

IMPROVING PROSPECT EVALUATION BY INTEGRATING PETROPHYSICAL MODELS INTO THE WORKFLOW

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ABSTRACT

The workflow to estimate the potential reserves of an exploration opportunity usually begins with a geophysicist identifying a subsurface feature on seismic. Then, a geologist constructs a geological model with which to calculate hydrocarbon in place. Finally, a reservoir engineer estimates potential recovery with an associated production profile that includes the number and phasing of development wells. As core and log data tends to be sparse in most new venture areas, petrophysicists are seldom called on to help in the process.

This omission may (and undoubtedly has) lead to major errors in the prospect evaluation. The problem stems from lack of communication and understanding between the various disciplines contributing to the various parts of the workflow.

The static geological model tends to be created and populated in the G&G domain, whereas the dynamic behaviour of the model falls in the domain of the reservoir engineer. It is the authors' experience that there is no guarantee that the assumed dynamic performance of the static model of rocks and fluids is realistic and appropriate.

It is the authors' experience that many bad practises occur in the initial setting up of Monte Carlo simulation model of hydrocarbon-in-place. For example, failure to consider the petrophysical model leads to incorrect distributions of the input parameters, neglecting to link dependent petrophysical parameters, and using "average" saturation values and ignoring height dependency.

However, the above errors are compounded if the reservoir engineer also neglects to enquire about the appropriate petrophysical model. Once the G&G team have decided upon an appropriate reservoir type plus source and migration for the prospect under investigation, the rock type and fluid type are "fixed". Hence, the petrophysical properties of net-to-gross, porosity, permeability and saturation will be "fixed". These in turn define saturation-height shape (capillary pressure curves), well deliverability (permeability-thickness), the production profile and ultimate recovery (relative permeability and fractional flow curves). Thus, the reservoir engineer assumptions will be quite constrained if the petrophysical model is adhered to in the workflow.

The paper outlines the prospect evaluation workflow in detail and illustrates the dramatic impact on estimated reserves if the petrophysical model is not "hard wired" into the workflow and compares the result to when it is integrated. Data from an oil field in the UKCS North Sea are used in the worked example.

INTRODUCTION

Oil companies employ sub-surface staff to estimate hydrocarbons in place, reserves and production profiles for their assets. Reserves are calculated from static petrophysical parameters such as porosity and water saturation and production profiles ultimately depend on an understanding of the permeability at reservoir conditions. Depending on how mature the asset is, these properties may vary from educated guesses, through offset well data to measurements obtained from wells within the field. No matter what their provenance, these properties can be and in some cases have to be, obtained from measurements on core. In fact core should be the preferred source of petrophysical properties even when an alternative source is available (e.g. logs for porosity and test data for permeability). There are three reasons for this. Firstly, core allows direct measurements of petrophysical properties to be made on a real piece of the reservoir. Secondly and more importantly in the context of this paper, it allows the trends and relationships between different petrophysical properties to be more clearly defined. Once they have been identified, these trends tie the petrophysical properties together, so that once one has been fixed the others are quite tightly constrained. Thirdly, core measurements can be made under conditions found anywhere in a reservoir, logs on the other hand will only provide data over intervals where the well has penetrated the reservoir.

The volumetric equation, used to compute hydrocarbon initially in place (HCIIP) is written:

$$\text{HCIIP} = \text{GRV} * \text{NTG} * \varnothing * (1 - S_w) * \text{FVF} \quad (1a)$$

where GRV is the gross rock volume enclosed between the top of the structure and the contact, NTG is the net to gross ratio or the fraction of this GRV that is of reservoir quality, \varnothing is the mean porosity of the reservoir quality rock and S_w is its mean water saturation. The latter three terms are sometimes referred to as the petrophysical group. The FVF is the formation volume factor of the hydrocarbon and will not be discussed further here, but all the other terms are to a greater or lesser extent defined by petrophysics and therefore core analysis. In fact, even the FVF is indirectly related to water saturation, since it is determined by the chemistry of the hydrocarbon, which also determines how it interacts with the reservoir rock. The volumetric equation can also be written in terms of area (A) and pay thickness (h).

$$\text{HCIIP} = A * h * \varnothing * (1 - S_w) * \text{FVF} \quad (1b)$$

At the exploration stage there may appear to be considerable latitude in the choice of parameters to go into the volumetric equation. In particular it is often assumed that the three parameters of the petrophysical group can be chosen more or less independently of each other. Unfortunately, there is often pressure from management to select the most optimistic values and, whilst individually these may be reasonable, taken together they are often highly improbable.

