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Reservoir management optimization: case study of an oil rim located in the Gulf of Guinea comparing dynamic simulation of low cost smart wells with conventional wells

By

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A report submitted in partial fulfilment of the requirements for the MSc and/or the DIC.

September 2011

DECLARATION OF OWN WORK

DECLARATION OF OWN WORK

I declare that this thesis:

Reservoir management optimization: case study in the Gulf of Guinea comparing dynamic simulation of low cost smart wells with conventional wells designs

is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and/or with appropriate acknowledgement given.

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Reservoir management optimization: case study of an oil rim located in the Gulf of Guinea comparing dynamic simulation of low cost smart wells with conventional wells

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Abstract

Edem is a green oilfield discovered in the late 70's. As part of the "Alternances deltaiques", this field is composed of stacked multi-reservoirs. Following a full field study, a thin oil rim (S7.5) with an oil column of 16 meters was proved to have a potential of 41Million barrels. S7.5 is overlain by a gas cap and underlain by a limited aquifer. The production of this type of thin oil rim presents two kinds of challenges: high gas production and early water breakthrough. Experience from neighbouring fields such as Kita where excessive gas production regularly leads to processing facilities shut-off, highlights how crucial it is to optimize the oil production while maintaining the reservoir energy. To optimize the oil production of this small size reservoir, the impact of deploying smart wells in this field was investigated.

This paper presents the results of a case study of reservoir simulation that compares the production of smart wells with the production achieved with conventional wells. With the objective of quantifying the value added of smart well solutions, two strategies were compared; one that can be qualified as a smart field where only smart wells are implemented and the other where only conventional wells are used. In both cases, the field development plan was kept unchanged; the only variable was set at the completion string.

These simulation studies were performed with Eclipse (SIS). The smart wells responses were modeled using the multi-segmentation methodology to mimic the complex well architecture behaviour. Numerical reservoir simulations were performed over the 20-year field life and show a great impact in the oil recovery. Indeed, the oil production increases by at least 50%, the gas production decreases by 18% and the cumulative water produced is cut by 30%. Beyond these volumetrics values, the economic impacts were studied. Deploying smart wells will create an increment in the internal rate of return greater than 10% and, the net present value of the project can be doubled in the base case scenario.

Introduction

A smart well is a well equipped with a completion system that has two functions. It can exert a selective control of incoming / outgoing flow from/to a particular interval of the reservoir and it allows real-time down-hole monitoring at all levels of the drainage area within the reservoirs. Therefore, the smartness comes from the ability of the operators to make the right decisions based on the numerous data gathered during the monitoring.

A wide range of smart completions were developed this last decade from the simplest to the most complex as illustrated by Gao and Rajeswaran (2007).The cost of which will directly depend on the level of technology employed. In the objective of quantifying the benefit of deploying smart wells in the specific case of Edem, this thesis will provide a case study comparing the reservoir simulation of low cost smart wells with the reservoir simulation of conventional wells. In this discussion, a smart well is defined as a well that is equipped with pressure – temperature gauges and flow control devices.

The project is undertaken with the following steps:

- Review and quality check the existing static model by analyzing the datasets detailed in Appendix B.
- Review and interpret the available dynamic datasets to build a dynamic reservoir model
- Compare two field development plans by optimization of:
    1. Conventional wells
    2. Smart wells

Edem Location and Potential

Edem is green field located in the Western end of the Rio Del Rey (RDR) basin. The RDR represents the eastern end of the Niger Delta that is one of the main African petroleum plays. Edem field was discovered in 1977, since then, many studies have been performed but the field still remains unproduced. The reason for this delay is the high uncertainties in the Gross Rock Volume (GRV). With the objective of addressing this major point, 3D seismic was shot and the subsequent studies infer an interesting reservoir potential with a STOIIP estimate of 73 Million barrels in two main reservoirs (P50 for the S7.3 and S7.5). Following this study, the primary objective was defined as the S7.5 where all the analyses were carried out.

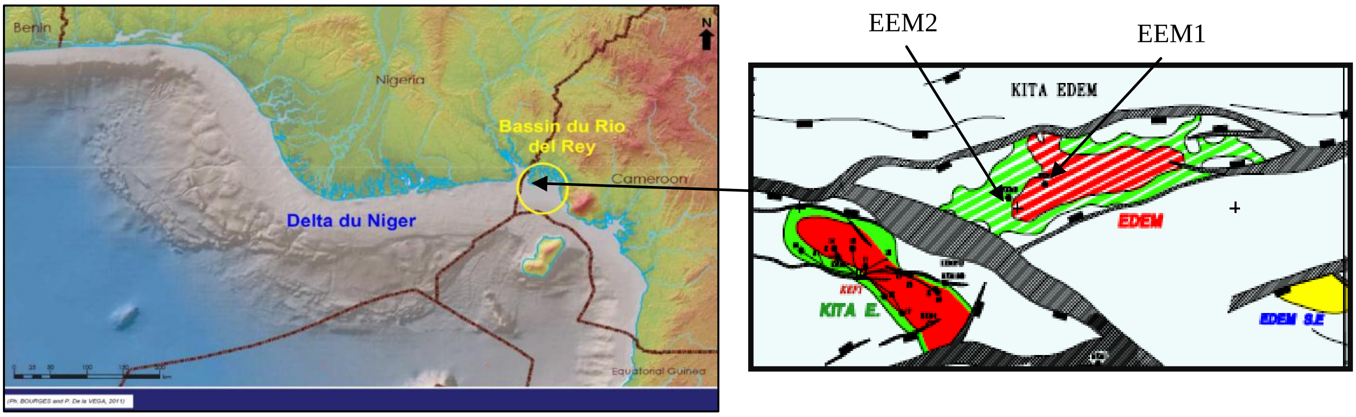

Figure 1 Location of the Edem Field - Rio Del Rey - Cameroon

Edem Petroleum Play

The primary target of this project is in the S7 sands with its oil bearing reservoirs. This formation is young with a deposition estimated from the Miocene (~ 7 to 23 Mas). The S7 belongs to the 'deltaic alternance' series that are composed of seal reservoir pairs. The oil found in this sand is saturated with a presence of large gas caps. The source rock has not been identified yet but is estimated from the Paleocene (~ 55 to 65 Mas).

Literature Review

Smart well solution represents a recent technology in the oil and gas industry. The first intelligent well system called Surface Controlled Reservoir Analysis and Management System was released in the market in 1996 and the first smart well was deployed in August 1997 in Saga Snorre Tension Leg Plateform, North Sea (Norway) (Gao and Rajeswaran (2007)).
Published studies include a broad range of reservoirs types, size and drive mechanisms.
Yeten and Jalali (2001) investigated the optimal placement of wells in a field like Edem that is overlain by a gas cap and underlain by an aquifer of limited extent. Following a comparison of the performance of smart and conventional wells, they demonstrated two main benefits of using smart wells. Firstly, smart completions are optimal in horizontal wells that have high-pressure drop resulting from the low permeability of the reservoir. Secondly, they showed that smart wells would reduce the production of associated gas and water thus increasing the ultimate oil recovery.
Holmes (2001) published a methodology to model advanced wells in reservoir simulation. This approach replicates the nodal analysis used in production engineering to estimate the contribution of each node. The multi well segmentation modelling enables a good modelling of the smart completion behaviour.
Davies (2004) enumerates the reasons why the smart well technology often fails to meet the operators' expectations. Indeed, in their first decade of utilization, these tools were not reliable and their market research was not effective. He highlights the need of providing better upfront design of smart well solutions.
Gao and Rajeswaran (2007) published a literature review on Smart Well Technology. They described the main components of the smart wells technology and reviewed applications of these technologies in the North Sea, Offshore England and in Brunei where the smart wells deployment was a success. They demonstrated how the smart well technology gained in reliability by the introduction of the fiber optic sensors and hydraulic surface control systems. At the time of their report, they counted 300 smart wells systems in the world and highlighted that these wells are becoming the North Sea standard. Their main applications are the water/gas production control and Distributed Temperature Control. (DTC)
Ageh et all (2009) considered the financial aspects of deploying smart wells once the increase in the oil recovery was assessed in a large field located deep offshore Nigeria. Indeed, they demonstrated that deploying smart wells in the base case study will results in 20% incremental reserves resulting in a 50% gain in Net Present Value (NPV) for the project.

Methodology

In the course of this analysis, a smart well is defined as a well that is equipped with smart completion. The benefit of the smart well solution comes from its ability to;

- Control the flow from the reservoir to the wellbore in the case of producers
- Control the flow from the wellbore to the reservoir for injectors
- Monitor the reservoir real time performance

The major reason of selecting smart completion to produce the S7.5 oil rim is to reduce the gas and water production that is assessed in thin oil rims (Razak et al (2011)). Other advantages of using smart completions in Edem are listed as follows:

- Commingled production can be achieved by the regulation of the backpressure at the zones having different permeability thus variable drawdown.
- Cross flow between zones of layers if different pemeabilities can be reduced or eliminated
- Throughout the life of the well, the GOR and the water cut are very likely to increase and this phenomena can be controlled by adjusting the downhole chokes
- When applied to injectors, the water and gas rates can be adapted thus reducing the number of wells to be drilled

A proposed smart system configuration is displayed in Figure 4

Smart Completions Components

Producers

The main smart well component is the Inflow Control Device (ICD) commonly called an equalizer. This completion device distributes the inflow uniformly along the length of the wellbore regardless of location and permeability variations. Five ICD are designed to be placed along the wellbore in the sweet spots. They will restrict the flow by inducing an additional pressure drop. The wellbore pressure drop will be evened out and thus produce an evenly distributed flow profile along the well. An ICD is composed of:

- Sand control screens: this will enable filtering the produced sand to prevent eroding or plugging the completion string. This well screen has a filter section in addition to a flow restrictor configured in such a way that all the filtered fluids flow through the flow restrictor.
- Flow restrictors that force the fluid to change momentum in order to regulate the pressure of the fluid coming from the wellbore.

The major application of these devices is to improve the sweep efficiency over the lifetime of the well. The main advantage of using ICDs in horizontal producers is to eliminate the non- uniform flux profiles due to formation heterogeneities and frictional effects in the wellbore. In the case of Edem the formation heterogeneities will play a major role as the permeability distribution was proven to be very broad. This will imply that a high drawdown variation will occur along the wellbore.

The increasing complexity of the smart wells alters their reliability as demonstrated by Davies and Birch (2004). One of the main causes of these counter-performances is the proactive control on the completion that is impletemented in many fields. In this matter, Yeten (2003) demonstrated that though this procedure is the best in theory; it appears not to be very applicable in practice. Consequently in this field, passive ICD were designed to be used, no automatic shut-off procedure was considered. When needed, shut-off will be performed manually by hydraulic surface control. Several types of remote control mechanisms are available in the oil and gas industry as described by Zhu and Furui (2006), one of the cheapest and simplest options is remotely controlled valves that enable to isolate the production from a selected interval using adjustable switches. In this study, the selected mechanism has four positions that are open, closed and two intermediates. This flow control device was deemed adequate for the S7.5 reservoir where choking capabilities will be required over the lifetime of the wells.

Injectors

Similarly to the producers, the equipment selected for the injectors has the option for the flow to be controlled from the surface. This feature will allow reducing the slick-line intervention cost and equipment. The completion string is composed of:
<u>Flow control valves</u> that can be set in four positions: fully open, closed and two intermediate positions that will enable operators to adjust the flow. The actual position of these vales will be known at all time and can be hydraulically set from a surface pressure unit.
<u>Gauges</u>: will provide a real time monitoring of the pressure and temperature in the tubing and annulus. From these measurements, water/gas injection rates can be set for every reservoir layer. Pressure monitoring will ensure that the formation integrity will be respected at all times by not exceeding the fracture pressure.

Figure 2 Hydraulic surface control unit where data are collected and sent to the operators for interpretation

Figure 3 Data are interpretated and actions are taken tol improve oil production. Open and close commands are sent to the hydraulic control unit that commands the appropriate downhole chokes.

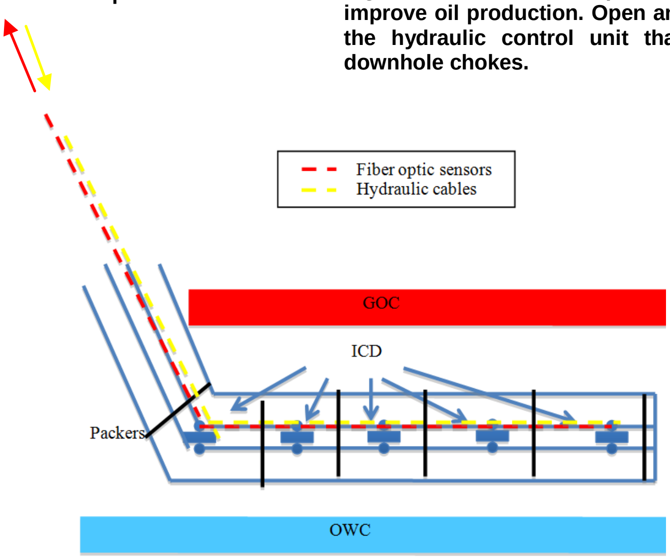

Figure 4 Smart wells configuration

Smart Completions Modelling

To simulate smart completions, the multi-segment model illustrated in Figure 5 was used. Each segment is connected to one or more reservoir 3D grid cells. The segments have two components; a node where the variables are calculated and a flow path representing the connectivity between segments. At the node, four equations are solved; three material-balance, one for each phase and one pressure drop equation. The resolution of these equations gives the values of the pressure, saturation and flow rate.

Each ICD is represented by a small segment perpendicular to the tubing-segments; all fluids coming from the reservoir are forced to pass through these ICDs. The ICD's responses are modeled by adding extra terms in the equation that governs the pressure drop across the valves. These terms are calibrated following laboratory experiments. In the model, the contributions of the various zones are combined and the flow in the annulus is neglected. The way the fluids flow between the grid cells and the tubing / annulus to the surface is illustrated in Figure 6.

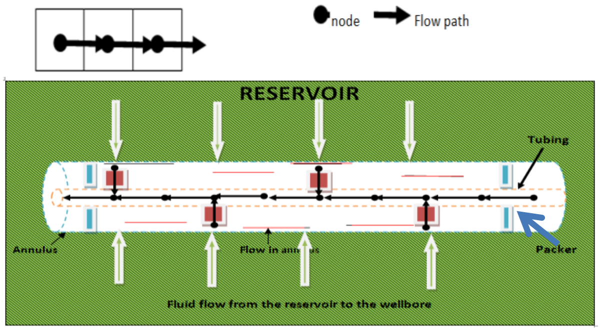

Figure 5 Multi-segment modelling in Eclipse

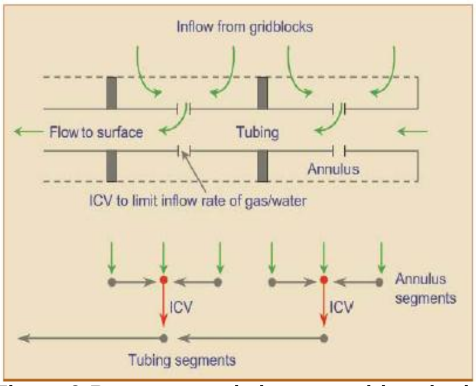

Figure 6 Remote completion control in a horizontal well and the corresponding network of well segments - SPE 72493

Reservoir Background

Geophysics and Geology

The geophysics interpretation performed by Djallo (2010) allowed delimiting Edem field approximately as a rectangle of 8Km by 2Km. Five main faults were picked, inferring that the field is closed by a series of faults. In the reservoir of interest (S7.5), the depth to OWC was estimated by horizontal stacking with an error of 8m. (Appendix C)

The geology of the Rio Del Rey basin was studied by Subra et all (1988), Le Dluz et all (1996) and Blin (2011). They demonstrated that the major petroleum play of this region appears from the Paleocene. It is characterized by a regressive fluvial-sequence composed by sands and shales.

Oil Field Play

The source rock in the Rio Del Rey Basin has not been identified yet. However, the Paleocene shales present the best potential as source rocks. Kerogen types II and III were defined as being the organic matters that originated the accumulations found in this basin. The geochemistry of the oil indicates a domination of a marine origin with two types of contributions: continental next to the coast and a mixture between fluvial and marine in the open sea areas.
Numerous seal reservoir pairs are found in the AGBADA formation. The thickness of the sands layers is not constant over the field and some areas have better sand units than others. Nine reservoirs zones S1 to S9 were identified across the basin.

Analog

From the geology point of view, Kita was identified as the analog of Edem. Indeed, the two reservoirs were deposited at the same period. The stratigraphic similarities of the two fields were demonstrated by the well to well correlation comprising 13 wells in Kita and 2 wells in Edem presented in Appendix D.

Quantitative Wire-Line Interpretation

Two sets of quad-combo wire-line data were used to perform the petrophysical interpretation during this project. The detailed analysis is presented in Appendix E. The results of the analysis were consistency-checked with the geological interpretation done at rig-site and with the regional petrophysical geology. The studies carried out can be summarized as follows:

<u>Fluid distribution</u>: In Edem, all the reservoirs above the S7 were proven to be water wet. The hydrocarbon zones were identified in the S7 sands and the absence of deeper reservoirs is suggested. The predominant hydrocarbon found is the gas that is present in clean and thick sand units. The oil, when present, is saturated with a presence of large gas caps.

<u>Reservoir lateral discontinuity</u>: Over the wells, a lateral discontinuity in the reservoirs properties was observed Indeed, EEM1 identified thicker and cleaner reservoirs than EEM2. (Well locations are shown in Figure 1.) This heterogeneity confirms the geological model where a prograding pattern was observed. The reservoir quality reduces when going to the west.

<u>Petrophysical properties</u>: The petrophysical interpretation detailed in Appendix E illustrates that the S7 sands holds a good potential with an average effective porosity of 23% and initial hydrocarbon saturations of 30%.

<u>Primary target</u>: The S7.5 was identified as the primary target as the delimitation of this reservoir offers a higher oil accumulation.

<u>Contacts</u>: The depths to contacts represent the main uncertainty in the GRV estimations. With the well path and geometry of the reservoir, it was not possible to estimate these contacts by the petrophysical interpretation. The depth to OWC was determined by the geophysics interpretation in the S7.5 detailed in Appendix C, and the other contacts were estimated by averaging the various depths obtained. The depths that were estimated are detailed in Table 1.

