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Drilling, Producing and Treating Complex Wells. A Collection of New Technologies to Optimise the Overall Well Process.

Ph. A. Charlez, TotalFinaElf

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Abstract

This paper highlights the concept of complex well through various advanced or emerging technologies involved during the well life process. The current state of the art states that drilling technology is more mature than production and treatment technologies.

The well life process is divided into four phases : pre-project, conception, realisation and exploitation. Each phase is studied in terms of productivity on one side, cost on the other. New concepts such as limitation of well oversizing or anticipation of field maturity are regarded through actual examples. It is finally concluded that this technical revolution can only be a success if culture and human organisation evolve at the same rythm. Well being the most transverse object of the E&P chain, it represents a fantastic opportunity for all disciplines to work in close collaboration within integrated teams and not anymore through conventional isolated petroleum professions.

Introduction

It is recognised that during the last twenty years, well engineers have met a technological revolution. Remember the past! To properly develop an oil field, numerous vertical wells were required (**Fig. 1**) devoted either to exploration, appraisal or development.

With proliferation of deviated and horizontal wells followed by the more recent breakthrough of multi-lateral and re-entry technologolies, the technical environment has completely changed. Today, extended reach wells are drilled with departures between 5 km and 10 km. Drilling off-shore reservoirs from on-shore facilities is now a reality. **LWD** (**L**ogging **W**hile **D**rilling) allows a single horizontal drain to be drilled through several lenticular reservoirs. Other emerging technologies such as **CTD**[1] (**C**oiled **T**ubing **D**rilling), **TTD**[2] (**T**hrough **T**ubing **D**rilling), Casing Drilling or Expandable Tubulars[3] will allow in a near future to put further and further the drilling limits.

This technological revolution has been widely applied within the TotalFinaElf Group through several exceptional realisations (**Fig. 2**) among which three world records have to be mentioned : lateral D05 of the Dunbar field[4] (North Sea), record in UDW on the Astrid field – 2800 m of water- (Gabon) and of course world record for an ERD with a departure of 10500 m (Terra del Fuego – Argentina[5, 6]). More globally, Girassol (Angola - 1400 m of water[7]) and Elgin Franklin (UK - 1100 bar of vrigin pore pressure, 200°C) have been recognised by the oil profession as world first class achievements.

The sharp upturn in the crude prices in 1973 was certainly a major driving force which has motivated operating and service companies to industrially launch the complex well concept. With a barrel above 10$, development of large off shore fields discovered in the North Sea and in the GOM a few years earlier became economically profitable providing reservoir being drained from a same *"tie in point"*.

This revolution was made possible thanks to three major and simultaneous technological breakthroughs : directional drilling, Measurement While Drilling and computer technology.

What is a complex well ?

A complex well has to be considered at two levels : its smart geometry (deviation, length, departure, 2D or 3D shape) on one hand, the complexity of the natural constraints (pressure, water thickness, depth, temperature, in-situ stresses, complex and heterogeneous geology, depleted reservoir) on the other.

Referring once more to the various projects mentionned above, the CS1 world record can be considered as “complex” according to the length of the well but “easy” if regarding the natural constraints (normal pressure, shallow depth). By contrast, Girassol and Elgin Franklin are “complex” referring to the natural constraints (water depth, HP/HT conditions) but “easy” with respect to their well geometry.

As pointed out in the diagram Departure/ Depth of **Fig. 3** (ERD envelopes from the beginning of the nineties) the trend clearly shows that long departure (complexity according to geometry) does not accomodate with deep natural conditions (difficulty according to natural constraints).

The complexity factor (integrating both geometry and natural constraints) makes drilling but also production, intervention & curative treatment challenging, risky and expensive. Indeed, if exceptionnal drilling performances have been achieved over the last ten years, the understanding of how such complex wells produce and how to succeed in treatments and intervention to maintain productivity over time remain highly questionable. The state of the art today can therefore be summarised by three key sentences :

- ✓ Drilling complex wells we nearly can do !
- ✓ Producing complex wells we cannot really do !
- ✓ Treating complex wells we really cannot do !

In spite of the huge progress made by the oil industry over the last ten years to reduce the average cost per barrel[1] (from 14 $/bbl in 1990 to less than 7 $/bbl today - **Fig. 4**), a lot of marginal resources cannot be economically produced and in many cases, well cost appears as a killing factor. This applies of course to technical complex objects such as Deep Water, HP/HT, foothills or artic regions but above all to existing resources for which the increase of the recovery becomes a top priority. When looking at the portfolio of TotalFinaElf, it is obvious that on-shore and conventional shallow off-shore represents 75% of the potential growth (**Fig. 5**) and that smart well technology (broad sense drilling, completion and treatment) has become a major tool to increase this recovery factor. This has pushed the TFE group to launch in all its affiliates a wide exercise called **PVR** (**P**lan de **V**alorisation des **R**essources) the goal of which is to identify advanced technologies able to tranform in the future non economic resources in economic reserves.

The well life process

The overal well life can be regarded through a chronological process involving four successive phases (**Fig. 6**) :

- ✓ The **pre-project phase** during which after a general agreement on a future productivity target, one searches to optimise CAPital EXpenditure,
- ✓ The **conception phase** during which the required rig and the well architecture will be optimised in terms of both casing and completion design,
- ✓ The **realisation phase** including well preparation and realisation. The goal of the realisation phase is to effectively reach the expected productivity target while minimizing costs particularly drilling **NPT** (**N**on **P**roductive **T**ime),
- ✓ The **exploitation phase** during which productivity has to be maintained as high as possible over a long period. This will require efficient interventions and treatments operations.

The rest of the paper is focused around a collection of technologies applicable to these four phases. Through specific examples we describe how theses technologies contribute to simulateously increase productivity and decrease cost.

The pre-project phase

It is generally considered that at the pre-project stage, main uncertainties are related to geosciences (i.e. structural geology, petrophysical properties and fluid distribution within the reservoir). Consequently, well design (broad sense) remains very often at a very basic level, the goal being restricted to a global cost estimation.

Nevertheless, new advanced tools such as **well planners** and **well models** allow a quick and a quite detailed screening of advanced architectures to be performed both from a drilling but also from a productivity point of view.

