Imperial College London

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Thesis title: Integrated analysis and synthesis of the dynamic behaviour of a carbonate field

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Abstract

This project was carried out in chronological order of the field development from exploration to production phase. The objective is to synthesize the evolution of the Alpha field representation and understanding over time by progressively doing integrated analysis on the field dynamic behaviour.

As the results, different dynamic models (MBAL/Eclipse) were constructed; field pressure, gas water contact rise and subsidence history matching were achieved with good matching qualities; early water breakthrough timing and risk were estimated; alternative scenarios are provided for comparison and forecasting use; synthesis/recommendations in terms of reservoir modelling, field development and monitoring are also given at the end of each phase, through which the evolution of the reservoir understanding in function of time and available data is clearly seen.

Alpha field is currently interpreted as a heterogeneous reservoir under significant rock compaction and aquifer drive. The lesson extracted from this project is: no matter which type of carbonate we are dealing with, the importance of water bearing reservoir rock compaction (derived from the plastic compressibility) and related early WBT problems should be taken into account from the very beginning where no signal is seen yet. Coherent models could only be constructed by integrating all available data. A wrong estimation of production energy leads to an incoherence from history and an overestimate of the final recovery factor.

Future works could be focus on the data acquisition such as core and fluid sampling from aquifer and full 4D seismic data (rather than 3 seismic lines) in order to better correlate the 4D effect observed in the aquifer.

Key word: Evolution, carbonate gas field, rock compaction

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Introduction

The Alpha gas field (Fig.1) is located offshore. Its carbonate platforms: the Oligo-Miocene were developed on an inner volcanic arc [1]. It presents an average reservoir thickness of 200 meters and an estimated Initial Gas in Place (IGIP) around 6 Tcf (Trillion cubic feet).

It is first discovered in 1982. The production started from the end of 1998, with an average production rate around 700 MMscf/D. Production is predicted up to 30 years at a recovery factor of 88%.

With regard to the dynamic behaviour, the Alpha field is a geologically heterogeneous carbonate reservoir under significant aquifer and compaction drive. The heterogeneity mainly comes from the fracture networks caused by dissolution process associated with the epikarst and island karst [4]. These vertical connections through fracture/fault corridors pose a risk of early water breakthrough, which will have a significant impact on the production forecast. On the other hand, an average value of 30 cm/year of subsidence was measured, which confirms that the field is experiencing an active compaction drive. Hence, more attention is paid to the fracture/fault and compaction modelling in this study in order to better capture the dynamic characters of the field. To achieve these objectives, an oedometric plastic compressibility law and a local grid refinement were respectively used in the dynamic modelling.

Many previous studies [2, 3, 4] have already been carried out, and the vision and representation of the reservoir evolved with time. The result of these studies provides this project a good start point, while the evolution requires a synthesis to better characterize the field's dynamic behaviour in the future.

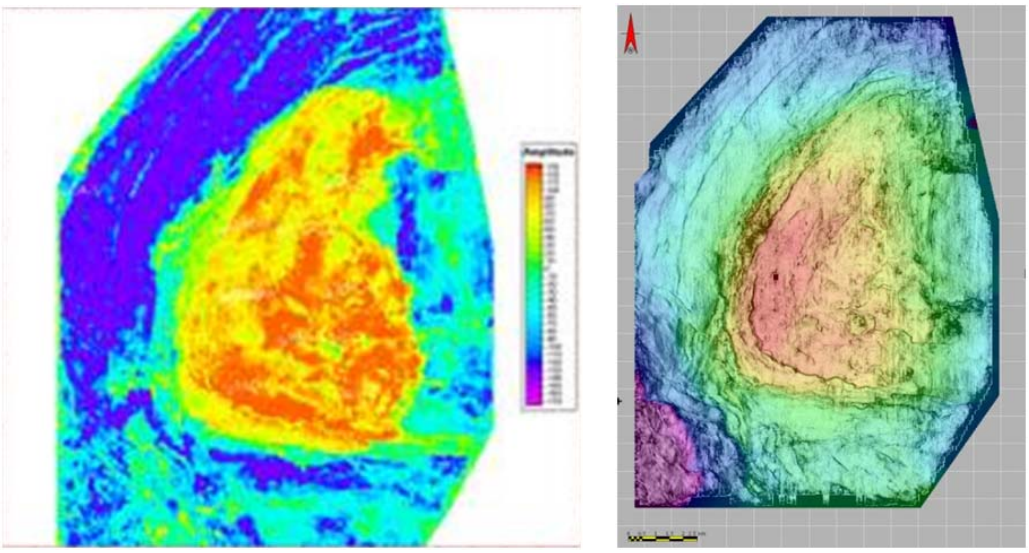

Figure 1: Top UBL (Upper B limestone) amplitude and time map of Alpha field

The main objectives of this project include:

- Integrated analysis of the field dynamic behaviour through exploration, appraisal and production phases;
- Synthesize the evolution of the reservoir representation and understanding;
- Give recommendations in terms of reservoir modelling, field development and monitoring for analogue fields;

The key point is to understand the evolution of the reservoir understanding along the time rather than to simply repeat the process. In order to achieve these objectives, the following concrete steps were carried out:

1. Critical literature review: To get familiar with the project background, the works that have already been done during the previous studies and the methodology that will be used for data analysis and reservoir modelling.
2. Exploration and appraisal phase study: To have a primitive understanding of the field behaviour with limited data and to summarize the evolution of reservoir understanding in terms of reserve assessment, uncertainties reduction and reservoir modelling.
3. Production phase study: To refine the reservoir model (Eclipse/Petrel) using the newly available data (Stratigraphic study, sedimentary study, aquifer study, rock typing, geomechanical measurements and subsidence monitoring etc.) and to synthesize the evolution of the reservoir understanding/modelling over time.

It is necessary to mention that at each phase by following the data availability order, we try to on one hand retrieve the interpretation result at time, and on the other hand to provide alternative scenarios and to analyze theirs impacts.

Critical literature review

Due to the limitation of the subject, very few SPE papers could be found that relate to the characterization and simulation of the Alpha field. Therefore, most literatures reviewed here are selected from the company internal archive database. Nevertheless, some SPE papers that concern the compaction drive and fracture/fault modelling are also selected to read in order to better understand the reservoir production mechanism.

"The Effect of Fluid Pressure Decline on Volumetric Changes of Porous Rocks" [5] provides one of the most foundamental theories about compaction drive mechanism, which helps to better understand the active compaction drive mechanism that is happening in the Alpha field. It could also be useful for the carbonate compaction drive modelling since this paper gave explicitely the relationship in limestone reservoir (although under assumption of homogeneous and continuous matrix material).

"Eocene to Miocene Composite Total Petroleum System" [1] provides very useful geological description about the stratigraphy, plate migration, source rocks, reservoirs, seals traps, timing, and petroleum information for the Eocene-Miocene Composite Total Petroleum System (within which the Alpha field is found), which is essential to understand geologically the formation and behaviour of the reservoir.