Table 1 Contacts in Edem field derived from the petrophysical interpretation - RDR - Cameroon

S7.5	EEM1	EEM2
Gas up to (m TVDss)	1440	-
Gas down to (m TVDss)	1449	-
GOC (m TVDss)	1452	
Oil up to (m TVDss)		1456
Oil down to (m TVDss)		1463

Core Analysis

Previous studies performed by TEPC engineers allowed identifying 3 main rock types in Kita listed in Table 2. Core analyses establish the poro-perm relationship and the J-function detailed in Appendix E. Wettability analyses enabled estimating the maximum recovery factor and identifying the reservoir as being mixed wet for dynamic studies.

Table 2 Listing of the rock-types encountered in Kita - RDR - Cameroon - After studies performed by TEPC

	Rock type 1	***Rock type 2***	***Rock type 3***
S_{wi}	15%	25%	40%
PHIE	Greater or equal to 25%	Between 17% and 25%	Less than 17%
Kv/Kh	0.1	0.05	0.001
Comments	Predominant in Kita	Predominant in Edem	Affected by presence of silt

The porosity distribution map in Edem shows that the sand bearing reservoirs in Edem has the same porosity distribution as rock type 2. Consequently, this rock type characteristic was used in all the studies derived from the cores analyses. The permeability values infer that Kita field has a broad permeability distribution with a good average permeability in the order of 300mD-10D.

Static Model Construction

In the course of this thesis, the following reservoir static model was constructed. The rock and fluids properties of the two exploration wells, the formation tops, the reservoirs bounds and the faults were integrated into the geo-model.

Structural Framework

The model framework was constructed following the orientation of the South-West / North-East bounding faults. The purpose was to keep the dip and strike orientation of the faults. In both models, the five major faults were imported.
The reservoir boundary was simplified as a polygon of 8km X 2km. Both 3D models grid orientation was kept to the South-West / North-East direction to reflect the orientation of the delimitation faults. Grid cells of 75m X 75m were chosen, as they were deemed most suitable to capture the horizontal heterogeneities within the reservoirs.

Reservoir Layering

A very fine layering was performed in order to capture the vertical heterogeneity of the reservoirs. No zonation was made in the static and dynamic models. Layers widths were reduced to 1m to improve the vertical resolution. The static model comprises 400 000 grid cells.

Facies Modelling

Two facies were considered when constructing the model: sand and shale. The truncated Gaussian with trends was used to scale-up the facies log across the field. This algorithm allows a better modelling of the prograding pattern of the reservoirs as discussed in Appendix D.

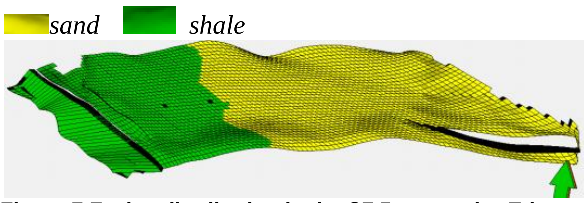

Figure 7 Facies distribution in the S7.5 reservoir - Edem

Petrophysical Model

The rock properties discussed in Appendix E were integrated into the geo-models. The spatial distribution of the water saturation shown in Figure 8 was derived from the J-function. The porosity model in Figure 9 was generated using the Gaussian random function with a facies conditioning. The permeability distribution was built on the poro-perm relationship. The Net to gross was defined for each 3D grid cells by applying the regional cut offs, cells with Sw ≤40% and PHIE ≥17%, were set to 1, otherwise NTG values were set to 0.

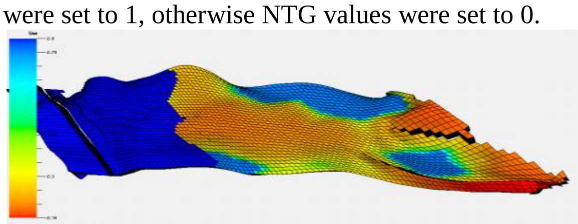

Figure 8 Sw distribution in the S7.5 - Edem

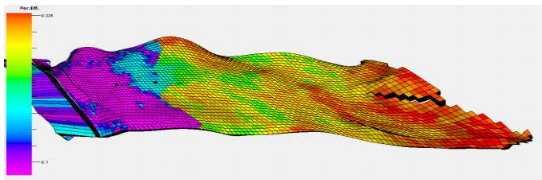

Figure 9 Porosity distribution in the S7.5 – Edem

Reservoir Fluids Properties

The reservoir fluids properties represent a major uncertainty in this study. The oil samples obtained from Edem were taken by the FIT method and were contaminated by sand and mud filtrate. Moreover, no quality check was performed on the samples as only one sample was taken for each depth.

Oil Properties

The PVT models of the oil present in the two reservoirs were built from the FIT performed in EEM1 using the standing correlations (Standing (1947)). The results are detailed in Table 3. Because of the high level of uncertainty of the oil properties, the values obtained were compared to the oil properties present in the Kita and Kole. Kole is an oilfield located in the center of the RDR. It represents also a suitable analog as the initial pressure in this field is in the same range the pressures in the S7.5 and the oil present in this field is saturated with a presence of gas cap.

Table 3 Summary of the S7.5 oil properties

Oil properties	KITA	S7.5	KOLE
Oil formation volume factor (rb/stb)	1.44	1.27	1.21
Oil viscosity (reservoir conditions) (cp)	0.44	0.45	0.97
Oil density (standard conditions) (kg/m^3)	820	840	853
Gas oil ratio (scf /stb)	750	600	360
Compressibility (bar^{-1})	5.00E-04	5.00E-04	5.00E-04
API (°)	41	37	34
Bubble point (bars)	223.4	135	121

Gas and Water properties

The gas properties in were found to be similar throughout the RDR. The gas was found to be of good quality with a percentage of methane greater than 88% and negligible impurity content.

No water sample was taken in Edem during the exploration campaign. Consequently, the water properties were estimated from the analog field Kita where the formation water salinity is estimated at 20 000ppm. The water PVT model described in Table 4 was derived from this measurement.

Table 4 Formation water properties and gas properties in the Kita Field

Water Properties (From Kita field)	
Salinity	20 000 ppm Cl-
Water density	1009 Kg / m3
Water Formation volume factor	1.01

Gas properties in Kita	
Bgi	0.005203
Gas specific gravity	0.66

Models Quality Checks

The reservoir model was quality-checked to ensure that it honours the geological model. The facies and petrophysical models passed the visual screening and were assessed to reflect the prograding pattern.

STOIIP Estimates and Related Uncertainties

The static model was used to perform volumetric calculations. A probability density function was built on the basis of the major uncertainties that were identified over 1000 Monte Carlo simulations on each variable. The results of these calculations summarized in Table 5 show that the Edem field holds interesting oil potential with a STOIIP of 41 Million barrels in the S7.5. The tornado chart in Figure 10 derived from the uncertainty analysis illustrates that the main uncertainties are the GRV (GOC & OWC) and the NTG. Appendix F details the range of parameter value used to perform this uncertainty analysis.

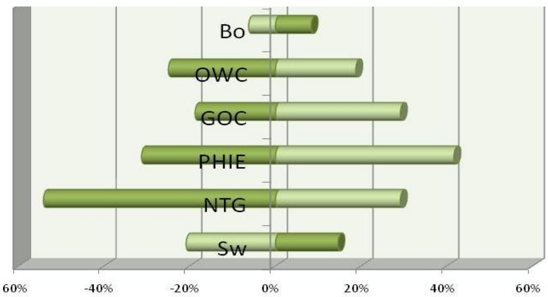

Figure 10 Tornado chart describing the impact on uncertainties in the STOIIP variation - S7.5 - Edem

Table 5 S7.5 oil rim potential - Edem

Reservoir	STOIIP (Million barrels)			Reserves (Million Barrels)		
S7.5	P90 : 30	P50 : 41	P10 : 66	P90 : 10	P50 : 20	P10 : 30

Reservoir Dynamic Model

The S7.5 static model was upscaled to build a reservoir dynamic model. The 400 000 cells in the static model were reduced to 20 000 cells in the dynamic model. This process resulted in a loss of resolution, however, in the vertical direction, the thickness of the cells were reduced by a factor two in order to keep the vertical heterogeneity within the reservoirs.

Folllowing this up-scaling, the dynamic model was quality checked to ensure that it honoured the static model. The QC was done first by visual inspection as shown in Figure 11 and Figure 12 where the permeability distribution in the two models is illustrated. Then the permeability distribution between the models were quantitatively checked by simulating the production of a well over 20 years field life in each model, Figure 13 illustrates the discrepancy between fluid production in the two models. The difference between the oil produced is negligible. As regards the water production, more water is produced in the static model as a result of the smaller grid cells. The reasons for the decreased water production are unclear.

Once initialized the volumes in place computed by the dynamic model were confirmed to match the volumes obtained in the static model with a change in STOIIP of 4%. And finally, the two exploration wells were confirmed to lay in the appropriate hydrocarbon zones. Figure 14 and Figure 16 confirm that EEM1 is in the gas zone and EEM2 is in the oil rim.

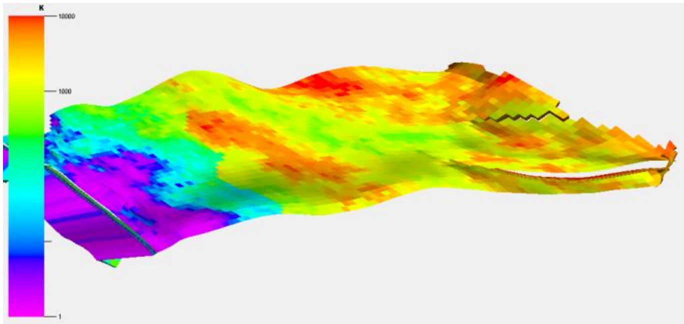

Figure 11 Permeability in the static model - S7.5 - Edem

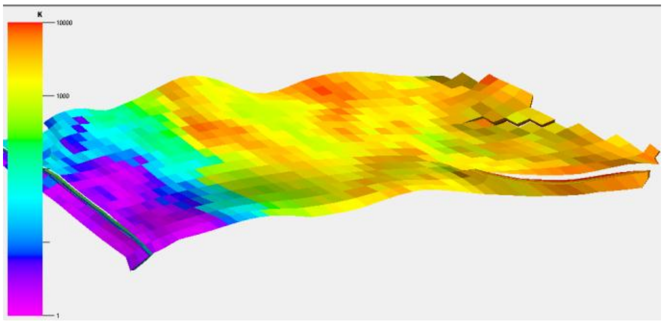

Figure 12 Permeability in the dynamic model - S7.5 - Edem

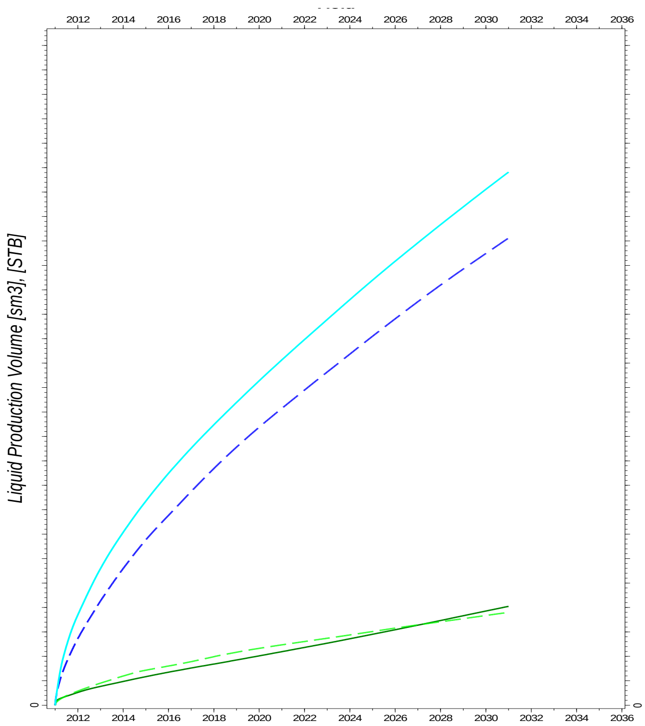

Figure 13 Comparison of fluid production between the static and dynamic models - S7.5 - Edem

Symbol legend
Oil production cumulative QC-Onewell-Static
Oil production cumulative QC-Onewelldynamic
Water production cumulative QC-Onewelldynamic
Water production cumulative QC-Onewell-Static

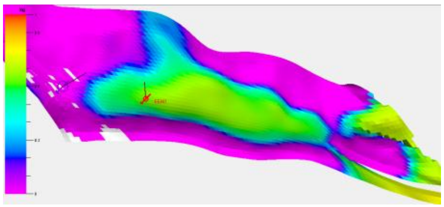

Figure 14 Sgi distribution after initialization of upscaled model - S7.5 - Edem

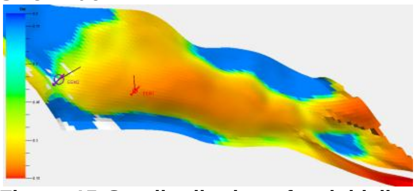

Figure 15 Sw distribution after initialization of upscaled model- S7.5 - Edem

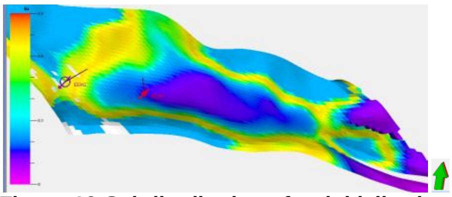

Figure 16 Soi distribution after initialization of upscaled model - S7.5 - Edem

Field Development Strategy

The average recovery factor in the Rio del Rey basin was estimated at 30% under primary recovery and up to 50% with secondary recovery by water injection. The field development strategy for Edem was optimized to achieve these targets.
Experience from the analog field Kita leads to the selection of gas cap expansion as main drive mechanism. To provide additional energy to the reservoir crestal gas injection was considered. This was confirmed by the analytical analyses carried out to predict the reservoir future performance detailed in Appendix H. Therefore, in the course of this study, injectors will be required to be drilled in the S7.5.
Re-injecting the produced gas into the gas cap is a novel approach in the Rio Del Rey Basin as no gas injector exists yet in this basin. The produced gas is either flared or used in the gas lift operations.

Producers were designed to be horizontal as these well paths were proven to optimize the reservoir drainage. In the course of this study, efficiency of horizontal wells and vertical wells were compared. Vertical wells provided 2.5% recovery whereas a horizontal well allowed achieving 11% recovery. Accordingly, 3 horizontal wells were placed in the S7.5 as shown in Figure 17. They were placed in the low part of the oil column to delay the gas cap production. The maximum length of the horizontal wells was maintained below 1000m as per the standard horizontal drains drilled in the RDR that are around 300m. In Edem East, no producer was planned because of the high uncertainty as regards the oil potential of this part of the field. The three proposal wells are EEM3 in the North, EEM4 in the West and EEM5 in the South.
Figure 18 shows how one gas injector was placed at the crest of the structure in order to inject gas away from the GOC. In the simulation studies; this gas re-injection provides additional energy to the gas cap and ensure pressure maintenance of the field.

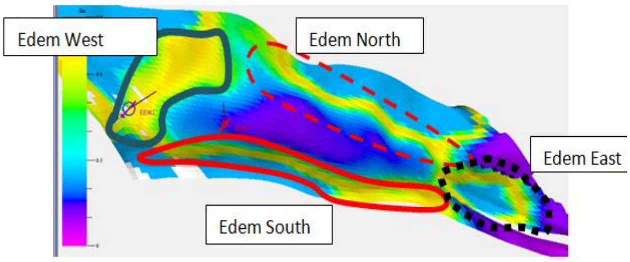

Figure 17 Placement of oil producers - S7.5 - Edem

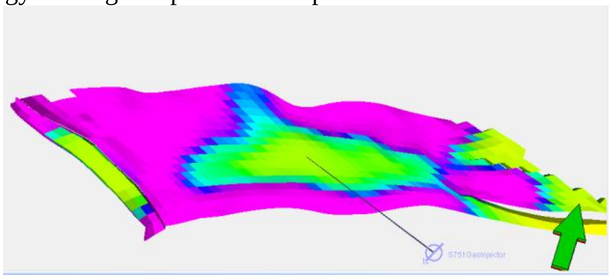

Figure 18 Placement of the gas injector in S7.5 - Edem

Results

The Field Development Plan described above was simulated over 20-year field life in Eclipse. The plateau rate was set at 6000bbl/d based on an annual production rate of 0.05X STOIIP. In this comparison, the only variable was the completion technology; all the other parameters involved in the reservoir optimization such as the drive mechanism and, well path were kept unchanged. To ensure the robustness of the results, P10, P50 and P90 cases defined in the static model were simulated. These scenarios were based on the location of the contacts. The results that were achieved are summarized in Table 6 and illustrated from Figure 19 to Figure 25.

Oil Production

In the S7.5 reservoir simulation, the use of smart wells shows positive impact. In terms of daily oil production, good improvement is achieved as shown in Figure 19 where the P50 case is illustrated. Indeed the conventional completions do not sustain the plateau rate to a period greater than 2 years; whereas the smart completions allow extending this plateau duration by an additional 3 years, resulting in a significant increase in the oil production forecast at the end of the field life shown in Figure 20. A 50% increase in the oil recovery from 12 Millions bbls to 18 Millions bbls is observed. This represents an increase from 30% to 44% oil recovery in the P50 model, and a 15% increase in the reserves. Figure 21 and Figure 22 illustrate the robustness of the simulation results. In the P10 and P90 scenarios, an increase of the oil production was similarily observed. In the P90 (low case with lower reservoir volume), a 50% increase in the oil recovery is obtained with an oil production that varies from 8 Million bbls to 12 Millions bbls leading to an increment in the recovery factor from 27% to 37%. The P10 (high case with highest reservoir volume) has the greatest increase of 60% in oil production with the cumulative oil production from 17 Millions bbls to 27 Millions bbls resulting in an increment of 15% in the reserves.

