A Simplified Scheme for Interpolation of Multiple Relative Permeability Sets in Simulation of Hybrid EOR Processes

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Abstract

In simulation of hybrid (composite) EOR processes there is a need for relative permeability curves which are a function of not only (water) saturation, but also of the concentrations of all the different fluid components that are included in the process, e.g. brine, surfactant, and polymer. These relative permeability curves must be computed as interpolated curves from a set of base curves, e.g. for minimum and maximum surfactant concentration. Currently, schemes for interpolation of one or two relative permeability sets are available in reservoir simulators, but no simulators are able to handle more than two sets, an option that is necessary to simulate many current hybrid EOR schemes. By a purely theoretical approach, we present a simple scheme for interpolation that can readily be generalized to any number of relative permeability sets, and hence should be relatively easy to implement as an extension to existing software algorithms, in e.g. commercial simulators. We also point at some challenges regarding availability of needed data.

Key words: Simulation, EOR, Hybrid EOR, Relative Permeability

1 Introduction

Hybrid EOR refers to a new combination of EOR methods which gives added incremental recovery over each method applied separately. The most interesting hybrid EOR processes that are recently being investigated include the combination of water based EOR processes such as surfactant flooding and polymer flooding with low salinity water injection [1, 10, 12]. Both surfactant and polymer behavior are highly dependent on the brine salinity and favor the low salinity environment. In the low salinity condition, retention of both surfactant and polymer decreases. This results in technically and economically efficient EOR processes. In recent years more complex processes for enhanced oil recovery (EOR) have been investigated both experimentally and by simulations [7, 10, 11, 14 - 17] An example is the PASF-scheme, Polymer Assisted Surfactant Flow, which in principle is performed as shown in Figure 1.

The scheme illustrated in Figure 1 is taken from a generic simulation study, and is representative for the hybrid schemes that are currently studied both in experiments and by simulation [11]. It is comprised of an initial injection period of standard sea water, followed by low salinity water and surfactant in a low salinity environment. Then polymer in low salinity brine is injected for a period, and finally a new period of low salinity surfactant. Ideally, each of the different fluids is injected for a sufficiently long period that maximum effect is achieved. Experimental findings are that such hybrid schemes often are more effective than the sum of isolated individual contributions of the EOR fluids.

The complex injection scheme itself is not straightforward to model in any simulator, and novel techniques have been developed to handle this. In this context we focus on the interpolation of multiple relative permeability sets.

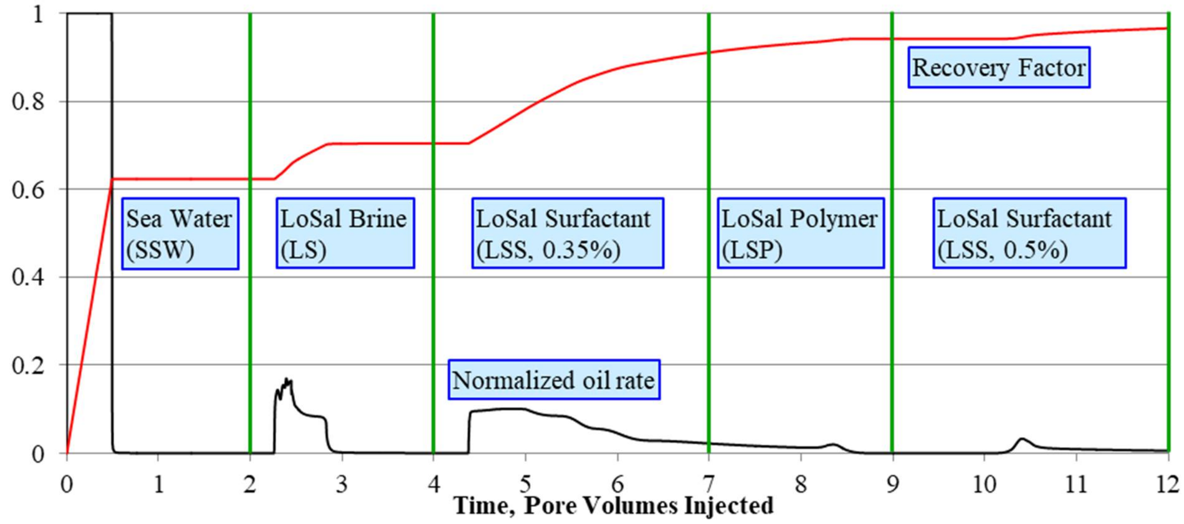

Fig. 1. Illustration of typical injection scheme for a complex hybrid EOR process, showing (normalized) oil rate, and recovery factor.

Interpolated relative permeability is needed when the relative permeability curves are not only dependent on (water) saturation, but also on concentration of one or more of the present EOR fluids, as e.g. $k_{rw} = k_{rw}(S_w, c_S)$, where S_w is water saturation and c_S is surfactant concentration.

We adapt the following terminology:

A *single relative permeability curve* is the (standard) curve, where relative permeability varies as a function of (normally) water saturation, with other parameters kept constant, e.g.,

$k_{rw} = k_{rw}(S_w, c)$, where S_w runs from minimum to maximum water saturations (typically S_{wc} to $1 - S_{or}$, where S_{wc} is connate or irreducible water and S_{or} is residual oil), and c is a constant fluid concentration, treated here as a parameter.

A *relative permeability set* is the set of single relative permeability curves generated by varying the parameter c in the definition above, i.e.

$k_{rw} = k_{rw}(S_w, c); S_{wc} \leq S_w \leq 1 - S_{or}; c^{min} \leq c \leq c^{max}$

The term *Multiple relative permeability sets* is used to denote relative permeability sets which depend on several concentrations, i.e.,

$k_{rw} = k_{rw}(S_w, c_1, c_2, \ldots); \; S_{wc} \leq S_w \leq 1 - S_{or}; \; c_i^{min} \leq c_i \leq c_i^{max}, i = 1, 2, \ldots$

As an example, when both salinity and surfactant concentration can take any value in their permitted ranges simultaneously, relative permeability curves will be needed as $k_{rl} = k_{rl}(S_w, c_B, c_S)$, ($l$ = oil, water) at all permitted values of salinity c_B and surfactant concentration c_S.