"Alpha, Beta, Integrated Field Study 2007" [2] provides very useful information to understand the slower than anticipated reservoir pressure decline due to either a larger IGIP or a stronger aquifer drive. Moreover, it clearly indicates an E-W tilt of the GWC rise. Therefore, more attention should be paid to aquifer modelling, IGIP assessment and GWC rise match for the Alpha field in my study.

The way that Luc CANTEGREL et al. [3] carried out their study could be used for my own study. This report also indicates 3 main aspects which control the Alpha field behaviour and which should be given more priority in my project: 1) Coral facies distribution and its petrophysical properties; 2) Heteogeneous water rise from the east; 3) Subsidence and reservoir compaction.

"Alpha 2010, Updated sedimentary model integrating diagenesis" [4] identified two main types of early diagenetic overprint by rock typing: epikarst and island karst. These are essential informations to understand the formation of the vertical fracture corridors existing in this field, which definitely has a significant impact on the water break through prediction.

Making development plan concerns the type of production wells that will be drilled. "Cost/Benefits of Horizontal Wells" [6] listed the benefits and disadvantages of horizontal wells in different applications, and compared the vertical wells cost/benefits with the horizontal ones, which contributed a lot to the benefit/risk assessement of Alpha field development plan using horizontal wells.

Exploration and appraisal phase study

The first regional seismic line (20x20km) was obtained in 1971. Since the discovery of Alpha field in 1982, in total 4 vertical exploration wells (namely A-a, A-b, A-c, and A-d) were drilled, cored and tested during the 1980s. Then a 3D seismic survey was performed and an appraisal program drilled another 4 vertical wells (namely A-1, A-2, A-3 & A-4) between Q1-Q3 1993 for the delineation. The following seismic interpretation, laboratory measurements and geological/reservoir studies were also carried out in order to estimate the reserve and the uncertainties related to each parameters.

Available data sources and parameters

All available data sources at this stage and the related parameters were analysed and organized in the Appendix B.

Apparently, except the well performance related parameters, all other major parameters were investigated both in exploration and appraisal phase. More importantly, we should note that the formation water analysis and the 3D seismic survey were only carried out during the appraisal phase. A range of values for the key parameters could therefore be obtained using different data sources, which is provided in the Appendix C. These parameters ranges will finally serve the IGIP/reserve calculation and the uncertainty analysis.

Reservoir dynamic characterization

Alpha is a shallow (Top reservoir - 1270 mTVDSS), low temperature (140F), low pressure (2520 psia @ datum) gas field, with an average porosity (cores and logs) of 28%, and an average field permeability of 170 mD. Permeabilities vary from well to well, while the wells situated in north showed apparently higher values than the southern ones, which is totally coherent with the AOFP (Absolute open flow pressure) and Fetkovich PI (Production index) calculation for all existing wells using DST data.

On plugs, Kh vs. Kv and Phi vs. Kh correlations are good (presented in the Appendix D), indicating a homogeneous medium with permeability anisotropy ratio Kv/Kh close to 1. The average gas saturation is around 80% (overburden corrected).

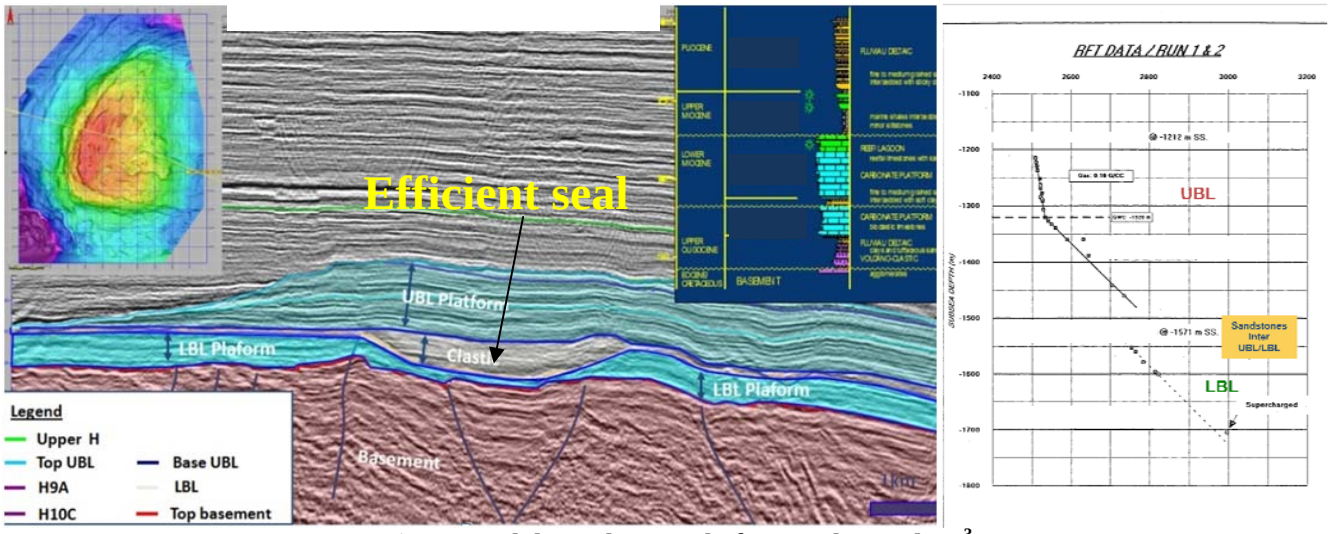

Figure 2: Alpha carbonate platform and RFT data [3]

From the RFT data shown above, Gas water contact was unambiguously identified at 1320mTVDSS, which is coherent with the log interpretation result. Moreover, the discontinuity of the water pressure gradient indicated the existence of vertical permeability barrier at bottom UBL, which limited the bottom aquifer at UBL platform only (rather than connected with LBL (Lower B limestones) low permeability aquifer).

IGIP/reserve assessment and uncertainty analysis

The standard geological and engineering methods (which are generally accepted by the petroleum industry) were used to estimate volumes of gas in place. Structure and isopach maps were prepared to aid in evaluating reservoir volumes. Welllogs, core analyses, fluid analyses, botlom-hole pressures, and other available data were also used to determ ine the volumes of gas contained in the reservoirs.

Table 1 shows a summary of IGIP and reserve assessment for Alpha field during the first two phases. The result of uncertainties analysis for different phases is presented in the Figure 3. An evolution of the uncertainty ranges could be observed, which will be discussed in the 'Synthesis' part of this chapter.

		P10	P50	P90	Difference between P10/P90
Exploration	**IGIP (Tcf)**	4,91	3,64	2,44	2,47
	reserve (Tcf)	4,42	2,80	1,22	3,20
Appraisal	**IGIP (Tcf)**	5,83	5,37	4,91	0,92
	reserve (Tcf)	5,25	4,13	2,46	2,79
Recovery factor		90%	77%	50%	-

Table 1: Evolution of IGIP/reserve assessment through exploration/appraisal phase

Apparently, the difference between P90 and P10 was greatly reduced during the appraisal phase. The recovery factor (RF) here was estimated on considering the fluid properties, the analogues, the reservoir permeability, the reservoir drive mechanism, the production technology and the irreducible hydrocarbon saturation. According to the field permeability sensitivity analysis (c.f. Appendix E), this high RF was also based on a good field permeability assumption (K_{av} >10 mD).