These tools allow drillers, geologists and reservoir engineers to plan complex well trajectories (horizontal, snake, multi-laterals) in complete immersion within a geomodel (broad sense from a basic seismic section to an advanced reservoir model - **Fig. 7**). Providing the geo model is fed with a reservoir grid, the well planner can be coupled with a well model (**Fig. 7**). The latter extracts from the reservoir model a refined grid surroundind the well (**VOI** – **V**olume **O**f **I**nterest) and allows to quickly estimate well productivity versus time. Integration in such models of well reservoir interface modules such as scale forecasts or solid production modelling should allow field maturity to be better anticipated with early recommendations on completion design.

The conception phase

The conception phase aims at looking in more details to rig size, casing and completion design following the recommendations issued from the pre-project phase. We develop below two fundamental concepts : **limit oversizing** and **anticipate maturity**.

The cost of a well being roughly equal to the product between daily rig cost and well duration, all action playing on well duration and rig cost will play positively on global well cost.

Well duration highly depends on the number of casing points which are mainly related to the geopressure (pore and fracturing pressure) profile along the planned trajectory. As rig cost highly depends on the global "size" of the well, innovative solutions reducing well oversizing (number of casing points, hole diameter, request in pumping and electricity) while maintaining a same level of safety will have a drastic effect on global well cost. Some emerging technologies and architecture such as expandable tubulars (monobore well), slim or lean hole[2], tubingless completion, surface BOP (case of deep water) allow to drill a same well in a shorter time with less hole, less metal, less mud, less cement, less cuttings, less weight and consequently…"less rig".

Completion has first of all to answer to initial production requirements. However, a clear anticipation of completion needs with respect to future maturity problems is of a strategic importance and unfortunately rarely regarded at this early

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[1] This cost includes all expenditures from the first seismic campaign until the bbl is charged in the tanker. It excludes all costs relates to transport and refining.

[2] Lean hole means a conventional casing design run in a reduced hole. For instance a $13^{"3/8}$ is run in a 16" hole instead in a conventional $17^{"1/2}$ hole.

conception stage. Nevertheless such problems always require heavy and sometimes risky intervention and treatment the cost of which can become prohibitive during a late mature production phase. We illustrate below this concept through two interesting exemples.

Scale problems on Dunbar field. Dunbar field is located in the nothern part of the North Sea and was put on stream in 1993. Several Brent levels among which Tarbert and Ness have been produced commingle. After a few years of prodcution, acute $BaSO_4$ scale problems have been reported on several wells with a drastic decrease in production. The upper graph of **Fig. 8** shows a first moderate reduction beginning 1997. However less than one year later, a more dramatic decrease occurred and only a re-perforation job allowed to recover temporarily an acceptable production level. A modelling study was performed using the reservoir model VIP coupled with the advanced well model REVEAL. Results have shown that the second drastic decrease in production was due to a mixing of water formation (rich in Barium) from the Ness and sea water (rich in sulfate) from the Tarbert (**Fig. 8**) in which the first (water formation breakthrough occurred earlier. A perforating strategy consisting of producing commingle Ness and Tarbert appears as the main driving force of the scaling problem. Such a study performed either at the pre-project or at the conception stage would have emphasised on the strategic importance of producing the two layers separtely.

Sand control & sand management. If solid control systems are quite powerful to stop sand influx and to avoid erosion of completion and surface facilities, they are always very detrimental for production. Screens and gravel can quickly plug after the well clean up under the effect of mud cake or later when formation begins to produce fines. Solid production generally initiates after a certain depletion level (which can correspond several years) and very often simultaneously with the first water breakthrough. Delayed implementation of sand control systems requires heavy and costly work over particularly in complex environments such as HP/HT or Deep Water.
Accepting sand to be produced (i.e. **"sand management"**) is another option but it can be quickly catastrophic for completion and surface facilities especially when producing large flow rates of unviscous fluid (gas). However, in the case of low mobility fluids and rocks fairly consolidated, producing sand in reasonable quantities can be acceptable according both to economics and safety. For production of extra heavy oil, a method called **CHOP** (**C**old **H**eavy **O**il **P**roduction - **Fig. 9**) which consists of a deliberate co-production of oil and sand has been proposed and widely applied over the last five years particularly in Canada. Where applicable, the performances of CHOP production is far superior to any other technique, both in terms of well productivity and ultimate recovery. The underlying principle is that the production of sand enhances the near well bore porosity and permeability, allowing higher oil rates to be achieved. A special model has been developed by TFE in collabration with University of Lille[8].

A new philosophy would consist of "weighting economically" sand control and sand management strategies. The earlier (pre-project or concetion phases) the decision the better. A typical decision tree is presented in **Fig. 10**. Starting from an early[3] proper data acquisition of the required parameters (stresses, rock strength, depletion scheme), one uses sand prediction software to detect **when** (according to depletion mainly) sand influx would be triggered. Then, the decision tree is divided in two different branches : sand control on the right, sand management on the left.
The sand control strategy necessitates first of all to choose the best sand control system and to implement it while minimising reservoir damage. Gravel pack placement and well clean up procedures will be of a strategic importance.
The sand management strategy necessitates to *"translate"* the sand influx in terms of completion (and surface facilities) life as well as in terms of safety risks. Sand production software (for a given depletion level, how much sand will be produced and at which velocity ?) and erosion models (impact of sand produced on completion and surface metal) are then necessary to close the loop. The final step is to balance production forecasts with the chosen sand control system on one side, completion life, safety risk and production forecast without sand control system on the other.
Several pieces of the puzzle (particularly reliable sand production and erosion software – overcoloured in red on - **Fig. 10**) do not exist today and need extensive R&D to be developed.