Typically, the single relative permeability curves within a relative permeability set are not known for all concentrations c, but only at some selected values $c^1, c^2, \ldots$, and therefore, permeability curves at a specific concentration c must be determined by interpolation of the available curves.

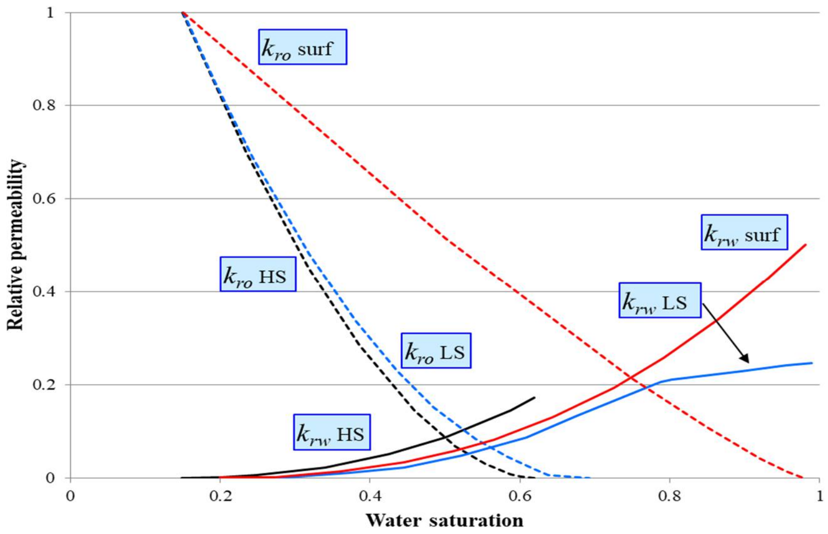

Fig. 2. Hybrid Lab Experiment Example, Relative permeability curves from history match of high salinity, low salinity water flood, and surfactant injection, followed with low salinity chase water (modified from [17])

The term Multiple interpolation is used for the situation where the relevant relative permeability curves must be determined from a multiple relative permeability set, depending on the concentrations of several different fluid components which are active in the process, e.g. salt, surfactant, and polymer concentrations in the water phase.

Figure 2 shows examples of relative permeability curves as derived from an experiment at Uni CIPR (now NORCE Energy), demonstrating how relative permeability curves may depend on the EOR-fluids diluted in the water [17].

1.1 Characteristics of Hybrid EOR Processes

Multiple interpolation of relative permeability and capillary pressure is especially important for hybrid Enhanced Oil Recovery processes [15]. Combination of two or more recovery methods (Hybrid EOR) may require more than two relative permeability interpolations simultaneously.

Examples of such processes are Low Salinity Surfactant and Low Salinity Polymers, [17]. The first relative permeability interpolation is needed to describe the differential pressure and oil production due to brine salinity changes as defined by Jerauld et al [6]. Given two set of saturation functions, one for low salinity and one for the high salinity, the relative permeabilities for water and oil, are interpolated as shown in section 2. Jerauld et al. [7] pointed at the need for interpolated relative permeability in EOR simulations. Later studies, among others projects at Uni CIPR [14 – 17] have expanded on the concept and also identified the need for more advanced and complex interpolation schemes.

Skauge et al. [14, 15] used two somewhat different approaches (ECLIPSE and UTCHEM) to model the exact oil produced by lowering brine salinity and also for modelling the surfactant injection (with the assumption of zero capillary pressure). The main assumptions of both of the applied models are shift in relative permeability to more water wet with lowering of brine ionic strength. The experimental results used in this simulation study are obtained from laboratory tests carried out on two core samples from the same block of Berea sandstone.

The main purpose of surfactant is to reduce interfacial tension (IFT) between oil and water, and thereby minimize trapping of oil mobilized by the salinity change. The surfactant-oil relative permeability will change with both surfactant concentration and brine salinity. In addition, the salinity impact on IFT will vary with surfactant concentration.

By combined low salinity surfactant flood a more efficient oil recovery process can be obtained. The low interfacial tension (IFT) environment established by surfactant would prevent re-trapping of mobilized oil by low salinity water injection.

Similarly, addition of polymer to the low salinity water could improve the stability of the low salinity flood (Tripathi and Mohanty 2008 [21]). Polymer improves the efficient banking of the oil through a favorable mobility ratio, and thus, increases the displacement efficiency of the low salinity floods.

Mohammadi and Jerauld [10] reported modelling of the combined effect of low salinity polymer flooding as a new hybrid EOR process. They simulated the effect of high salinity water, low salinity water, conventional polymer flooding and combined low salinity polymer flooding on increased oil recovery.

The polymer enters other phenomena as water phase viscosity will change with polymer concentration and brine salinity. Additional oil produced in low salinity polymer show the need for additional relative permeability functions [12]. These complex interpolation schemes both need more systematic approach to multiple interpolations.

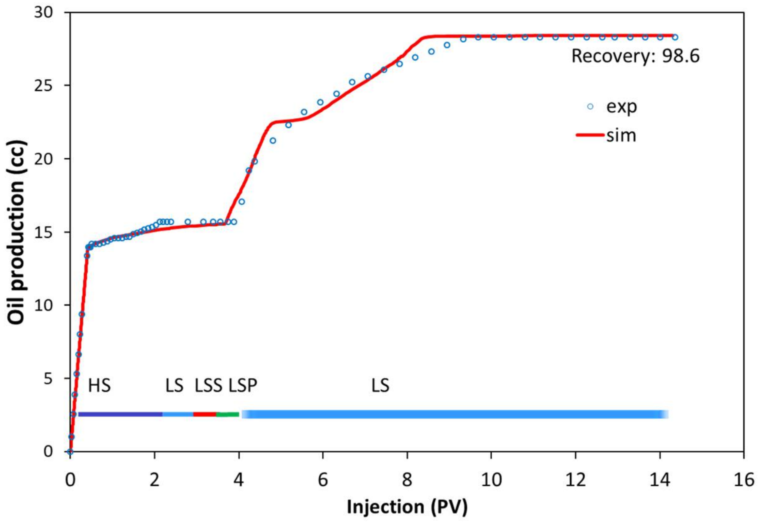

Fig. 3. Example of hybrid EOR experiment: oil production resulting from injection of different EOR fluids (Sea water, low salinity water, surfactant, polymer, and finally low salinity water). Also shown is the accompanying history matched simulation. Innovative multiple interpolation schemes were needed to achieve this match (modified from [17]).