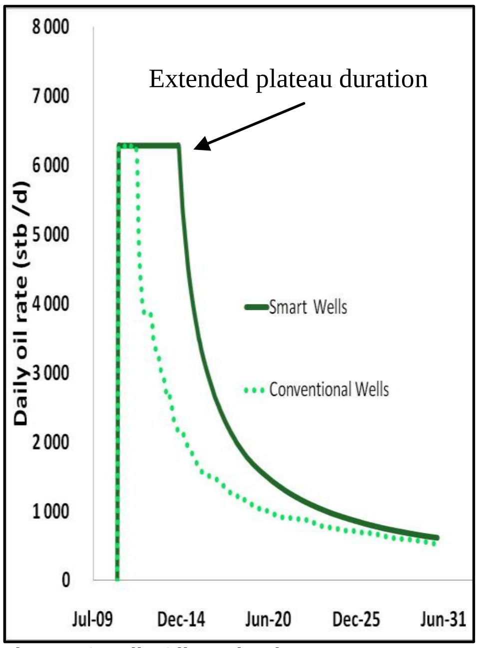

Figure 19 Daily Oil production– smart vs conventional – P50 – Edem

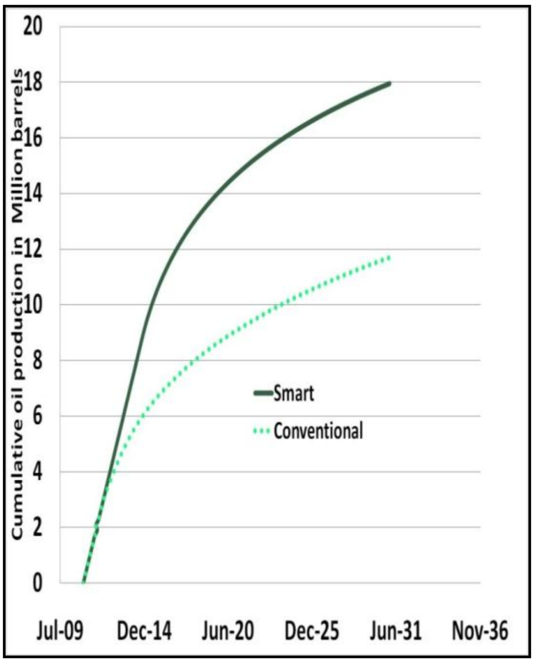

Figure 20 Cumulative Oil production– smart vs conventional – P50 – Edem

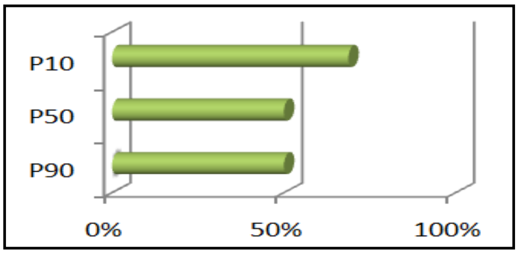

Figure 21 Percentage Increase in oil cumulative production when using smart wells - S7.5 - Edem

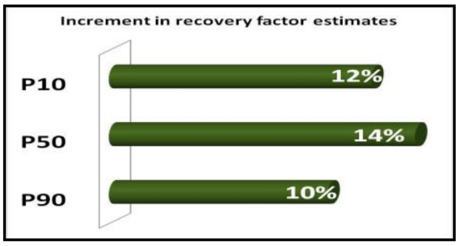

Figure 22 Increase in recovery factors when using smart wells - S7.5 - Edem

Water and Gas Production

Smart wells also impact the gas and water production.Figure 23 and Figure 24 illustrate how the water breakthrough is delayed, and at the end of the field life the cumulative water production is reduced by 30%. Free gas produced decreases when using smart well technology by 20% in the P90 and 60% in the P10 as shown in Figure 25. The general trend in the associated gas and water production is that the larger the reservoir volume, the higher the reduction in free gas production and water cut.

In smart wells, the improvement of the oil production and decrease of water and gas production are the results of the actions of flow controllers. By regulating the pressure in the vicinity of the wellbore, the flow control devices enable a uniform rise of the aquifer and the uniform fall of the gas cap. The thicker the oil column, the longer it takes for fluids in the aquifer or gas cap to reach the wellbore. In the smart configuration, the oil phase will flow for longer before the gas and water breakthrough as the oil saturation will decrease slower. In conventional wells, the pressure is not regulated along the wellbore, consequently, the drained intervals with high permeabilities will have higher drawdown and the oil saturation will decrease rapidly near those areas resulting in earlier water and gas coning.

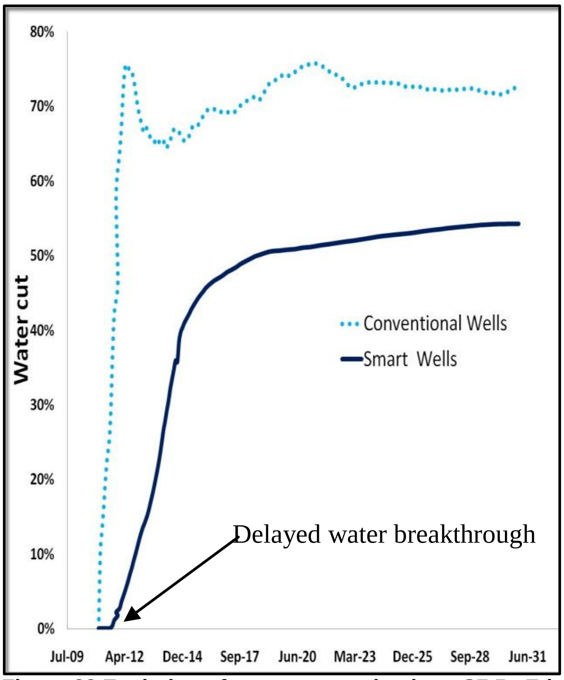

Figure 23 Evolution of water cut production - S7.5 - Edem

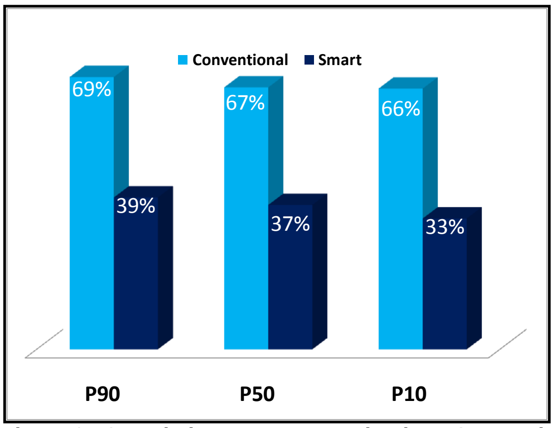

Figure 24 Cumulative water cut production - S7.5 - Edem

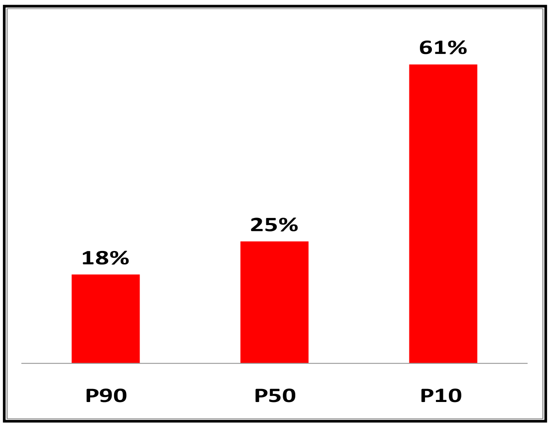

Figure 25 Decrease in gas production when using smart wells - S7.5 – Edem

Table 6 Production estimates derived from 20 years field life simulation of the S7.5 - Edem - RDR - Cameroon

S7.5	Smart wells			Conventional wells		
OIl production (MMbbls)	P90 : 12	P50 : 18	P10 : 27	P90 : 8	P50 :12	P10 : 17
Recovery factor	37%	44%	41%	27%	30%	26%
Gas production (MMMm^3)	P90 : 3000	P50 : 2900	P10 : 2400	P90 : 2700	P50 :2800	P10 : 2400
Water production (MMbbls)	P90 : 7	P50 : 10	P10 : 13	P90 : 18	P50 :24	P10 : 31

Economics

Evaluating the economics is one of the key factors in deploying smart wells technology[Gai (2002)]. Indeed, although the increase in the oil production can be assessed, deploying smart wells solutions can be so expensive that the economics are not favourable for their use.

Figure 26 and Figure 27 illustrate that deploying smart well solutions in Edem in the base case development enables to double the Net Present Value of the project; subsequently the Internal Rate of Return will gain 29%. Likewise, the P10 and P90 scenarios show increased NPV and IRR but not in the same order than the P50. This is because the economic optimization was performed solely on the base case.

These calculations were based on an industry standard excel sheet. This spreadsheet is used to calculate the economics of projects having the same partners as Edem. The parameters that were considered in this analysis are as follows:

- Capital expenditure:
    - The additional costs of smart completions were estimated to 2 million USD per well. This pricing was estimated based on proposals given by services companies (Pinson (2008)).
    - No surface facility was planned to be constructed in Edem. Instead, a 3km pipeline was forecasted to connect the two platforms and convey the live oil to Kita. In Kita, the existing installations can handle the oil production forecasted but the separator and the export pipelines need to be upgraded and these extra costs were integrated in these economic studies.
    - Gas injection system and associated compressor will be installed in Kita. This will enable use of the gas produced in Kita in the event where the produced gas from Edem will not be sufficient to ensure pressure maintenance in Edem.
- Operational costs are estimated per barrel produced at a fixed value of 7 USD per barrel. This cost includes workover operations; pumps installatio, maintenance in addition of gas lift operations.
- Discount rate of 12%
- Price per barrel was fixed at 75$. No sensitivity was performed on the oil price.
- Risks assessment: experience with completions in the northern part of the Rio Del Rey Basin highlight few failure risks for conventional completions because of the favourable environment dowhnole areas. Likewise, these failures were deemed negligible in the low cost smart wells options considered in this study. The highest risk was tracked at the hydraulic and fiber optic cables that could be damaged while running the completion or while setting the wellhead. To

mitigate this risk, while installing the completions and the well head structure, special emphasis will be put onsite to ensure that the integrity of the cables are respected.

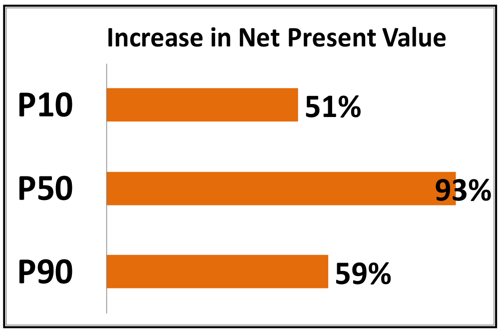

Figure 26 Increase in NPV when using smart wells – S7.5 - Edem

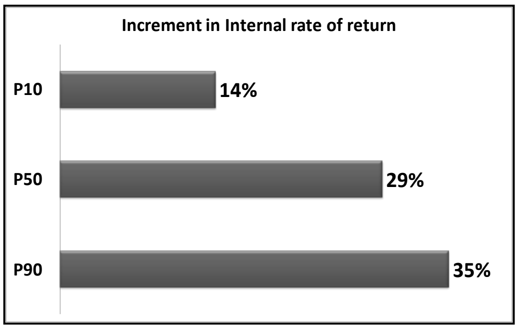

Figure 27 Increment in IRR when using smart wells - S7.5 – Edem

Related Uncertainties

The impact of uncertainties was assessed in the tornado chart displayed in Figure 28. The base case is the conventional wells that represent the standard in the Rio del Rey Basin. Apart from the smartness of the completion, parameters that have the most impact in the oil production are the STOIIP, followed by the size of the gas cap.

Gas cap: the base case was built assuming that the gas cap will provide the same support as the one in the analog field Kita. The presence of a gas cap was confirmed in the S7.5. The two main uncertainties are related to its size and connectivity to the oil column. In the logs, it was identified that the gas cap is of a greater size than the oil column, if this proportion happens to be respected then, a gas cap of 1.2 or 2 times the oil column can be expected. The low case was built with a gas cap of half the size of the oil column and the high case has a gas cap 2 times the size of the oil column. The effect of size of the gas cap can be mitigated by injecting more gas into the gas cap by drilling additional wells provided a good connection with the gas cap is assessed.

Kv/KH: this ratio was obtained from the rock typing of Kita. The lowest value was taken at 0.1 which is the most favourable rock type and the low end was taken to 0.05 which represents the values for the least favourable rock type .

KH: The horizontal permeability range of the cores taken in Kita was used with the low value taken at 300mD and the highest at 10 Darcies

Aquifer: No sensitivity was done in the aquifer size as the aquifer support was deemed to be limited. In the S7.5, the presence of an aquifer has not been demonstrated. Furthermore, if an aquifer exists, the connectivity to the oil column is uncertain. In fact, as part of the deltaic alternance, the oil bearing sands are stacked between shales barriers and the geological model did not assess these connections. Finally, Edem is closed by a series of faults and the contour maps shows that if an aquifer exists in this horizon, it will be of limited size thus would not provide a strong support.

STOIIP: From 8 Millions barrels produced in the low case, this production reaches 17 Millions in the high case. By and large this parameter represents the highest uncertainty in this model. Clearly, the more oil there is underground, the more will be produced at surface.

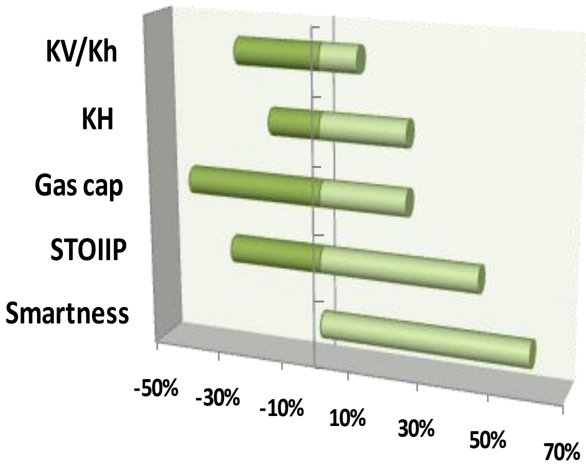

Figure 28 Tornado chart assessing the impact of uncertainties in the reservoir simulation studies - S7.5 - Edem

Conclusions

These past decades, the deployment of smart well technology was challenged by its high associated costs and lack of reliability. To improve the economics of smart wells, oil service providers developed the low cost smart well concept. This approach keeps the key components of smart well technology while minimizing the use of electronics, thus improving their reliability and reducing their costs. The integration of this low cost smart solution into the simulation studies of Edem field will enable increased oil production and decreased water and the gas production. This study is the first-ever published comparison of reservoir simulation and economic evaluation of regular wells versus intelligent wells in one of the Rio Del Rey Basin small oil rims. The main conclusions of this case study can be summarized as follows:

1. The simulation results demonstrate encouraging impact of using smart wells: the oil production estimate is increased by 50% regardless of the volumetrics. An increment in the recovery factor between 10 and 14% is predicted. Moreover, a significant decrease of associated gas and water is assessed. Indeed, the water and gas production are reduced by at least 20%.
2. Economics derived from these simulations studies are very positive with a NPV that is doubled in the base case scenario and an increment of 29% in the IRR.
3. The results of these studies are very promising but remain results of simulations that were built based on dynamic data acquired in the analog field Kita. In order to reduce the uncertainty on the dynamic model and fine tune this sudy, a data acquisition strategy must be set up to acquire cores and PVT samples from Edem.
    a. Core analysis will enable to determine the actual formation water saturation of the field and perform wettability studies to improve the relative permeability data and investigate further the secondary recovery mechanism options.
    b. The PVT model needs to be improved by gathering oil samples and undertaking full PVT analysis that will enable defining the oil properties in all the reservoirs of interest.
    c. Well test analysis must be perfomed to confirm the non-transmittivity of the faults, the reservoirs initial pressures, average reservoir permeability and KvKh ratio.
    d. A complete logging program needs to be carried out to reduce the uncertainties of the static model and have a better estimate of the contacts.
4. Beyond these direct positive impacts in oil recovery, the secondary recovery mechanism by gas injection into the gas cap represents a novel approach in the Rio Del Rey Basin. So far, in this basin, this technic has not been employed and the produced gas is flaired. Consequently with this development strategy, a positive environmental impact can be achieved. Furthermore, once the oil will be exhausted, the total gas stored in the reservoir can be produced and delivered to the future gas market that is planned to be launched by 2015.

Recommendations

- Drill appraisal/development well in the North – East of the structure to improve both static and dynamic models
- Deploy Edem as a smart field
- Deploy smart well technology in the Kita field to assess the efficiency of smart well solution and edit a case study of the conclusions. Using smart wells offers great potential in the Rio del Rey Basin. Indeed, all the reservoirs that are producing in this area and suffer from gas and water coning could benefit from the smart well technology.
- Smart completion vendors should create more tools to model the smart completions behaviours in reservoir simulations..