The realisation phase

Successfull well realisation [including short term well preparation (i.e. drilling program) and realisation itself] essentially lies in good dilling an completion practices minimizing more particularly hole problems (losses, kick, hole stability, differential sticking) but also formation damage while drilling.
Drilling above pore pressure (overbalanced drilling) can be very detrimental to well productivity. Mud solid and filtrate penetrate into the porous medium and form both internal and external cakes inducing in the near well bore area a reduction of permeability (damage skin) with drastic inflow restriction. **IRP** (**I**nitial **R**eturn **P**ermeability) after damage is highly dependent on the Jamming Ratio (ratio between mean pore diameter and mean mud solid particles - **Fig. 11**). Adaptation of solid size with respect to pore size is therefore of great importance to limit formation damage while drilling. However to recover natural inflow performances additional operations can be required.
Natural clean up consists of removing naturally part of the external cake by putting the well on stream. To unstick the mud cake from the wall, a sufficient pressure called **LOP** (**L**ift **O**ff **P**ressure) has to be applied. Like IRP, LOP is highly dependent on the Jamming Ratio. **Fig. 12** relates results obtained from an advanced piece of software able to reproduce both damage and natural clean up phases[9]. Using LOP deduced from experimental lab tests (LOP depends on type of rock but also on type of mud) and a refined mesh describing both internal and experimental cakes, the software allows to

[3] Decision in terms of sand control always suffer of a lack of data.

locate after simulation of clean up where pressure is able to un-stick the cake. The software can possibly be used to optimise the clean up procedure.
An other alternative is to destroy the cake using chemicals called **cake breakers**[10]. Extensive laboratory tests have shown that (specially for wells drilled with an OBM) cake breakers can be quite detrimental to productivity. In all cases it is therefore recommended to favour a natural cleanup.
Finally, **UBD** (**U**nder **B**alanced **D**rilling) which consists of adjusting the Mud Weight below the pore pressure to avoid any drilling fluid penetration in the porous space is an original drilling alternative to minimize formation damage. However, all UBD efforts may be jeopardized if underbalanced conditions are lost even during a few minutes (drilling fluid is then allowed to penetrate in the near well bore rock). Consequently, reliability of hydraulic models remains the critical point of UBD. Very few models existing on the market [Mudlite (Maurer), Dynaflowdrill (Rogaland) and WellFlow (Neotec)] have been benchmarked against the in-house TFE (ECDELF) for which specific rheology for both aerated and foamy fluids have been considered. Results have shown that ECDELF was the best software to forecast ECD under under-balanced conditions (**Fig. 14**). Let us note that a new approach[11] for calculating ECDs during underbalanced operations has been recently proposed. It is composed of a set of mechanistic steady-state models (dispersed bubble, slug flow…) allowing to predict flow patterns and calculate pressure. The issued model has been validated against two real wellbore configurations with different flow areas under steady state as well as transient conditions.

The exploitation phase

Maintaining productivity at a high level during the exploitation phase requires on one hand to manage as well as possible all the traps set by the nature, on the other to implement at the best cost the required “therapies” (i.e. treatments and interventions).
Managing the decrease of well pressure. Depletion of a reservoir means less available natural energy for the fluid to flow from down hole to the surface. This lack of energy shall be progressively compensated by artificial devices among which down hole pumping (**ESP** - **E**lectric **S**ubmersible **P**umps or others) is by far as the most efficient (**Fig. 15**). However, gas lift remains still widely used, the reliability of ESP (and the cost of associated work overs) being still in many cases a killing factor.
THERMOLIFT[12] is an innovative concept which consists of reducing the apparent weight of the fluid column by keeping as hot as possible the effluent in the well thanks to a proper thermal insulation of the tubing. Keeping the effluent as hot as possible has many benefits such as extending the natural flowing period, stabilizing production in facilities, postponing the needs for artificial lift as well as the tragic self killing scenario. THERMOLIFT is preferentially adapted to low flow rates (**Fig. 16**) for which the reduction of apparent weight is maximum. The method appears particularly attractive for gas wells or oil wells with high GOR and reservoir temperatures above 70°C.
To put thermolift into practice, an insulation material has to be introduced in the annulus space between the production casing and the tubing. For existing wells, two different techniques can be used. If the well is equipped with a down-hole circulation port, the insulating gel can be circulated into the annulus. However, if no circulation equipment is available or if production shut-in appears un-economic, the annulus may be emptied (providing the casing resistance allows it), dried and then back-filled using pneumatic devices. This VAPO EMPTYING technique has been successfully tested in a shallow school well (350 m) in 2001.

Managing the increase in water production. Water production (what ever its origin – formation or injection) is a main source of outflow performances restriction particularly when the effluent is light (gas or oil with high GOR), well killing being the ultimate dramatic step. Many technical solutions exist to solve this acute productivity problem.
The problem can be first of all treated directly in the reservoir. The **WATER SINK** concept (**Fig. 17**) consists of reversing the water coning around a well by producing separately (using a dual completion system) oil and water.
A second alternative consists of blocking water influx in the near well bore area. This method called **WSO** (**W**ater **S**hut **O**ff) can be performed either mechanically (using dedicated packers) or chemically. Even if widely used, WSO are not always as efficient as expected. Degradation of plugging materials versus time (particularly for temperature above 120°C) and proper placement in long heterogeneous horizontals where water influx is always difficult to precisely locate are considered today as the most acute problems.
Finally **DOWS** (**D**ownhole **O**il **W**ater **S**eparation) is an emerging technology using downhole cyclones as separation devices. They act as “water cut reducers”. At the oil outlet, water cut is reduced but the mixture still contents between 30% and 50% of oil. However, at the water outlet, water is practically oil free (only a few tens of ppm) and can be directly re-injected (**PWRI** – **P**roduced **W**ater **R**e-**I**njection) either in a depleted reservoir or in the overburden. DOWS could normally be achieved by three different types of apparatus : static separators (based on difference of gravity between oil and water), centrifuges and cyclones. Static separators are restricted to low flow rates whereas centrifuges are limited by their size. Consequently, only cyclones could reasonably achieve requested flow. Such a system has been installed in a well of the LACQ field for a long term (two years) test. Separation was performed downhole but to check the efficiency of the separator, the two effluents (both at water and oil inlets) were produced after separation. As pointed out on **Fig. 18**, the test was very successfull : the hydrated fluid (98% water cut) have been separated in a 35% mixture water cut at the oil exit and clean water (300 ppm of oil) at the water exit. The latter has the specifications to be re-injected. Furthermore, after separation, the effluent (which contents less water) being lighter, less down-hole energy will be required to lift the mixture and possible risks of self killing will be delayed. In the case of the LACQ pilote, pumping was boosted to simulate artificially this secondary effect (oil production passes from 1,5 m^3/d to 4,5m^3/d).
Conventional static cyclones (movement of fluid is only due to the cyclonic effect but the metallic support remains fixed) as that used on the LACQ pilote are limited in terms of flow rates

(<2000 BPD) and water cut (>80%). To treat higher flow rate it is necessary to put several systems in series. Another alternative consists of using **rotating cyclones**. Compared to static cyclones, rotating cyclones (the metallic support itself is rotated at high speed – range of 3000 rpm) work in a much larger area with a good efficiency at higher flow rates and lower water cut. A surface prototype of rotating cyclone (under the name OPTISEP) has been built by TFE and successfully tested in a laboratory bench. As pointed out in **Fig. 19**, OPTISEP is able to process up to 10000 bpd of effluent with a water cut down to 50%.