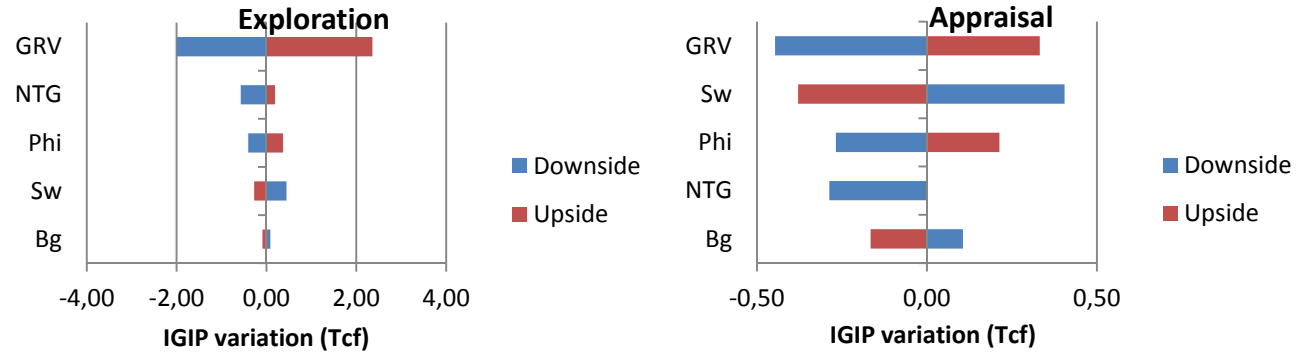

Figure 3: Evolution of uncertainties ranges through exploration/appraisal phase

Thanks to more available data sources and more robust seismic interpretation, the uncertainty range of each parameter especially GRV, NTG and porosity is greatly reduced. At the end of the appraisal stage, GRV, Sw and porosity are identified as the major uncertainties.

Construction of MBAL / Eclipse model

MBAL model (Exploration phase)

With limited reservoir data and knowledge, a simplified MBAL model could already be built during the exploration phase. At this early stage, this model was then used for production forecasting and recovery factor range validation use. Its key parameters are listed in the Table 2. By varying aquifer permeability, aquifer volume, plateau rate, irreducible gas saturation and the rock compressibility, MBAL sensitivity analysis gave a RF range from 76% - 89%, which corresponds well to the result obtained previously.

Petrel / Eclipse model (Appraisal phase)

During the appraisal phase for IGIP assessment use, a simplified Petrel model was first built by the geologist colleagues using the 3D seismic interpretation and available well logs, with the main set of parameters listed in the Table 2. Based on its grid, an Eclipse model was then built for sensitivity analysis and development strategy study use. Similar key parameters were used as in the MBAL model, which are also listed in the Table 2 below.

MBAL model	ECL model	Petrel
Rock Cp: 2.4e-5 1/psi Water Cp: 3.0e-6 1/psi IGIP: 5.53 Tcf Phi: 0.28	Aquifer Cp: 1.0e-5 1/psi GWC: 1320 TVBSS Gridded bottom aquifer Well specifications Grid & Heterogeneities K & Phi tables	Block size: 200 x 200 m Vertical layer numbers: 32 IGIP: 5.53 Tcf Seismic Horizons Well markers and logs Fault polygons sticks or surface Facies numbers: 2 Phi/K law (core)
PVT, Saturation table Production strategy and constraint Fluid properties, reservoir pressure & temperature Aquifer type: Carter-Tracy & properties		

Table 2: Parameters used for the construction of different models

By running a simple forecasting case without aquifer using the same production control and strategies, the average field pressure profile of ECL and MBAL models matches each other well (c.f: Figure 4a), which undoubtedly confirmed the coherence between the different dynamic models.

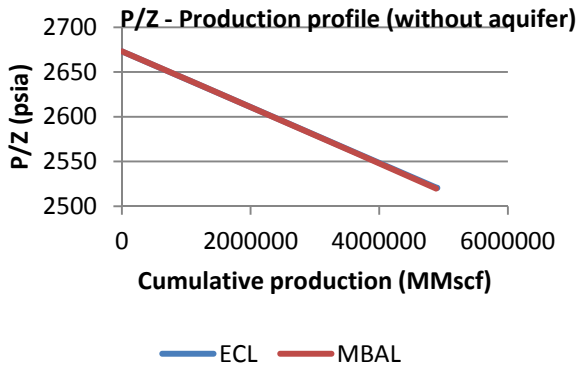

Figure 4a: Comparison without aquifer

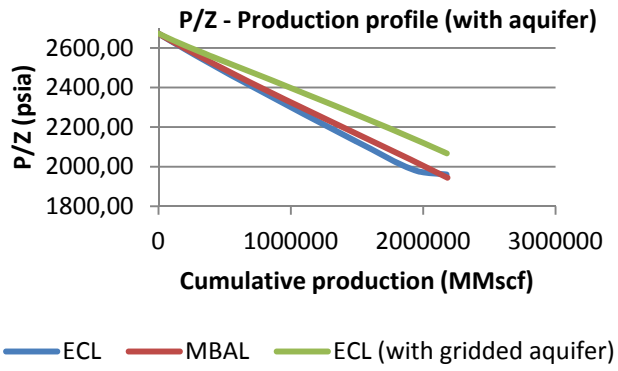

Figure 4b: Comparison with aquifer

However, by adding a Carter-Tracy aquifer with the same set of parameters (angle, thickness, radius, permeability, compressibility etc.), same simulation was repeated and a non-negligible difference appeared between the two models (c.f: Figure 4b). Since MBAL model is too simplified to modelling the rock compressibility, the aquifer connection area/influx direction and the field heterogeneities, it will not be as useful as Eclipse for further reservoir studies such as water breakthrough forecasting during the following phase.

Development strategy revision

Since we can not change the development strategy that was already adopted, the objective of this revision stays on giving suggestions for analogue reservoirs' development. Different development scenarios were studied and the benefits/risks related to each scenario were also analyzed. Sensitivity analysis were carried out with regard to the well types, well numbers, well locations, well size and well operation using Prosper + Eclipse, and the two optimized candidate scenarios were presented in the Table 3 and Figure 5.