The three terms of the petrophysical group are intimately linked because they ultimately depend on the nature of the pore system. In the context of the volumetric equation (Equation 1) there are fundamental differences in their nature as well. Thus, porosity is basically determined by the raw material of the reservoir rock and its geological history. Two pieces of rock that have originated from the same assembly of mineral grains and have undergone identical burial and diagenesis processes will have the same porosities (and permeabilities) regardless of the size and shape of reservoir they end up in. The average S_w however depends on the nature of the pore system but also the hydrocarbon column height, the nature of the hydrocarbon and the way the reservoir volume is distributed as a function of height (most conveniently expressed as an area-depth curve). Net (and therefore NTG) also depends on all these factors as it is normally defined by S_w exceeding a cut-off value.

Nowadays GRV is normally defined by 3D seismic, but at the pre-drill stage the other parameters have to be based on offset wells or even analogues from other basins. Average porosity can sometimes be reliably predicted at the pre-drill stage using porosity-depth trends and once a well has been drilled porosity can normally be accurately estimated from logs even if core has not been cut. As discussed above the calculation of average S_w is more complicated however and requires knowledge of the way S_w and reservoir volume vary with height. The latter comes from geophysics, but the former ideally should come from core that has been obtained from the structure of interest or a close analogue. Logs can and do give accurate estimates of S_w , but it is unusual for the first well on the structure to penetrate a full hydrocarbon column and a contact. So even after a well has been drilled, log analysis may not be able to produce a reliable average S_w .

Relying on offset data or other analogues is also risky. There is, famously, no general relation linking porosity and permeability but it is often felt that given porosity and permeability most of the other properties such as capillary pressure (P_c) curves, relative permeability end-points are reasonably well constrained. This is not generally true however and Figure 1 illustrates this with Special Core Analysis (SCAL) data from water wet sandstone core plugs from a wide range of geological environments, but a narrow range of porosities ($12 \text{ pu} \pm 1$). The histogram of permeabilities in the range 0 to 100mD is shown in Figure 1a which shows they fairly uniformly cover the range 0.2 to 100mD (and one plug has a permeability in excess of 100mD). Figure 1.1b shows irreducible water saturation (S_{wirr}) as a function of these permeabilities and, although intuitively one might expect S_{wirr} to fall with increasing permeability for these plugs the actual relationship is weak. Figure 1c shows the P_c for air needed to reduce the brine saturation to 75%, plotted as a function of permeability. This is a measure of the shape of the P_c curve, which in turn determines the shape of the saturation-height function. Again, there is at best a weak relationship between the shape of the P_c curve and permeability, so attempting to rely on general trends could be very misleading. In other words, there is no substitute for good quality core data.