An example is shown in Figures 3 and 4, which show results from a lab experiment which was history matched using CMG STARS compositional simulator. The experiment, a typical hybrid EOR process, was comprised of an initial period of sea water injection, followed by injection of low salinity water, then surfactant in low salinity water, followed by a period of injection of polymer in low salinity water. The final stage was a relatively long period of injection of low salinity water. This and other experiments have demonstrated that the effect of the different injection fluids is somewhat delayed compared to the injection interval, and that the resulting increase in oil recovery is larger for a hybrid process than the sum of the contributions from the individual components. In this context the history matched simulation results are probably equally interesting. We see from the Figures 3 and 4 that a very good match has been achieved.

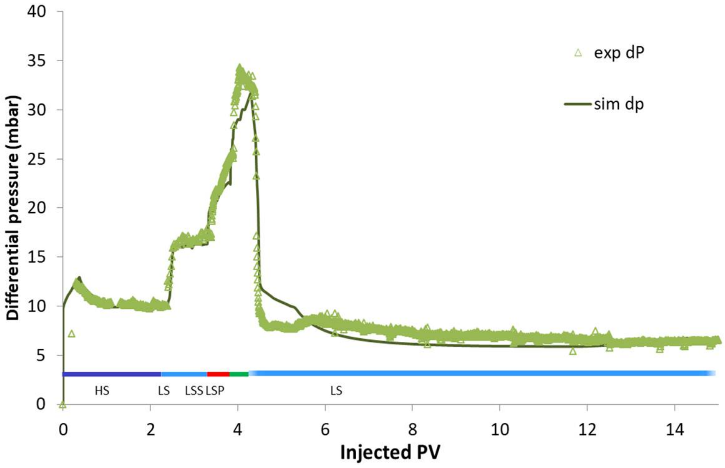

Fig 4. Differential pressure (across core) from the same hybrid EOR experiment as in Fig. 3. Experimental and history matched simulation results (modified from [17]).

This was only possible by adjusting the shapes and end points (S_{wc} and $1 - S_{or}$) of the relative permeability curves for all the involved EOR fluids, low salinity water, surfactant, and polymer, and not the least by utilizing the available algorithms for (multiple) interpolation of these relative permeability curves. In this example, multiple interpolation was used for the combination of salinity and surfactant concentrations, while the polymer relative permeability curves were assumed independent of polymer concentration [17]. This may or may not be a valid assumption, but was partly enforced by limitations in current algorithms, which can only handle interpolation of maximum two relative permeability sets. Hence these kinds of experiments also identified a strong need for algorithms for interpolation of more than two relative permeability sets.

This additional complexity has recently been identified and described, as some researchers claim that polymer can alter both the residual oil and the shape of the relative permeability curves (e.g. [2, 5, 22 – 24]). Hence to handle this situation we would need even more general relative permeability curves, of the form $k_{rl} = k_{rl}(S_w, c_B, c_S, c_P)$, where the added term is the polymer concentration.

Almost all hybrid EOR processes will benefit from a generalized treatment of multiple interpolations. Other obvious candidates involving gas are Polymer assisted Water Alternate Gas (PAG) [9], foam assisted WAG (FAWAG) [13], and low tension gas (LTG) [4].

The common factor of all the reported simulation models is that relative permeability curves must be interpolated to obtain curves valid at any combination of fluid concentrations. Interpolation of single relative permeability sets have been implemented by several commercial simulators (e.g. ECLIPSE [18, 19], CMG STARS [3]), and interpolation of two sets has been implemented in e.g. CMG STARS. However, interpolation of more than two relative permeability sets has not been successfully implemented in any software that this author is aware of. We therefore present a purely theoretical and relatively straightforward manner to simplify and generalize already commonly used methods, and hence should be a candidate for implementing in existing software. First, the procedures in use in present simulators are discussed.

2 Interpolation of a Single Relative Permeability Set

Interpolation of relative permeability curves for a single fluid entity is needed in the following setting: Relative permeability k_r is dependent not only on (water) saturation, but also on the concentration of a component diluted in one of the phases, normally water. E.g. during surfactant injection, relative permeability will be dependent on the concentration of surfactant in the water phase.

Hence, $k_{rl} = k_{rl}(S_w, c)$, where *l* denotes the phase (water, oil, gas), and *c* is the surfactant concentration.

In this paper we focus on oil and water relative permeability, as the gas curves have no or minor influence on the relation between fluid flow and fluid concentrations.

Typically, the relative permeability curves will be known for limiting concentration values c^{min} and c^{max}. So, the task is to compute $k_{rl}(S_w, c)$ when $k_{rl}(S_w, c^{min})$ and $k_{rl}(S_w, c^{max})$ are known. The simplest and most intuitive way to do this, is to use linear interpolation based on the normalized concentration, *F(c)*, where *F* is linear, and $F(c^{min}) = 0$, $F(c^{max}) = 1$.

For simplicity, define $k_{rl}(S_w, c^{min}) = k_{rl}{}^{min}$ and $k_{rl}(S_w, c^{max}) = k_{rl}{}^{max}$, and in the following we will also omit the phase subscript *l*, as the description will be equally valid for both phases, except where explicitly stated.