Scenario	Well type	Well numbers	Tubing inner diameter (inches)	Average PI (Mscf/D/psi)	Plateau length (years)	Advantage
1	Vertical	24	6	3000	8,9	Low cost Easier to manage
2	Horionzontal	6	10	5000	8,7	Low water cut Higher recovery

Table 3: Different development strategy comparison

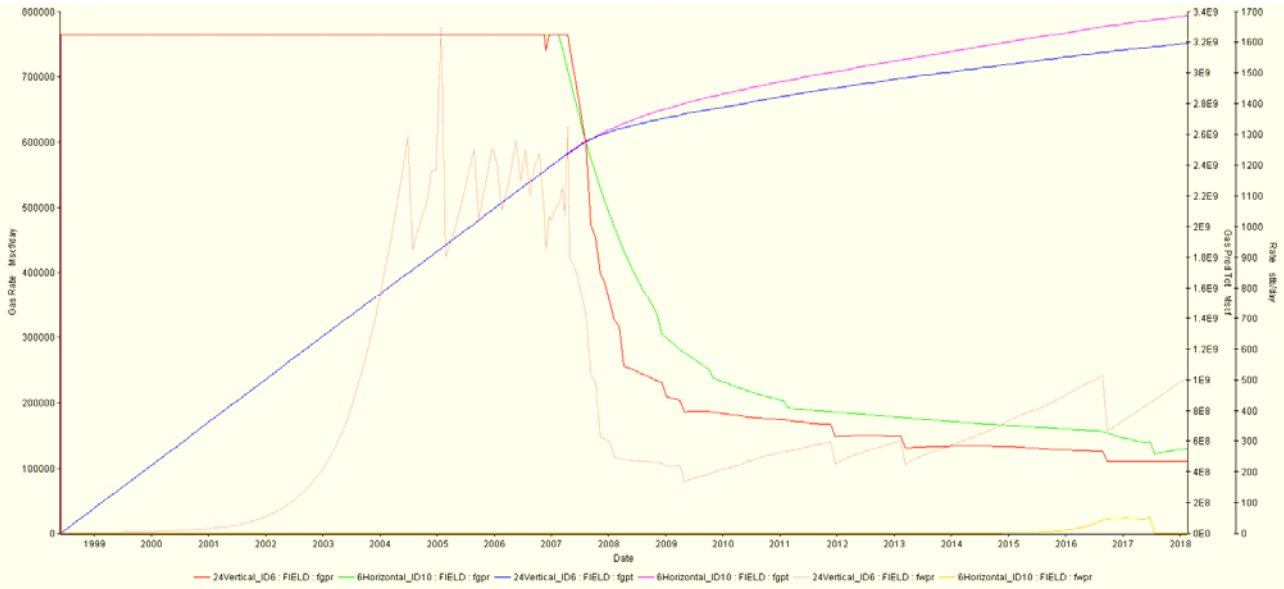

Figure 5: Production profile of the 2 optimized development scenarios

Based on the accompanied economics analysis, the horizontal well option seems more attractive on taking into account the cost and the recovery. We should bear in mind that in case of a multiple pay-zone reservoir especially with important vertical permeability barriers [7], there could be a huge drain problem if all wells were located at the same depth. As to Alpha field, although some barriers were observed from certain wells previously drilled, the well correlation showed no connection between these barriers and therefore eliminates this risk from happening.

Synthesis

From the exploration phase (4 exploration wells) to the appraisal phase (4 appraisal wells more), more information from coring, logging and 3D seismic survey was available, which leads to a better reservoir characterization and therefore greatly reduced the major uncertainties such as:

- GRV: The adequate and detailed 3D image of the subsurface and the additional wells for VSP calibration together lead to a more reliable seismic interpretation, which helps greatly reduce the uncertainty range of GRV;
- NTG: Due to the poor well location and data quality, the NTG range from exploration wells was estimated from 80% to 1. However, all the 4 new appraisal wells give NTG values very close to 1 (based on the fact that no permeability lower than 0.1 mD has been encountered on plugs), which greatly reduce the uncertainty range of NTG;
- Sw: A better estimation of the brine water salinity and resistivity was obtained by brine water analysis, which partly reduced the uncertainty range of Sw in petrophysical analysis;
- Porosity: Initially, the porosity distribution of Alpha field was relatively narrow and concentrated around 28% during the exploration phase. New RCAL and logs data from appraisal wells further confirmed and reduced this range.

Moreover, based on advanced simulatiors and newly obtained information, integrated static and dynamic models rather than a “Tank” model were built during the appraisal phase, which largely inhanced the capacity and accuracy of reservoir modelling.

Nevertheless, three features were shared by these early phases during the study of the reservoir behaviour:

- Limited data source: No production data, no geomechanical measurement, no 4D seismic interpretation, etc.
- Relatively poor data quality: Weak representativeness of data from certain wells, low seismic section resolution, etc.
- Primitive methodology of interpretation and modelling: Block size, properties modelling methods, WTA, etc.

Behaving like a simple "pressurised tank", Alpha is temporarily interpreted as a homogeneous reservoir under bottom aquifer drive with a volume of 80 Grb/1.28E+10 m3 (8000*8000*200m). Aquifer water influx and gas expansion constitute the major production energy. However, the heterogeneity can express itself later in the field life, which will be discussed in the next chapter.

Without dynamic data, the major objective of this stage stays on the reservoir static characterization and the reserve assessment. The initial GWC was determined, the first reservoir model was constructed, the major uncertainties were identified and a range of IGIP was estimated as listed previously. Other uncertainties lie in the heterogeneity characterization and the aquifer size/strength determination due to the limited data source.

Production phase study

Based on the previous studies, the development decision was made and the accompanied development strategies were also formed. The development drilling was carried out in 1997-1998 from two platforms WP1 and WP2, during which one vertical (observation) and six horizontal (production) wells were drilled from each of the two platforms. The production started from May 1998, with an average rate around 700 MMscf/D to meet the DCQ (Daily Contract Quota). Geological model update, 4D seismic interpretation, updated sedimentary study, geomechanical measurements, aquifer studies, RST test and subsidence monitoring were then carried out during this phase, which largely enriched the reservoir database.

Static model update (Petrel grid)

A refinement of the Petrel grid was carried out by geologist colleagues using stratigraphic and 4D seismic data, and a finer grid (block size 100 x 100 m, with an increased vertical layer number of 44 and the new fault sticks mapped in 2009) was generated with objective to improve the conditions of the dynamic simulations. Moreover, 9 Petro Geological Groups (PGG) were defined by doing Rock Typing (RT), which further improved the facies/petrophysical properties modelling in Petrel.

Base case IGIP of the updated model is: 5.58 Tcf. All the studies below are based on the updated model using the refined grid.

History matching (HM) & Dynamic model calibration

The production history was divided into two stages (first 300 Bcf production/total productions) in order to show the evolution of reservoir interpretations along the time. HM was respectively carried out for these two stages to dynamically recalibrate the model including the IGIP (using pore volume multiplier), rock compressibility (based on the available geomechanical data), fracturation/fault impact (based on the available sedimentary study), aquifer related parameters (based on the available sedimentary interpretation) and GWC rise (based on the RST campaign data).

History matching P/Z vs Gp for the first stage (until Mars, 2002) provided different matching scenarios summarized in the Appendix F. The P/Z vs Gp rather than P vs Date was used because it is independent of the gas production rate and more meanful to present the production energy evolution.