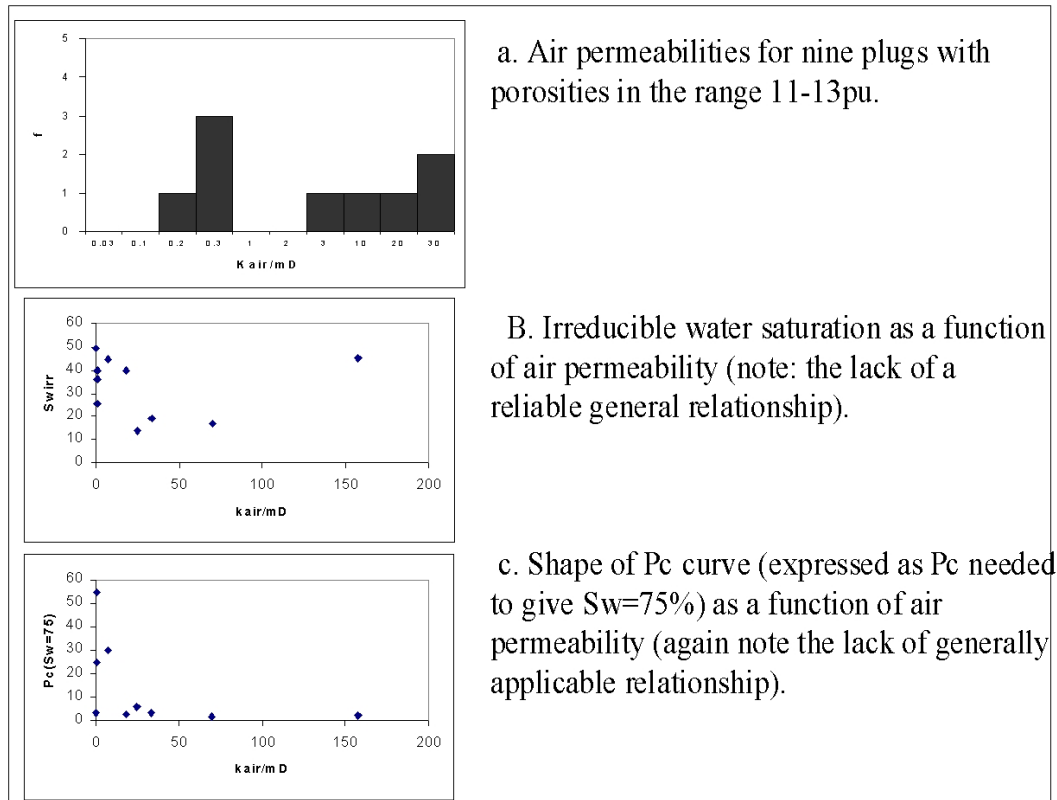


Figure 1. SCAL data for sandstone core plugs from a variety of environments, but a very limited porosity range.

Even when porosity is well understood, there seems to be a lot of room for manoeuvre in the selection of average S_w and Pay to Gross. In reality however, the petrophysical properties are quite tightly linked and, once the nature of the pore space, the fluids that occupy it and the geometry of the reservoir are defined or known, the HCIIP will be quite tightly constrained. Note that although so far this discussion has assumed the reservoir consists of only one type of rock, the argument can easily be extended to any number of rock types.

This linkage follows through to the calculation of production profiles and reserves. In this case the flowing properties of the formation become important and so permeability, and equally importantly, the relative permeability, of the formation to the water and hydrocarbon contained in the reservoir, comes into play. These permeabilities are also determined by the nature of the pore system and the fluids within.

The consequences of the dependencies between the petrophysical properties, for production, and thus reserves, was elegantly expressed by Fertl¹. He showed how graphs (Figure 2), that are normally obtained from SCAL, can be used to predict how S_w varies with height, where the deepest hydrocarbon production will occur and up to what depth

water production can be expected. In principle, this information can be obtained after the first well has been drilled on a structure and even before that if one has a good analogue.

However, there will be many times when the hydrocarbon-water contact depth will not be defined. Indeed, this is always the case with undrilled prospects and there is always the chance that the reservoirs are not full down to their spill point. How much fill should we use in our prospect? This will greatly affect our predicted depth of the contact in the prospect, which in turn will impact directly on any S_w computed from an appropriate saturation-height function.

