived from the steady state (SS) method (yellow triangles and blue circles), the laboratories application of Corey functions fitted to the Darcy derived SS data (dashed lines), centrifuge oil relative permeability data (green circles) and the numerical history matched relative permeability curves (solid lines).

It is often stated that centrifuge relative permeability provides Sor and late-life kro. However, these data show a case where capillary pressure has affected the centrifuge kro data because Sor was not achieved. This is because an insufficient spin speed (RPM) was applied.

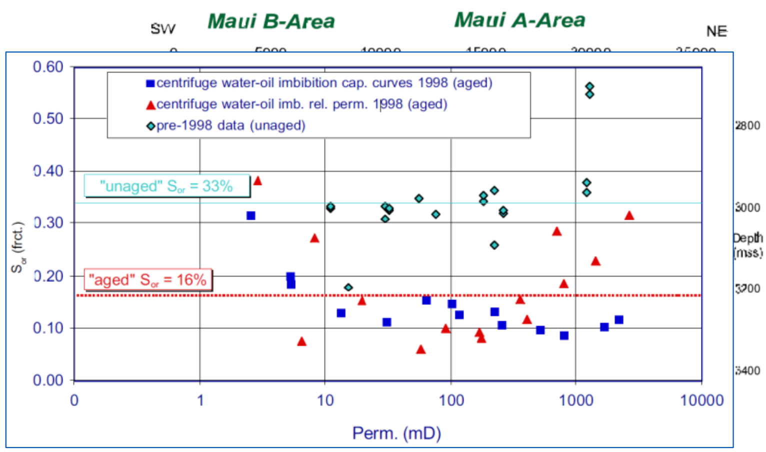
The green solid line and overlaying green dashed-line – are the simulated relative permeability data, which have incorporated capillary pressure.

Summary of boundary effects

- Suppression of recovery resulting in overestimate of residual oil saturation
- Error in analytically derived relative permeability (assuming Pc=0)
- Flooding does not always achieve residual saturation – even with bump floods

Impact on field calculations

- Error in residual oil saturation – SPE 68741
  - 12.2 MM m^3
- Sor error = 17%



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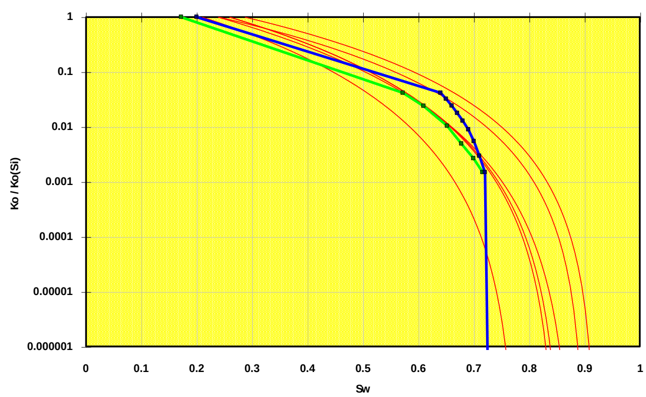
What is the impact of wrong relative permeability data on reservoir properties.

It is essential to have correct wettability when performing relative permeability.
This case shows a 17% error in Sor from this field data – due to incorrect wettability: old water-wet data versus wettability restored (aged) data.

Impact on field calculations

- Error in residual oil saturation – flooding vs. centrifuge

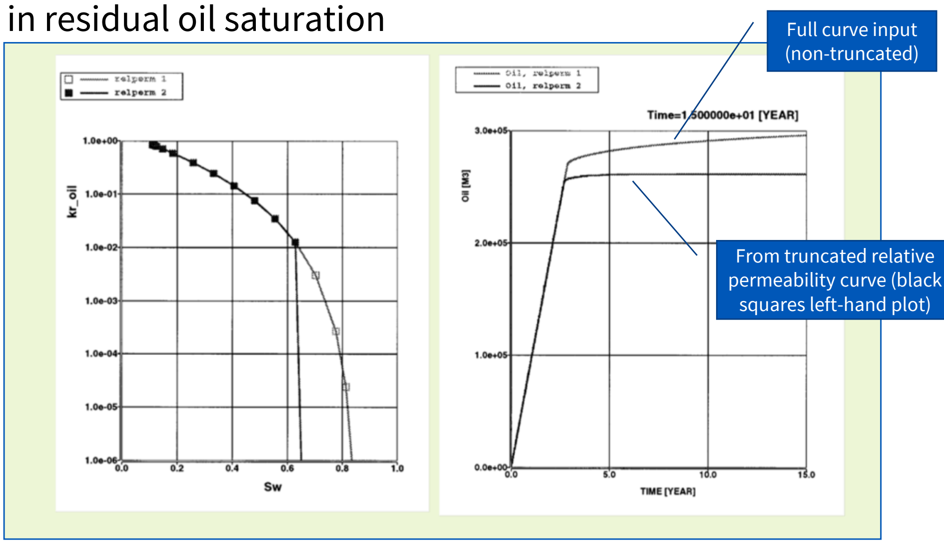


This and following slide show the impact of using wrong data.