Then, the interpolated relative permeability will be defined by

$$k_r(c) = (1 - F)k_r{}^{min} + Fk_r{}^{max} \tag{1}$$

(*F* is to be understood as *F*(*c*), taken at concentration of fluid in question, unless elsewise stated.)

2.1 Some comments on the interpolation algorithm

2.1.1 Increasing or decreasing concentration

Above, *F* was taken as normalized concentration, which is often the logical choice. One obvious exception is when the “concentration” is water salinity. As the standard enhanced oil recovery (EOR) mechanism based on salinity consists of injecting water of lower salinity than the standard sea water, the “basis” relative permeability curve becomes the one valid for the *highest* salinity s^{max}, while the curve corresponding to EOR is the low salinity curve s^{min}. To reflect this, the normalized concentration is typically defined opposite, as in; *F* is linear, and $F(s^{max}) = 0$, $F(s^{min}) = 1$, where *s* denotes salinity. For the remaining part of the paper we will treat *F* as normalized concentration, tacitly acknowledging this duality.

2.1.2 Residual oil dependent on concentration

In most cases, not only the shape of the relative permeability curves is affected by the concentration, but also the interval of mobile oil. I.e. the value of the residual oil S_{or} is often reduced with increasing concentration. Hence a more accurate definition of Equation (1) would be:

At minimum and maximum concentrations c^{min} and c^{max} the relevant relative permeability curves are

$$k_r{}^{min}, \text{ defined on } S_{wm} \le S_w \le S_{wM}{}^{min}, \text{ and}$$
$$k_r{}^{max}, \text{ defined on } S_{wm} \le S_w \le S_{wM}{}^{max} \tag{2}$$

where the minimum value S_{wm} is typically connate water S_{wc}, and the maximum value $S_{wM} = 1 - S_{or}$, reflecting that the minimum saturation is normally not affected by the concentration, while the maximum is.

For the rest of the paper we omit the subscript w, as relative permeability will be understood as depending on water saturation.

The maximum saturation S_M for any concentration between c^{min} and c^{max} will be the interpolated value of the min/max value, as reflected in the updated formula, where scaled saturations S^* are used in the interpolation formula:

$$S_M{}^c = (1-F)S_M{}^{min} + FS_M{}^{max}$$

$S^{*l} = S_m + p\left(S_M{}^l - S_m\right)$, where p runs from 0 to 1, and $l = min, max, c$

$$k_r(S^{*c}) = (1-F)k_r{}^{min}(S^{*min}) + Fk_r{}^{max}(S^{*max}) \tag{3}$$

An example of the interpolation is shown in Figure 5.

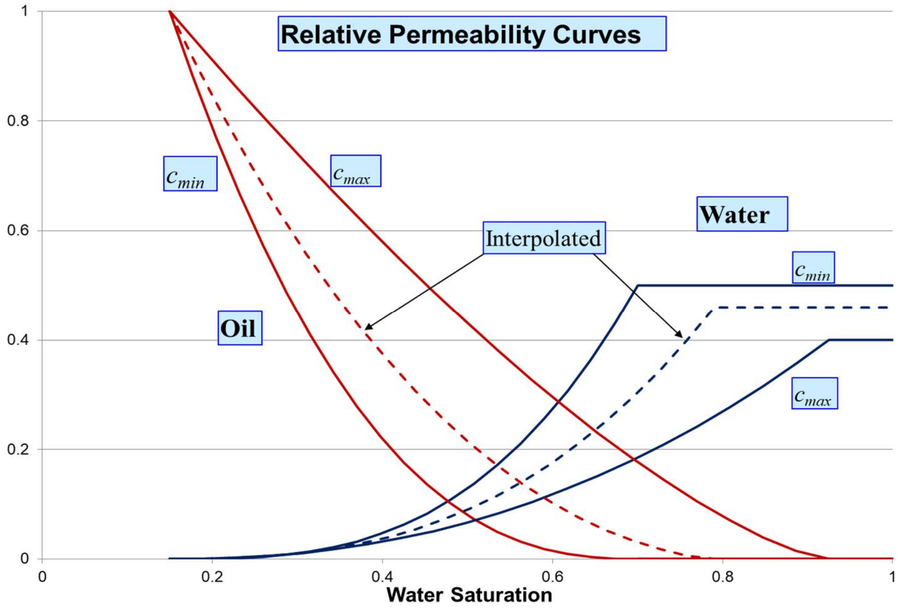

Fig. 5. Basic linear interpolation of relative permeability curves. Oil and Water Curves corresponding to minimum and maximum EOR-fluid concentration is shown, in addition to the interpolated Relative Permeability Curve for some intermediate concentration, as defined by Equation (3)

2.1.3 Nonlinear user-defined interpolation function

As mentioned above, the simple approach is to assume linear interpolation. However, allowing for more general interpolation functions is no more complex than assuming linearity.

As an example, the brine / salinity model in ECLIPSE 100 allows for a quite general user-defined F-function, the only restrictions being that it must be monotone, and take values on the interval [0, 1]. [18]

The compositional simulator STARS from Computer Modeling Group (CMG) defines interpolation by Equation (3), but with a more general function F:

$$F = \left(\frac{c - c_m}{c_M - c_m}\right)^{n_\alpha} \tag{4}$$

where n_α can be any value, and c_m and c_M are user-defined low and high concentrations [3]. Obviously, if $n_\alpha = 1$ and c_m and c_M are taken as minimum and maximum concentrations, this formula becomes equivalent to the methods presented earlier.

For any of these approaches, different F-functions can be used for each phase, increasing generality even more.

For some EOR-fluids, noticeably surfactant, it is taken as physically more correct to base the interpolation on the Capillary Desaturation Curve (CDC) in lieu of concentration. The CDC is a function of interfacial tension (see e.g. [8]), and the interpolation function can be interpreted in several ways; by basing the F-function directly on interfacial tension, by defining a mapping between concentration and interfacial tension and using a standard F versus concentration relation, or as done by CMG STARS, basing F on the capillary number N_c, which is a function of interfacial tension, normally given by a user-defined table. Then $N_c = \frac{\mu^p v}{\sigma}$ (where μ^p is phase viscosity, v is the Darcy velocity, and σ is the interfacial tension).