Nomenclature

bbl = blue barrel
bpd = barrel per day
°C = Degrees Celsius
Cl = Chloride
FDP = Field development Plan
GDT = Gas down to
GOC = Gas oil contact
GOR = Gas oil Ratio
GUT = Gas up to
ICD = Inflow control device
ICV = Inflow control valve

Kh = Horizontal permeability
Kv = Vertical permeability
QC = Quality Control
M = Thousand
MD = Measured depth
mD = MilliDarcys
MM = Million
MSL = Mean Sea Level
NPV = Net Present value
ODT = Oil down to
OUT = Oil up to
OPEX = Operational expenditure
OWC = Oil Water Contact
PHIE = Effective Porosity
ppm = Parts per million
psi = Pounds per square inch
Psig = Pound force per square inch gauge
PVT = Pressure Volume Temperature
RCAL = Routine Core Analysis
RF = Recovery Factor
RFT = Repeat formation tester
RDR = Rio Del Rey
SC = Smart completion
SCAL = Specialized core analysis
scf = Standard Cubic Feet
Sg = Gas saturation
Sgi = Initial gas saturation
So = Oil saturation
Soi = Initial oil saturation
Sor = Irreducible oil saturation
STOIIP = Stock Tank Oil Initially in Place
SW = Smart well
Sw = Water Saturation
Swc = Connate water saturation
Swi =Irreducible water stauration
TVDss = True Vertical Depth sub sea
USD =United States Dollars

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- Imperial professors who gave me good knowledge of petroleum engineering that enabled me to tackle the challenges faced while performing this analysis. A special thanks to Tara Laforce who was my tutor these past months for her technical support

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Appendix A – Critical Literature Review

A -1 Milestones in Smart Wells technologies

SPE Paper n°	Year	Title	Authors	Contribution
62953-MS	2000	Production Experience From Smart Wells in the Oseberg Field	Sigurd M. Erlandsen	Provide a case history of the impact of using smart wells in a mature field. Over 3 months, 314 000 additional bbls were produced while using smart wells Smart wells results were altered by downhole equipment failure
72493-MS	2001	Modelling Advanced Wells in Reservoir Simulation	Jonathan A. Holmes	Modeling of intelligent completions in simulators.
77941-MS	2002	A Method to Assess the Value of Intelligent Wells	H. Gai	Proposes a systematic method to quantify the value of intelligent wells technology in specific applications.
88505-MS	2002	Intelligent Technology, Well Management Miracle - Fact or Fantasy	John Davies Bill Birch Syd Littleford	Give explanations as of the delay of smart well technology breakthrough in the oil and gas industry
32149	2002	Smart Fields: How to generate more value from hydrocarbon resources	Pieter K.A. Kapteijn	This paper covers the fundamental elements of smart developments and discusses Shell case studies and projects to show the value of using Smart Well and Field technology.
81107-MS	2003	Reservoir Aspects of Smart Wells	Carlos A. Glandt	Detaiil of how smart wells can help improving the whole reservoir management using transverse techniques.
88649-MS	2004	Toucan Smart Field Development: How to Generate More Value from Hydrocarbon Resources	.R. Braithwaite, S. Müssig, R. van der Poel, S. van Putten, W. van de Waal	Case study of deployment of smart wells in the Toucan Field in Gabon
103575-MS	2006	Smart Fields—Making the Most of our Assets	SPE Russian Oil and Gas Technical Conference and Exhibition	This paper provides an evaluation of the business impact of Smart Fields concepts and technologies
104227-MS	2006	Smart-Well Completion Utilizes Natural Reservoir Energy To Produce High-Water-Cut And Low-Productivity-Index Well in Abqaiq Field	Nashi M. Al-Otaibi Abdulwafi A. Al-Gamber Michael Konopczynski Suresh Jacob	This paper presents how smart well technology did enhance oil recovery in low productivity wells.
107117-MS	2007	Achievements of Smart Well Operations: Completion Case Studies for Hydro	I. Raw E. Tenold,	This paper enumerates the different technical reasons to use intelligent completions.
11630-MS	2007	Using Down-Hole Control Valves to Sustain Oil Production From the First Maximum Reservoir		Case-study detailing planning, completion, testing, and production of the first Maximum Reservoir Contact (MRC), Multilateral (ML) and Smart Completion (SC) deployment in the largest oilfield

		Contact, Multilateral and Smart Well in Ghawar Field: Case Study		accumulation of the world.
106011-MS	2007	A Literature Review on Smart Well Technology	Changhong Gao T. Rajeswaran Edson Nakagawa	Describe the evolution of the smart well technology
129577-MS	2009	Business Case for Intelligent Well Deployment in a Subsea Development Project - A Case Study	E.A. Ageh, O.J. Uzoh, B. Bracewell, M. Abulu, J. Reinders,	Describe a business case to determine the economic value of deploying smart wells in deep offshore Africa.
123563-MS	2009	Optimization of Smart Wells in the St. Joseph Field	G.M. van Essen J.D. Jansen D.R. Brouwer S.G. Douma K.I. Rollett D.P. Harris	Case history of infill drilling using smart wells
122654-MS	2009	Viability Study of Implementing Smart/Intelligent Completion in Commingled Wells in an Australian Offshore Oil Field	Society of Petroleum Engineers	This paper describes how numerical reservoir simulator was used to model reservoir performance and production from individual zones. The results show that smart completion is viable for this field.
121279-MS	2009.	Comparison Between Smart and Conventional Wells Considering Uncertainties	João Paulo Q. G. da Silva, Denis J. Schiozer	This study compares optimization results between smart wells and conventional wells.

A – 2 Critical Literature Review

1. SPE 62953-MS (2000)

Production Experience From Smart Wells in the Oseberg Field

Authors: Sigurd M. Erlandsen, Norsk Hydro ASA

Contribution in smart well technology:
Description of how using smart completion helped improving the oil recovery. The reliability of the downhole sensor were challenged as communication was lost with three of the four zones after 40 days production.

Methodology:
Use of remotely operated devices

Conclusion:
Improvement of oil recovery by switching off zones with high gas rates

2. SPE 72493-MS (2001)

Modeling Advanced Wells in Reservoir Simulation

Author: Jonathan A. Holmes

Objective:
Present the recent advances in various areas of petroleum engineering and amongst these new technologies, smart wells are discussed.

Conclusions:
The smart well model must be able to predict effects of the control devices. Therefore, it is important that the well model be able to calculate, with a reasonable degree of accuracy, the pressure and fluid-flow rates at all locations in the well (including any lateral branches) and the pressure drop across control devices. For this degree of functionality, a suitably advanced form of well model must be used.

3. SPE 77941-MS (2002)

A Method to Assess the Value of Intelligent Wells

Author: H. Gai

Objective:
Articulate the understanding of the value of the Intelligent Well (IW) technology, and presents a systematic method to quantify the value of IW technology in specific applications.

Methodology
The method described is a collection of common sense approaches, leading to a recommendation for the applications, based on the value and other considerations. Step-by-step explanation is presented. Circular debates arise and decisionmaking becomes difficult. Decision is then made by default of choosing the least resistance and most conventional, often apparently because of pressure of time, but there are usually underlying reasons too. Not to understand the value over the life of the well or reservoir is a main one.

Conclusion
In the context of IW technology, there were speculative type of investments and sometimes unpleasant consequences and frustration. Today there is so acute a consciousness not to “waste” money that the industry is almost limiting the resources only to secured applications to ensure quick return. The confusion of risks and perception, and the inability to disentangle the issues also have had negative impact on the industry. The disproportionately high cost further aggravates the situation, hindering the progress.

4. SPE 32149 (2002)

SMART FIELDS: HOW TO GENERATE MORE VALUE FROM HYDROCARBON RESOURCES

Author: Pieter K.A. Kapteijn

Objective of the study:
The paper proposes a conceptual framework for the understanding and design of E&P `smartness'

Contribution to smart well technology:
Integration of transverse approach to improve performance of smart wells.

Conclusion:
Time-lapse seismic, subsurface modeling, dynamic reservoir simulation, smart wells and production facilities will yield significant improvements in recovery and productivity as well as a reduction in the environmental impact of oil and gas developments.

5. SPE 81107-MS (2003)

Reservoir Aspects of Smart Wells

Author: Carlos A. Glandt

Conclusions:
A well equipped with intelligent components is considered SMART only when it maximizes its value over the life of the project. The definition of the adequate level of intelligence is the outcome of a multidisciplinary discussion that focuses on the well and reservoir management. To effectively realize the value associated with these technologies Shell set up a Global Implementation Smart Wells Team at its E&P Technical Center. Jointly with asset teams from around the world it has reviewed more than 80 projects over the last 3 years. The main result of this work is a faster and more meaningful implementation effectively realizing the value associated with these technologies. An important byproduct of this work is a list of identified well and reservoir opportunities where smart completions can add significant value. This paper reviews these opportunities and provides selected examples.

6. SPE 88505-MS (2004)

Intelligent Technology, Well Management Miracle - Fact or Fantasy

Authors: John Davies, Bill Birch, Syd Littleford

Contribution to smart well technology:
This paper provides reasons why smart well technology fails to meet its expected success other than risk aversion of operators

Objective of the paper:
The aim of this paper is to challenge the value of the current intelligent well toolbox, and promote potential alternatives that have higher value to both Vendor and Operator.

Conclusion:
Smart completions service providers need to keep up with the technologand offer tools that will alow to model their actual behaviour.

7. SPE 16162-MS (2004)

Improving Oil Production Using Smart Fields Technology in the SF30 Satellite Oil Development Offshore Malaysia

Authors: P.M. Bogaert, Shell Brazil (previously Shell Malaysia EP); W. Yang, Shell Malaysia EP; H.C. Meijers, Shell Malaysia EP; C.M van Dongen, Shell International Exploration and Production B.V.; M. Konopczynski, Well Dynamics

Contribution to smart well technology understanding:
Provide a successful case study of implementing smart fields in Malaysia

Objective of the paper:
Present the value added of smart fiels deployment

Methodology:
Smart well completion technology was combined to intelligent gas lift optimization. In this field all operations were performed remotely while analyzing real time data.

Conclusions:
The achievments of such project were an increase of 10% production and 2% additional reserves.

8. SPE 88649-MS (2004)

Toucan Smart Field Development: How to Generate More Value from Hydrocarbon Resources

Authors: S.R. Braithwaite, S. Müssig, R. van der Poel, S. van Putten, W. van de Waal,; M. Kass,

Contribution:
Provides a case study of deployment of smart wells in the Toucan field in Gabon. Toucan Field is an oil rim.

Methodology:
Based on simulation work, various strategies for well operation are discussed, along with their various merits; both in the context of the well, and the field. Secondly the combination of frequent well tests, production optimization, and the use of reservoir surveillance tools is used to deliver an optimal solution to help the asset team analyze deviations from the expected reservoir performance.

Conclusions:
The business benefits of these smart technologies are viable in the context of implementation in a medium sized oil rim.

9. SPE 103575-MS (2006)

Smart Fields—Making the Most of our Assets

Objective

To detail under which circumstances smart fields become fully functional.

Contribution in the smart wells technology:
Introduction of the concept of value loop that makes the smart well concept fully functional. Description of the Shell universe tool.

Methodology
Smart Field can be fully utilized if the three main elements fully integrate, technology, process and resources. Smart Fields is not only about automation. It is about making available the three key ingredients needed to efficiently operate any piece of equipment: reliable performance data, an integrated suite of tools to turn these data to information and operational advisories and a cadre of appropriately skilled professionals that use the information to make the right decisions.

Conclusion
Value is created through execution of the ‘value loop’, repeating the cycle of measuring, modeling, decision-making and controlling to get the maximum amount of hydrocarbons out of the reservoirs in the most cost- effective way. 8% Ultimate recovery increase (5% gas and 10% oil);10% Increased production;Reduced development risk and uncertainty;Other important benefits include improved HSE.

10. SPE 104227-MS (2006)

Smart-Well Completion Utilizes Natural Reservoir Energy To Produce High-Water-Cut And Low-Productivity-Index Well in Abqaiq Field

Authors : Nashi M. Al-Otaibi and Abdulwafi A. Al-Gamber, Saudi Aramco, and Michael Konopczynski, and Suresh Jacob, WellDynamics Inc.

Contribution to smart well technology:
Successful case study of smart wells performance in the Abqaiq field – Saudi Arabia

Objective of the paper:
Describes how smart well technology applications have helped overcome the challenges of complex and mature fields such as the Abqaiq field

Conclusion.
Smart wells allowed improving oil recovey on a field using the gas cap expansion “free energy" from an overlying gas cap to produce high water-cut and low productivity wells completed in underlying reservoirs.

11. SPE 106011-MS (2007)

A Literature Review on Smart Well Technology

Authors: Changhong Gao and T. Rajeswaran, Edson Nakagawa

Contribution to smart well technology:
This paper provides a full description of the main components of smart wells technology available in the oil service companies. Moreover some common applications are illustrated such as cases in the North Sea, offshore England, and offshore Brunei

Objective of the paper:
Present the major components of smart well technology developed by oil service companies and provide case studies on deployement of smart wells.

Conclusion:
To realize its true value, the permanent monitoring system of smart wells must be fully functional throughout the life time of the well. Accordingly, service providers will need to develop a technology solution aimed at expanding the market by lowering costs and improving reliability.

12. SPE 107117-MS (2007)

Achievements of Smart Well Operations: Completion Case Studies for Hydro

Authors: I. Raw and E. Tenold,

Objective:
To provide and discuss several case histories of smart wells implementation.

Methodology:
Installation of a natural gas lift application to enhance oil production at Troll field, which used a single control line to surface to operate a six-position gas lift valve to regulate flow from the gas cap.
Installation of multizone monobore completions in the Oseberg field to offset production decline, in which several highly deviated and long-reach wells were successfully completed in two to three zones with established zonal isolation and flow control.
Other case histories include the creation of innovative intelligent completions for multilateral wells with lateral flow control and natural gas lift with the gas cap perforated by tubing-conveyed perforating guns side-mounted on the production tubing.

Conclusions
Among the observations made is that implementation of reliable pressure, temperature, and flow monitoring in the industry has not kept pace with the complexity of the flow control capability. The ongoing challenge is to create intelligent wells with reliable monitoring technologies to fully capitalize on the benefits and opportunities of zonal flow control. Innovative completion designs and state-of-the-art reservoir monitoring and control technologies are critical to intelligent well development.

13. **SPE 11630-MS (2007)**

Using Down-Hole Control Valves to Sustain Oil Production From the First Maximum Reservoir Contact, Multilateral and Smart Well in Ghawar Field: Case Study

Authors: S.M. Mubarak, T.R. Pham, and S.S. Shamrani and M. Shafiq,

Objective:
Provide a a case-study detailing planning, completion, testing, and production of the first Maximum Reservoir Contact (MRC), Multilateral (ML) and Smart Completion (SC) deployment in Ghawar Field.

Methodology:
The SC provides isolation and down hole control of commingled production from the laterals. Using the variable positions flow control valve, the well was managed to improve and sustain oil production by eliminating water production. Monitoring the rate and the flowing pressure in real time allowed producing the well optimally.The appraisal and acceptance loop of the completion has been closed by having this well completed, put on production and tested. Approval of the concept was achieved when the anticipated benefits were realized by monitoring the actual performance of the well.

Conclusions:
Leveraged knowledge from this pilot has provided an insight into SC capabilities and implementation. Moreover, it has set the stage for other developments within Saudi Aramco.

14. SPE 105618-MS (2007)

Smart Wells Experiences and Best Practices at Haradh Increment-III, Ghawar Field

Authors: Ibrahim H. Al-Arnaout and Rashad M. Al-Zahrani, and Suresh Jacob

Contribution of smart well technology:
Provides description of the case study of 28 smart wells deployement in the world' greatest oilfield ; the Ghawar field. Performance reliability of 97% was achieved while using best practices.

Methodology:
Provides an insight into how a large-scale application of smart completion technology can be handled in a systematic way to achieve a successful conclusion.

Conclusion:
Performance reliability of 97% was achieved while usaing best practices.

15. SPE 129577-MS (2009)

Business Case for Intelligent Well Deployment in a Subsea Development Project - A Case Study

Authors: E.A. Ageh, O.J. Uzoh, B. Bracewell, M. Abulu, J. Reinders

Contribution:
Business case illustrating economics of smart wells

Methodology:
Economics method used was based on an analysis of possible completion failure scenarios, the probability of occurrence of these scenarios and the reliability of the downhole intelligent completion equipment. The cost analysis carried out, weighed the benefit of smart wells against conventional and stacking (commingling of zones) completion types. CAPEX was risked using Decision Tree analysis with data input from a wide range of data bases including fields in the Nigerian DeepWater blocks.

Conclusions:
Deploying smart wells provides an opportunity to develop 20% incremental reserves that would otherwise be uneconomical to develop without the ability to use a multizone completion solution. This results in a 50% gain (risked gain) in NPV for the project.

16. **SPE 123563-MS (2009)**

Optimization of Smart Wells in the St. Joseph Field

Authors: G.M. van Essen, J.D. Jansen, D.R. Brouwer, S.G. Douma, K.I. Rollett, D.P. Harris

Objective:

To describe how the configuration of inflow cpntrol valves did improve the oil recovery in the St. Joseph brown field.

Methodology:
Optimal control theory was used to optimize monetary value over the remaining producing life of the field, and in particular to select the optimal number of ICVs, the optimal configuration of the perforation zones, and the optimal operational strategies for the ICVs. A gradient-based optimization technique was implemented in a reservoir simulator equipped with the adjoint functionality to compute gradients of an objective function with respect to control parameters. For computational reasons an initial optimization study was performed on a sector model, which showed promising results.

17. SPE 122654-MS (2009)

Viability Study of Implementing Smart/Intelligent Completion in Commingled Wells in an Australian Offshore Oil Field

Authors: M. Nadri Pari, A.H. Kabir

Objective:
To present a study undertaken to justify installation of a surface controlled ICV in a group of wells located off-shore Australia with commingled production.

Methodology:
A numerical reservoir simulator has been used to model reservoir performance and production from individual zones. Also, well and production network has been simulated using a well and Production Network Flow Simulators. An interface “simulation manager” is used to facilitate information exchange between the two simulation programs and optimization of the process. Proper control of ICVs is simulated based on reservoir and well-bore simulation data which will result in maximum oil production of field network system resulting in higher recovery.

Conclusions:
The benefit of surface controlled ICV versus uncontrolled commingled production has been compared. Economic studies perfomed based on these results show that smart completion is viable

18. **SPE 121279-MS (2009)**

Comparison Between Smart and Conventional Wells Considering Uncertainties

Authors: João Paulo Q. G. da Silva, Denis J. Schiozer

Objective:
Compare smart and conventional wells performance

Methodology:
A methodology of production strategy optimization, which considers the availability of different platforms, each one with a particular fluid treatment capacity, was developed and applied to both the conventional and smart wells. Special care was given to some details of the methodology in order to guarantee a fair comparison between the two options. The methodology was applied to a heterogeneous reservoir, considering a deterministic case. After it, the sensibility of the model was studied by changing geological characteristics, adding uncertainties to the problem. The optimization results showed small differences between the two alternatives.

Conclusion:
Smart wells are able to improve oil production and reduce water production but the net present value (NPV) indicated that the use of conventional well was, in average, slightly more advantageous.

Appendix B : Datasets Review and Quality check

The two exploration wells EEM1 and EEM2 intersect the reservoir horizons at the estimated top/base zones. The dataset listed in Table 9and Table 10 was found to be adequate for the engineering purposes of this study. Cores data of EEM1 and EEM2 have not been found yet, consequently, the core data of the analog field Kita were used. The amount and quality of data was not sufficient to perform cross-checks of critical properties such as the effective porosity and the water saturation. Moreover the fluid properties were derived from analysis that were performed in the late seventies thus represent a high level of uncertainty.

Data	Description
EEM1	Velocity Sonic Profile
	Well deviation
	Wireline raw data comprising : ✓ Gamma ray ✓ Density ✓ Neutron Porosity ✓ Caliper ✓ Sonic ✓ Deep resistivity ✓ Spontaneous potential
	FIT data
EEM2	Well deviation
	Wireline raw data comprising : ✓ Gamma ray ✓ Density ✓ Neutron Porosity ✓ Caliper ✓ Sonic ✓ Deep resistivity ✓ Spontaneous potential
3D seismic survey	2 sets of 3D seismic surveys

Appendix C: Geophysics and Related Uncertanties

Description of horizon picking

The delimitation of the hydrocarbon bearing reservoirs was the main objectives of the seismic interpretation. The latter was performed after merging two seismic datasets. It was estimated that the top horizons have a strong seismic signature allowing their picking.

The time depth conversion was done at EEM1 as illustrated in Figure 29 and then extrapolated across the field. This gave a good level of confidence on the depth of the horizon nearby the wells, with an uncertainty range that increases away from this well

The structure of the reservoir combined to the seismic resolution did not allow picking the base horizons. Instead, these bases were estimated using the well log responses and the top of the next horizon. The assumption was made that the bases were parallel to the top horizons.
The resolution of the seismic data is estimated at 10 m that represents the minimum uncertainty in the depth to the top horizons.