Good match is still achievable. Temporarily, no analytical aquifer was attached on taking into account the result of an aquifer sensitivity analysis which showed that the additional analytical aquifer has negligible influence on the field pressure profile at the beginning. However, the Figure 6 showed that the homogeneous models leaded to a much weak pressure support than the reality during the later part of the production history (until Dec, 2009).

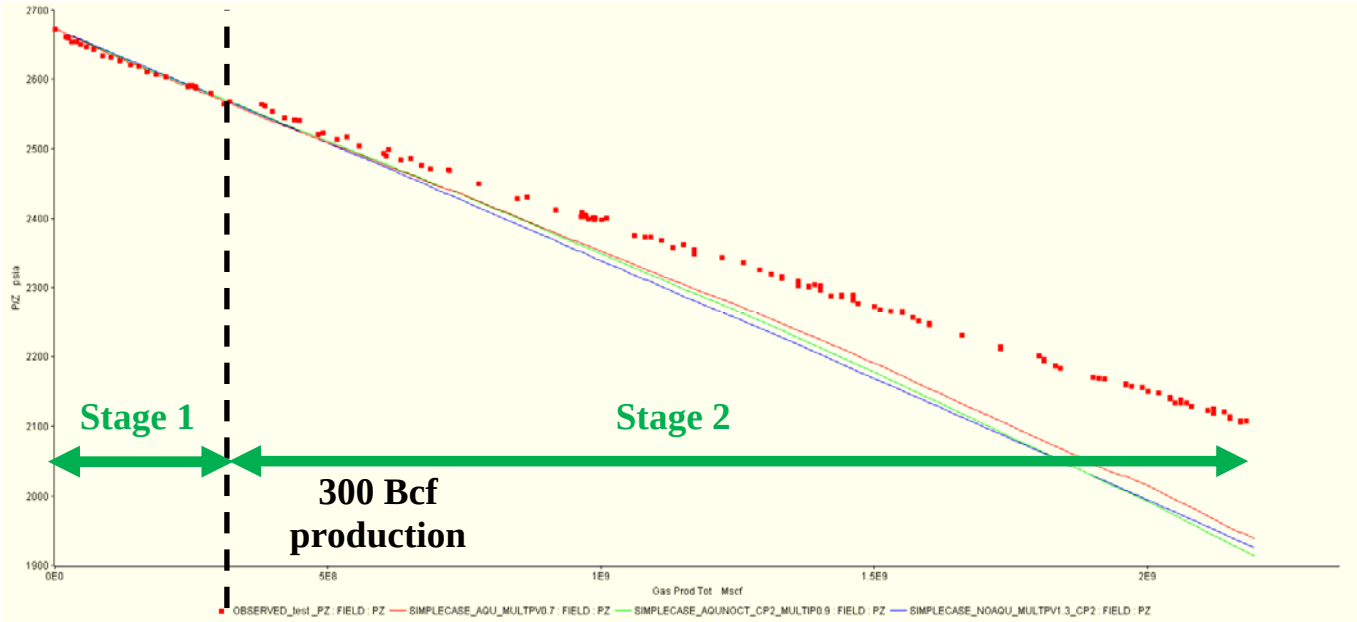

Figure 6: Simulation of 10 years pressure profile using parameters from the first stage

For the no aquifer case, the real pressure support is too good to be only associated with the IGIP and rock compressibility, which clearly indicated the existence of a strong aquifer. As to the cases with aquifers, it was difficult as well to match the

later and earlier part of the history at the same time due to the bending shape of the history curve, which no doubt suggested that further refinements of the reservoir model are necessary.

Rock compaction modelling

During the production phase, a geomechanical test was carried out in order to measure the rock collapse stress, elastic and plastic compressibility at different saturation state (C.f. Appendix K). By fitting the discrete lab data, a Collapse Stress – Porosity correlation and the compressibility laws corresponding to different cells in function of saturation change (ΔSw > 10%) were generated and presented in the Figure 7, which favors the collapse of aquifer. These relations were corrected from the loading rate effect using De Waal's concept [8]. Moreover, to represent the oedometric strain conditions in the field, the values are also corrected using the following equation:

$$C_{pp}^{Oedo} = C_{pp}^{iso}\left(1 - \frac{2\alpha(1-2\nu)}{3(1-\nu)}\right) - C_s\,,$$ with: α=0.85, ν=0.25 and C_s=0.013E-04 bar^{-1} for carbonate

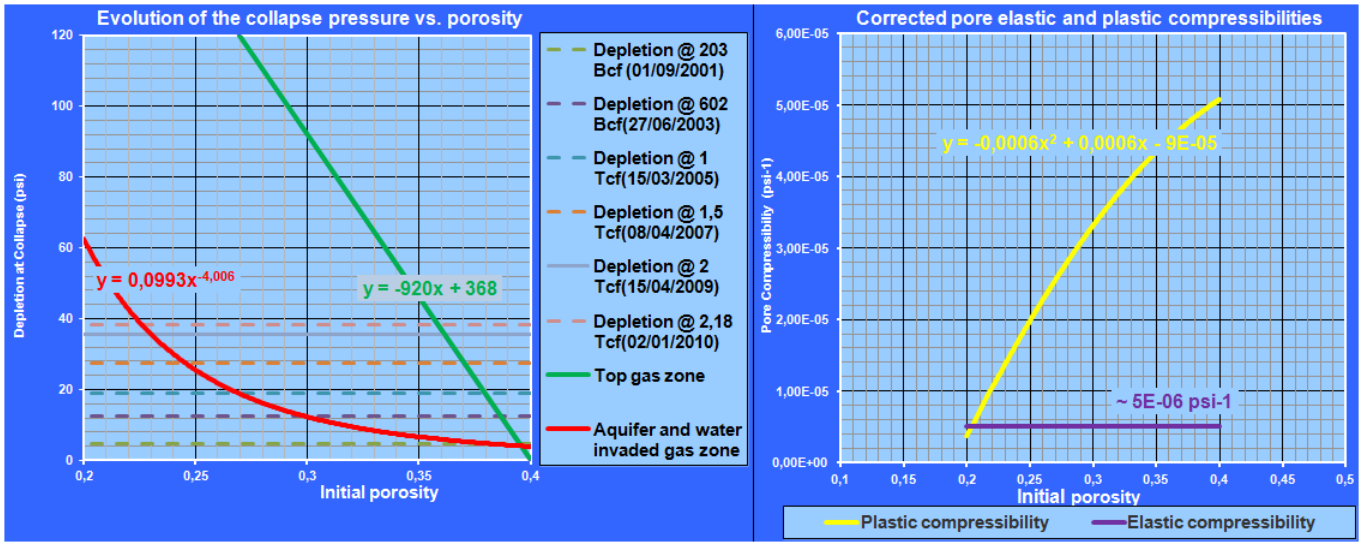

Figure 7: Rock collapse stress and compressibility laws

However, the lack of information about the initial reservoir stress could have a significant impact on the accuracy of the plastic compressibility curve, hence this relation was treated as a variable to match the subsidence, GWC rising and the field pressure.