The main interest of DOWS is a coupling with PWRI. Such a methodology would allow to decrease the amount of water to be processed at the surface and consequently to downsize facilities. Compared to Sea Water Injection, Produced Water Re-Injection is highly affected by the near wellbore damage due the quite large concentration of impurities (solid impurities and remaining oil) contained in the injected water. Consequently, enven in high permeability formations, the well reservoir interface quickly plugs and injection has to be resumed under fracturing regime. A field data base built in the scope of PEA-23 (**Fig. 20**) has shown that damage effect due to solid particles and oil drops highly differ in such a way that, for a same concentration, solids produce a damaging effect 20 times higher than oil. Following these results, a specific damage model has been developed and introduced in a code coupling a multi phase reservoir model and a simplified contained 2D fracture model. HYDFRAC allows to simulate re-injection of produced water above the fracturing pressure during quite long periods (several years) and takes into account thermal and porous effects as well as the possible plugging of the fracture faces by an un-cleaned fluid. The damage process considers formation of both internal (penetration of fluid or solid particles into the porous medium) and external cakes (plugging material filling progressively the fracture itself). For given injection conditions, HYDFRAC estimates evolution of propagation pressure and fracture length versus time as well as injectivity index.
HYDFRAC potentialities are summarised in **Fig. 21** where a half year injecting period has been simulated. Both cleaned and un-cleaned fluids have been considered. Injection of cleaned water leads to a fracture of 25 meters length after 100 days. Injection of un-cleaned water induces both formation of internal cake (less filtration through the fracture faces with a drastic increase of fracture length – red line-) then of external cake (plugging material filling the fracture with a drastic decrease of the length over which the fracture is opened). The external cake (plugging material finally fills 40% of the fracture volume - **Fig. 21**) is also accompanied by an increase of the propagation pressure. Let us finally note that compared with internal cake, external cake forms very quickly.

The diversion problem. A major factor affecting the success of treatment in long heterogeneous horizontals producing commingle and presenting a wide range of permeability is the correct placement of a dedicated chemical (acid, scale inhibitor, water or gas shut-off). When injected into the well, the chemical follows the path of least resistance and preferably enters the section with the highest permeability and/or with the lowest skin. Mechanical (using packers) or chemical (using specific diverting agents) diversion remains today an acute un-solved problem which explains most of treatment failures.
Proper treatment of a complex well also lies in a better knowledge of permeability and skin profiles (they can both evolve with field maturity). The cyclic test (patented by the French company Geoenergy) consists of applying in the well a sinusoïdal flow rate and to measure the sinusoïdal pressure response which is shift-phased with respect to the flow signal. Theory shows that the amplitude ratio flow/pressure gives access to permeability whereas phase shift between the two waves gives access to skin. Cyclic test should be a powerful monitoring technique allowing to log without packers heterogeneous wells in terms of permeability and skin. Currently, some demonstration tests have been performed by using a dedicated surface regulated pump and a down-hole PLT. A down-hole tool prototype (**Fig. 22**) able to create a periodic flow is currently under development. It consists of an "umbrella" acting on the flow when partially or totally open. The flow modulation sub is simply integrated above the PLT in the logging assembly.

Conclusions
By optimising well productivity, initial CAPEX (use of reduced surface facilities) and OPEX (less meters drilled for a same production), complex wells have largely participated over the last ten years to significantly reduce cost per barrel. If smart drilling has reached today a certain technological maturity with remarkable results according both to geometry and difficult natural conditions, reservoir drainage and well flowing conditions are far from fully understood. Consequently, complex well are not only challenging for drillers and well engineers but also for production geologists, reservoir and production engineers.
This technical revolution can only be a success if culture and human organisation evolve at the same rythm. These new architectures represent a tremendous opportunity for all disciplines to work in close collaboration within integrated teams and not anymore in conventional isolated petroleum professions. In that context, the winners will not be only those who will choose the best technology but those who will optimise their human resources through the most intelligent organisations.

Acknowledgement
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Fig. 1 Vertical wells pattern (Baku Azerbadjian)

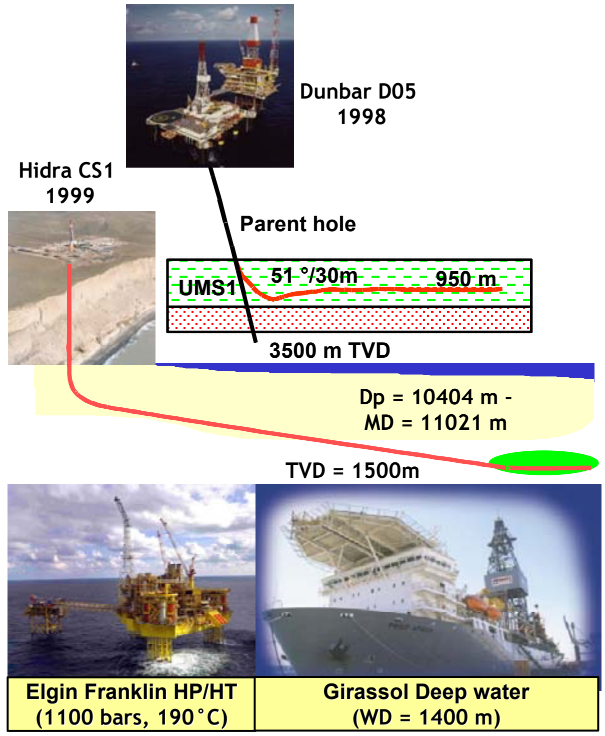

Fig. 2 World records on CS1 and D05.
Deep water and HP/HT Girassol and Elgin Franklin