The interpolation function is defined as [3]:

$$F = \left(\frac{log_{10} N_c - log_{10} {N_c}^m}{log_{10} {N_c}^M - log_{10} {N_c}^m}\right)^{n_\alpha} \tag{5}$$

In most cases, as above, $n_\alpha = 1$, and m and M are taken at minimum and maximum concentrations.

2.1.4 Nonlinear interpolation

Although the interpolation function F in the generalizations above was nonlinear, the interpolation itself, as defined by Equation (1) or (3) is always linear. It could be possible to define the interpolation by any consistent formula, but an alternative approach is simpler and easier to generalize. So far it has tacitly been assumed that the interpolation is always based on only the two endpoint concentrations (e.g. c^{min} and c^{max}). When relative permeability curves are available also for other concentrations, these should obviously be honored in the interpolation scheme. In general, assume that relative permeability curves are known for concentrations $c^{min} < c^1 < c^2 < \ldots < c^{max}$: $k_r(c^{min})$, $k_r(c^1)$, $k_r(c^2)$, ... $k_r(c^{max})$

Then for any concentration c, with $c^i < c \leq c^{i+1}$, the interpolated relative permeability curve is found by Equation (3), using c^i and c^{i+1} as bounding values. The final version of the scheme for interpolation of a single set then becomes:

Assume relative permeability curves are known for concentrations c^k, $k = min, 1, 2, \ldots, max$.

The relative permeability curve $k_r(S, c)$, valid at concentration c, with $c^i < c \leq c^{i+1}$, is found by:

$${S_M}^c = (1 - F){S_M}^{min} + F{S_M}^{max}$$

$S^{*l} = S_m + p\left({S_M}^l - S_m\right)$, where p runs from 0 to 1, and $l = i, i{+}1, c$

$$k_r(S^{*c}) = (1 - F){k_r}^i(S^{*i}) + F{k_r}^{i+1}(S^{*(i+1)}) \tag{6}$$

The interpolation algorithm (6) appears more complex, but the logic is unaltered.

2.2 Summary Interpolation of a Single Relative Permeability set

The interpolation is defined by Equation (6) above, where the interpolation function F can be defined in several ways, allowing for great flexibility and degrees of freedom as seen from the user standpoint. The challenge with allowing for such generality is that we seldom or never have enough empirical data to support such decisions. Actually, in most simulation of EOR processes we do not even have a complete parameter set to support even the most basic assumptions. When proceeding to more complex hybrid processes the lack of data becomes even more apparent. Hence, even though the more general descriptions are available, almost all practical simulations are based on the simplest assumptions on a minimum parameter set, i.e. a linear F or CDC defined on the range $[c^{min}, c^{max}]$.

3 Multiple Interpolation – Simultaneous Interpolation of Several Relative Permeability Sets

In composite, or hybrid EOR processes, as e.g. injection of low salinity brine followed by injection of surfactant, the reservoir water at any point in the reservoir will be characterized by the combination of the two concentrations *salinity* and *surfactant* concentration. More generally we assume that water is characterized by the concentrations of n EOR-fluids diluted in the water, with concentrations $c_1, c_2, \ldots, c_n$.

The single set interpolation as described above can be seen as interpolation in a one-dimensional concentration space, or simply as interpolation along the c-axis, where c is the single concentration of interest.

Generalizing this concept, multiple interpolation can be viewed as interpolation in an n-dimensional concentration space $(c_1, c_2, \ldots, c_n)$.

For simplicity we first describe the algorithm for the two-dimensional case, i.e. when two different EOR-fluids are present.

CMG STARS includes the option to interpolate two different relative permeability sets, denoted k_{r1} and k_{r2}. A relatively general and apparently complex interpolation function is allowed, namely

$$G^{interp} = \left[\frac{\frac{1}{x-x_1+\varepsilon}-\frac{1}{\varepsilon}}{\frac{1}{x_2-x_1+\varepsilon}-\frac{1}{\varepsilon}}\right] \tag{7}$$

where x_1 and x_2 are user defined interpolation parameters, and ε is a user-defined curvature constant [3]. Then the interpolated relative permeability curve is defined as

$$k_r^{interp} = k_{r1} + G^{interp}(k_{r2} - k_{r1}). \tag{8}$$

This algorithm allows for large flexibility, but in practice x_1 and x_2 are almost always taken as the minimum and maximum concentrations for the two sets, and ε is set to the default (STARS-) value of 10. In that case the algorithm is reduced to (almost) standard linear interpolation as defined above. However, by defining the "double" interpolation in this manner, it is not obvious how to generalize it to more than two sets.

We choose a different approach here, assuming that interpolation of n multiple relative permeability sets can be performed as n independent, one-dimensional interpolations. The motivation for this is partly simplicity, partly that there is no theoretical or experimental justification for more complex models.

The challenge at hand is to define a relative permeability set at concentrations (c_1, c_2).

We adapt the following notation:
k_{ri} is the relative permeability for EOR fluid i diluted in water with a concentration c_i, and the interpolation function for this relative permeability set is F_i, $i = 1, 2$.

For notational convenience, we base these generalizations on Eq. (3). If relevant, the discussed scheme (including the figures) should be modified to honor the more general Eq. (6). This is straightforward, but would obscure the presentation.

