Mecánica Computacional Vol. XXIII, pp. 1825-1842
G.Buscaglia, E.Dari, O.Zamonsky (Eds.)
Bariloche, Argentina, November 2004

SIMULATION OF HIGH PERMEABILITY VISCOUS OIL RESERVOIRS IN VENEZUELA, COLOMBIA AND ECUADOR,

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Key Words: Reservoir Simulation, Coning, Viscous Oil

Abstract. *High-permeability viscous oil reservoirs are common in Venezuela, Colombia, Ecuador and Peru. They represent a special problem category with respect to subsurface evaluation and water management. Coning is often the main production problem combined with sand production. Frequently the reservoirs are well pressure supported by natural aquifers and early and significant water production is usually observed. The completion decision is the main decision to take in the development of these fields. This decision has to be linked to the artificial lift, the reservoir management as well as to the surface facilities. These fields are often found in fluvial or deltaic depositional environments and contain numerous reservoirs. This paper presents the problems encountered in reservoir simulation studies of these fields.*

The workflow of the reservoir simulation study is often as follows: single well models to support the understanding of the properties of different rocktypes, simplification of a 3D field wide property model, choice of a numerical simulator, history match, and production forecast. The emphasis in this presentation will be put on the initial single well models, the upscaling of 3D property models to a numerical reservoir simulation model and the choice of a numerical solver.

1 INTRODUCTION

In the area stretching from the Oficina basin in the eastern part of Venezulea through the Magdelena basin in Colombia and into the Napo basin in Ecuador a number of oil fields are found with a common set of characteristics. They contain oil of relatively high viscosity and have a strong aquifer support. These fields are generally found in reservoirs of fluvial character with reservoir perm eabilities in the high range (in excess of 2 Darcy). These fields include examples such as Dacion in Venezuela, San Francisco in Colombia and the Repsol block in Ecuador.

The problem associated with the modeling of these fields lies in a numerical uncertainty and in that the assumptions made in many commercial software packages for simulation do not hold. The numerical problem is linked to the large viscosity contrast between the oil and water phase. In terms of flow this results in either fingering or wat er underrun in the reservoirs. The assumption that is often made in numerical simulation studies of oil reservoirs is that the rock properties are constant with respect to porosity and permeability. It is possible to account for compression effects, but difficult to account for structural changes in the packing of the sands due to stress effects. Both of the above effects have a negative impact on production. Numerical simulation studies therefore tend to underestimate the water production in this type of fields. Likewise, sand failure can result in what appears as sudden well failures and is not always associated with sand production. In many cases, going to a streamline simulation approach can solve the numerical instability problem. But streamline simulation has got some limitations as well.

In this paper a workflow will be described, which is a combination of analytical and numerical techniques. The focus is on checking what assumptions can be made with respect to numerical simulation and on knowing what assumptions have been made in the software package used.

The initial single well models and generic simulation models are important to diagnose the reservoir problems. Examples will be illustrated from some fields in the region. Without the diagnostics work up front, errors can easily be made in the field assessments, which will be illustrated as well.

Going from a 3D property model to a reservoir simulation model through a process of upscaling, should include the upscaling of both the rock properties and the relative permeability curves. The later is often neglected and the associated error will be illustrated. Many papers have been published on different processes. Some of these approaches will be discussed and how these impact the performance of the numerical simulation model.

2 DIAGNOSTICS

When an oil field is producing water, it has proved difficult to define the numerical model unless the possible causes have been identified. For example, forcing a numerical model to match the behavior of a well that has got a problem with the cement bounding the casing will result in invalid results. An estimate of the underlying reason for the water production is therefore essential before any analysis of the subsurface is attempted.

The reasons behind water production can in general be classed in 10 groups. These reasons are listed below in increasing order of complexity:

1. Tubing / Casing / Packer Leak
2. Near-Wellbore Flow (Cement Failure)
3. OWC moving up
4. High Perm Layer with no crossflow
5. Fissures to an injector
6. Fissures to a water source
7. Water Coning
8. Poor Area Sweep
9. Gravity Segregated flow
10. High Perm Layer with Cross flow

A quick look at the list stresses the fact that the water production diagnostics have to be carried out prior to any simulation work. The feature that causes the water production has to be present in the model. Commonly, the effect of natural fissures in reservoirs is underestimated; additionally, homogenous sand is usually assumed in the numerical simulation model. Attempting to match such a model against the observed production will result in a meaningless model.

In recent years a number of companies have developed various types of expert systems, which can help to identify the cause behind the water production. However, in many cases, the cause can be identified from a plot of water cut versus cumulative oil production or the producing water oil ratio versus time on a completion or well basis by an experienced petroleum engineer. This is illustrated in Figure 1, for two cases.

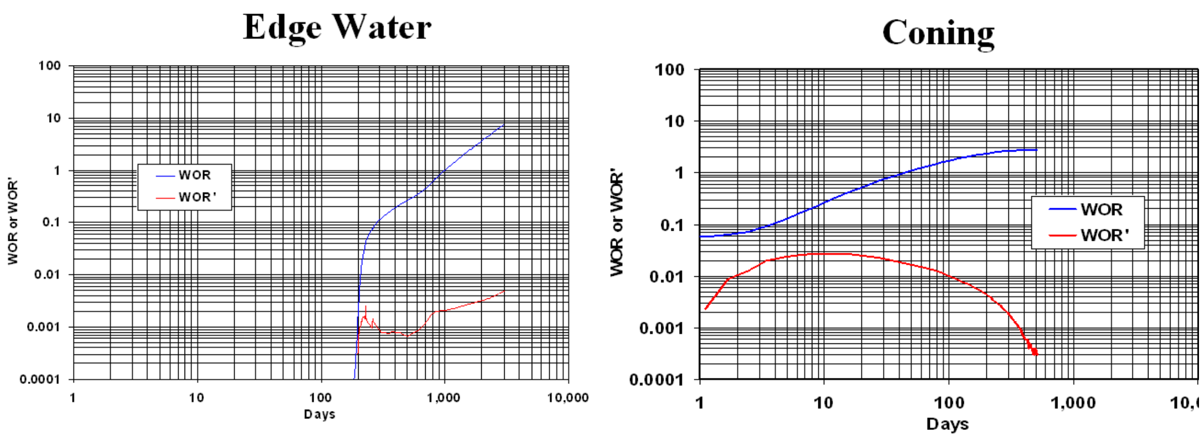

Figure 1: Plots of water-to-oil ratio (edge water drive and bottom water drive with coning)

In the figures the water to oil ratio is plotted against time. The first case represents a well producing from an edge water drive reservoir and the second case represents a well producing from a bottom water drive reservoir with a severe coning effect. The two examples show clearly that the production behavior exhibits different developments of the water production over time. The 10 causes of water production show different water cut developments. Sometimes the behavior observed in wells is a combination of different effects. But unless that combination of effects is in the model, the predictions are associated with severe errors.