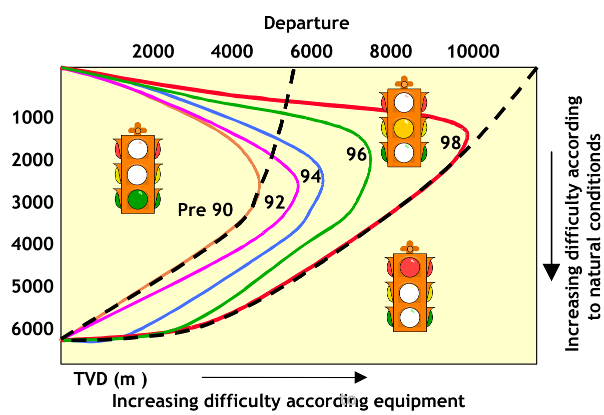

Fig. 3 ERD technology : limitation comes from the conjunction of complex geometry and natural conditions

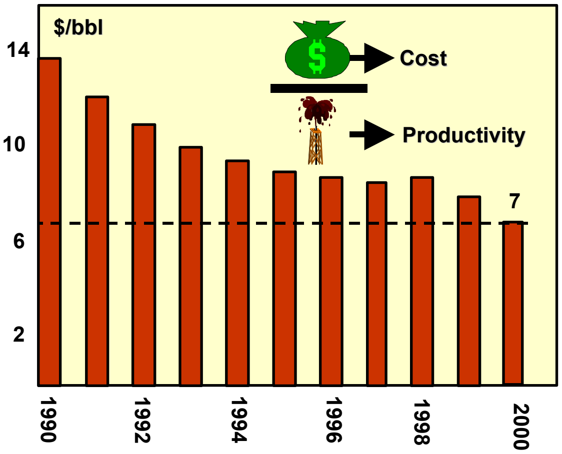

Fig. 4 Evolution of global costs from the beginning of the nineties

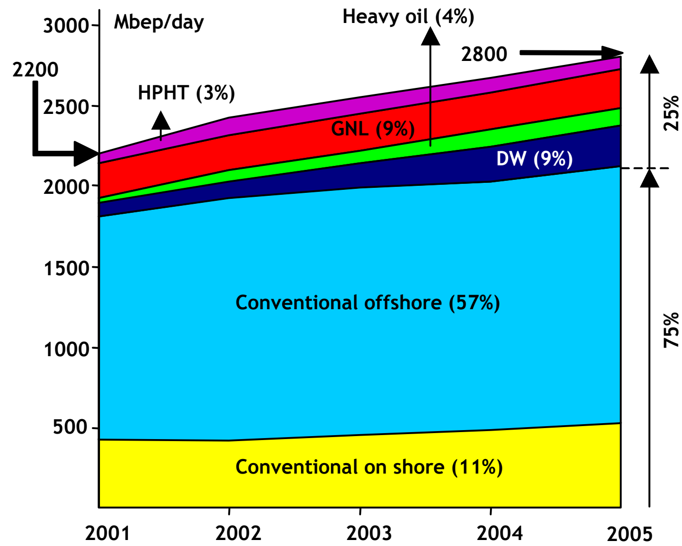

Fig. 5 Expected production of the TFE group. Conventional = 75%, Technological = 75 %.

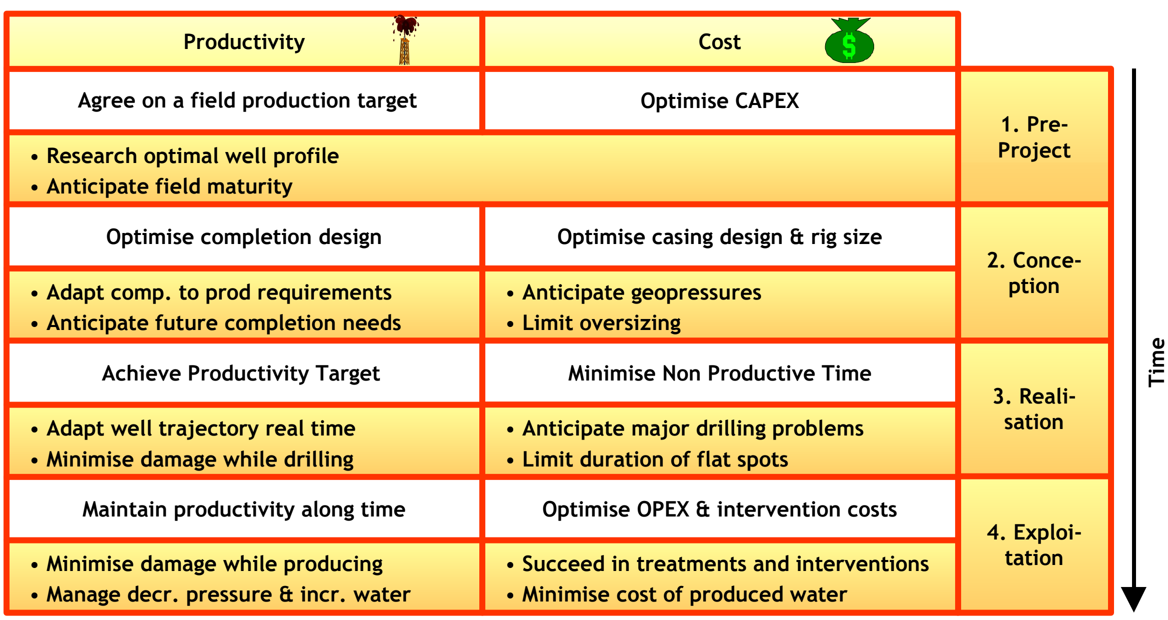

Fig. 6 Requirements in terms of productivity and cost diring the overall well process