The uncertainty related to the thickness of the S7.5 reservoir is illustrated in Figure 30. The picking of the previous study is marked in purple. This figure represents the variation derived from the interpretation performed in 2010 and previous interpretation performed in 2006. It was estimated that the mean uncertainty of the depth of the S7.5 reservoir is ~3m as shown in Figure 31. The variance map was obtained by squaring the map of the standard deviation. This map shows the uncertainty map as regards the picking of the top of the S7.5 reservoir across the field. In the vicinity of the EEM1, this error is negligible but it increases away from the field.

Faults locations

The localization of the faults was undertaken in order to have a good estimate of the reservoir extent and the compartments within the field if any. Five main faults were picked, inferring that the Edem field is closed by a series of faults.
The main uncertainty in this fault determination is the location of the western fault. The picking of this fault was found difficult because of the pull-up & pull-down phenomena caused by the vertical velocity variation and diffractions at truncated reflectors. As illustrated in Figure 32, two hypotheses were considered as regards the location of this fault. The dotted yellow line illustrates one position and the solid yellow line illustrates another possible position. The selection of one or the other fault will result in a change in the GRV.

Fluid distribution

The shape of the reservoirs and the position of the wells did not allow determining the contacts in S7.3 and S7.5 reservoirs by the petrophysical interpretation. A horizontal stacking along the S7.5 allowed estimating the depth to OWC in this reservoir. Two horizontal stacking analyses were performed, the first one is illustrated in Figure 20 where the OWC in the S7.5 was obtained by extracting the amplitude map in the S7.5 horizon; the extinction of the amplitude at 1476m suggests the depth to OWC. Another study performed in 2010 gave a shallower depth to OWC at 1468m TVDss. Base on these two interpretations, the error in the picking of this contact is estimated at 8m. This shallower contact of 1468m TVDss was used as base case in the reservoir models and the deeper depth was considered in the uncertainty studies as the optimistic scenario. The fluid distribution derived from these studies is shown in Figure 34.

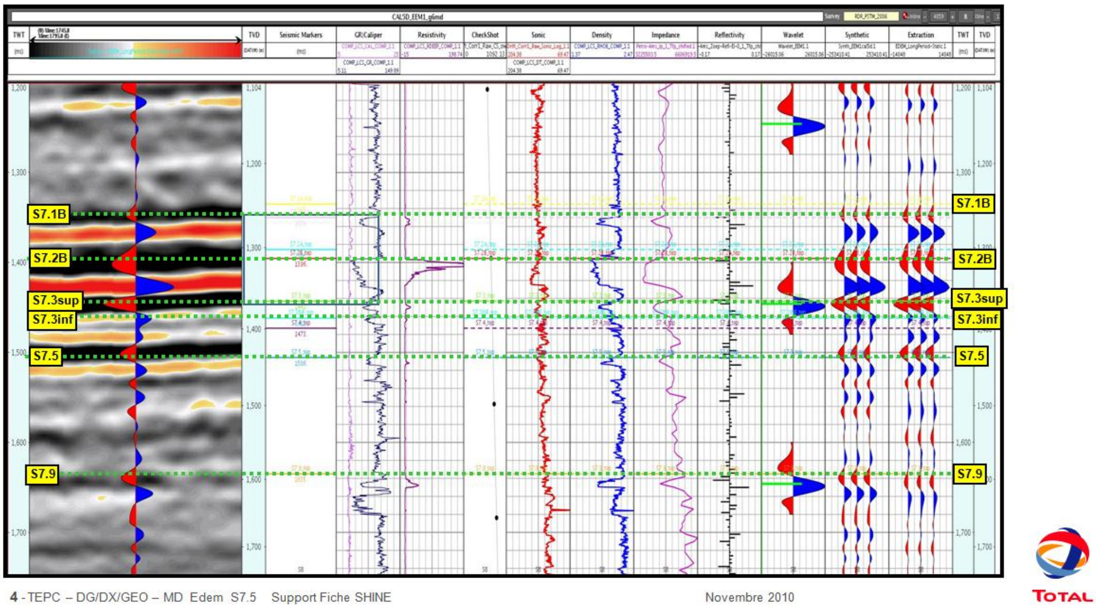


Figure 29: Horizon picking at the EEM1 - Edem - RDR - Cameroon

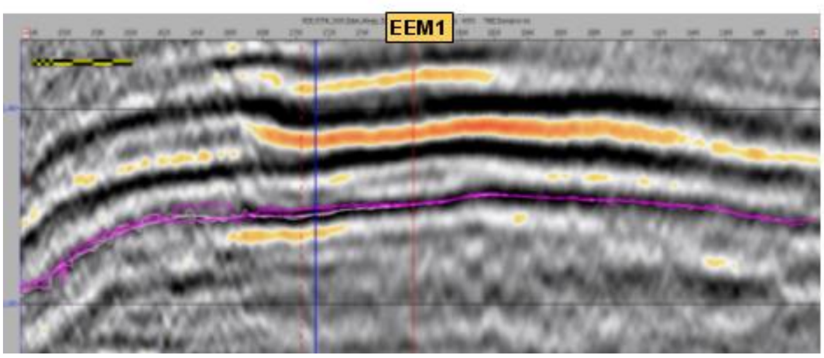
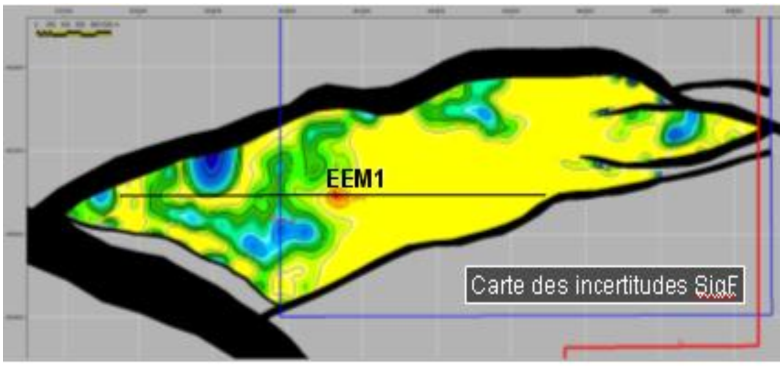


Figure 30 Variation in the S7.5 reservoir distribution - Edem



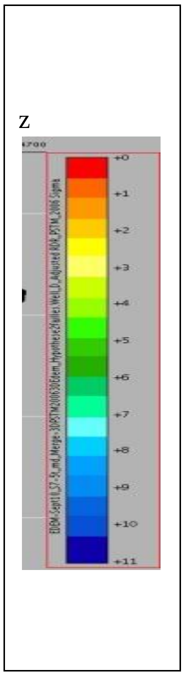


Figure 31 Uncertainty map as regards the picking of the top S7.5 - Edem

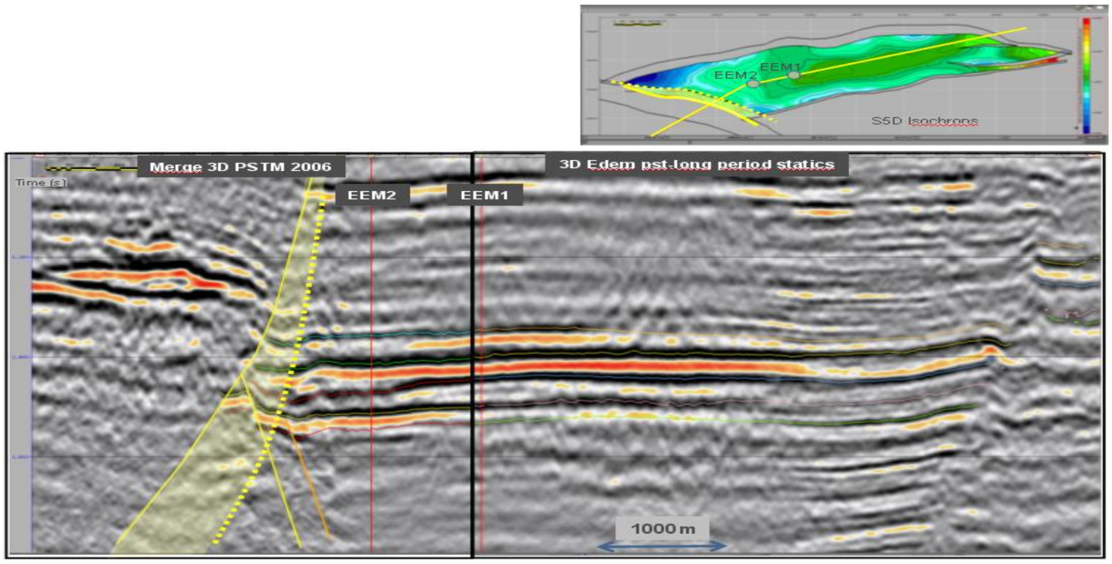


Figure 32 Scenarios considered as regards the position of the west fault -- After M. Djallo (TEPC)

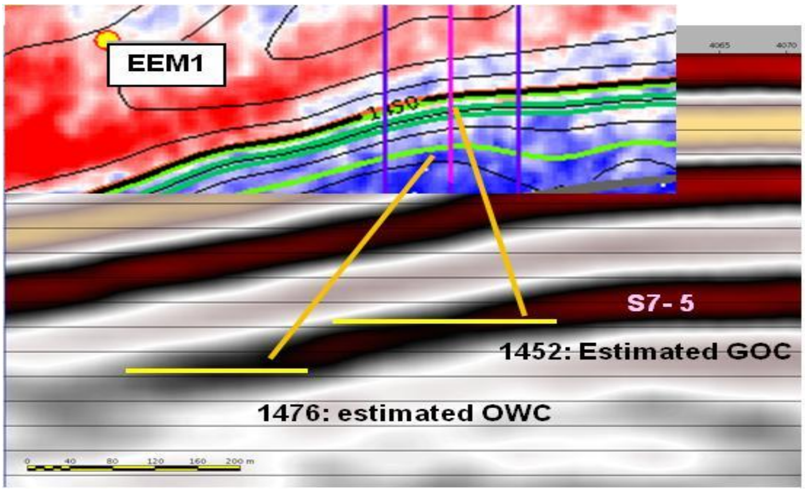


Figure 33 Estimation of the contacts in the S7.5 reservoir - Edem Field - RDR- Cameroon- After studies performed by TEPC

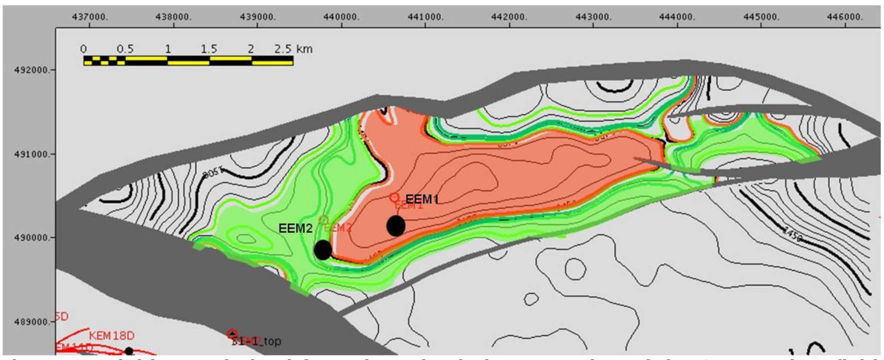


Figure 34 Fluid map derived from the seismic interpretation of the S7.5 - Edem field - RDR - Cameroon - After studies performed by TEPC

Oil Gas

Appendix D: Geology of the Rio del Rey Basin

Edem is located in the North-West of the Rio del Rey Basin (see Figure 1). This Basin corresponds to the eastern end of the Niger Delta. Consequently, this area exhibits lots of lithographic similarities with well-known Nigerian Oil-fields. The three main structural domains that emerged in the Tertiary are classified as follows:

O The North corresponding to an area of growth faults generally trending in the East-West direction.

O The Center characterized by the presence of shale ridges.

O The South dominated by folds along the thrust faults corresponding to the delta front belt also called “Bourrelet frontal”

These three areas are the results of the gravitational tectonic actions with displacement towards the south presenting an extension in the North-Delta and a compression in the South-Delta. The south part acted as cushion of the deformation; therefore, this part is characterized by over-pressured areas.

The major petroleum play of this region appears from the Paleocene. It is characterized by a regressive fluvial-sequence composed by sands and shales in Table 7 which formations in were identified.

Table 7: Major formations found in the Rio del Rey Basin - Cameroon - Africa

Age	Formation name	Description
Pliocene to Pleistocene	BENIN	Clean and massive sand zone generally fresh-water bearing
Upper Miocene to Pliocene	AGBADA	Massive deltaic alternance’. It is composed by an alternation of sand and shales. The great majority of the accumulations found in the Rio del Rey Basin are present in this formation.
Lower to upper Miocene	AFAGA	Underlain by the ISONGO turbidites. Composed by shales and sands from the Delta. This formation is located in the Northern part of the Rio del Rey Basin.
Lower to upper Miocene	ISONGO	Turbidite formations
Paleocene Eocene	AKATA	Corresponds to marine shales in which are inter-bedded OONGUE turbidites. This formation is mainly present in the North east of the basin

Oil field play

Origin of the hydrocarbons and source rocks

Kerogen Types 2 and 3 were defined as being the organic matters that originated the accumulations found in this basin. These were found very rich with high hydrocarbon productivity index of 300. The geochemistry of the oil indicates a domination of a marine origin with two types of contributions:

- A continental contribution next to the coast
- A mixture between fluvial and marine in the open sea areas

Following the analysis of several wells in the Rio de Rey Basin, it was recognized that the quality of the kerogen present in the source rocks (Paleocene - Miocene) was improving from the coast to the ocean suggesting that the potential is better in the South-West.
The source rock in the Rio Del Rey Basin has not been identified yet. But, it was proven that the Paleocene shales present the best potential as source rocks.

Cap Rock & Reservoir Rock

Numerous seal reservoir pairs are found in the AGBADA formation. Hydrocarbons were trapped during their migration wherever a shale barrier was present on top of the sand layers. The thickness of the sands layers is not constant over the field and some areas have better sand units than others. Nine reservoirs zones S1 to S9 were identified across the basin. The numbering of these zones reflects the deposition sequences: S1 being the youngest and shallowest, S9 the deepest and oldest.
In the Northern part of the RDR Basin, in the study area, hydrocarbons accumulations were found in the S7. All the upper formations were proven to be water-bearing. Within the S7, many reservoirs were identified as hydrocarbon bearing. However, only the S7.3 and S7.5 layers in Edem field were considered in this study as these appear to be the ones with the best oil

accumulation potential and not yet produced.

Facies interpretation

The facies of the wells were interpreted based on the well to well correlation. Indeed, three main facies were identified:

O Clean sands in the upper part

O Shaly sands in the middle part

O Silty sands in the lower part

Reservoir zonation

S7.3 and S7.5 were divided into 3 main units. The determination of the top of the zone was driven by the variation on the shale volume ratio.

Zone 1 has the best reservoir properties. It is characterized by a clean sand deposit that is well correlated across the two wells. This zone exhibits a high net to gross ~70 to 90%. It was observed that this zone shows a prograding pattern when moving to the west. Indeed, the thickness of this zone is greater in EEM1 (east Edem) than in EEM2 (west Edem).

Zone 2: is dominated by sands alternated by thin shale layers that erode into shales at the base. The thickness of this base is not constant over the two wells as it gets thicker when going to the west. This unit has a lower net to gross as compared to zone 1 ~60%.

Zone 3 that has the poorest reservoir quality is described by sands deposits with alternation of silt. This unit shows a prograding pattern to the west with variations in thickness over the two wells. Indeed, in EEM1 this unit is dominated by sands and in EEM2, this unit is predominantly composed of silt. Consequently, the net to gross varies from 30% in EEM 1 to 0% in EEM2. In EEM2, only this zone is present.

Generally, it was observed that the zonation pattern is more favourable in the east of the field characterized by thicker and cleaner sand packs that the west of the field. For modeling purposes, the variations within the zones were simplified.

Analog

In the geology point of view, Kita was identified as the analog of Edem. Indeed, the two reservoirs were deposited at the same period. The stratigraphic similarities of the two fields were demonstrated by the well to well correlation comprising 13 wells in Kita and 2 wells in Edem. Figure 36 illustrates the analogy between the two fields and also illustrated the 450m shift between the two fields along the North-South thrust fault.

Faulting systems

The Rio Del Rey Basin is highly faulted as a result of the high tectonic activity in the region. These faults have two major directions:

- East-West: corresponds to the group of the regional growth faults with a roll-over system and back-to-back structures
- North-South: correlated to the uplift of the shales ridges that generate extrados' faults and formation collapses along those ridges.

The Edem field is closed by a very complex faulting system as illustrated in Figure 35. This feature will be considered in the dynamic model as there is a possibility of compartmentalization of the field mainly in the western end.