The red curves are more correct relative permeability data, extending to true Sor. The other coloured series (blue and green with markers) are flooding data with similar curvature but limited production – i.e. 15 – 20% higher residual oil.

Impact on field calculations

- Error in residual oil saturation



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The impact of higher Sor is shown in these plots.

The right-hand plot shows simulated cumulative production estimated from a truncated relative permeability and a non-truncated one (achieving full Sor)

Production data simulated a 15 year production period and indicated a difference in breakthrough time and volume – even though the curves were essentially the same (except Sor).

Impact on field calculations

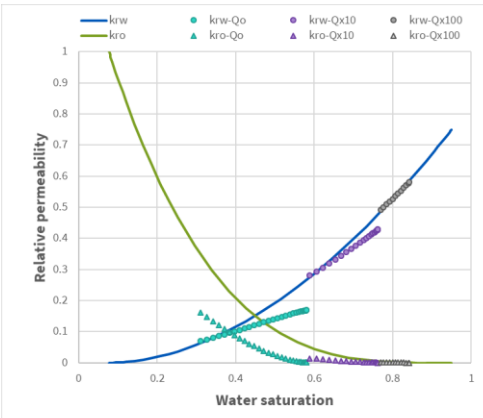
Region	Current	Old
North Sea 1	15%	28%
North Sea 2	15	25-30
North Sea 3	14	29
North Sea 4	10-15	-
Middle East 1	20	
Middle East 2	15-25	
Middle East	10-20	
South America	10	>= 40
Africa	15-20	25-35

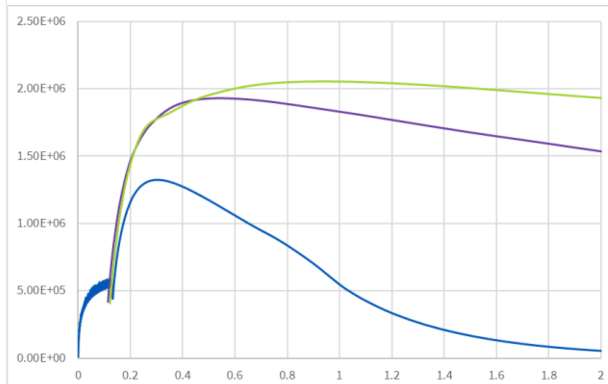
Jos Maas – Coreflood simulation training 2013

This table is from Jos Maas's training material indicating evidence of a difference in old and current Sor data. These indicate that, historically, Sor has been overestimated by an average 15-20%

Impact on field calculations

- Different relative permeability result in different production profiles





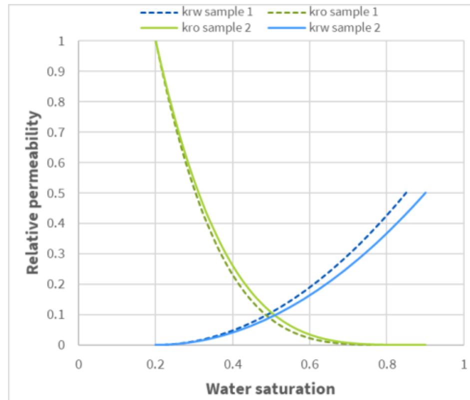
The right-hand plot shows the impact on reservoir simulated incremental production volumes using the analytical relative permeability curves.

- blue production curves were derived from the turquoise kr data
- purple production curves were derived from the purple kr data
- green production curves were derived from the grey kr data

Impact on field calculations

- Error in residual oil saturation
  - Case shown has a 5 saturation unit difference in Sor (0.10 and 0.15)
    - Swi = 0.2,
    - Nw = 2,
    - No = 4,
    - krw' = 0.5
  - Difference in RF = 7%
  - For 300 MMbbl (48 MM m^3) = 21 MMbbl
    - approx. 1.3 billion USD @ $60 /bbl

$$RF = \frac{(1 - S_{wi} - S_{or})}{(1 - S_{wi})}$$



These data indicate the simple calculation of expected recovery factor (RF) from average endpoint saturations.
Data was used to calculate fractional flow curves (fw vs Sw), which were subsequently used to determine Sor at an economic cut-off of fw = 0.95 (95% water cut).