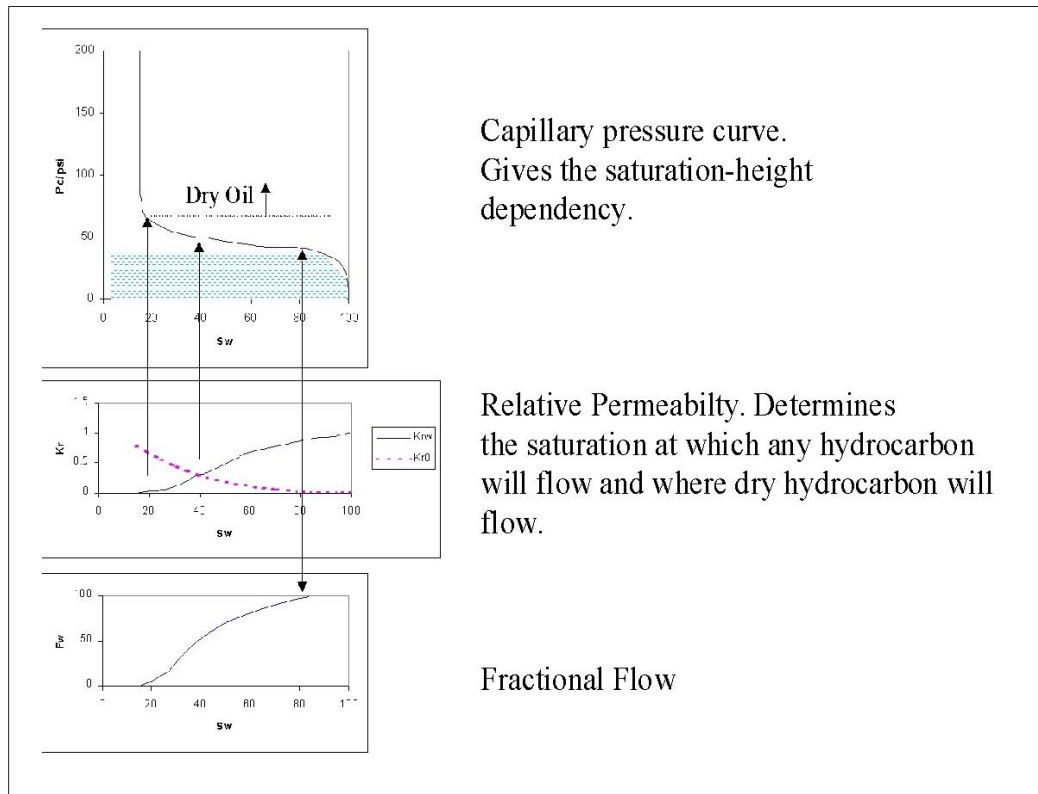


Figure 2. Relationship between capillary pressure, relative permeability and reservoir performance (after Fertl¹).

The P_c curve (first graph of Figure 2) can be converted to a saturation-height function, provided the nature of the fluid is known. This then determines the average water saturation in the reservoir. The relative permeability (second graph of Figure 2) determines the depth below which hydrocarbon will not flow and the depth above which water production is not expected. This information is summarised in the fractional flow curve (third graph of Figure 2).

In this paper these powerful concepts are illustrated by means of a case study. It is worth noting that used in this way SCAL data, which is sometimes dismissed as providing a

very precise description of an insignificant volume of the reservoir, can actually help better describe the entire reservoir.²

EXAMPLE DATA SET

The rather vague concepts outlined above are better illustrated by means of a simple hypothetical case study. First of all we will discuss the data set itself.

The example oil field is a typical Palaeocene oil accumulation, located in the Central North Sea of the UKCS. The reservoir is Upper Forties turbidite sandstone, with classic channel and interchannel sands that tend to be stacked into identifiable flow units. The oil is fairly volatile, with a gravity of 38°API and a gas oil ratio of 600 scf/b, and has an in-situ viscosity of less than 1cp. Hence, mobility ratio is less than one and good displacement by water is expected. The fields in the region tend to be normally pressured and are often in pressure communication with each via the extensive underlying aquifers. Hence, formation water drive tends to be basal, although additional pressure support from water injection adds an element of edge water drive. Figure 3 shows the gross rock area (GRA) vs. depth curve for the example oil field. Typically, fields in the region are areally extensive, but relatively “thin”. GRV tends to be defined between the spill point of the accumulation and a regional shale that is draped over the structure.

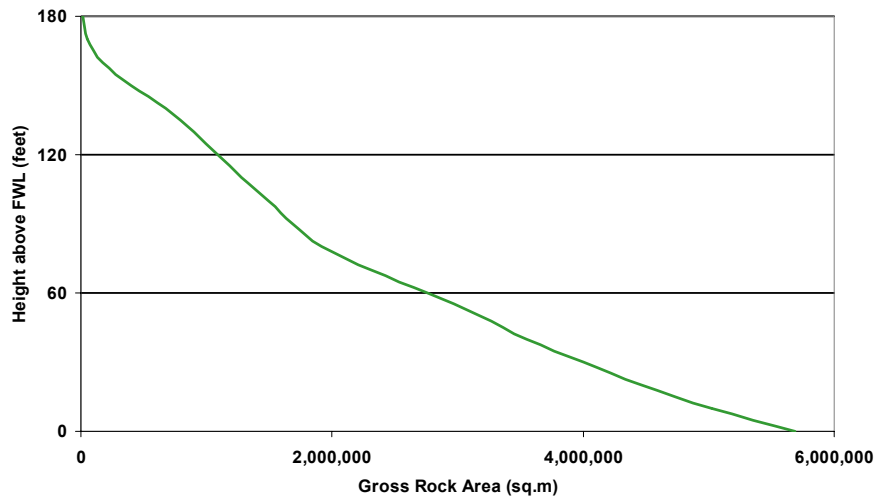


Figure 3. Gross rock area versus height above free water level for the example field.