Interpolation of relative permeability set no. 1 by Equation (3) is denoted $I_1(c, c_1; c_2)$, i.e. we use Equation (3) with $k_r = k_{r1}$, $F = F_1$, $c = c_1$, and c_2 as a parameter considered constant during the interpolation. Then the interpolated relative permeability at concentration c, in the direction c_1, with the "other" fluid concentration c_2 treated as a constant parameter in the process is defined as:

$I_1(c, c_1; c_2)$:

$$S_M{}^c = (1 - F_1) S_M{}^{min} + F_1 S_M{}^{max}$$

$S^{*l} = S_m + p\left(S_M{}^l - S_m\right)$, where p runs from 0 to 1, and $l = min, max, c$

$$k_{r1}(S^{*c}) = (1 - F_1) k_{r1}{}^{min}(S^{*min}) + F_1 k_{r1}{}^{max}(S^{*max}) \tag{9}$$

and equivalent for EOR-fluid 2 with relative permeability k_{r2}.

The relative permeability curve at concentrations (c_1*, c_2*) is found by two consecutive interpolations, $I_1(c_1*, c_1; c_2)$ followed by $I_2(c_2*, c_2; c_1*)$

The process can be visualized in the two-dimensional concentration space (or plane) (c_1, c_2), ref. Figure 6. In order to be able to carry through the "double" interpolation, the 2-D interpolation space must be a *true extension* of the one-dimensional c_1-space, and the base relative permeability curves used for the interpolation must *span the space*. The first requirement signifies that (the 2-D) relative permeability along the line $c_2 = 0$ must be identical to the 1-D relative permeability curves defined in the absence of EOR-fluid *2*. (In a fluid system with varying salinity and surfactant we would require that the curves defined for salinity variation alone must be equal to the surfactant – salinity curves at vanishing surfactant concentration.)
The second requirement means that sufficient curves must be defined that interpolation is defined in all points of interest in the (c_1, c_2) plane, in practice by defining the relative permeability curves in the four relevant corners (c_1^{min}, c_2^{min}), (c_1^{max}, c_2^{min}), (c_1^{max}, c_2^{min}), (c_1^{max}, c_2^{max}). However to meet the true extension criterion, c_2^{min} must be set to zero. In most situations, c_1^{min} is also zero.

Referring to Figure 6, to determine the relative permeability at concentrations (c_1*, c_2*), $k_r = k_r(c_1*, c_2*)$, first interpolate k_{r1} along $c_2 = 0$, i.e. $I_1(c_1*, c_1; c_2{=}0)$, (interpolate $\mathbf{A_1}$ and $\mathbf{A_2}$ to **A)**. Then similarly interpolate k_{r1} along $c_2 = c_2^{max}$, i.e. $I_1(c_1*, c_1; c_2 = c_2^{max})$, (interpolate $\mathbf{B_1}$ and $\mathbf{B_2}$ to **B**). Lastly interpolate k_{r2} along $c_1 = c_1*$, i.e. $I_2(c_2*, c_2; c_1 = c_1*)$, (interpolate **A** and **B** to **C**).

All interpolations are done along a line as described by Equation (3).

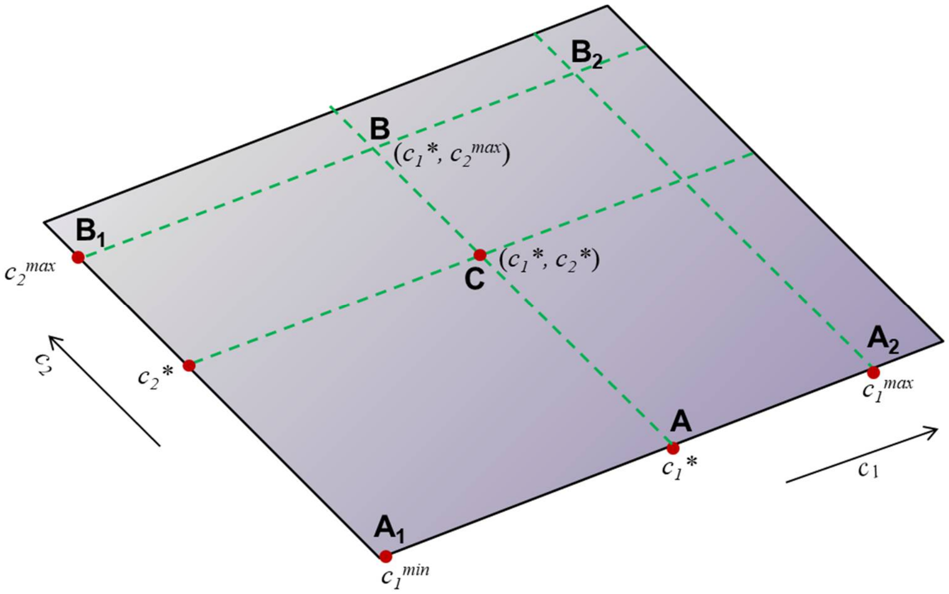

Fig. 6. Interpolation of two relative permeability curve sets, at concentrations *c1**, *c2**. The composite interpolation is built up of simple linear interpolations along the lines $\mathbf{A}_1$-$\mathbf{A}_2$, $\mathbf{B}_1$-$\mathbf{B}_2$, and **A**-**B**

As defined, the final interpolated curve should be independent of the order of the interpolations (i.e. first interpolation in the c_1-direction is equivalent to first interpolation in the c_2-direction), which is readily shown by performing the detail arithmetic using Equation (3), and also by direct simulation tests. (This statement has also been tested true for the procedure used by CMG STARS.)

The key observation in this procedure is that relative permeability curves are needed in all four "corners" of the plane to enable computing of the relative permeability for any concentration combination in question. This requirement may be difficult to fulfil in practice. As an example, most or all of the hybrid experiments performed at Uni CIPR labs have been according to the scheme, first the core is flooded with low salinity brine until the core is completely at low salinity conditions. Then surfactant is injected; hence the surfactant appears only in a low salinity environment (which is actually the essence of these experiments). Relative permeability curves are recorded (often by simulation validation) at the start of the experiment, i.e. high salinity, no surfactant; at the end of the low salinity flooding (low salinity, no surfactant), and at the end of the experiment (low salinity, maximum surfactant concentration). Hence we have no indications of the relative permeability for the combination high salinity, maximum surfactant concentration (c_1^{min}, c_2^{max}) at all, as this combination is not really interesting in the experimental setting.