By applying these geo-mechanical laws, a water induced rock compaction model was constructed using keywords ROCK2D, ROCKWNOD and ROCKOPTS to replace the simple elastic rock model previously used. Once the pore space collapses (elasto-plastic regime changes) due to the depletion, a much higher plastic compressibility will dominate the rock behaviour, which corresponds well to the upward bending trend observed in the Figure 6. The extended 4D anomalies observed in the aquifer (c.f. Appendix G) could probably be explained by this rock compaction modelling: the water bearing zone has a larger thickness, higher average porosity and lower collapse stress, which leads to a larger compaction and fracturation effect corresponding to those 4D effects.

Edge aquifer

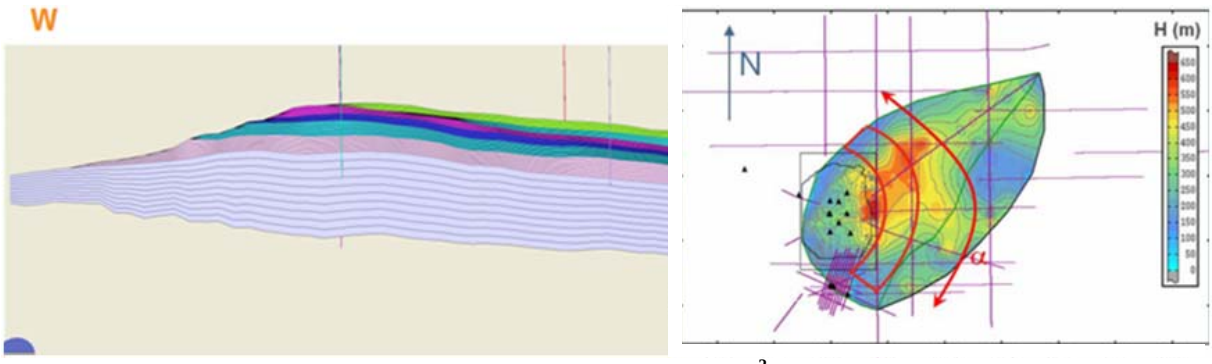

Figure 8: Aquifer extension [2]

According to the aquifer study carried out during this phase, the bottom aquifer was actually extended towards the east (Figure 8) with an estimated volume between 2.3E+10 m3 and 3.1E+10 m3. Hence, an additional analytical Carter-Tracy aquifer was attached to the east, north and south edge of reservoir model in order to represent the aquifer extension and to give a better estimation of the production energy distribution. The key parameters used are listed in the Table 4, which were chosen in agreement with the surface map given above.

Aquifer Permeability (md)	153
Aqfuier Porosity (%)	28,50%
Outside radius of reservoir (ft)	15000
Aquifer Thickness (ft)	1500
Outter/inner radius ratio	3.5

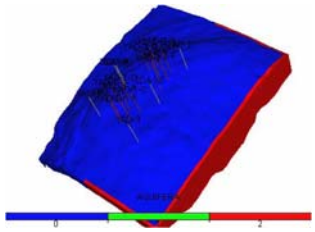

Table 4: Base case Carter-Tracy parameters & aquifer-grid connections

The importance of analytical aquifer could be seen at the later stage of production. Additionally, no 4D effect was observed below the base UBL (c.f. Appendix G), which is consistent with the fact that the bottom aquifer is limited by base UBL.

Subsidence modelling

Subsidence is a common fenomenon widely observed in reservoirs under rock compaction drive such as Ekofisk. In 2010, a bathymetric measurement was carried out over the field area and was compared with the bathymetry data from 1993 3D seismic. Through the tide and datum correction, a subsidence map was generated by subtraction 1993-2010 (Fig. 14a). The maximum subsidence is found North West of the platform 1at -2.5m.
Under oedometric conditions, we suppose that the area DX*DY does not change along the time for each block. Therefore,

$$\Delta V_b = DX * DY * \delta L$$

According to the compressibility definition, we have:

$$\frac{\partial V_b}{\partial P} = \frac{\partial V_p}{\partial P} + \frac{\partial V_s}{\partial P} = C_{pp} * V_p + C_{ps} * V_s = C_{pp} * V_p + C_{ps} * V_p * (1-\phi)/\phi$$

Therefore, by plugging the second formula into the first one we have:

$$\delta L = \frac{V_p * \left(C_{pp} * \Delta P + C_{ps} * \Delta P * (1-\phi)/\phi\right)}{DX * DY}$$

Since $C_{pp} * \Delta P = \frac{\partial V_p}{V_p}$ which is an Eclipse output, finally we have:

$$\delta L = \frac{V_p * \left(\frac{\partial V_p}{V_p} + C_{ps} * \Delta P * (1-\phi)/\phi\right)}{DX * DY} \qquad (*)$$

Using equation (*), simulation output and Petrel properties calculator, we could calculate a subsidence map by summing up vertically the ΔL field. The total subsidence volume was then calculated by integrating the ΔV_b over the field.

Conductive faults modelling

Strong 4D effects were also observed along certain faults, which indicated that the active faults and fracture networks caused by dissolution process associated with the epikarst and island karst [4] should be introduced into the dynamic model. According to the faults activity summary (c.f. Appendix H), two faults located in the central east/south-east region (c.f. Fig.9) were identified as the potential conductive faults, which penetrate through the reservoir to the bottom aquifer and could bring us severe early water break through (WBT) problems. Hence, the conductive faults modelling was carried out in order to estimate the water production related risks and to optimize the field development strategy.

A proper way of doing faults modelling is to integrate the faults related characters directly into the grid files. However, due to the information availability and the time limit of the project, we used Local Grid Refinement (LGR) instead to assess qualitatively the influence of the conductive faults. Based on the fault surface, the LGR was carried out on the grid along these two faults (The parent block size is 100*100 m). Since Petrel can not split single cells with gradient, the cells were sized manully. Different permeability and a porosity of 1 were assigned to the strip in the middle along the faults (c.f. Fig.10).