The above examples are from Eastern Venezuela. The curves found from some of the fields in Colombia show the presence of fissures. Fissures are characterized by the fact that the water cut or water oil ratio remains constant for a significant period.

3 SINGLE WELL MODELS

3.1 Representing production behavior

Once a possible cause for the water production has been established, modeling of the well using numerical simulation may become an option. Assuming this is done correctly, a model of a well can be constructed based on log, pressure and well information with the features for representing the cause of the water production. Single well models are traditionally based on a finite difference solver approach. A grid representing the structure has to be built and at this stage some assumptions are made with respect to grid block sizes. In general the smaller the grid blocks, the more accurate a definition of the reservoir and the better a solution can be obtained. However, due to computational and time limitations, coarser models are often built. The objective is to get the right balance between the computational time and capacity and the required accuracy of the solution.

In the viscous oilfields we deal with, the water has a significant mobility compared to the oil. Water can move extremely fast from a source to a producing well. This is illustrated in the examples shown in Figure 2. The illustration shows a reservoir where the main water source is a natural aquifer. The reservoir has high permeability (>2Darcy) and the oil is viscous (~40 cP). The first picture illustrates the saturation distribution at the starting point. Red represents oil and blue represents water. The second picture illustrates the water saturation after 1 month of production assuming the sand is clean with no low permeability streaks. In the third picture the saturation distribution is illustrated after 1 month assuming there is a number of partially sealing streaks in the main sand unit. In most cases the water has traveled from the aquifer to the producer in a very short timeframe. The water has moved along the bottom of the clean sand units and though little oil has been displaced a significant water production is taking place in the well. This behavior is complicated to represent. Where the water is moving, a fine grid resolution is required to represent the saturation changes. This reverses simulation, as an idea of the outcome is required before the model can be defined. However, as single well model usually represents a limited volume, a fine resolution can be defined in the whole volume and the lessons from these models can be used when defining the grid for the larger reservoir scale simulation.

In the simulator, the sweep within the grid blocks is defined by the relative permeability functions; additionally, the area and vertical sweep efficiency is 1. In the referred to example the key problem is vertical sweep. Consequently the vertical grid resolution has to be fine. The coarser the model is, the higher the vertical sweep efficiency calculated. The grid defines the resolution of the estimate of the area and vertical sweep efficiencies. So, the initial single well and generic type modeling has to be as fine as possible to capture the detail. Once a small-scale model exists, decisions can be made on how to upscale this to a higher -level reservoir evaluation.

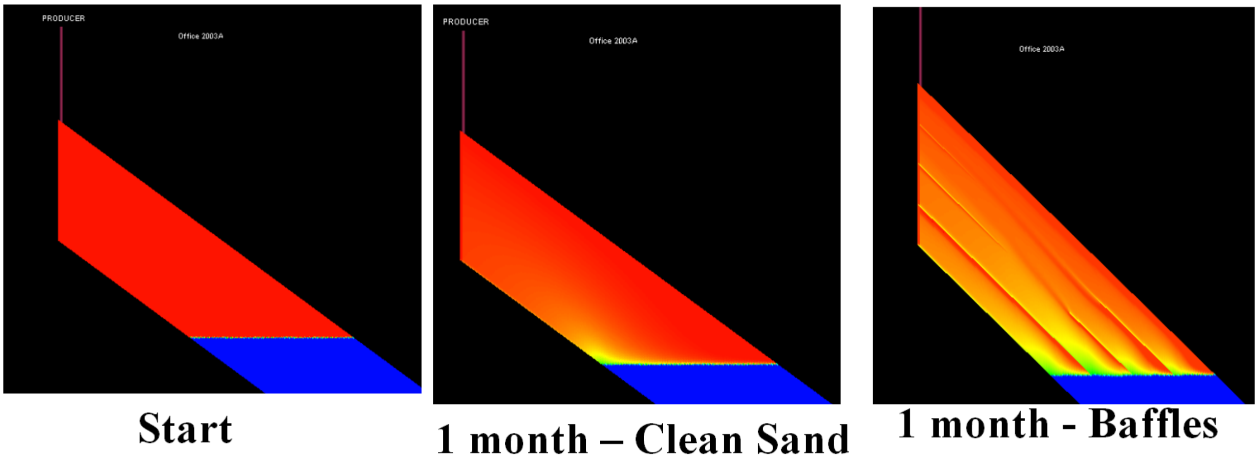

Figure 2: Illustration of Sweep Evaluation

The next step is to match the simulation model to the observed production by adjusting the properties assumed within the uncertainties of the input data. If it is not possible to converge on a match between model and observed data, the underlying assumptions are most likely wrong. This is where many mistakes are made in the industry as a match is forced to the observed data changing some of the input data outside the error of the measurement. This results in a model with very poor predictability. As the underlying reason for water production is not understood, a more valid forecast is to project the existing production behavior using a straightforward decline forecast.

3.2 Testing Different Well types

As many of the existing fields in the region are fairly mature, it is seldom that a production forecast and evaluation have to be made without adaptation to past production history. The majority of activities today are associated with understanding the behavior of the historical wells and then evaluating the impact of implementing newer equipment and a different type of wells.

It is important to stress here that, if the history match of the historical well is done correctly and the adjustments are quantified, the underlying grid can be changed to represent different well configurations. In Figure 3 an example is shown in which the historical production data from the existing vertical well was matched by adjusting the vertical permeability profile. This profile was then taken to a different model in which a horizontal well was represented. The single well match was made in a radial grid and the prediction of the horizontal replacement well was made in a corner point grid. A different grid was required for the horizontal well, because the geometry of a cone around a vertical and horizontal well is different. Fine grid resolution is required where large saturation changes occur.

The first picture in Figure 3 illustrates the water cone. Only grid blocks with high water saturation are shown. The second picture illustrates a comparison between the existing vertical well and what a horizontal well would have produced in the place (the fat lines represent the horizontal well and the thin the vertical, green is oil rate and blue is water rate).