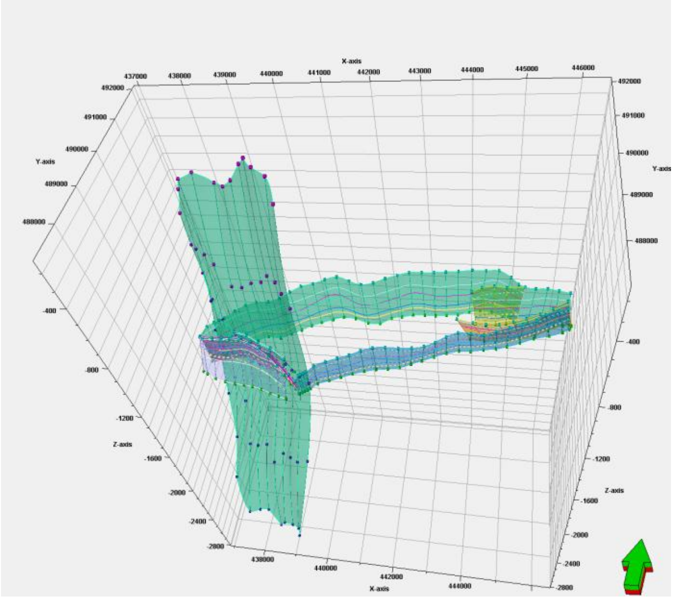


Figure 35 Faulting system of Edem

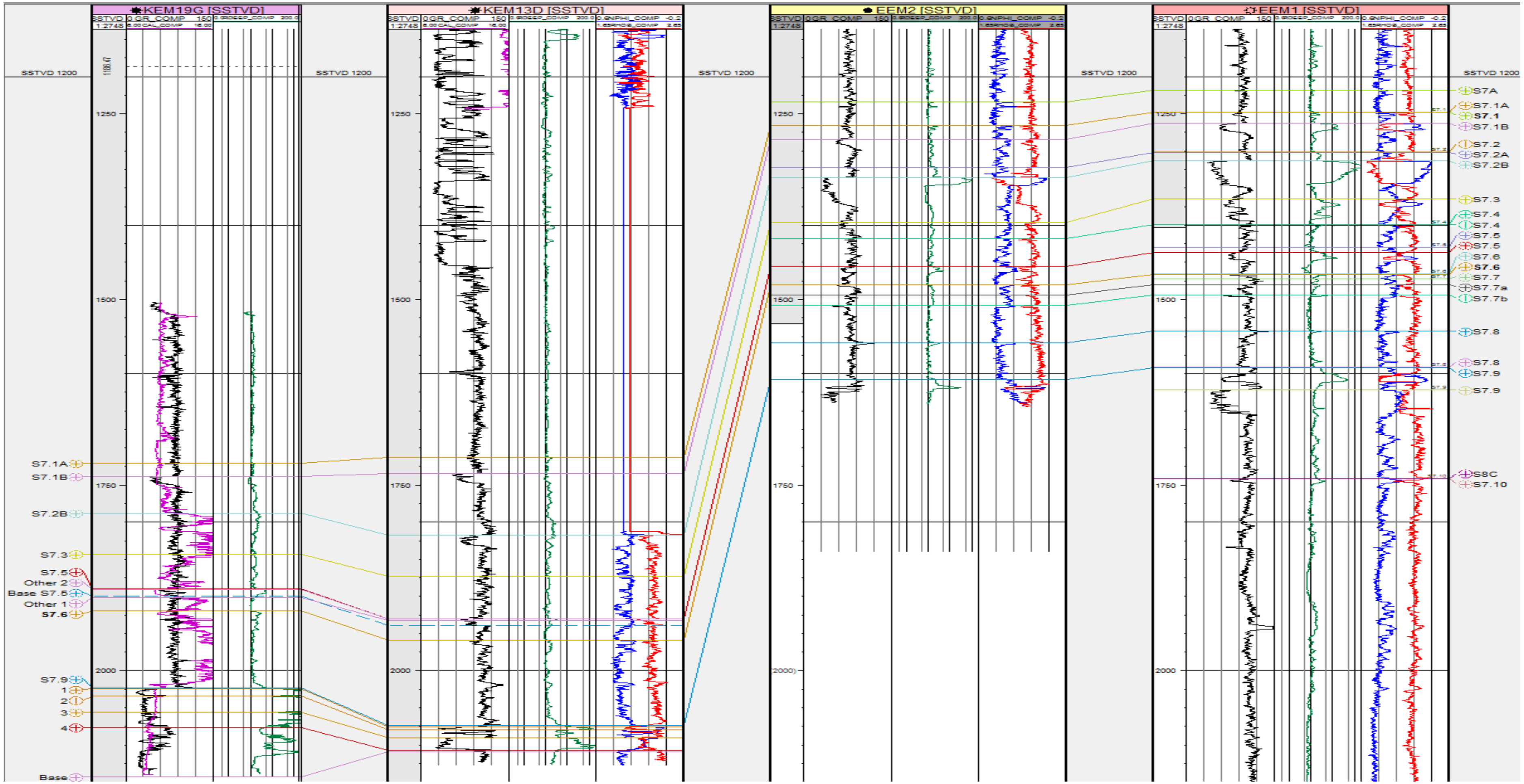


Figure 36 Well to well correlation between Kita and Edem - RDR - Cameroon

Appendix E: Rock properties

Poro-Perm Relationship

The poro-perm relationship in Figure 37 was established by TEPC reservoir engineers using 272 cores from the well KEM11D. It was found that the porosity range obtained with the core analysis is consistent with the effective porosity data derived from the petrophysical interpretation. The permeability values infer that Kita field has a broad permeability distribution with a good average permeability in the order of 3-10 darcies.

$$\mathbf{Kh(PHIE) = (12.055*PHIE+0.142)^{10}}$$

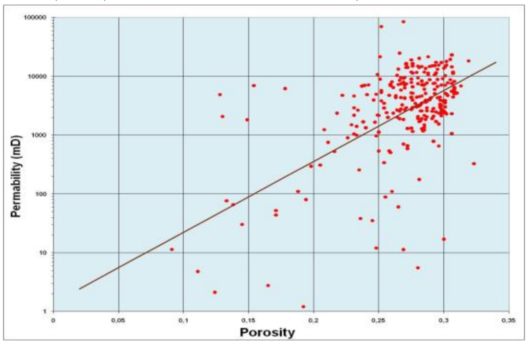


Figure 37 Poro-Perm Relationship in Well KEM11D – Kita

J-Function

The J-function was derived from four capillary pressure curves obtained through Mercury injection. All the cores have the same range of petrophysical properties. Figure 38 represents the J-function obtained after merging the core data
It can be seen that the transition zone in the Kita field is negligible. This confirms the good reservoir quality of Kita that exhibits very good porosity greater than 25%.
This modeled J-Function was used in the reservoir modeling to build the 3-D water saturation distribution across the Edem field. $\mathbf{J(S_w) = 0.05+0.04*(S_w-S_{wi})^{-2.5}}$

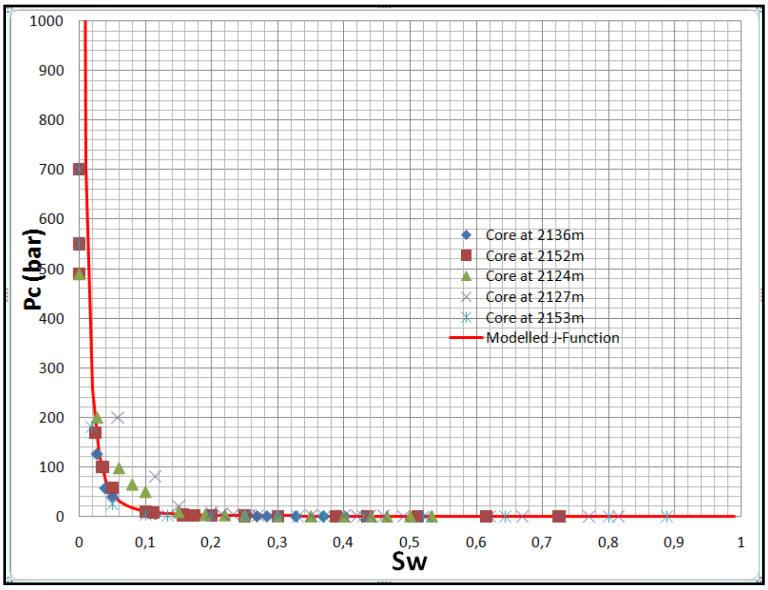


Figure 38 J-Function construction derived from cores taken in the KITA field – well KEM-11D

Petrophysical data quality check

Hole condition

When available, the caliper was used to perform the QC for the hole conditions. Overall the hole in EEM1 seems to be in gauge with no evidence of washout throughout the run (see Figure 39). The data acquired inside the casing were disregarded to perform the petrophysical interpretation.
For EEM2, in the absence of the caliper data, the QC was performed using the resistivity response, solely to identify data that were logged inside the casing. As shown in Figure 40, resistivity data acquired inside casing are affected by the presence of metal thus read higher than the actual resistivity of the formation. No other QC was performed as regards the hole conditions as only deep resistivity data were available.

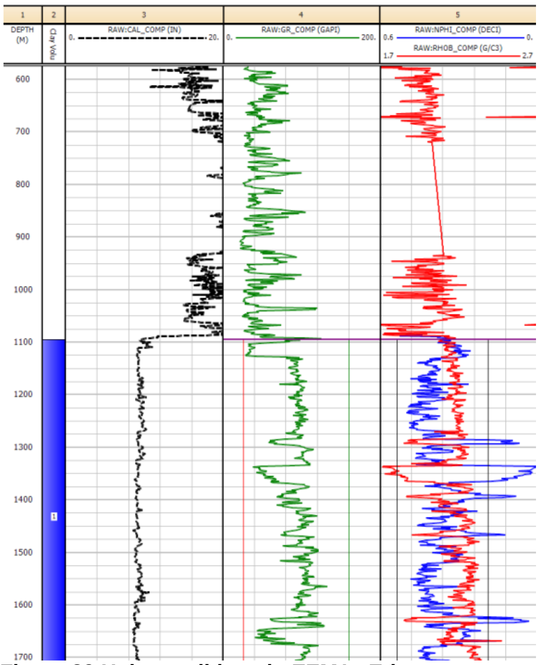


Figure 39 Hole conditions in EEM1 - Edem

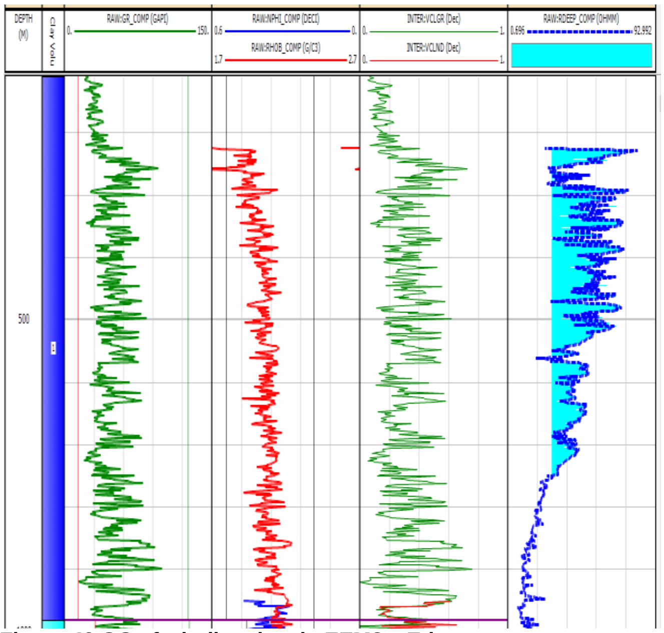


Figure 40 QC of wireline data in EEM2 – Edem

Wireline data

Generally it was observed that the resistivity readings between the two wells were different. EEM1 reads higher resistivity values than EEM2. Consequently, the formation water resistivity readings were lower in EEM2 than in EEM1 with respective values of 0.21ohmm and 0.351 ohmm at 25°C. Although the formation water resistivities were estimated in different reservoirs, the geological model suggests that the S7 series should have the same formation waters. The resistivity readings were taken as a guideline and it was assumed that it represents a high level of uncertainty.

The raw porosity readings in the two wells were found to be too high for the matrix sandstone with values up to 50%. No quality control could be performed in the porosity data as the environmental corrections that were applied if any were not reported. Consequently this was incorporated in the uncertainty analysis.

Petrophysical interpretation

The petrophysical analysis was performed with interactive petrophysics.

<u>Vshale</u>

The clay concentration was estimated using the gamma ray response. The shale line was put at 80% clay concentration and the sand line was set at 2 -5% clay concentration. The neutron density curves allowed performing a quality check on these results. Figure 41 and Figure 42 below illustrate the difference between the Vshale values obtained with these two methods. A good match is observed between the two curves.

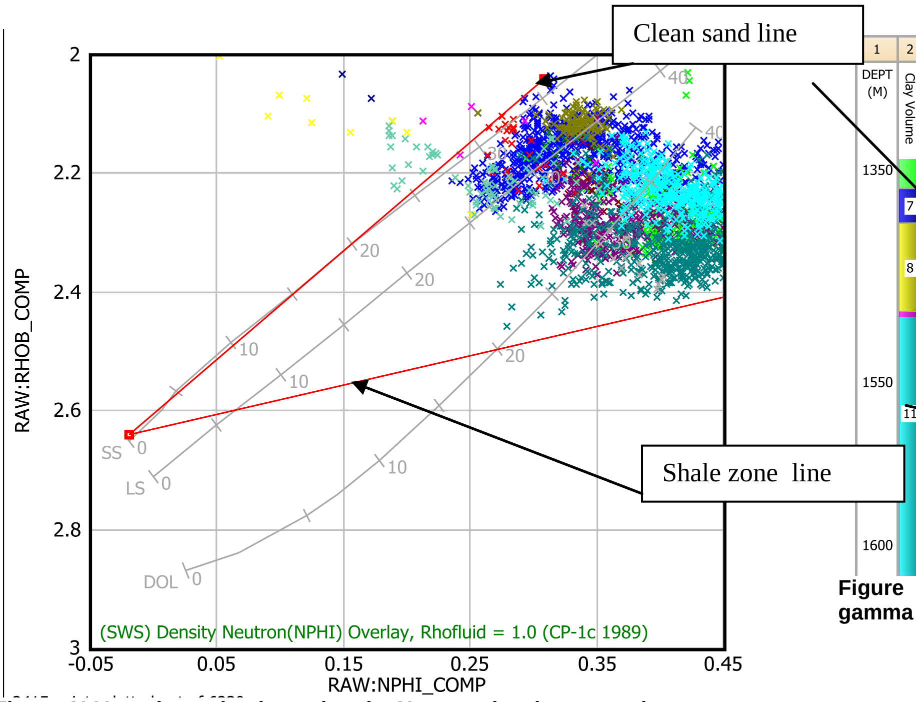


Figure 41 V_{shale} determination using the Neutron density cross plot

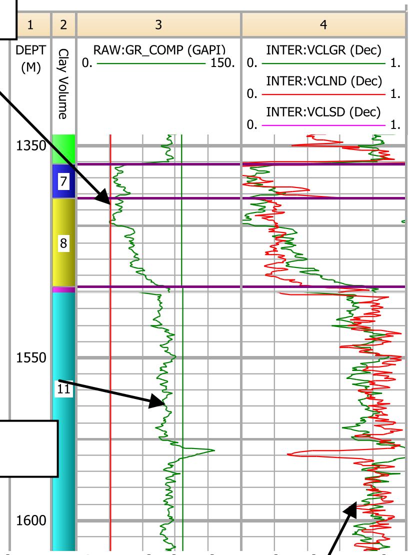


Figure 42 Vshale determination using the gamma ray curve

The red curve shows V_{shale} obtained with the Neutron-density Xplot and the green curve represents the V_{shale} obtained with the gamma. The two curves almost overlays.

Effective porosity

- Presence of clay

The presence of clay in the formation affects the neutron porosity readings yielding to an overestimation of these porosity values. A correction needs to be applied in order to measure the effective porosity. The effective porosity data computed is using the Vshale concentration to correct for the porosity inferred by the wet clay. The discrepancy between these 2 variables is shown Figure 31.

- Impact of gas

Due to the gas low hydrogen index, the porosity in the gas zone is underestimated by the neutron tool. This is corrected by the use of the sonic density crossplot..

Water Saturation

The lack of reliability of the resistivity readings renders the water saturations calculations very challenging. Furthermore, the formation water resistivity/salinity is unknown as no formation water samples from Edem were analyzed. When back-calculating this value in the water bearing sand zones; two different values were obtained: Rw = 0.17ohmm@25°C in EEM1 and Rw= 0.351ohmm @25°C in EEM2. Which represent a formation water salinity of 16 000ppm Cl- in EEM1 and 35000ppmCl- in EEM2. This salinity range is EEM1 in depth with the salinity encountered in the RDR basin which was estimated between 8000 and 20000 ppmCl-. Consequently the saturations were estimated relatively to the formation water readings in each well. To estimate the saturations, the Juhaz method was used. This method assesses the presence of clay in the sands

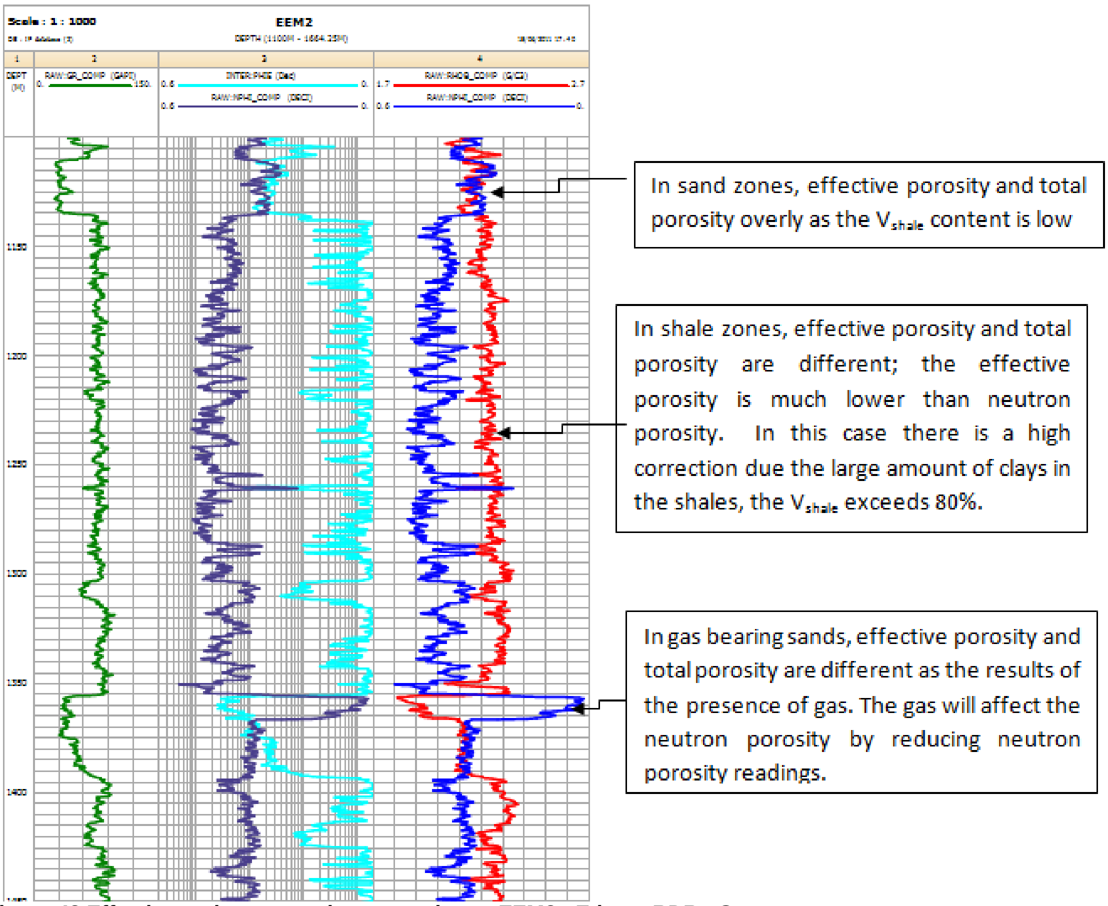


Figure 43 Effective and raw porsoity comparison - EEM2 - Edem - RDR - Cameroon

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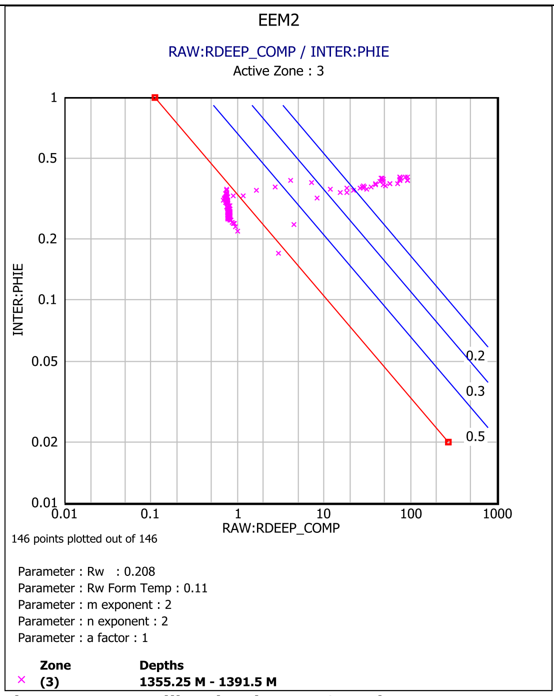