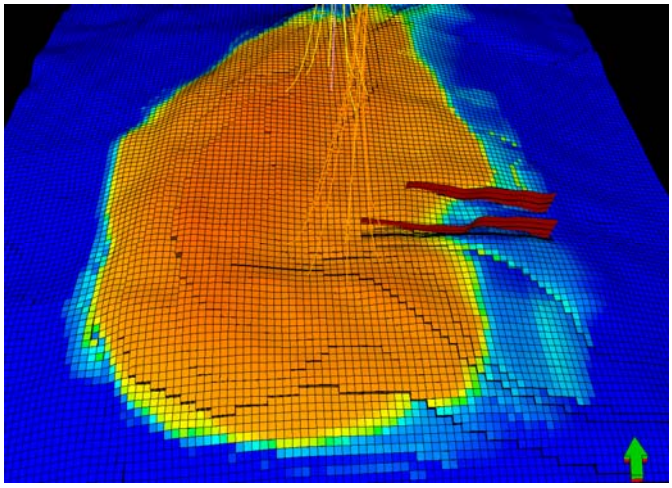

Figure 9: Locations of the two conductive faults modeled

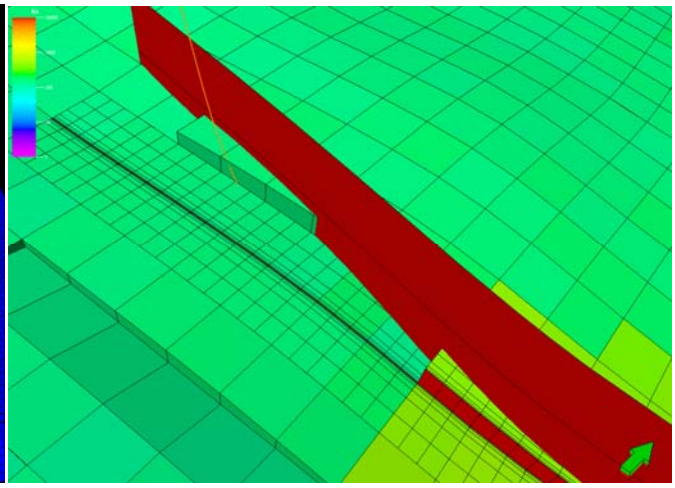

Figure 10: LGR along faults surface

Severe convergence problems were encountered during the simulation due to the pore volume and permeability contrast between local cells and adjacent global cells, which were solved by refining additional global cells and by adjusting the MINPVV/TUNING keywords. Sensitivity analysis concerning the fault permeability, fault numbers, fault size and potential horizontal barriers were respectively carried out, and the simulation results are presented in the Fig.11 below:

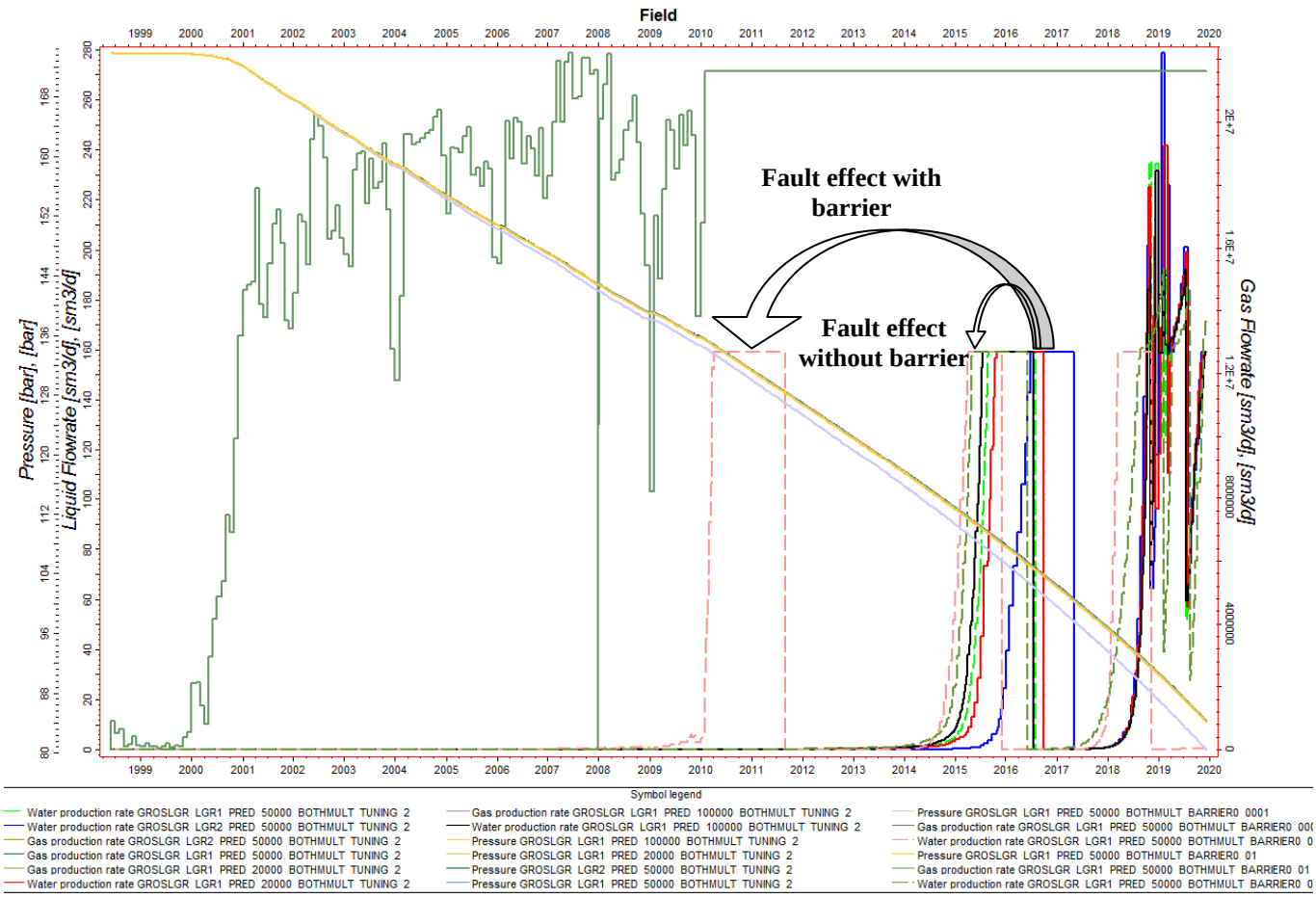

Figure 11: Faults modelling sensitivity analysis results (Basecase in blue)

Some conclusions could therefore be drawn:

- The fault far from the wells has negligible impact on the pressure and production profile compared to the other one;
- More permeable the fault is, earlier the WBT will happen;

- The water production profile seems not very sensitive to the size of the fault;
- The WBT time was significantly advanced when a potential vertical flow barrier was taken into account (the position of the barrier was identified from the well logs). The less permeable the barrier is, the earlier we have the water production. Here the conductive fault behaves as the only vertical flow corridor and therefore can cause severe water conning problem to the wells nearby. When a permeability multiplier of 0.0001 was applied to the barrier, an earlier WBT could even be observed in 2010. Although in reality we have no water production, the potential risk should still be considered at the time of making development strategy.

GWC rise modelling

4D effect observed above the initial GWC could be partly caused by the aquifer influx (C.f. Appendix G). Several RST campaigns were carried out during the production phase, which makes the GWC rise modelling an available option to further calibrate the model.

According to the RT result, 16 saturation tables and 16 imbibition tables were respectively constructed corresponding to different water saturation and different PGGs previously identified [4]. These tables together with the SATNUM/IMBNUM were integrated into ECLIPSE and a hysteresis saturation model rather than a simple one (using only one saturation table) was hence created. A LGR (vertical resolution of 1 meter) was also added along the observation well.