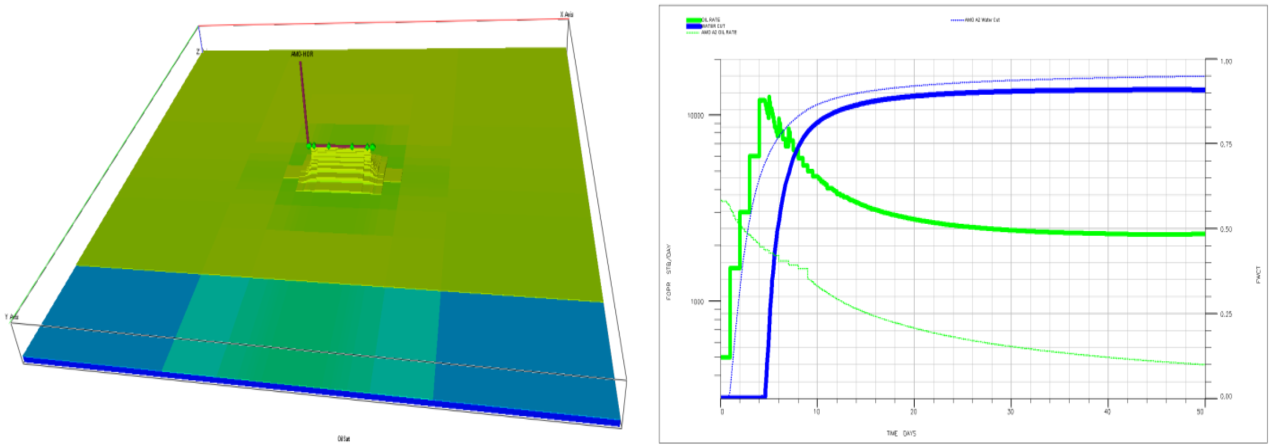

Figure 3: Illustration of a Horizontal Coning case and comparison to existing vertical well

3.3 Perforation and lift

In areas where relatively low quality oil is found (API in the range 17 to 25) and artificial lift is implemented in the form of gas lifting, a correlation may exist between the perforation interval and the lift capacity. This is usually due to the formation of oil/water emulsions. A typical problem is illustrated in Figure 4. The target sand has water at the bottom. The objective is to define the perforation strategy. Should the top of the sand be perforated, allowing for an early drier production with a rising water cut as a cone establishes around the well. Perhaps the whole sand should be completed to obtain higher total productivities.

The problem is more complicated than it initially appears and there is not a general conclusion applicable to the whole region. The conclusion depends on the properties at the location, the fluid properties and the lift system. The reservoir may posses partially sealing baffles to vertical flow in the shape of shale layers or silts. For this part a fine vertical property understanding is required. Secondly sand may possess more sand facies [1,2,3]. In each of the facies the fractional water mobility may be different (different relative permeability curves). So, in some cases it is possible to mitigate the water production by perforating an interval

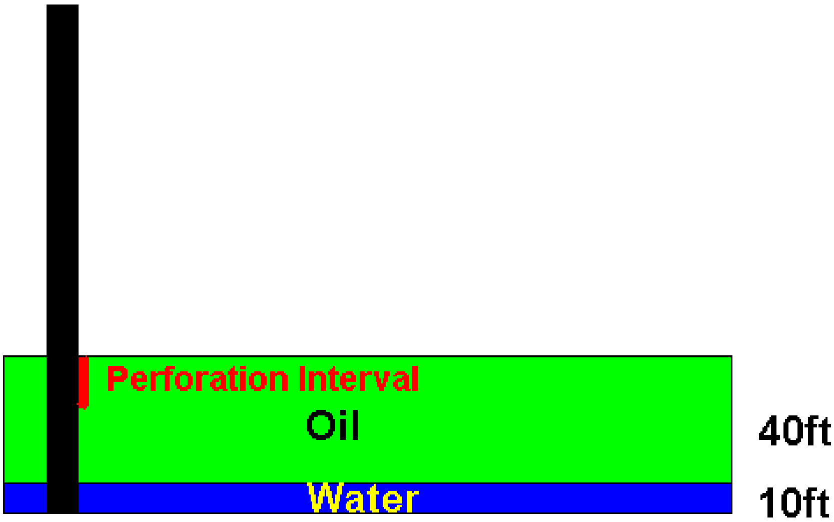

Figure 4: Illustration of the Perforation Decision issue

which may be protected from vertical flow (coning) and may have a lower tendency for water production. But a smaller perforation interval results in a lower well productivity. Perforating the whole sand will result in higher liquid rates and very likely higher oil rates, but more fluid has to be lifted to surface. The problem is to optimize lift versus water cut.

The emulsions, which are formed in the heavier oils, represent an additional complication. These emulsions are especially a problem in gas lifted wel ls, which tend to operate at lower temperatures than electric submersible pumps. Secondly the gas may be a catalyst to the emulsion formation.

Figure 5 illustrates an example from Venezuela. The liquid production rate is plotted versus the producing water cut for a number of different perforation cases (from top 10 ft of the sand perforated to the whole sand perforated). This example was based on nodal analysis of a specific well for a given type of emulsion. As the water cut rises the emulsion problems increase resulting in a higher viscosity of the mixed phase. At about 60 percent water cut the largest impact of the emulsion is observed. This point represents the border between the water in oil emulsion and the oil in water emulsion. As the water cut incr eases over 60 percent the impact of the emulsion disappears. In the case of the full sand perforation, the producing water cut is above the emulsion problem range. In this example the decision was to perforate the whole sand as the cost of lifting and proc essing the additional water was low compared to the cost of using chemicals to break the emulsions. Secondly, the full perforation gave not only a higher liquid rate, but also a higher oil rate, albeit at a higher water cut.