The interpreted logs from the Palaeocene discovery well, drilled just off top structure, are shown in Figure 4. The well encountered an oil water contact and wireline formation tester pressure measurements vs. depth located the free water level (FWL). The well was drilled and cored with oil-based mud, which allowed log-derived S_w in the connate region to be matched to the Dean Stark S_w measurements performed on the core. The transition zone begins where the log-derived S_w diverges from those from Dean Stark measurements, which is roughly 65 feet above the FWL in the example oil well.

Hence, integrating the saturation-height information from Figure 4 with the volumetric data from Figure 3, it can be seen that only 45% of the GRV of the example structure lies above the transition zone.

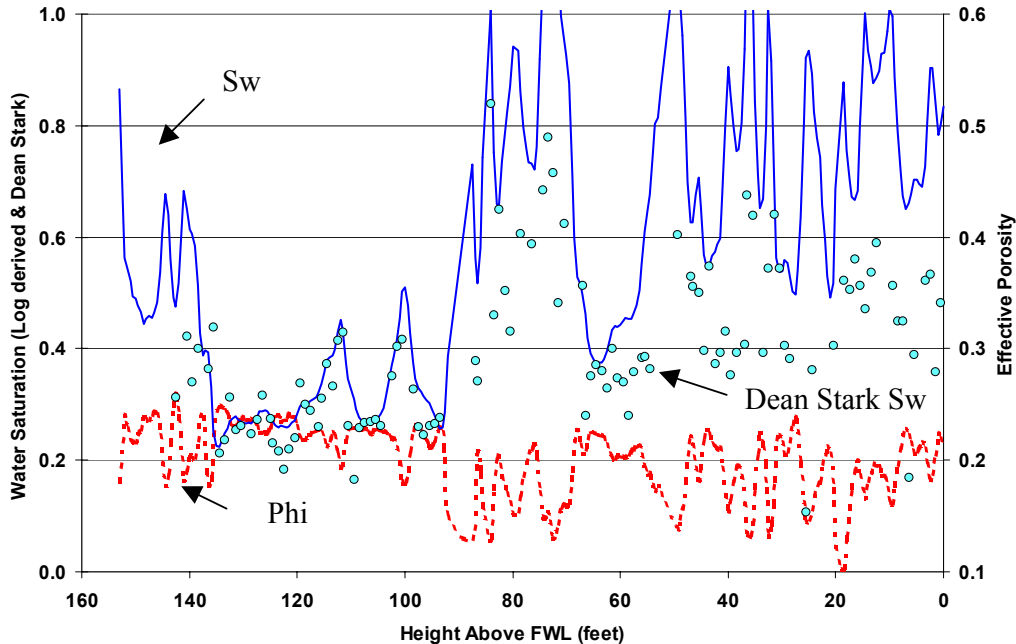


Figure 4. Log-derived Porosity and Sw with Dean Stark Sw points in the Example Well.

Shale volume (V_{sh}) is low throughout the reservoir section, but where it does increase, effective porosity falls with a corresponding fall in permeability, i.e. the porosity curve is a “mirror image” of the Sw curve. Porosity is traditionally used as a proxy for permeability in matrix porosity systems as the latter is related to pore throat diameter and pore geometry

The discovery well’s key petrophysical parameters were determined. Their probable distribution or range of was derived from analysis of log data from many offset wells drilled into the same formation in near-by structures. These values are given in Table 1.

Table 1. Key Petrophysical Averages and Distributions for the Example Well

Petrophysical Parameter	Effective Porosity	Oil Saturation	Net To Gross
Average Value	0.218	0.535	0.68
Standard Deviation	0.037	0.133	0.16
Distribution Type	Normal	Normal	Normal

If the example structure had been in a new play the properties would be estimated from outcrops and/or analogues from similar geological settings.

To investigate the dependency between parameters, a range of possible porosity cut-offs was applied to the example well data set. As the porosity cut-off is increased, less reservoir gets over the “hurdle”, but the rock that does is of better quality, i.e. lower average Vsh, lower average Sw and higher average porosity. Figure 5 shows the strong dependency between porosity, Sw and NTG and highlights a critical value of porosity cut-off (about 0.14) above which its impact is felt.