For simulation of this kind of experiment we could use "any" curve at (c_1^{min}, c_2^{max}), as the experiment never enters the inner part of the concentration plane at all, but follows the curve (c_1^{min}, c_2^{min})→ (c_1^{max}, c_2^{min}) → (c_1^{max}, c_2^{max}), hence only a subset of the full or "real" multiple interpolation scheme is used. However, the curves and procedure have also been used to simulate full 3-D Field cases, and in this case we cannot guarantee that the reservoir is completely at low salinity conditions before surfactant injection, actually the opposite is most probably true. In that case reliable relative permeability curves are needed also for the "missing" corner. So either this must be determined experimentally, or estimated on a sound physical basis.

3.1 General Multiple Interpolation

Following the description in the previous section, generalization to more than two sets of relative permeability sets is straightforward. First we note that the interpolation of n relative permeability sets (corresponding to n different EOR-fluids) is done in the n-dimensional concentration space ($c_1, c_2, \ldots, c_n$), and it should also be apparent that this requires $2n$ relative permeability curves defined in the "corners" of the space (all combinations of minimum and maximum concentrations). In the same manner as extending from a single to two sets as described above, extending from (n-1) to n curve sets requires that the n-dimensional space is a true extension of the (n-1)-dimensional space, i.e. a set of curves must be defined in the restricted space $c_n = 0$, and this set of curves must be identical to the curves defined in the (n – 1)-dimensional space. Then interpolation is performed as a series of interpolations along lines of constant concentration, building up to the final curve $k_r(\mathbf{c}^*)$, where $\mathbf{c}^* = (c_1^*, c_2^*, \ldots, c_n^*)$ is the relevant point in concentration space.

We visualize the procedure for $n = 3$, i.e. one set more than in the case discussed in the previous section (ref Figure 7). The interpolated relative permeability at concentration $\mathbf{c}^* = (c_1^*, c_2^*, c_3^*)$ is calculated by a series of one-dimensional interpolations where two of the parameters are kept constant. As noted above, this is independent of the order of the interpolations, so the order used in the example can be changed without consequences. First we compute the relative permeability curves in the point (c_1^*, c_2^*), for $c_3^* = 0$ and c_3^{max} (points **A** and **B** on the figure). Point **A** is calculated by first interpolating between $c_1 = 0$ and $c_1 = c_1^{max}$, for c_2 taking its minimum and maximum values, i.e. the value in $\mathbf{A_1}$ is the interpolated value between $\mathbf{A_{11}}$ and $\mathbf{A_{12}}$, and $\mathbf{A_2}$ is the interpolated value between $\mathbf{A_{21}}$ and $\mathbf{A_{22}}$. An equivalent procedure is used to compute the relative permeability in point **B** for $c_3^* = c_3^{max}$. The final relative permeability curve at point $\mathbf{c}^* = (c_1^*, c_2^*, c_3^*)$ (**C** on Figure 5) is found by interpolating between **A** and **B**. Using the notation of Equation 3, this last interpolation would be denoted $I_3(c_3^*, c_3; c_1^*, c_2^*)$.

We immediately recognize that in this situation, with three different concentrations, requiring 8 relative permeability curves at all combinations of minimum and maximum concentrations, the data requirement can be even more difficult to fulfil. Indeed, again referring to experiments performed at Uni CIPR, with salinity as c_1, surfactant concentration as c_2, and polymer concentration as c_3, the measured / computed relative permeability curves would typically be provided for ($c_1^{min}, c_2^{min}, c_3^{min}$), ($c_1^{max}, c_2^{min}, c_3^{min}$), ($c_1^{max}, c_2^{max}, c_3^{min}$), and ($c_1^{max}, c_2^{max}, c_3^{max}$). The remaining four needed relative permeability curves will normally be "guestimates", or more elaborate experiments would have to be performed. Certainly, the consequences of missing or estimated data will be dependent on the process simulated. For lab experiments the missing curves may not be relevant or needed at all, while in general full field 3-D models, "anything" can happen, and good estimates of all 8 base curves should be available.