Considering a case with the only difference being 5% Sor, a difference in RF of 7% was observed.
RF can be directly calculated into a simplistic production volume by multiplying the STOOIP – to obtain the RF volume.
Multiplying RF volumes by current crude oil prices can estimate the monetary value of the error. In this case – 1.3 billion USD.

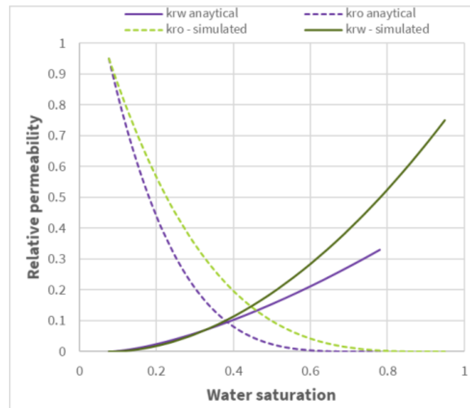
Impact on field calculations

- Error in analytical relative permeability
  - Case shown

Property	Analytical	Simluated
Sor	0.22	0.05
Nw	1.5	1.9
No	4.0	3.4
Krw’	0.33	0.75

  - Difference in RF = 19%
  - For 300 MMbbl (48 MM m^3) = 56 MMbbl
    - approx. 3.4 billion USD @ $60 /bbl

$$RF = \frac{(1 - S_{wi} - S_{or})}{(1 - S_{wi})}$$



These data indicate the simple calculation of differences in expected recovery factor (RF) due to errors in relative permeability and Sor.
Data was used to calculate fractional flow curves (fw vs Sw), which were subsequently used to determine Sor at an economic cut-off of fw = 0.95 (95% water cut).

Considering this case with the 17% Sor difference and other curvature differences, RF error was 19%.
RF can be directly calculated into a simplistic production volume by multiplying the STOOIP – to obtain the RF volume.
Multiplying RF volumes by current crude oil prices can estimate the monetary value of the error. In this case – 3.4 billion USD.

QC Checks

- Sample selection – homogeneity
  - most coreflood simulators ascribe homogeneous properties
- Wettability - Essential
- Swi – Check against petrophysical dataset
- Endpoint permeability – statistical or property-based correlations
  - Ko @Swi, Kg @Swi, Kw @Sor, kg @Sor+Swi (hence, corresponding kr)
- Capillary pressure – same or sister sample, or petrophysical correlations
- Sor (or final water saturation – Swf) – cross-check and correlate

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Before using time, resources and money to history match relative permeability data, these QC checks should be performed.

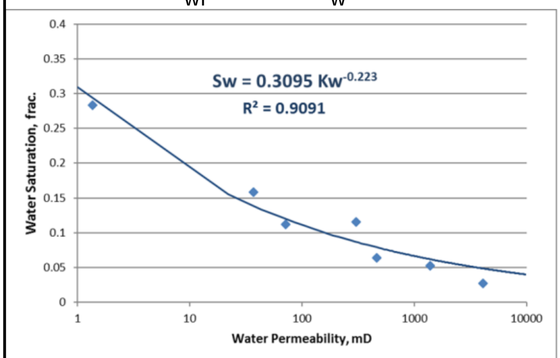
- Sample selection (ensuring a homogeneous core plug) is essential. Most (if not all) commercial coreflood simulators (CYDAR, PORLAB, SCORES, SENDRA) impute homogeneous properties (i.e. a single permeability, porosity, initial saturation, etc. for the core plug).
  - In my experience of reviewing unusual relative permeability data, most often it was derived from data using a heterogeneous core plug)
- Wettability – it is essential to have correct wetting.
  - Incorrect wetting → wrong capillary pressure, wrong relative permeability → unable to correct and thus, **= rubbish**
- Swi
  - Check that Swi agrees with Swi from other datasets
  - Check (from volumetric data) that the Swi (from production volumes) agrees
- Endpoint permeability
  - Correlate endpoints to reservoir properties or into distribution bins.
  - How do your data correlate? Do the coreflood data correlate?
  - If not, care must be taken when considering endpoint parameters in the simulations, since this is a variable in simulated derivations and therefore, large variance in possible endpoint may lead to difficulty finding more unique solutions
- Capillary pressure
  - Preferably, capillary should be obtained either from the same sample or a sister sample (where the sister sample exhibits similar properties at all stages of testing) – this requires appropriate QC of these properties.