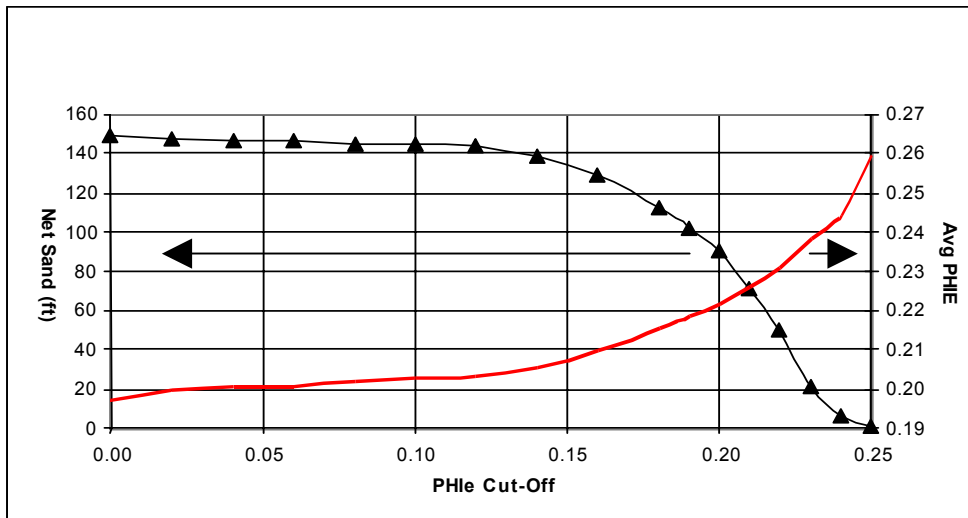


Figure 5. Strong dependency between porosity, Sw and NTG in the Example Well.

Now we have introduced and described the example data set, let us review some of the more common examples of “malpractice” we have seen in the generation of prospect volumetrics and production profiles. The first two deal with incorrect modelling of the volumetric estimate, the third one deals with changing forecast fluid production profiles without revisiting the original assumed petrophysical model to confirm that the profile is actually feasible.

Malpractice 1 – Not Linking Dependent Petrophysical Parameters

Many geo-scientists assume that all variables in the volumetric equation are not dependent on each other. Thus, in a Monte Carlo “iteration”, the value chosen for a particular parameter is not influenced by the value chosen for any other parameter. In the case of our example well, we know this assumption is incorrect³. In general, defining a positive dependency increases the mean and increases the spread. A negative dependency has the reverse effect.

Dependency between porosity and So is achieved by setting a positive correlation rank between them in the Monte Carlo programme (e.g. we set them to +0.9). The negative dependency between NTG and porosity and NTG and So is achieved by setting a negative correlation rank between them (e.g. we set them to -0.9).

To see the impact on oil-in-place calculations when key petrophysical parameters are classed as dependent, we simulated the HCIIP of our example field using the values, ranges and bonding strengths discussed above. The model was run twice: initially with all parameters independent of each other, then again with NTG, porosity and Sw linked together. For this exercise, the Sw range used was based on average values estimated from the field saturation-height function. The resulting cumulative probability plot of HCIIP is shown in Figure 6 below.

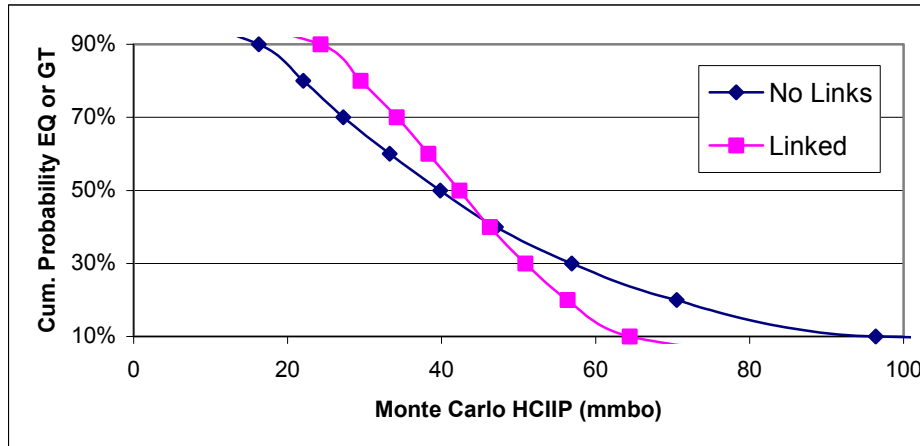


Figure 6. Impact of linking petrophysical parameters on HCIIP in the Example Field.