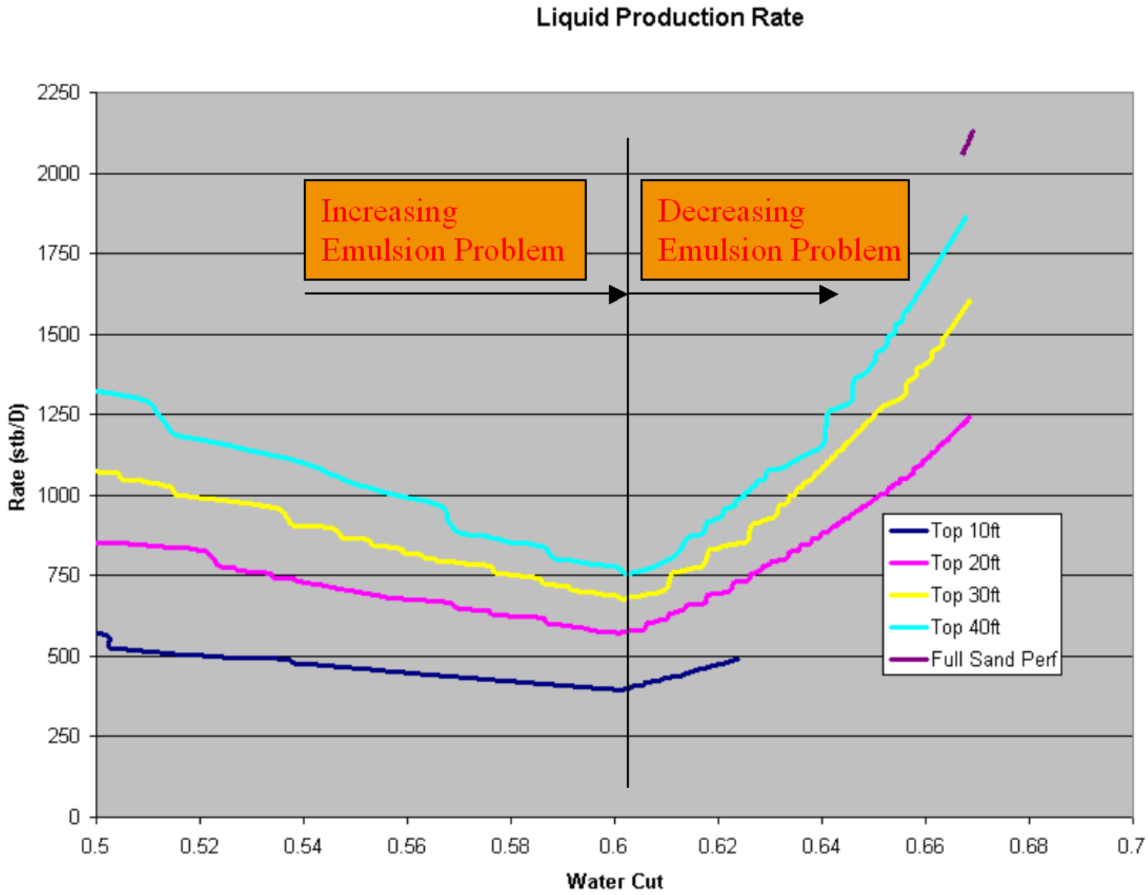

Figure 5: Example of Water Emulsion Case

3.4 Sand Production and rock strength

As mentioned earlier, if it not possible to match a model to the observed production, it is because the underlying problem is not present in the model. One of the very weak assumptions in reservoir simulatio n has been the assumption of constant permeability. This is a good assumption in many pressurized and well-cemented sand reservoirs. It assumes that the sand is independent of pressure, temperature and the amount of fluid flow.

In highly permeable sands, the sand is often poorly cemented. As the field pressure lowers with depletion, the sand starts to fail and pack differently. In terms of production this often results in a sudden change in production level or complete failure of a well. Physically, what is happening is either a closure of the perforation tunnels or, if the flow is sufficient to transport, an increase of the size of the perforation tunnels. These tunnels were created with a gun that shot a hole through the casing and into the reservoir for mation. The tunnels are often unsupported and when the fluid pressure near the well bore drops below a critical level, the tunnels collapse as the sand repacks. The outcome is a sudden change in the well productivity and is often not associated with any sand production prior to the event.

The sand failure is a serious issue in many of the fields in Colombia and in Ecuador. This is especially observed in the mature fields where the current reservoir pressure is significantly lower than the original pressure.

Significant development work is taking place in most software companies to implement a Mechanical Earth Model in the numerical reservoir simulator. Today the rock strength calculations tend to be done separately from the reservoir simulation work. Apart from being a software development area, little data is currently available to support inclusion of rock mechanics in studies.

3.5 Going to unstructured gridding

Drilling has developed dramatically over the last years. The introduction of coiled tubing drilling has made it possible to put more horizontal extensions on existing wells resulting in very complicated geometric structure. This has introduced a higher level of complexity for the reservoir engineer who has to evaluate these wells.

In viscous oil fields where water coning and water under-run are common features, the potential impact of multibranch wells is significant. However, care has to be taken in the grid construction, as a very fine definition is required close to the wellbore. The traditional grid used in finite difference solvers has a rectangular shape, be it a corner point definition or a Cartesian grid. It is therefore difficult to construct the grid in such a way that all the branches of the well are parallel to one of the grid axes. A very fine grid definition is a possibility using a local grid refinement option. However, the fine grid is very costly in terms of computing time. An alternative and faster way to represent multibranch wells is to apply an unstructured gridding approach. This is today an option in a number of commercial software packages and is basically an approach by which the dimensions of the simulation grid are calculated based on the well and reservoir information. This allows for a fine grid definition close to the wellbores and coarser grids as the distance to the completion increases. Near horizontal completions a rectangular grid is created parallel to the completion. Further away from the completions a PEBI grid is used to represent the reservoir. A calculated grid for a “fishbone” well is illustrated in Figure 6.

4 SCALING UP FOR FULL FIELD MODELS

4.1 Scaling up Models – Pore Volume preservation

The structural and rock property information used in the numerical simulator tends to come from a 3D property model. This model is constructed by a geologist and consists of a matrix of typically more than 1 million grid block cells. Each cell represents an area in space and is associated with at least a value for porosity, permeability, and often sand facies flag. The typical workflow is to take such a model and reduce the number of cells to something a numerical simulator can handle through the process of upscaling and then to go ahead with the simulation.