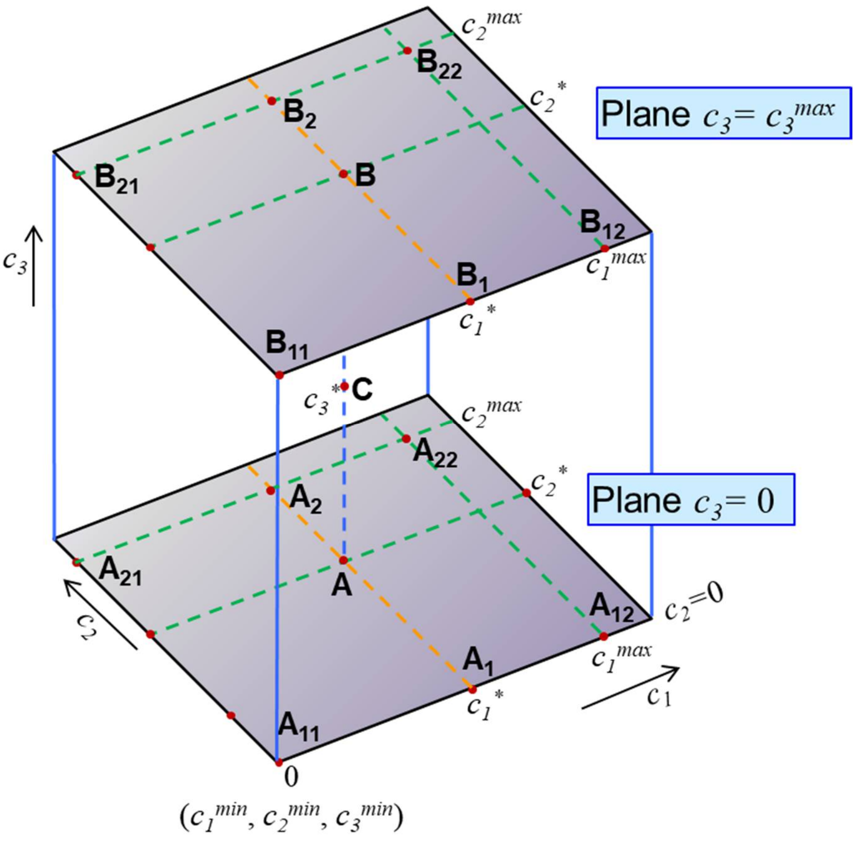

Fig. 7. Visualization of interpolation of three relative permeability sets. The composite interpolations are performed as a series of interpolations along lines: **A**$_{11}$ - **A**$_{12}$ → **A**$_1$; **A**$_{21}$ - **A**$_{22}$ → **A**2; **A**$_1$ - **A**$_2$ → **A**, and similar for the **B**s. Finally **A**-**B** → **C**

4 Hysteresis and reversibility

In complex hybrid processes, it is not obvious how fluids behave and should be modelled under certain circumstances. As an example, assume surfactant treatment is done as injecting a slug of surfactant, followed by a period of low salinity brine, a scheme that would typically be used to reduce costs. As the maximum concentration surfactant curves typically will have a lower residual oil saturation than the low salinity curves, this scheme implies increasing residual oil from a previous minimum. In a one-dimensional core plug experiment this configuration does not cause any problems, as the core oil saturation has already been reduced to a minimum by the surfactant slug, and there is no oil in place that could increase the oil saturation above the minimum after surfactant flooding. But in a 3-D case the behavior is not that clear-cut. We could imagine that remaining oil in nearby layers that was classified as immobile during the surfactant flooding now becomes mobile and flows into already flooded pores, hence rising the oil saturation and thereby actually reducing oil recovery – definitely an undesired effect. If this could actually happen in practice is at the moment an unresolved question, but the algorithms should provide both options;

1. Handle curves as they are defined, allowing for residual oil to decrease and increase during a complex process, and hence allowing for immobile oil to be mobilized and vice versa, according to the simulated process
2. Classify the processes as irreversible, i.e. record historical minimum residual oil saturation in all grid cells, and modify any computed relative permeability curve such that the historical minimum residual oil is honored at all later times

In CMG STARS, the option (1) has been implemented, and this can result in curves like the ones depicted in Figure 6, taken from a synthetic 3-D field case. We see that for the surfactant slug injection scheme, after the slug has passed, oil flows into the cell from neighbor cells, hence increasing the oil saturation from the previously achieved almost residual oil. Whether this behavior is in accordance to actual physics or not is at the time unanswered. In the continuous surfactant scheme on the other hand, the oil saturation is continually decreasing.

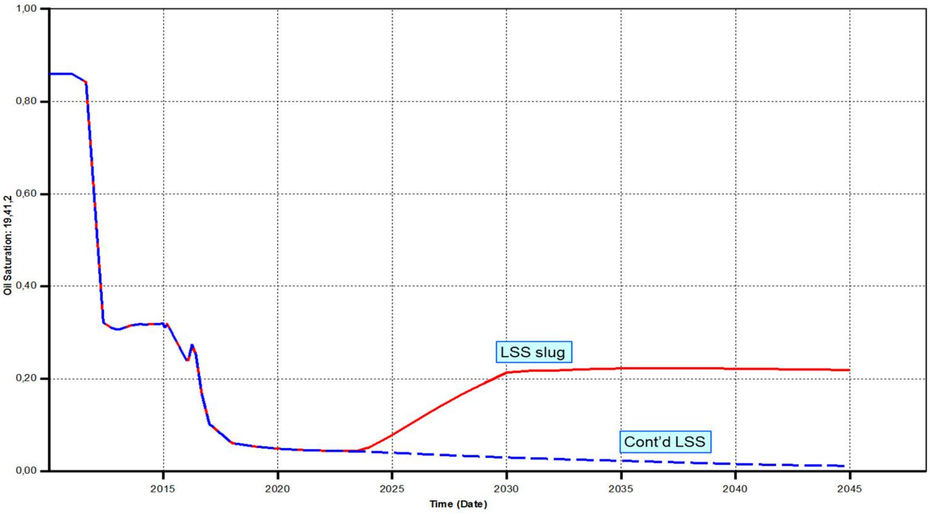

Fig. 8. Oil Saturation in a grid cell from a generic full field simulation. Surfactant slug injection compared to continuous surfactant injection

5 Conclusions

By assuming dimensional independency, interpolation of any number of relative permeability sets, (each set corresponding to an EOR fluid concentration), can be broken down to a series of linear interpolations, and hence can be managed and coded, although the logistics handling can become a challenge for a description of "any" number of curves. The case of three EOR fluids (three relative permeability sets) is relatively straightforward to handle. No commercial simulators have implemented this case, however, and hence should be a candidate for including in such software.

We have pointed at the potential challenge of obtaining sufficient data to satisfy the minimum requirements for these algorithms, but that is a challenge that should be handled in a different context.

Nomenclature

CDC	Capillary Desaturation Curve
HS	High salinity
LS	Low salinity
LSP	Polymer in low salinity water
LSS	Surfactant in low salinity water
$c, c_i, c_S, \ldots$	Concentration of EOR fluid in water phase
c_i^{min}, c_i^{max}	Minimum and maximum concentration values, fluid i
F, $F(c)$	Interpolation function, e.g. normalized concentration
$I_i(c, c_1; c_2)$	Interpolation at concentration c with varying c_1, treating c_2 as a (constant) parameter
k_r^{min}, k_r^{max}	Relative permeability at min and max concentration
k_{ro}, k_{rw}	Relative permeability to oil, water
N_C	Capillary number
S_m, S_M	Minimum and maximum saturation in the mobile oil interval
S_w, S	Water saturation

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