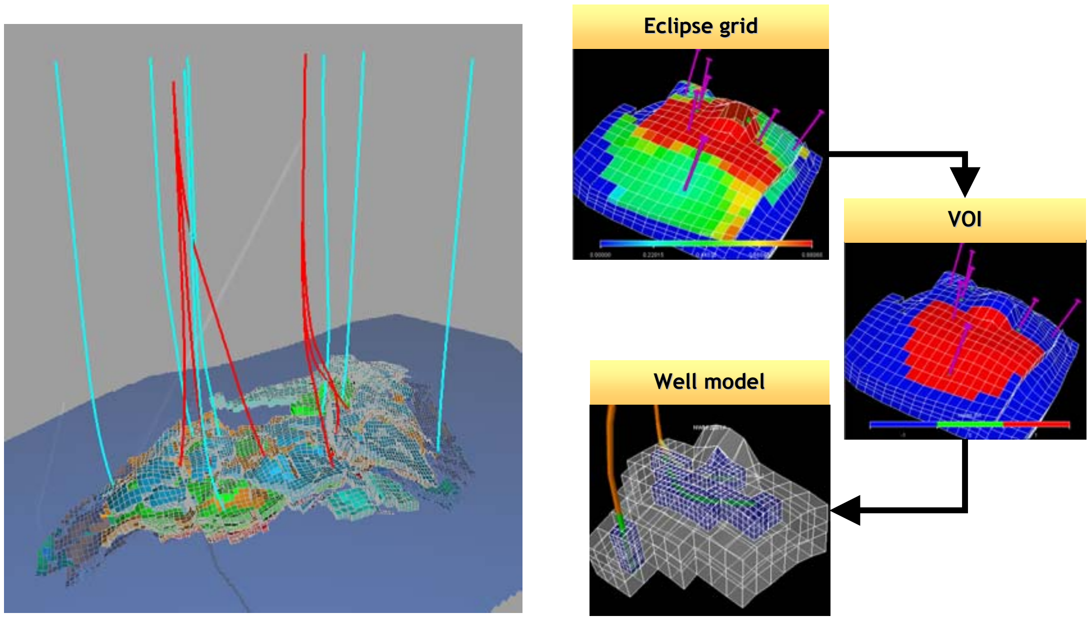

Fig. 7 Well Planner RMS-Wellplan (left) and well model Near Wellbore (right)

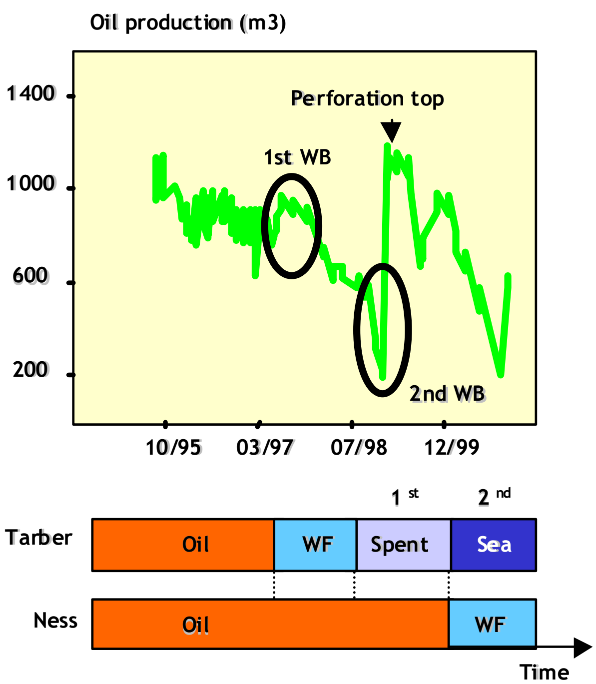

Fig. 8 Example of $BaSO_4$ scale problems due to commingle perforation (Dunbar field – North Sea)

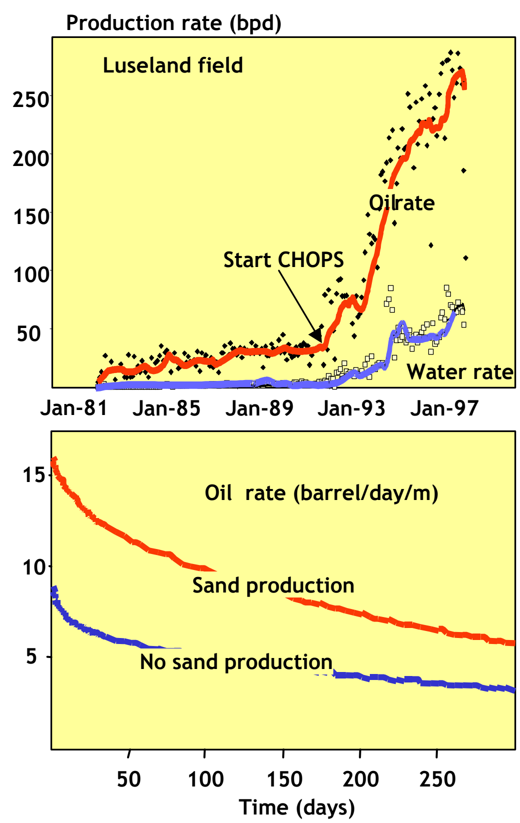

Fig. 9 Cold Heavy Oil Production

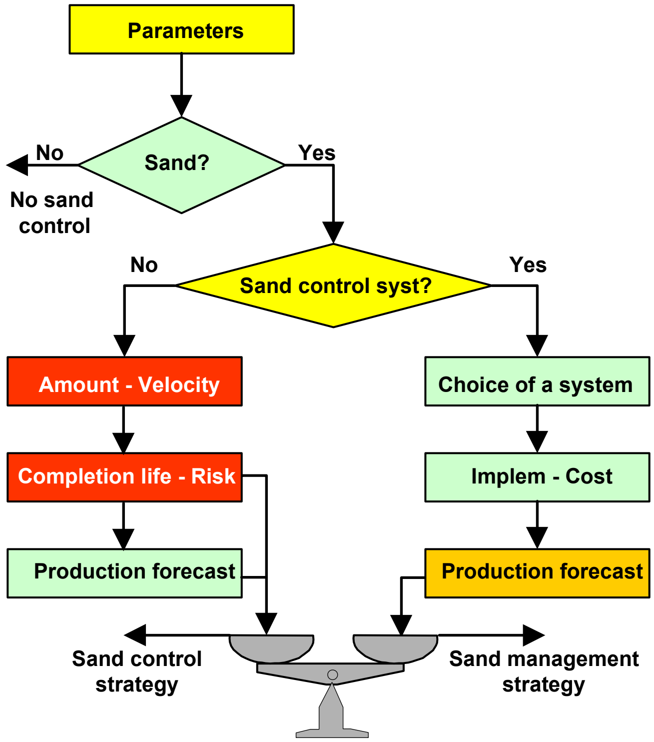

Fig. 10 Decision tree between sand control and sand management strategies

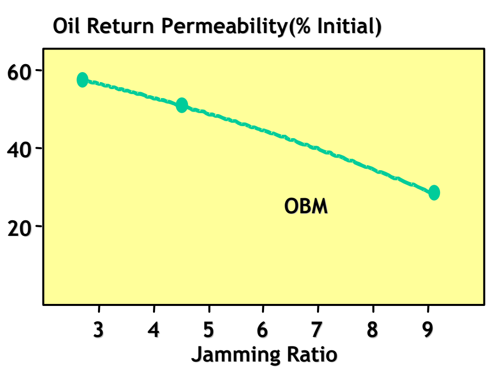

Fig. 11 Impact of Jamming Ratio on the oil return permeability (lab test)