The mean of the HCIIP distribution of the example field is reduced from 50 to 43 MMbo if the petrophysical parameters are linked, i.e. a reduction of 14%. The models almost intersect at the P50 or most likely value of just over 40 MMbo, but exhibit large variation at the P90 and P10 extremes. Linking porosity, NTG and Sw reduced the range of the distribution from 16 up to 24 MMbo and from 96 down to 64 MMbo, i.e. a reduction in range of 50%.

Malpractice 2 – Not Including Saturation-Height Behavior in Volumetrics

At the pre-drill stage it is tempting to calculate the HCIIP deterministically using equation 1a with irreducible Sw in place of an average Sw. This gives a value of an overly optimistic HCIIP compared with that from the average Sw approach. However, this takes no account of the saturation-height behaviour that is determined by the Pc curve of the sand, the density between the oil and water at reservoir conditions and the interfacial tension of the oil and water. We readily admit that this inclusion of saturation-height behaviour may be of no consequence in gas fields, very high permeability reservoirs or those with high relief. However, in the vast majority of oil fields, saturation-height behaviour is important and should be included⁴. At the pre-drill stage of a prospect, saturation-height data has to come from offset wells. Our example data set confirms the existence of a significant transition zone. In this simple exercise we included a *single* saturation height function in the volumetric model, but in doing so, we are making the implicit assumption that the reservoir is a *single* rock type. If the reservoir is

comprised of several different rock types, then several corresponding volumetric models should be constructed and the results summed during the Monte Carlo simulation. If we incorporate saturation-height behaviour into our hypothetical volumetric model and compare to with the previous two methods, a significant range of HCIIP will result as shown in Table 2.

Table 2. Impact of Assumed Sw Distribution on HCIIP for the Example Field

Sw Model Assumed	Irreducible Sw	Average Sw	Sw varies with Height (Base Case)
Computed HCIIP (MMbo)	57	41	33
Difference in HCIIP	73%	24%	-

We can see that the irreducible Sw approach gives far too high an estimate of HCIIP. The average Sw approach is better, but still on the optimistic side. This has dire consequences for the explorationists as their expectation of what a wildcat drilling programme may yield will be wildly inflated. Farm in deals will be made, which should never have been done.

Malpractice 3 – Assuming Published Relative Permeability Relationships Work Anywhere

Geologists are not the only culprits in misrepresenting prospects. Once the HCIIP estimate has been made, it is the starting point from which the prospect's recoverable reserves and production profile are defined by the reservoir engineer. With limited data at his disposal in the exploration and appraisal stage, the latter often employs published relative permeability curves, which dictate dynamic fluid behaviour. Even if the engineer chooses a relative permeability relationship that "conforms" to the assumed petrophysical model, there is no guarantee it will provide a realistic water cut development profile for the prospect in question. The fractional flow of the displacing fluid,⁶ i.e. water, usually denoted by the term, F_w , is usually derived from the simplified Buckley-Leverett equation shown in Equation 2.

$$F_w = 1 / [1 + (K_{ro}/K_{rw})(\mu_w/\mu_o)] \quad (2)$$

where the rock term is given by the K_{ro} to K_{rw} relative permeability ratio of oil to water, and the fluid term is given by the μ_w to μ_o viscosity ratio of water to oil, respectively. F_w is proportional to S_w as relative permeability is a function of S_w in that K_{ro} falls and K_{rw} rises as S_w increases.

The resultant fractional flow of water (F_w) curves, derived using published relative permeability curves for water wet sandstone⁽⁵⁾ along with rock and fluid properties for the example field, are shown in the left hand panel of Figure 7. The actual water cut data from the example field are also shown it is clear that water production develops much

more quickly than the published relationships infer. This is in part to the engineer using a single relative permeability curve, i.e. modelling the prospect as one rock type. Another simple 1D displacement analytical technique⁽⁸⁾ uses conventional core measurements of porosity and permeability to estimate the water displacement with oil recovery. The Stiles method assumes each layer acts in isolation from those adjacent to it, and once a layer is swept by water, that it will continue to produce only water. The order of water breakthrough is controlled by permeability variation, so the layer with the highest permeability will be flooded out first and so on. Of course, this is for reservoirs with edge drive. If the water drive mechanism is from the base, the first layer to be flooded out will be the bottom one; the final layer to be swept will be that at the top. The results of a Stiles analysis for both edge and basal water drive using conventional core data from the example field is shown in the right hand panel of Figure 7. Experience in the Palaeocene fields on the Central Graben area of the UK North Sea (where the example field is located) has shown that they share massive aquifers that provide strong pressure support. Hence, the unordered version of the Stiles analysis provides the better estimate. Using the entire core data set also allows the engineer to account for some of the heterogeneity inherent in a reservoir (in a vertical sense at least).