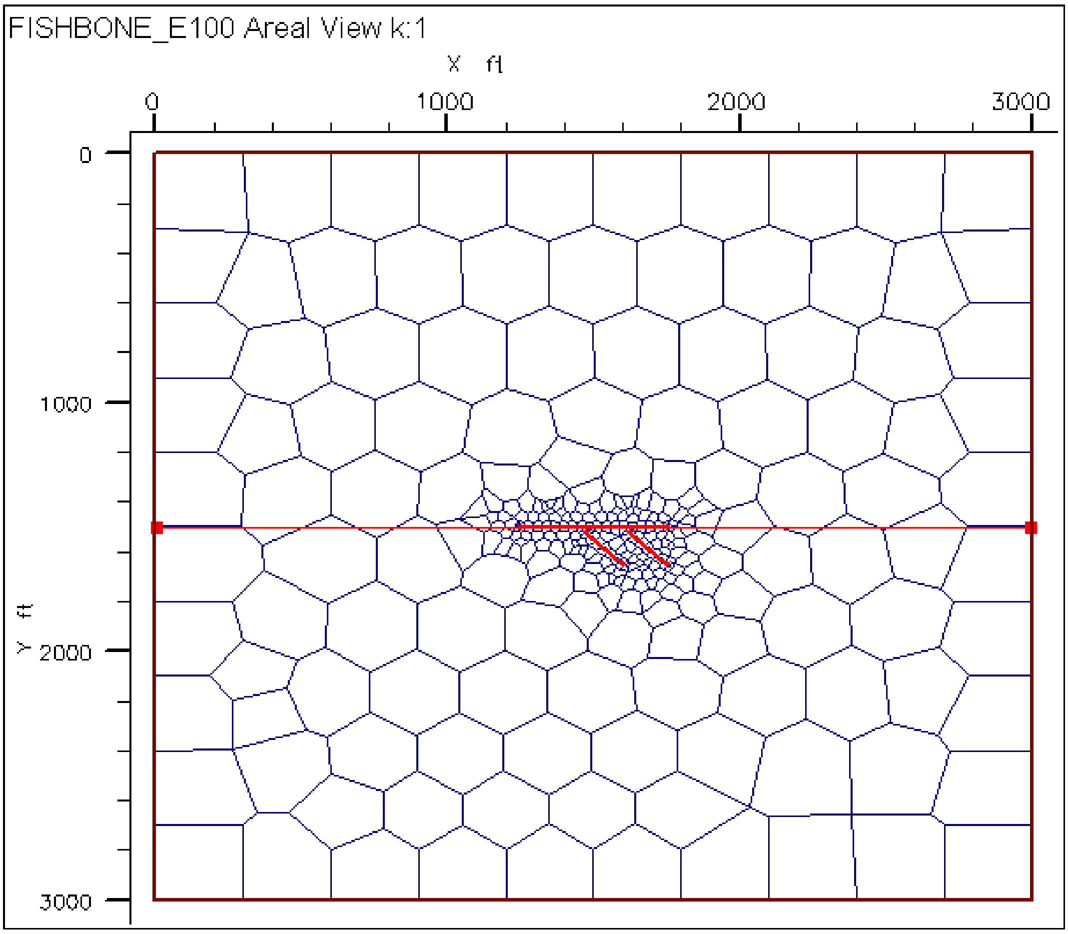

Figure 6: Grid Used to simulate a fishbone well.

Let it be stressed that this grid was defined to account for property variation and is not the simulation grid. As the property information often comes from logging of wells, which have a high resolution, property models tend to have a fine vertical definition and a coarser area definition. In terms of area, the information may come from seismic data or only from the well locations. In both cases the area coverage is relatively coarse compared to the vertical data acquisition.

When creating a field wide reservoir model, the first issue is to check the required grid resolution and then to look at upscaling the property model. Often upscaling is done directly on the matrix containing the total field information. This process is risky when dealing with the fluvial environments encountered in Venezuela, Colombia and Ecuador. The problem is shown in Figure 7, from an example found in Venezuela.

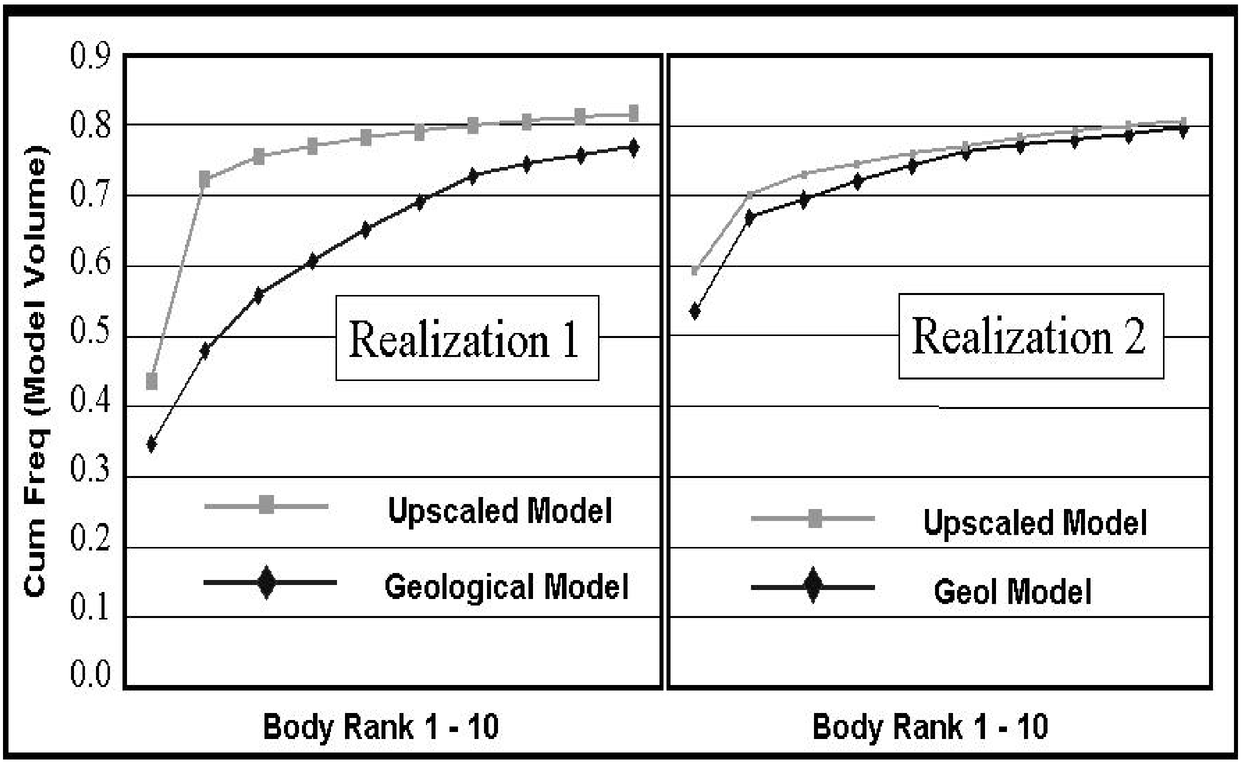

Figure 7: The problem associated with upscaling the full matrix

In the figure, the cumulative fraction of the total oil in place is plotted versus reservoir (body) size for 2 different geostatistical realizations. For realization 1, the largest reservoir accounts for about 35% of the oil in place and the two largest reservoirs account for 49% of the oil in place. Though the information the two realizations are based on is identical, there appears to be a significant difference between the two realizations. This is because the realizations are based on well and seismic observations. No production information has been used to condition the volumes. A simple material balance approach may help to eliminate some of these realizations as being possible outcomes, a way to condition them with respect to production.

The dark curve in the figure (Figure 7) is the size distribution prior to upscaling. The lighter curve is the size distribution of the reservoir units after upscaling of the total volume of interest. The process of upscaling coarsens the definition and it is difficult to maintain the pore volume distribution from the fine scale to the coarse scale.

A simple way to maintain the volumes from the fine geological model in the upscaling is to build independent models for the individual reservoir units through upscaling of each of these units one by one.

4.2 The pseudo permeability function for finite difference

The relative permeability function accounts for the relative flow of the different phases.

Sometimes studies are carried out on core plug samples. These are typically of a radius of 2 inches and a length of approximately the same dimensions. The test is often referred to as special core analysis (SCAL). The results of these tests can in general be described by the Corey equation:

$$k_{ri} = k_{ri,max}\,(S_{iD})^{Ni} \tag{1}$$

The letter i refers to the phase (oil, water and sometimes gas). The $k_{ri,max}$ is the maximum value of the relative permeability at the end point and Ni is often referred to as the Corey exponent. S_{iD} is the dimensionless saturation, defined as

$$S_{iD} = (S_i - S_{ii})/(1-S_{ii}-S_{ir}) \tag{2}$$

S_i is the actual saturation. S_{ii} is the initial saturation (irreducible) and Sir is the residual at the end of the flood. The dimensional saturation will always be between 0 and 1.