    - If no sister sample is available, then alternative petrophysical correlations may be necessary, but this will increase the number of simulations required
- Sor (or other endpoint saturation data)
    - Cross-checks should be performed using Dean-Stark extraction, Karl Fischer Titration, Dispersion testing or other alternative methods, to ensure the quality of this final parameter
    - All values should be correlated against reservoir properties to verify data, outliers, etc.

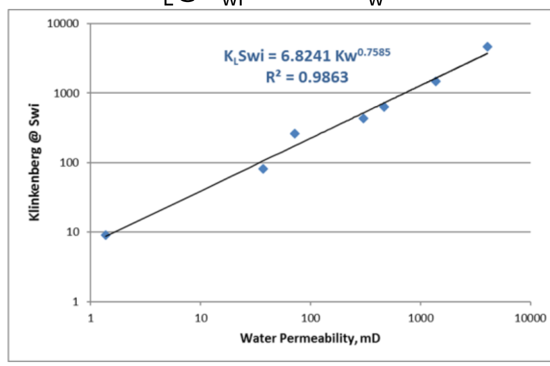
QC Checks – Endpoint correlations

- Attempt to determine relative permeability endpoints correlations and/or variance

S_{wi} versus k_w



$k_L@S_{wi}$ versus k_w

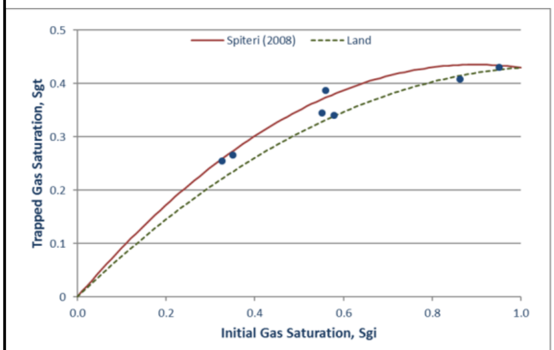


This and the next slide show examples of high quality parameter correlations, that allow implementation of these endpoint saturations and endpoint permeability against other reservoir properties. Sensitivity and/or variance analysis can also be performed to consider bounding limits from these data.

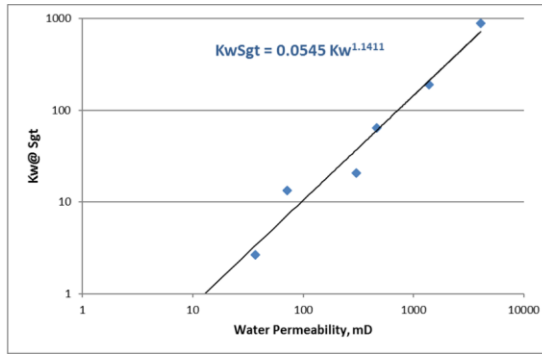
QC Checks – Endpoint correlations

- Attempt to determine relative permeability endpoints correlations and/or variance

S_{gr} versus S_{gi}

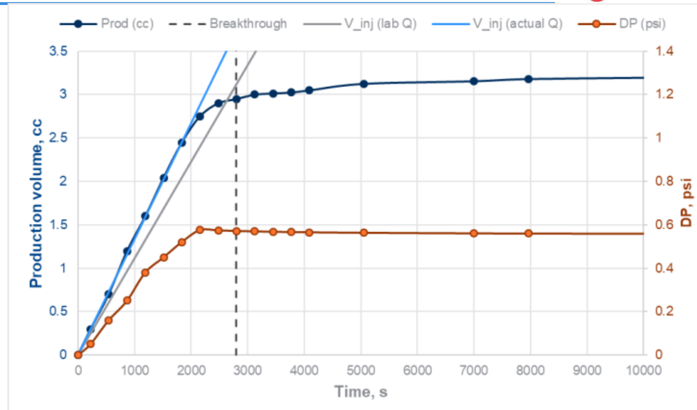


$k_w@S_{gt}$ versus k_w



USS – QC checks

- Check Swi & Swf (or other phase saturations)
- Check production values
- Check breakthrough time aligned in production and dP



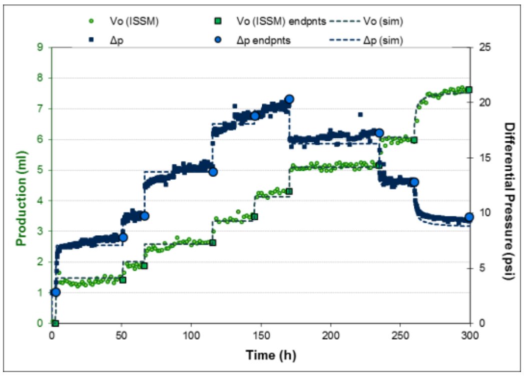
- Check linear production = linear injection
  - **above case had 17% rate error = 17% effective k error = 17% kr error**