Figure 44 Rw calibration in EEM2 - Edem – RDR

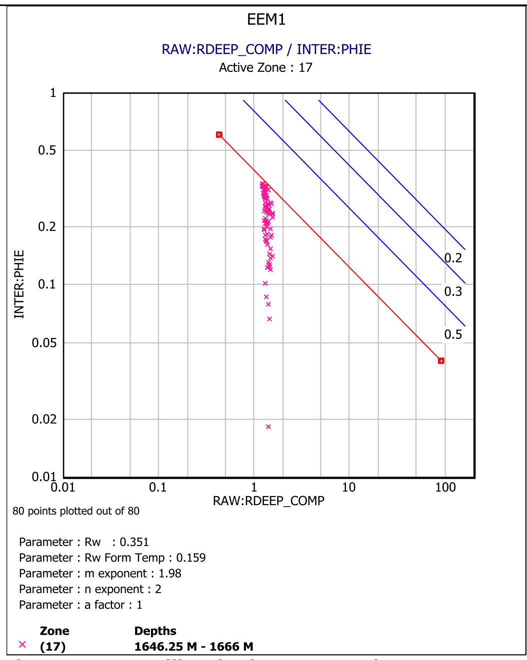

Figure 45 Rw calibrationin EEM1 - Edem

Results

Table 8: Summary of EEM1 petrophysical Properties - Edem - RDR

EEM1							
Zone Name	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl	
	TVDSS	TVDSS	TVDSS			Ari	
S7.1	28.00	9.75	0.348	0.269	0.276	0.173	Gas
S7.2	49.50	29.25	0.591	0.35	0.170	0.15	Thick gas zone
S7.3	37.50	10.00	0.267	0.25	0.20	0.20	Gas + Oil
S7.4	24.25	2.75	0.113	0.175	0.298	0.454	Water
S7.5	24.50	6.75	0.276	0.231	0.284	0.326	Gas
S7.6	5.50	1.25	0.227	0.288	0.169	0.261	Thin oil layer
S7.7	25.50	1.25	0.049	0.281	0.199	0.225	Thin oil layer
S7.8	23.00	10.00	0.435	0.155	0.075	0.259	Thick Gas layer
S7.9	36.00	0.00	0.000	---	---	---	Water
S7.10	7.00	1.75	0.250	0.225	0.420	0.306	??

Table 9: Summary of EEM2 petrophysical Properties - Edem - RDR

EEM2							
Zone Name	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl	Fluids
	TVDSS	TVDSS	TVDSS			Ari	
S7.1	27.00	0.00	0.000				Water
S7.2	54.50	10.50	0.193	0.35	0.15	0.10	Small gas zone with GWC
S7.3	34.00	0.00	0.000				No reservoir
S7.4	24.00	0.00	0.000				No reservoir
S7.5	18.50	5.50	0.297	0.24	0.35	0.25	Oil
S7.6	4.00	0.00	0.000				water
S7.7	25.00	0.00	0.000				Water
S7.8	14.00	2.00	0.143	0.36	0.062	0.05	Thin gas layer
S7.9	19.50	$$0.00	0.000				Water

Appendix F: Related uncertainties in the static model

The volumetrics were derived from 1000 Monte Carlo suimulations in each variable. The range and method used for the variables are detaile in the
Table 10 below:

Variable	Base value	Distribution	Parameters for the S7.3			
GOC	-1384	Uniform	Min	-1386	Max	-1380
PHIE	0.25	Normal	Mean	0.2	Std	0.5
SW	0.25	Uniform	Min	0.15	Max	0.40
Bo	1.30	Uniform	Min	1.10	Max	1.25
NTG	0.6	Normal	Mean	0.5	Std	0.2

Variable	Base value	Distribution	Parameters for the S7.3			
GOC	-1452	Uniform	Min	-1456	Max	-1449
OWC	-1468	Uniform	Min	-1476	Max	-1463
PHIE	0.23	Uniform	Min	0.17	Max	0.35
Sw	0.25	Uniform	Min	0.15	Max	0.40
Bo	1.25	Uniform	Min	1.15	Max	1.35

NTG	0.56	Uniform	Min	0.35	Max	0.7

Table 10 Distribution range of variables used to build the PDF

GOC : In the S7.3 and the S7.5; the base value used was the midpoint between the gas down to and the oil up to. The minimum value was taken at the GDT that was seen at the log and the maximum depth was set at the value of oil up to.

OWC: The uncertainty range of the OWC in the S7.3 was challenging to set up. Indeed, apart from the petrophysical interpretation, no other method could be used to estimate this depth. Consequently, no sensitivity was done on the depth to the OWC. In the S7.5; two different geophysical interpretations gave two different depths to OWC. Consequently, the shallower depth (1468m TVDss) was used as being the base case and the deeper depth (1476m TVDss) was selected as being the high case.

PHIE: The regional cut off of 17% was used as the low case scenario for the effective porosity. The maximum value was set at 35%, this porosity represents the highest value measured in the cores taken in the Kita field.

S_W: The minimum value of water saturation (15%) was taken at the value given by the rock-type 1 that was defined in the Kita field. The maximum was the Sw value of rocktype 3 ie 40%.

PARAMETER	ESTIMATION METHOD	SOURCES OF UNCERTAINTY	Min	Max
OWC	Seismic interpretation	Seismic resolution, depth conversion and picking error	-1463m	-1476m
GOC	Averaging method		-1449m	-1456m
NTG	Wireline interpretation	Facies distribution model, wireline log data and its interpretation	30%	80%
PHIE	Wireline interpretation	Vshale calculation method, log data quality, porosity modelling	17%	35%
S_{wi}	Core analysis	Core acquisition and treatment, log data quality	15%	45%
B_O	PVT analysis	Sample acquisition and contamination	1.05	1.44

Appendix G: Relative permeability curves

The relative permeability analyses were performed for oil versus water and oil versus gas. The rel-perm curves are illustrated in Figure 46 below. These curves were integrated into the reservoir dynamic model

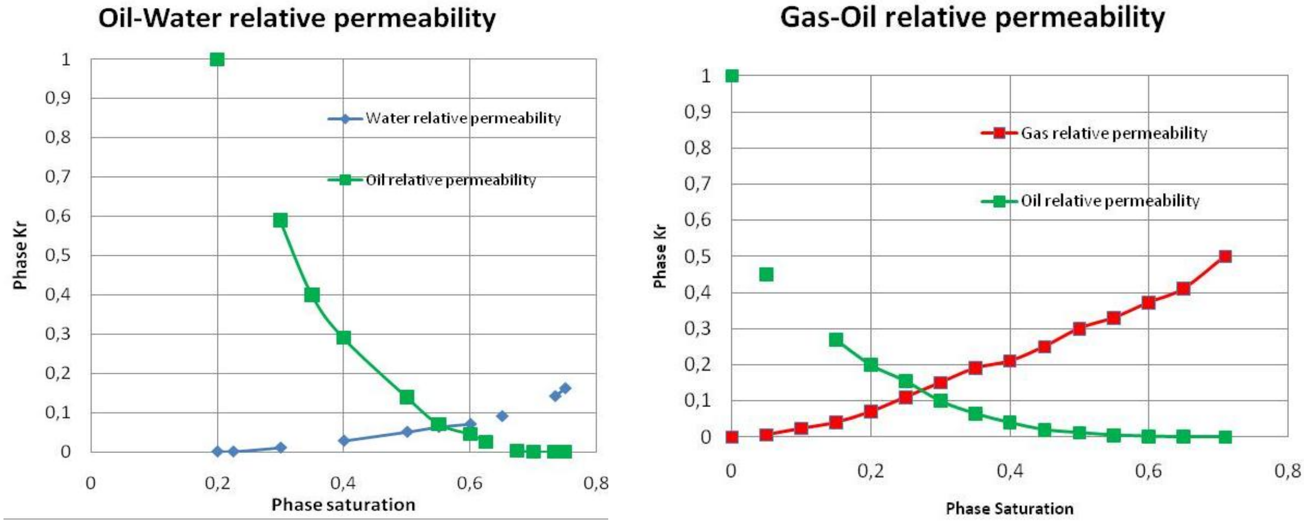

Figure 46 Relative permeability logs -Kita - RDR

Appendix G: Reservoir performance prediction: Buckley Leverett

Two analytical analyses were carried out to predict the Edem reservoir future performance. It is reminded the datasets used to perform these studies were obtained from the Kita field in the absence of datasets from Edem. The first approach presented is the Buckley-Leverett theory that will provide an estimate of the efficiency of a selection of secondary recovery mechanisms. The second study is a material balance analysis carried out in Kita that aims to determine the range of recovery factor that can be achieved in analogs with primary drive mechanisms that are similar to the Edem Field.

Buckley-Leverett

The Buckley-Leverett theory was applied to the relative permeability data gathered from the cores of Kita. The datasets allowed investigating two types of secondary recovery mechanisms. The first is the injection of gas in the oil column and the second is water flooding. The discussion presented below demonstrates that water flooding will lead to better recovery than gas injection in the oil column.

- Water flooding efficiency

The relative’ permeability values were obtained at steady state with a low displacement rate. The cores used to get these measurements confirmed the good reservoir properties in Kita with low residual oil saturation, high permeability and porosity. The water fractional flow curve plotted in Figure 48 shows that the water breakthrough will occur at a water saturation of 64%. To estimate the efficiency of the water flooding, the pore volume recovered as a function of pore volume injected was plotted in Figure 47. The recovery factor increases linearly up to 20% injection till injecting 20% of the pore volume where a good recovery of 46% can be expected assuming a 100% sweep efficiency. When pursuing the water injection, the pore volume recovered could reach an asymptote to the maximum value of 52%.

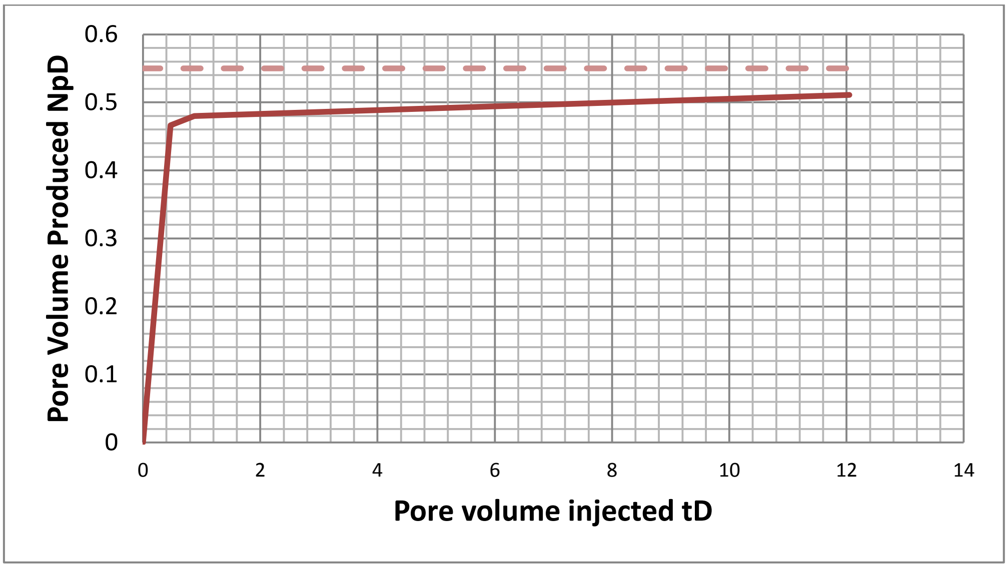

Figure 47 Efficiency of water flooding as a function of pore volume injected - From cores at 2152m MD in KEM11D - Kita - RDR - Cameroon

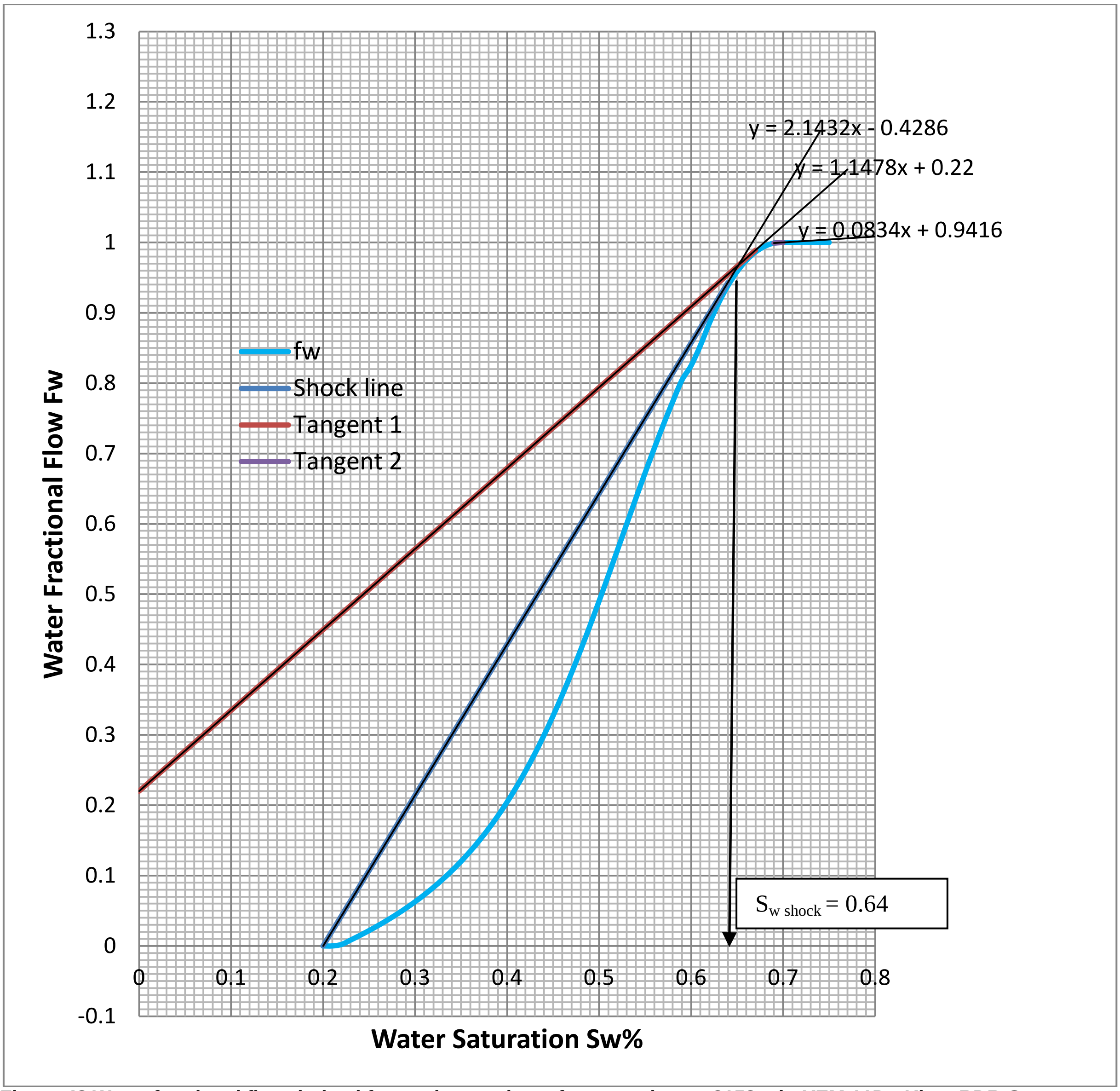

Figure 48 Water fractional flow derived from rel-perm data of a core taken at 2152m in KEM 11D - Kita - RDR Cameroon

- Gas injection into the oil column

Figure 49 representing the gas fractional flow shows that the gas breakthrough occurs at a low gas saturation of 13%. Indeed, even at low saturation, the gas phase has a very high mobility and very quickly, the gas phase overtakes the oil phase. This phenomenon will affect the gas displacement efficiency. The alteration of the gas injection efficiency is confirmed by **Error! eference source not found.**that represents the pore volume produced as a function of the pore volume injected. It can be seen that when injecting 40% of the pore volume, 24% of recovery can be expected assuming 100% sweep efficiency. After injecting 14 times the pore volume of gas, a maximum recovery factor of 38% could be reached.
These results demonstrated that in a case of gas injection into the oil column, the ultimate recovery will be affected by the higher gas phase mobility. The injection of gas into the oil column will not be optimal when compared to the water flooding option. Consequently, injection gas into the oil column will not be investigated in the field development strategy. Pressure maintenance by water injection will be considered during the reservoir simulation studies.