The SCAL experiment is carried out on a sample that has a size significantly different from a grid block in a simulation model. The issue is therefore how to scale the estimated rock relative permeability data to represent the fractional flow within a grid block in a simulation model. The process is often referred to as pseudo relative permeabilities in literature. The approach consists on defining simulation models using a very fine grid and later upscaling this to a coarser grid with a grid block length and thickness in line with the full scale reservoir simulation models. This process can, for simplicity, be carried out on a simple 2D model first and later the results can be used from this upscaling to the larger scale reservoir simulation model. In principle a pseudo relative permeability curve can be calculated for every single grid block in the coarse model. In Figure 8 this is illustrated for a few different blocks at different level in the reservoir. These curves are then averaged out using different algorithms. In principle an average function can be used based on the curves calculated for the blocks with the largest changes in saturation. The final curves have to be monotonous otherwise convergence problems will be encountered.

Going from the SCAL data to a set of relative permeability functions, which can be used in the numerical simulation of a field, is a critical step when dealing with viscous oil fields where an unfavorable mobility ratio is encountered. If the SCAL data is assumed valid in the simulation model, the timing and the level of the early water production can be completely misjudged. This is illustrated in the example given in Figure 9. The red curve represents the cumulative production for the fine model. The green curve illustrates the cumulative oil production for a coarse model using the same set of relative permeability functions. Finally the red curve with the plus signs shows the results of a coarse grid model using pseudo relative permeability values. In this case, the error on the cumulative production, if a coarse model is used with no relative permeability correction, is of the scale of 10 percent.

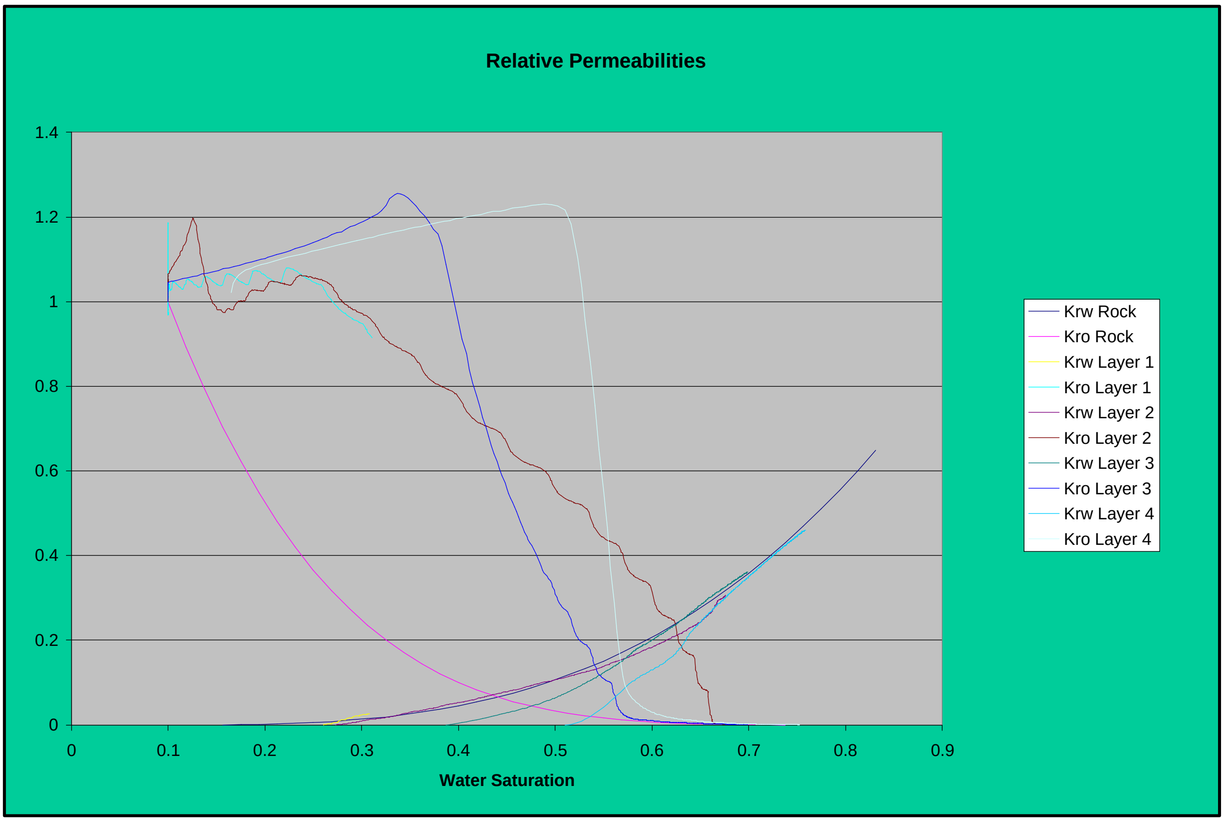

Figure 8: Example of a set of Pseudo Relative Permeability curves calculated from a fine 2D model

4.3 The streamline option

The alternative to using the traditional Finite Difference solver is to use a streamline approach. Streamlines are based on the principle of t he implicit pressure explicit saturation solver. But the saturations are sampled from the streamlines onto the simulation grid. The flow in the streamlines is based on a Buckley-Leverett approach.

Originally the Streamline applications could not account for gravity. Today a set of gravity lines has been implemented in the applications. But the use of streamlines has to be taken with caution. This is because the user defines the timesteps. Larger timesteps allow the computation of models with half a million or more grid blocks. With larger timesteps the streamline simulator is significantly faster than the traditional finite difference approach. However, the limitation is accounting for gravity effects. In the high permeability reservoirs where gravity segregation is taking place, shorter timesteps have to be used at the price of a longer computation time.