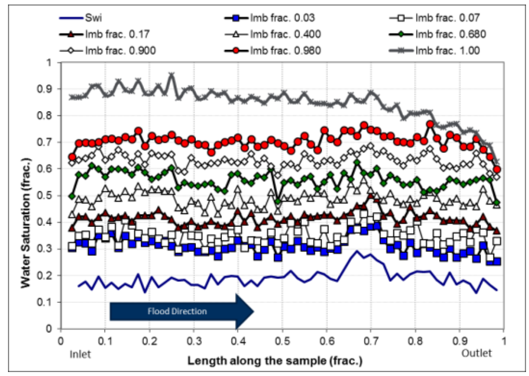
Finally, for USS relative permeability the above checks should be performed:
- check endpoint saturations agree by determining these values by alternative measurements (volumetric/gravimetric/DS extraction/dispersion/etc.)

Obtain raw coreflood data: production volumes vs time, dP vs time
- Check production volumes, used to determine saturation, agree with the raw data volumes
- check breakthrough time aligns in both production and dP timelines
- check produced volume rate = injection rate before breakthrough
- if pressure offsets are known, check whether these have or have not been applied

SS – Example Data

- Check Swi, Swf (other phase saturations if required)
- Plot and check stabilised production and dP versus time
- Check ISSM calculations – particularly error in SS scans





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For SS testing these are checks required before simulating:

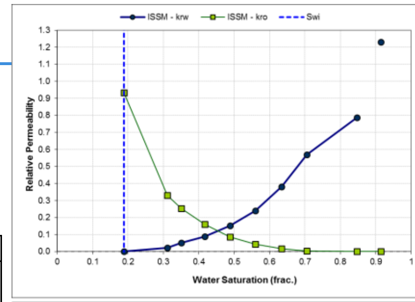
- As per USS, check endpoint saturations using an alternative measurement technique (e.g. volumetric/gravimetric/DS extraction/dispersion/etc.)
- Plot and check stabilized production and dP versus time (left-hand plot)
    - The left-hand plot clearly shows reasonable agreement between the selected endpoint data (light blue circles – dP, green squares – Vo) and the raw data (dark blue squares dP, light green circles – Vo)
    - Use these endpoint to recalculate Darcy permeabilities kw and ko at each SS fraction
- Check ISSM calculations – particularly the error in scans at SS conditions (this error should be within ± 1 saturation unit (s.u.) producing a variance of 2 s.u. – hence 0.03 SD

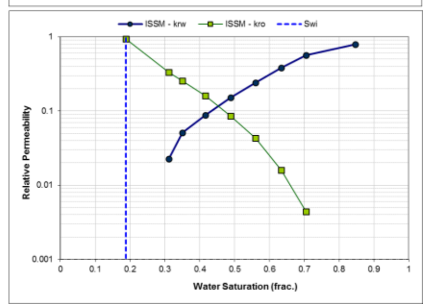
SS – Example Data

Imbibition Relative Permeability - Analytical

Base permeability: ko(Swi) 10.1 (mD)

Rate		Water					S_w		
Water	Oil	Fraction	Δp	Δp	k_w	k_o	ISSM	k_{rw}	k_{ro}
(ml/hr)	(ml/hr)	F_w	(mbar)	(psi)	(mD)	(mD)	(frac.)	(frac.)	(frac.)
0.00	60.00	0.000	195	2.84	0.00	9.5	0.188	0.000	0.935
1.50	58.50	0.025	539	7.82	0.23	3.4	0.311	0.022	0.330
4.20	55.80	0.070	670	9.7	0.51	2.57	0.351	0.051	0.253
10.20	49.80	0.170	941	13.6	0.9	1.64	0.416	0.088	0.161
24.00	36.00	0.400	1278	18.54	1.5	0.87	0.489	0.152	0.086
40.80	19.20	0.680	1369	19.86	2.4	0.43	0.560	0.241	0.043
54.00	6.00	0.900	1146	16.63	3.9	0.16	0.633	0.381	0.016
58.80	1.20	0.980	835	12.11	5.8	0.04	0.706	0.569	0.004
60.00	0.00	1.000	616	8.94	8.0	0.00	0.847	0.787	0.000
600	10 x Bump	1.000	3943	57.2	12.5	0.00	0.914	1.230	0.000





Recalculated SS data and the lab data should match

Thank you

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