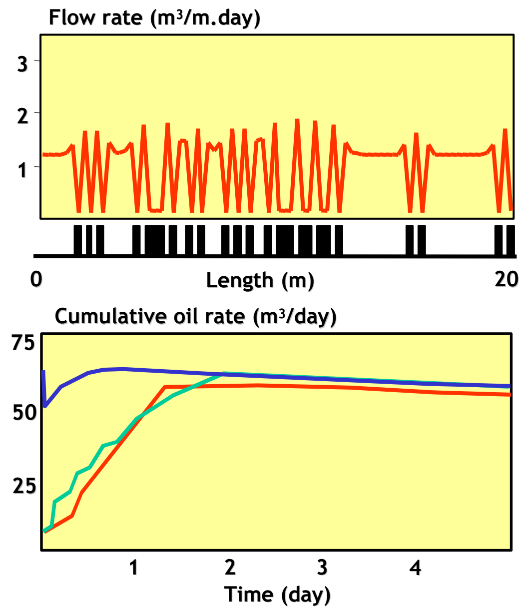

Fig. 12 Simulation of natural well clean up using the ATHOS IFP software

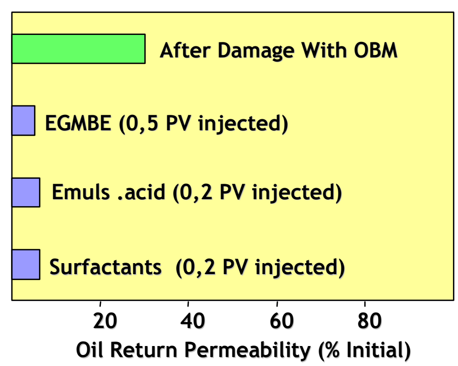

Fig. 13 Results of lab test after treatment with various cake breakers

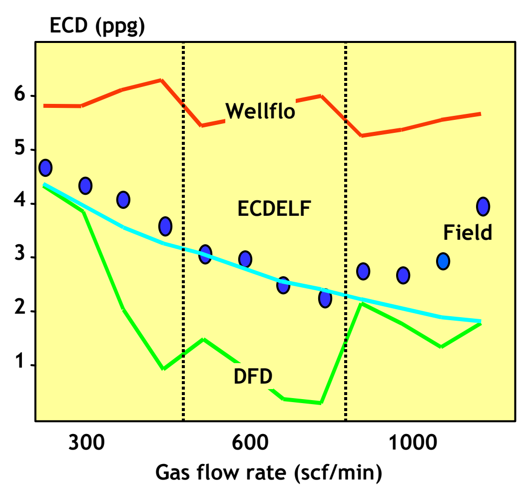

Fig. 14 Validation of ECDELF (TFE), DynaflowDrill and Wellflo on field tests performed with nitrified water.

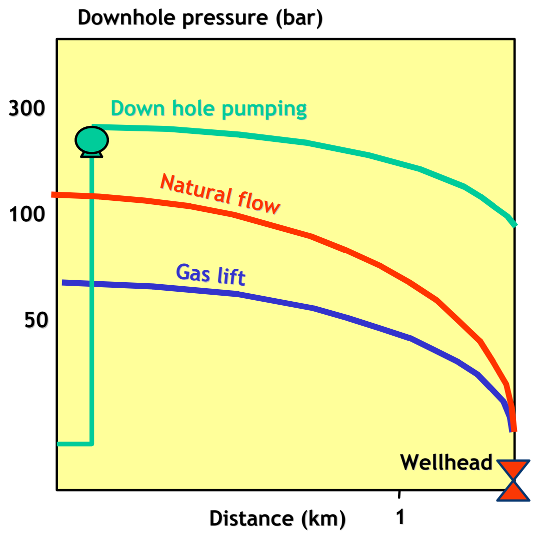

Fig. 15 Comparaison of efficiency of downhole pumping with artificial lift.