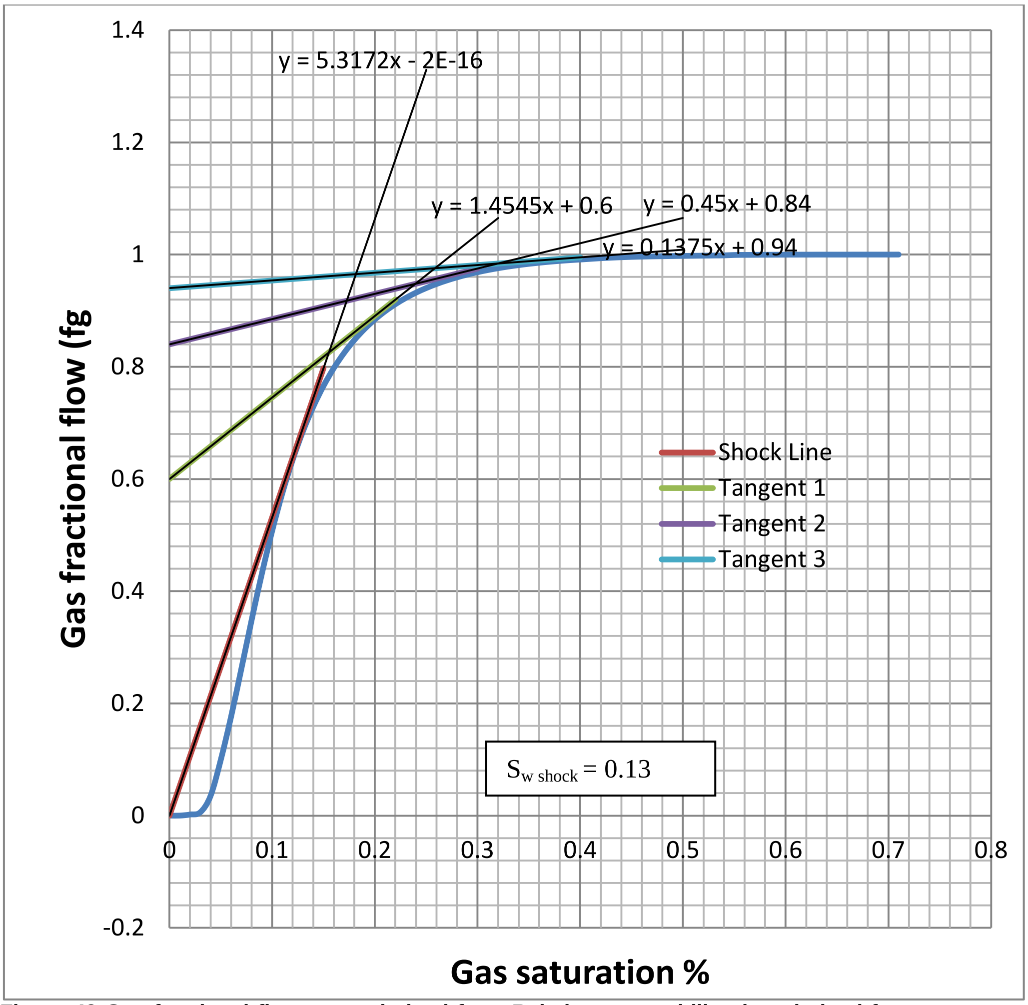

Figure 49 Gas fractional flow curve derived from Relative permeability data derived from a core at 2124m-KEM 11D – Kita – RDR – Cameroon

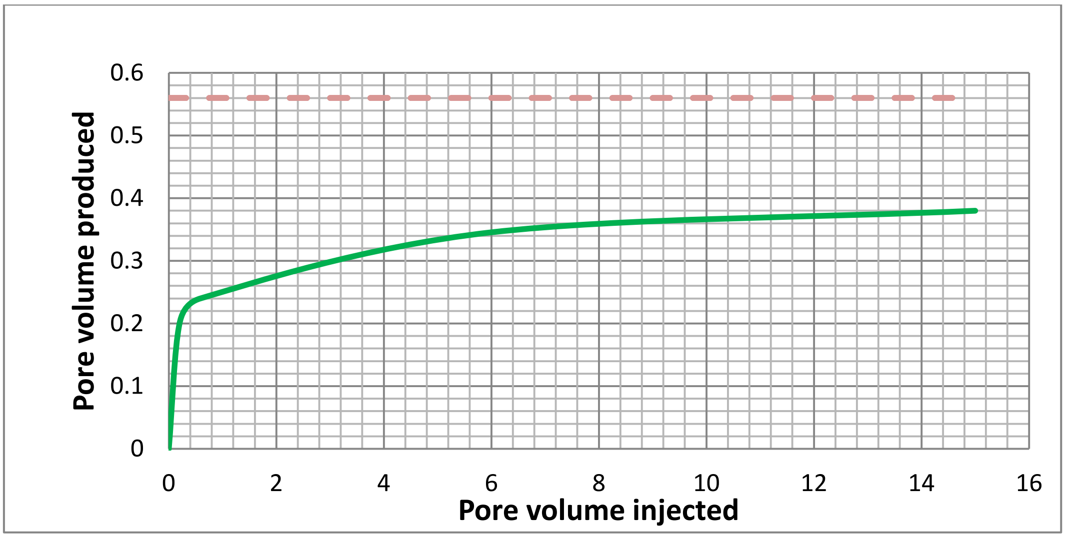

Figure 50 Gas injection efficiency: pore volume produced as a function of pore volume injected - Well KEM 11D - 2124m MD - Kita - RDR - Cameroon

Material balance

In Kita, two layers are producing since 1982: S5H & S7.8. The S7.8 was identified as being the most interesting oil bearing accumulation of the field with a STOIIP of 54 MMBbls (P50 of previous studies performed by Total E&P Cameroun). The pressure decline was only monitored in this reservoir, consequently, the following discussion only covers the S7.8 reservoir.
To conduct this analysis, two scenarios were considered. The first scenario confirmed the results of the previous studies performed on the field with a mismatch from 2003 in the model. The second approach has a reasonable match all through the production history with a very good match from 2003.

Scenario 1: Gas cap expansion combined to infinite aquifer support

As shown in Table 11; the OIIP derived thru this analysis is in depth with the previous studies. The energy plot in Figure 52 demonstrates that the drive mechanism in Kita is quite complex. Indeed; at the start of the production, the primary energy of the field is the gas cap expansion. After 5 years of production, an infinite aquifer gets activated and provides additional energy to the reservoir thus improving the oil production (See
Figure 53).This aquifer impact gets more and more important in time. This external aquifer support was explained by the geological model. The field seems to be opened in the western end of the Basin.
Figure 51 compares the simulation and production data from 1984 till June 2011. Although this model provides a good match until 2003, the last pressure point taken in 2009 challenges this scenario. Moreover, the size of the gas cap is not confirmed by the petrophysical quick-look interpretation and the connectivity to an aquifer needs to be proven as well.

Scenario 2: Gas cap expansion with limited aquifer support

The parameters in this scenario that allows achieving a good match are detailed in Table 12. In this case, a reasonable pressure match is obtained throughout the production history as shown in Figure 55. The OIIP was found to be at 120MMbls which represents twice the STOIIP estimated by the previous studies. With this STOIIP, the recovery factor as of today of this layer is less than 20%. The energy plot in Figure 56 indicates that the main drive mechanism is the gas cap expansion.
In the two cases described above, the main drive mechanism that was identified is the gas cap expansion, in the first scenario; it provides around 40% recovery in combination with an infinite acting aquifer that still needs to be localized. And in the second case less than 20% recovery can be achieved. Whatever the scenario considered, the main drive mechanism of the reservoir seems to be the gas cap expansion. In order to discriminate one or the other case, a quality check of the pressure data taken in 2009 is recommended. This will improve the level of confidence in the results of this study.
The first scenario cannot be applied to the Edem as the existent of an infinite acting aquifer is very unlikely because of the closure of the field. Whereas, the second case can be encompassed in Edem as the existence of a gas cap of the same proportion than in Kita has been identified in both reservoirs of interest.

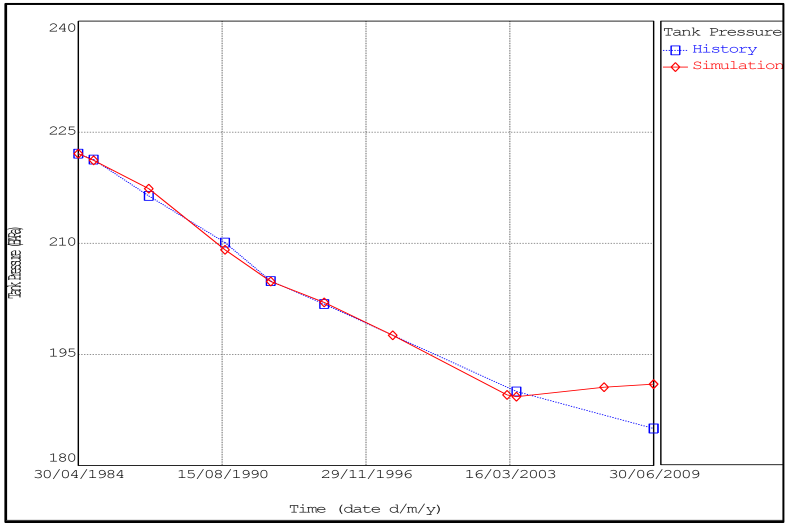

Figure 51: Pressure Match between history and simulated data – Data from reservoir S7.8- KITA field

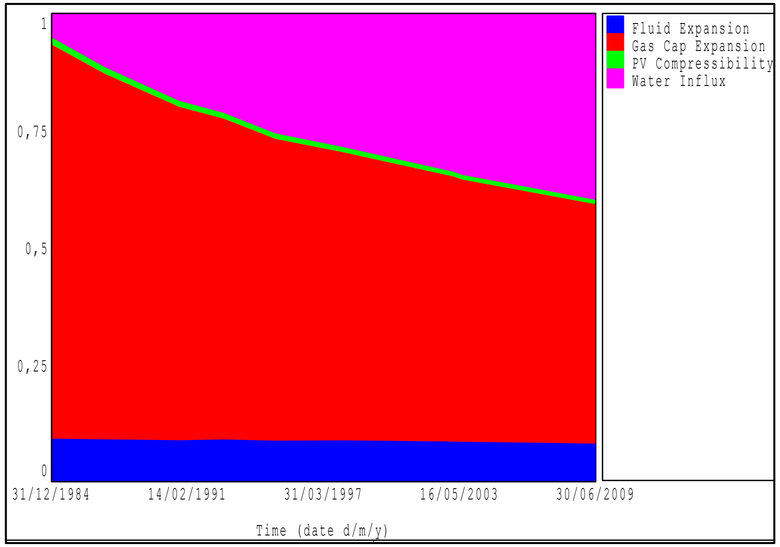

Figure 52 : Identification of Kita field drive mechanisms – Reservoir S7.8

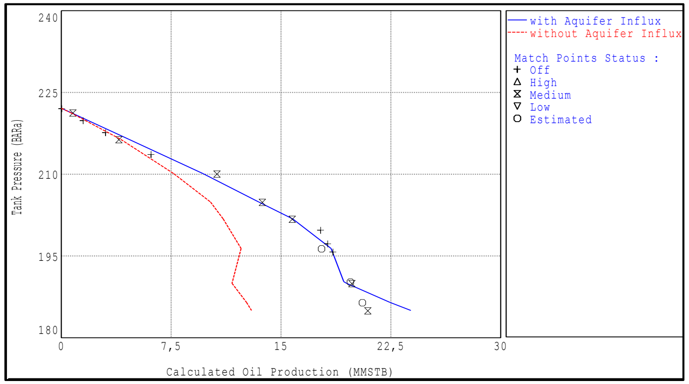

Figure 53: Pressure decline versus cumulative oil production in the S7.8 reservoir – KITA

Table 11: Model parameters for the S7.8 reservoir - Kita - RDR - Cameroon

Reservoir volumetrics			Aquifer characteristics		
Tank Temperature	103	(deg C)	Aquifer Model	Hurst-van Everdingen-Dake	
Tank Pressure	222,1	(BARa)	Aquifer System	Radial Aquifer	
Tank Porosity	0,3	(fraction)	Outer/Inner Radius	25	
nate Water Saturation	0,2	(fraction)	Encroachment Angle	100	(degrees)
Water Compressibility	Use Corr	(1/psi)	Calc. Aquifer Volume	64785,8	(MMRB)
ation Compressibility	3,2e-6	(1/psi)	Aquifer Permeability	50	(md)
Initial Gas Cap	2		Tank Thickness	30	(feet)
Oil in Place	60	(MMSTB)	Tank Radius	30000	(feet)
Production Start	30/04/1984	(date d/m/y)			

Table 12: Model parameters for the S7.8 reservoir - Kita - RDR - Cameroon

Tank Temperature	103	(deg C)
Tank Pressure	222,3	(BARg)
Tank Porosity	0,3	(fraction)
Connate Water Saturation	0,2	(fraction)
Water Compressibility	Use Corr	(1/psi)
Formation Compressibility	3,2e-6	(1/psi)
Initial Gas Cap	1,4	
Oil in Place	120	(MMSTB)
Production Start	30/04/1984	(date d/m/y)

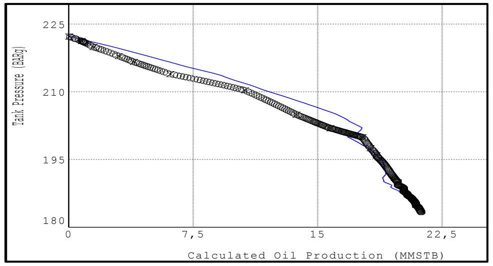

Figure 54: Pressure decline versus cumulative oil production in the S7.8 reservoir – Kita

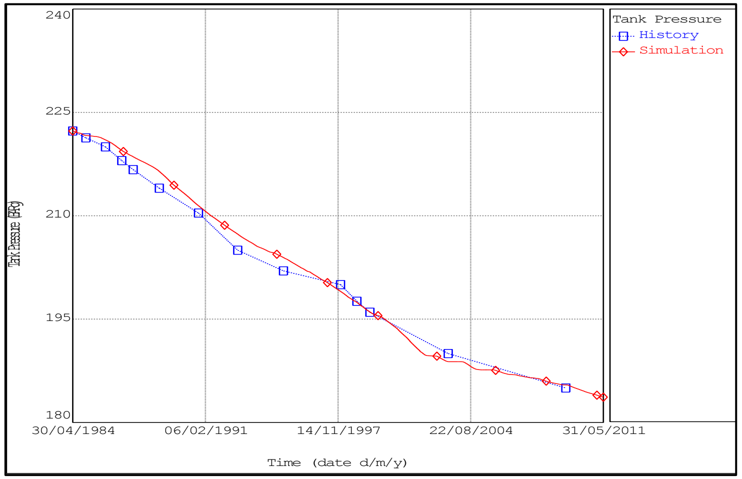

Figure 55: Pressure match - 2nd scenario - Kita field- Rio De Rey

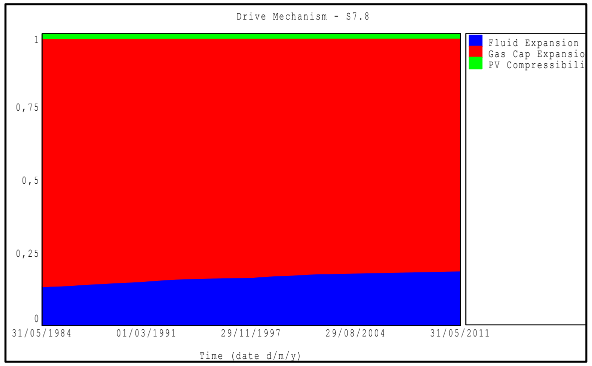

Figure 56 Identification of Kita field drive mechanisms – Reservoir S7.8 - RDR

Appendix I: Secondary recovery optimization

Following the reservoir performance prediction studies, two secondary mechanisms were identified as being able to improve the oil recovery in the S7.5. It was then decided to select between these two methods in order to reduce the numbers of injectors to be drilled. Gas injection into the gas cap and waterflooding efficiency was compared. Gas injection was simulated by modeling a very strong gas cap and water flooding was simulated by configuring a strong aquifer support. The results are illustrated in figure 38. It can be deduced that crestal gas injection will have a greater impact on the oil recovery than water flooding. Indeed; the gas cap is more in contact with the oil column than the aquifer. Moreover, the gas cap injection will ensure a better pressure maintenance.

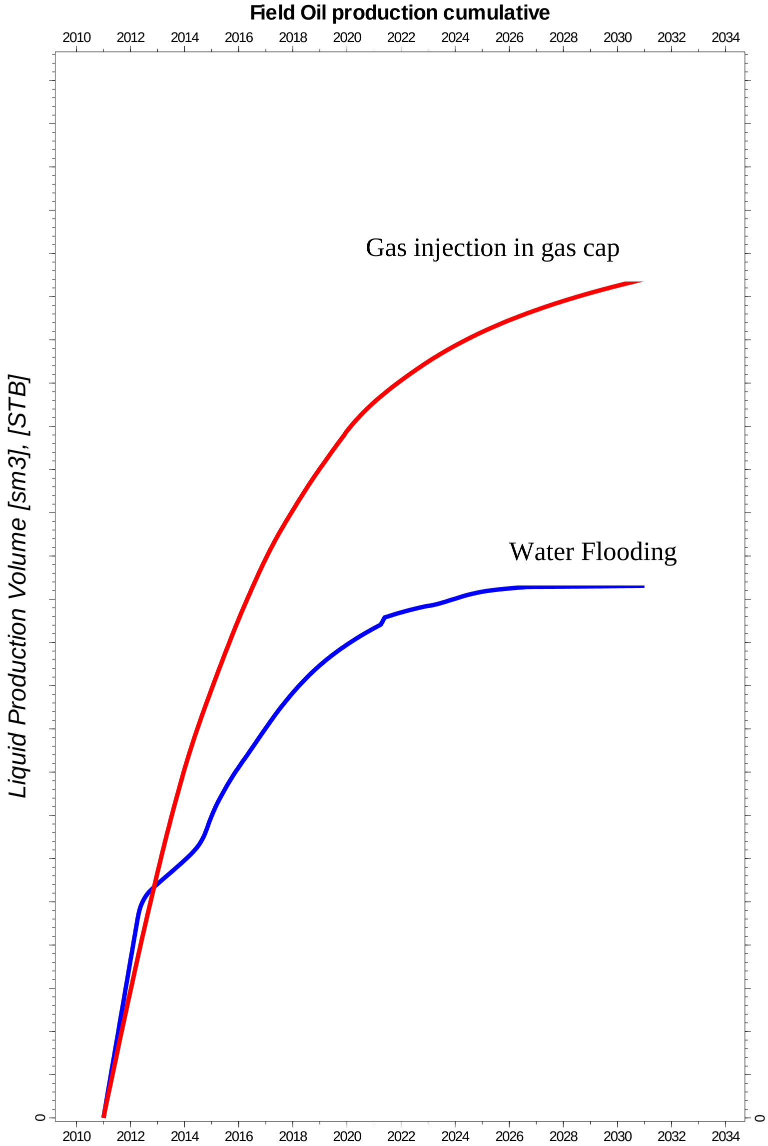

Figure 57: Comparison between waterflloding and gas cap injection - S7.5 - Edem - RDR