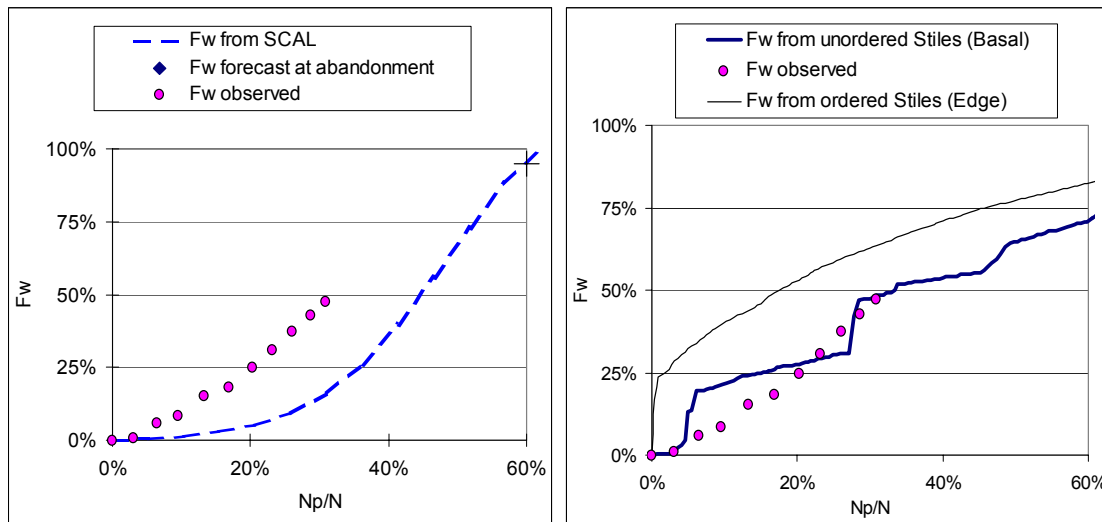


Figure 7. Comparing different theoretical models of fractional flow of water with actual water cut development with oil recovery in the Example Field.

Using inappropriate relative permeability curves to generate a forecast of water cut development mean that the prospect will be underestimated, both in breakthrough time and the amount produced. This means oil production (the revenue driver) will be optimistic as in reality it will decrease, being backed out by the increasing water cut. Facilities design will be incorrect, leading to errors in costing, which all comes down to a higher value being assigned to the prospect than may be warranted. Engineers must be aware of this and look at different models and different types of drive in order to better describe the envelope of uncertainty when generating production profiles.

CONCLUSIONS

- Neglecting the input from a petrophysicist when estimating the potential reserves of an exploration opportunity will lead to major errors in the prospect evaluation. As the geological focus on static data is a world away from the engineer's focus on dynamic data, there is no guarantee that the forecast production performance of the geo-model will be valid.
- Special Core Analysis is the most reliable source of information on average hydrocarbon saturation (through Pc curves) and the depth at which hydrocarbon production is first expected to occur.
- This data is best obtained from cores cut from the reservoir of interest, failing this offset well data may be satisfactory. Other analogue data should be treated with caution.
- Several examples of malpractice have been highlighted, which occur all too frequently in the modelling of prospects. These happen as some geoscientists fail to consider the implications of the chosen petrophysical model.
- Accurate reserves estimation demands the correct distributions of the parameters are input to the hydrocarbon in place equation and that dependent petrophysical parameters are linked where appropriate.
- The tendency to ignore saturation-height dependency can severely overestimate a prospect's hydrocarbon in place.
- Once the rock and fluid model has been decided upon, almost all the petrophysical properties of the prospect will be "fixed". Reservoir engineers need to ensure their subsequent assumptions in the reserves workflow conform to this chosen petrophysical model.
- Published relative relationships are not universally applicable. The use of a single rock type will not capture the inherent heterogeneity in a reservoir and thus the water cut profiles will invariably be optimistic. A range of analytical methods should be employed in order to capture the possible range of outcomes.

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