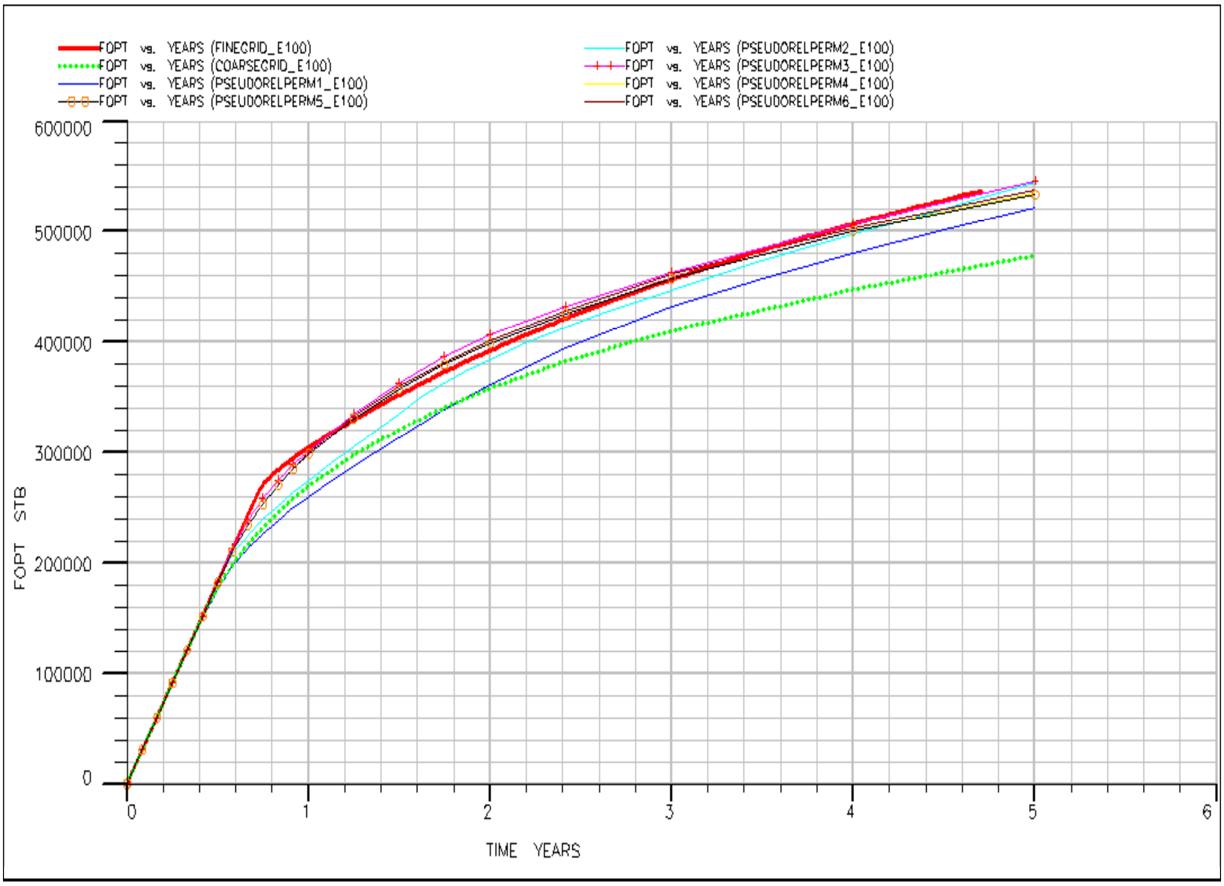

Figure 9: Impact of not using Pseudo Relative permeability in Viscous systems

Figure 10 illustrates a comparison between the saturation profiles calculated by a streamline programme using timesteps in the range of months. For the same timestep, the profile calculated using a finite difference solver is illustrated. The latter was using timesteps in the range of hours. This is a comparison based on reservoir data from Ecuador. The oil viscosity is in the range of 20 cP and the rock has a permeability of about 2 Darcy. By reducing the timesteps in the streamline case, it is possible to represent the same solution. But the speed of the streamline simulation is severely reduced. The important issue to note is that the problem associated with using streamlines is to define the size of the timesteps.

In the study of heavy oil fields with viscous oil with a high gravity impact, the finite difference solver is preferable. In cases with lower density difference between the oil and water phase and lower permeability, the streamline approach can be considered. A 2D model study as illustrated in Figure 10 can be used to validate the options.

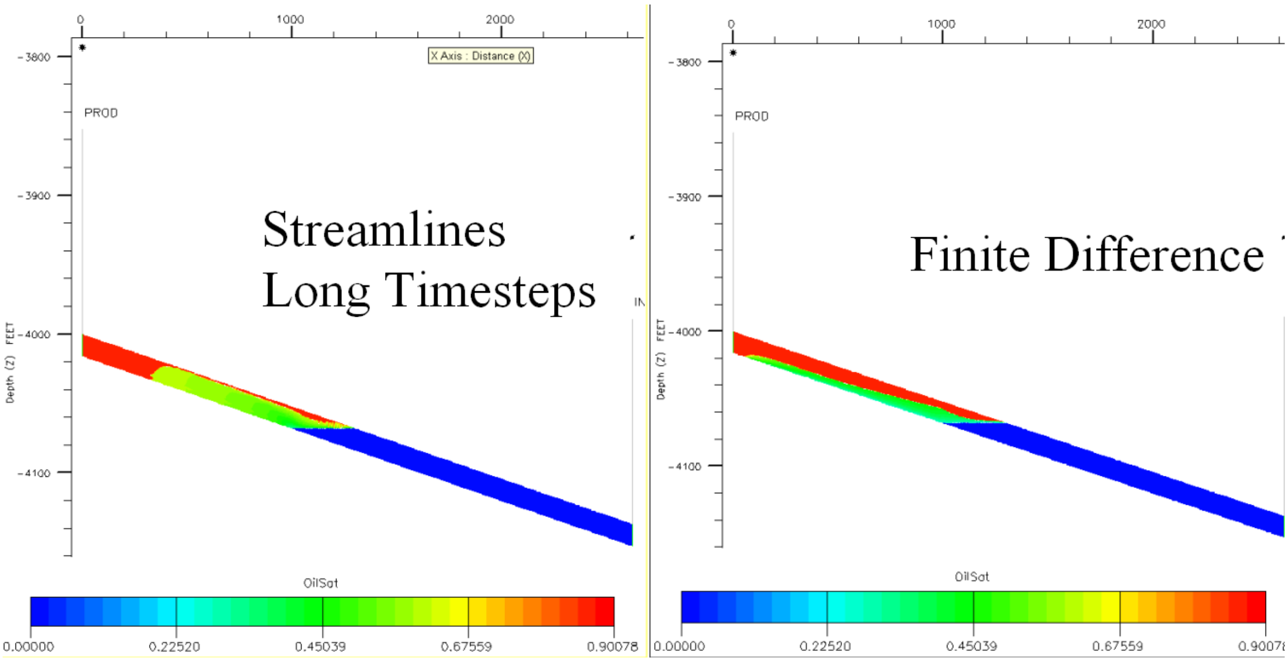

Figure 10: Streamline and Finite Difference Solver Comparison

4.4 Permeability and Skin not Constant

Normally formation permeability and Skin are considered constant properties. However, due to the rock mechanics issues described previously, this assumption does not always hold in mature fields. Examples can be given from Colombia, where wells after 30 years of production fail. Simulation studies of such fields tend to overestimate the recovery from existing and proposed new wells.

Data may not be available to quantify the stresse s, but the wells used in the production forecasts in the simulation work should not be assumed to have a longer completion lifetime than offset historical wells.