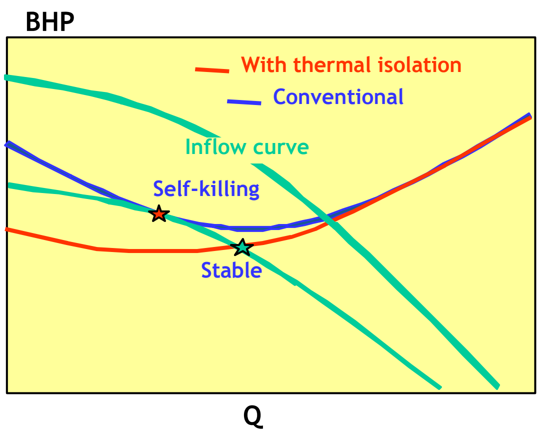

Fig. 16 The THERMOLIFT concept

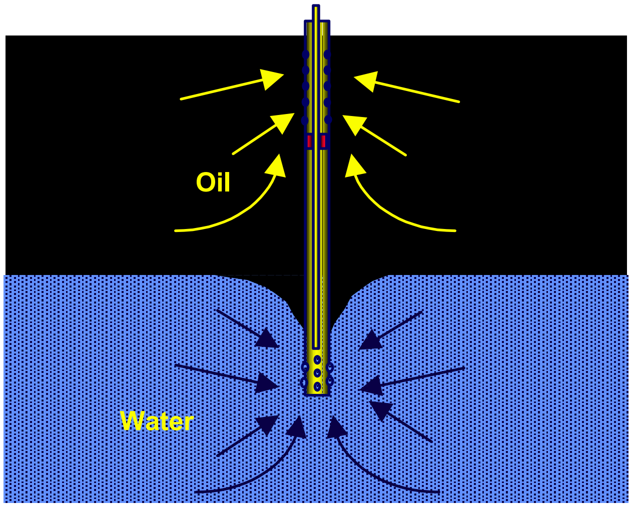

Fig. 17 Water sink concept

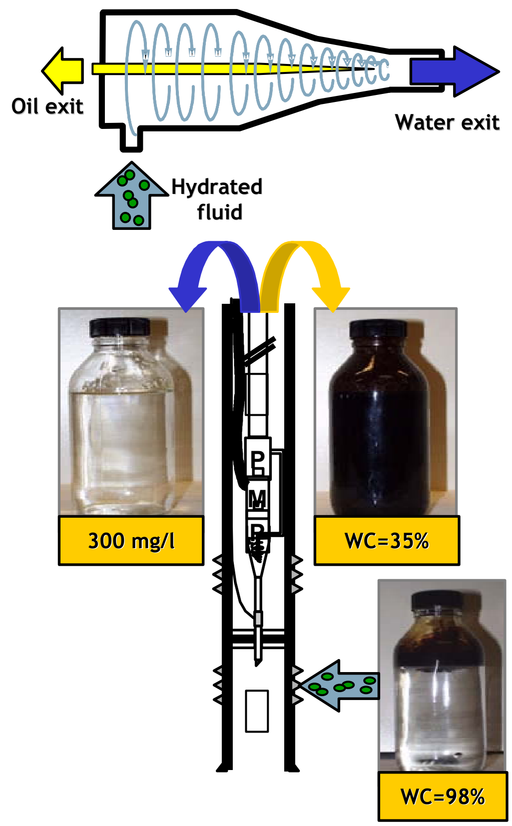

Fig. 18 Down hole separation test on Lacq 90 Using static cyclones

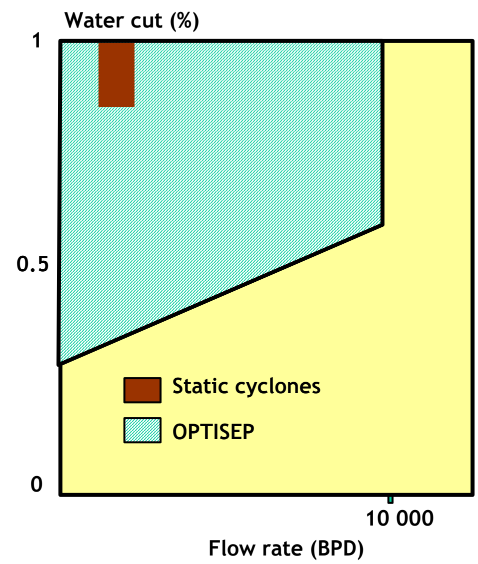

Fig. 19 Comparison of application domain ff static and dynamic cyclones

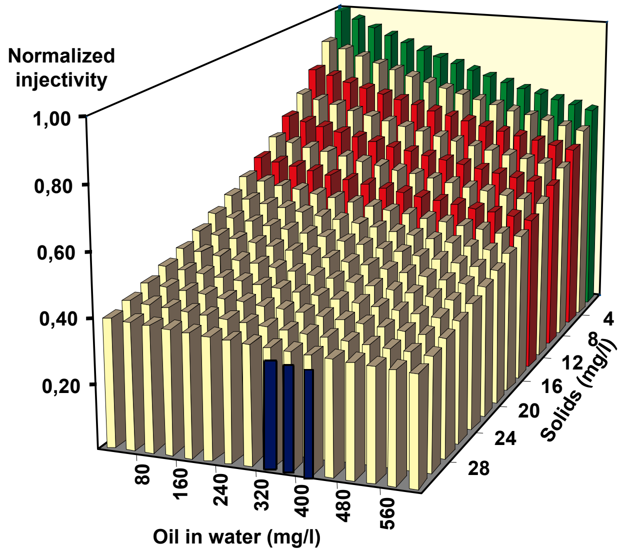

Fig. 20 Impact of solid particles and oil content on injectivity (data base issued from the PWRI JIP)

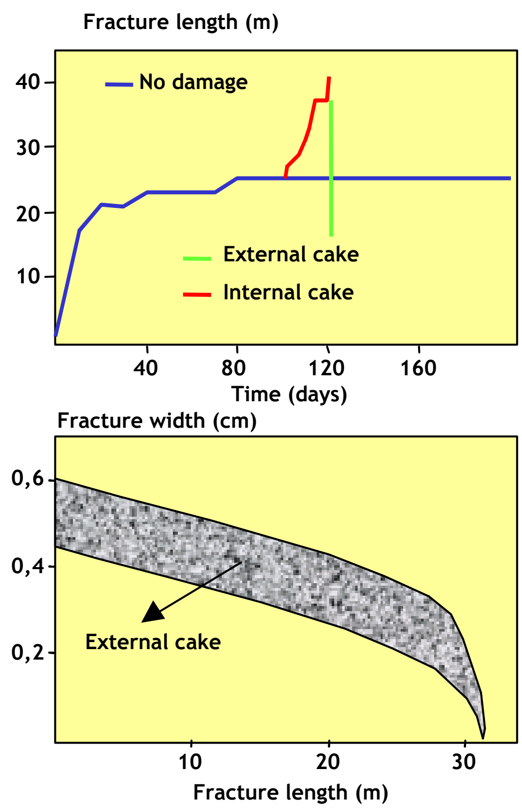

Fig. 21 Example of simulation obtained with the HYDFRAC PWRI model

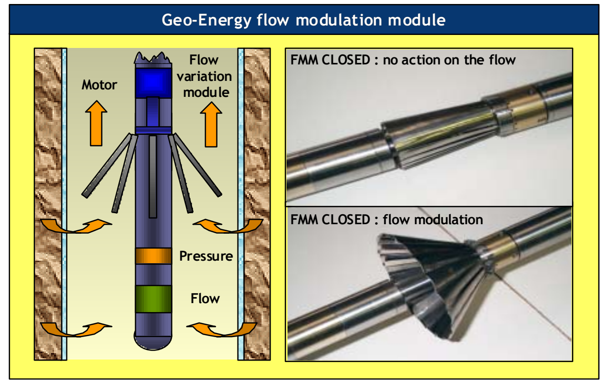

Fig. 22 Flow modulator to be used to generate downhole sinusoïdal pulse