4.5 Single Cell Representation of Reservoirs

Fluvial Environment fields tend to have a large numb er of reservoirs due to the heterogeneity of the sands. The number of reservoirs in a field can be anywhere from a few to a few thousand. It basically depends on the sand concentration. Due to the large number of reservoirs, a numerical simulation study is the only option, when it comes to the larger units. These have more well penetrations, larger volumes of oil and often more production history. But the larger reservoirs may only represent a small fraction of the total number of reservoirs and these reservoirs are often the most depleted. In Figure 11, an example of a size distribution is illustrated.

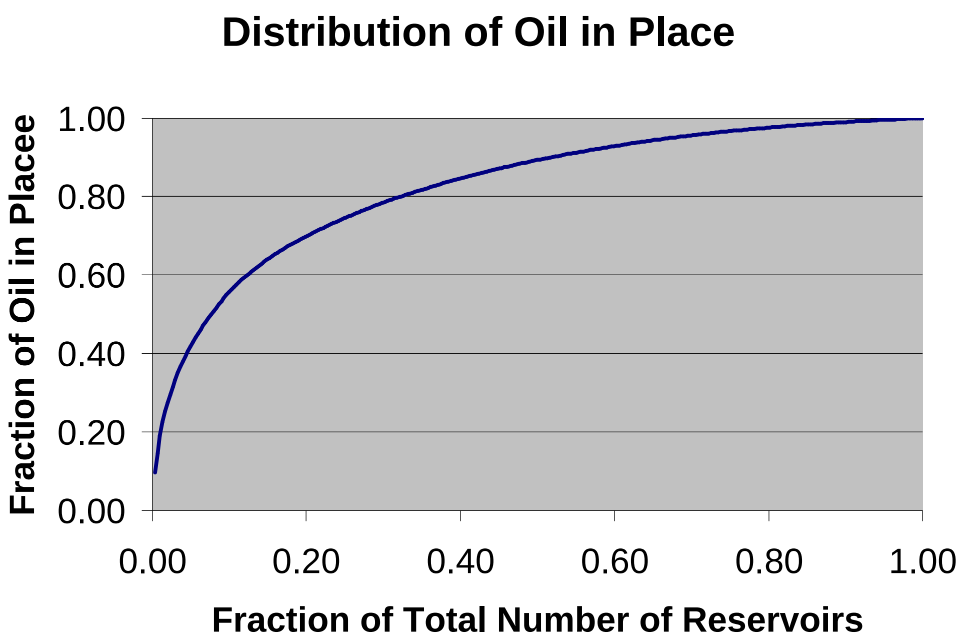

Figure 11: Example of Distribution of Reservoir Sizes in a Fluvial oil field (Venezuela)

In the example case, 10 percent of the reservoirs contains 50 pe rcent of the oil in place. In this field example, the majority of the untapped reserves are found in the smaller units. In this case the focus is to understand how to develop the smaller units. Single cell modeling was used.

Historically single cell modeling has been used for a long time. It is in principle a material balance approach in which the phase distribution in the well inflow is described as a function of the average fluid saturations in the reservoirs. The error of such an approach can be significant, especially if wells are matched against a reservoir using individual relative permeability functions for each completion. The main issue when applying this technique in the fluvial environments is how to generate a general simplified model of the frac tional flow that is a function of reservoir properties without having to create a simulation model. The aim was to generate a parameterization of the single cell relative permeabilities, which could be applied on a reservoir basis. In this paper such an approach is described. The latest example was published in 2001 [4]. Coarse simulation models have been used in the region [5] to represent the fields, but in the fluvial environment this is complicated due to the large contrast in reservoir sizes.

In fields with high permeability, viscous oil, and strong gravity segregation, the relative permeability function can be expressed as a function of the relative level difference between the level of the completion and the contact [1]. In other cases, where patterne d water injection is taking place, the single cell volume can represent the volume of the pattern.

In Figure 12 a previously presented example is illustrated [1]. The figure illustrates a number of well locations and the color reference refers to the quality of the history match. This was originally believed to be a single reservoir. The calculations include relative permeability functions based on the position of the wells with respect to the top of the sand and to the contact. Some matches were bad (blac k). These turned out to be related to wells with cement problems. The area to the East appeared to give a modest match and was later discovered to be a different and separate reservoir.

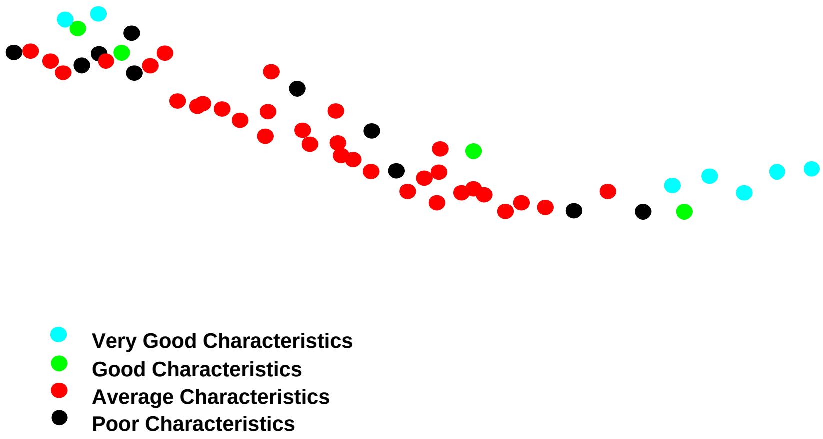

Figure 12: Example of a single cell approach

The single cell appro ach has proven useful when dealing with reservoirs that only justify workovers or a single low cost well.

5 CONCLUSIONS

In this paper, the experiences and lessons learnt from the study of the fluvial reservoirs with viscous oil have been summarized. The stages can be defined as follows:

1. Diagnostics phase
2. Single Well Models
3. Scaling of model
4. History Matching
5. Understanding the critical Stresses
6. Simple Approach for large number reservoirs

The diagnostic phase is required to understand the possible reason behind water production and to identify which features to implement in the numerical model. This exercise is very simple and can lead to significant reduction in the study time and especially in the history match of the model to previous production information.

The single well models and generic 2D sweep models help to understand the area and vertical sweep efficiencies and how to construct a grid for an accurate representation of the input data.

Rescaling of the geological property model is required to obtai n a stable and representable model. Upscaling smaller units at a time helps to preserve the distribution of reservoir sizes in the simulation model. Scaling of relative permeability is required to maintain accuracy on a larger level.

When running the mod el, it is important that reasonable pressure constraints are used. These should be within the critical pressure to avoid failure of the sand. However, in some cases this is unavoidable. These cases represent a significant level of complication because understanding of the stresses is required to be integrated into the modeling work. Alternatively, the life span of the completions has to be reduced with respect to historical information.

When managing a field, hundreds of reservoirs have to be taken into account. Many of these reservoirs are small and can only justify a few perforations (secondary targets). One way to include these in the studies is through the application of Single Well modeling

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