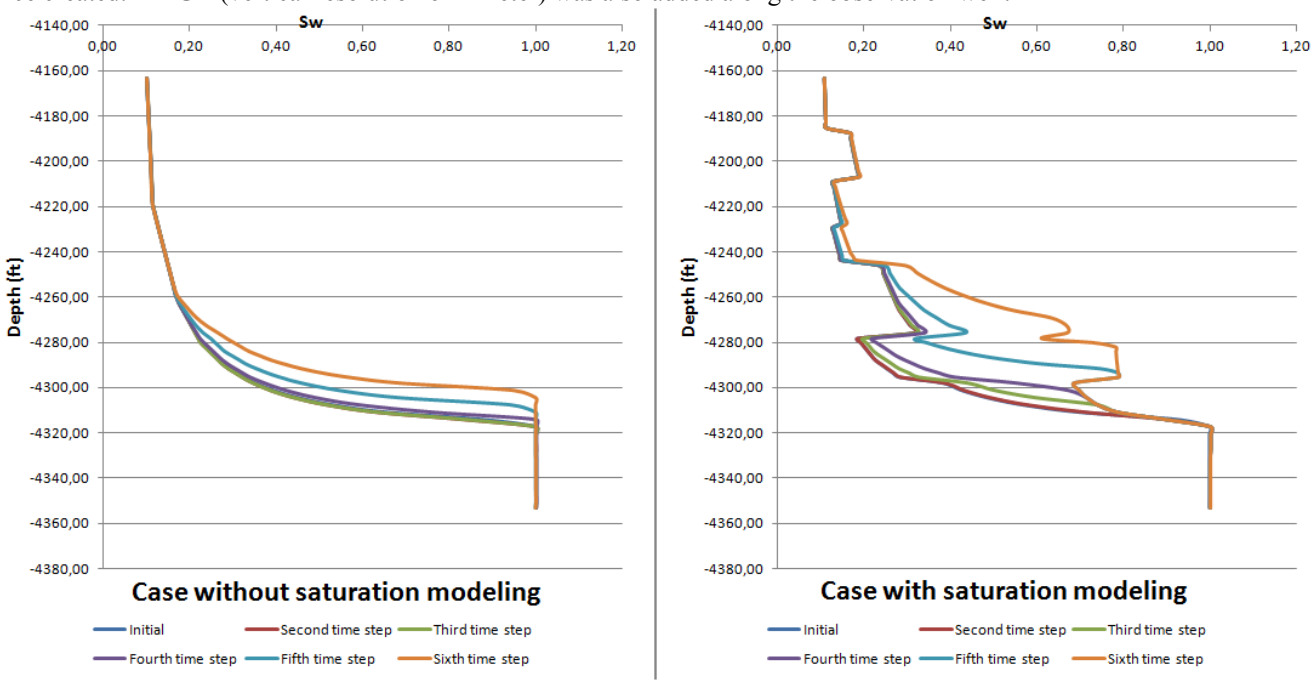

Figure 12: Comparison of the saturation profile along the observation well

Vertical heterogeneities rather than homogeneous behaviour along the observation well could be clearly seen in the Fig.12 after GWC rise modelling. Sensivity analysis were carried out in function of IGIP, aquifer related parameters and rock compaction model. No significant impact was observed while varying the aquifer size and connections. The final result will be discussed in the following section.

Final result & Prediction

The final pressure, subsidence and saturation matches were achieved by tuning the dynamic parameters listed in the Table 5:

IGIP (Tcf)	Plastic compressibility law	Aquifer Outter/inner radius ratio	Aquifer inside radius	Aquifer thickness	Horizontal barrier K multiplier
5.86	$Cp=-6.9E-04*\phi^2+6.9E-04*\phi-1.03E-04$	3	16000 ft	1200 ft	0.01

Table 5: Value of key dynamic parameters for P50 case

The mapped aquifer (c.f. Fig.8) has an estimated maximum connected volume of nearly 400 Grb, while the combined gridded aquifer + analytical aquifer used to achieve HM is about 310 Grb, which is fairly close to that value.

By running sensitivity analysis for different key parameters previously identified, a final field pressure history match was obtained (c.f. Fig.13 for P50 case):

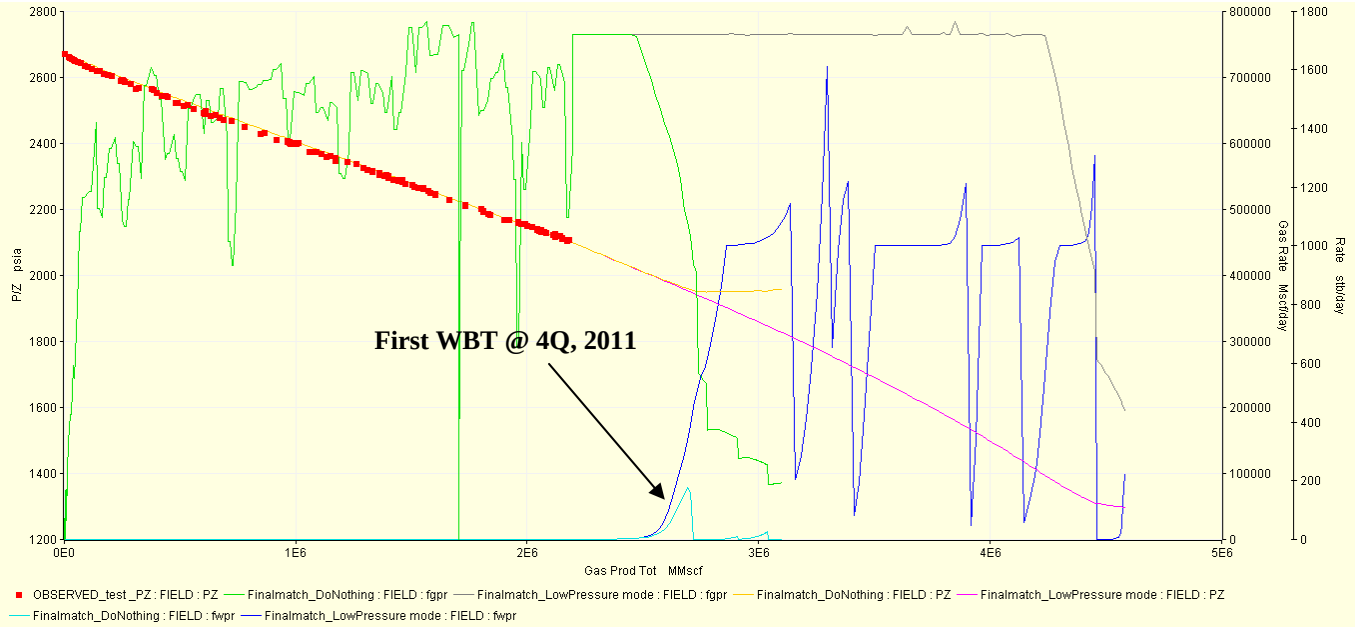

Figure 13: Final pressure HM and forecasting result with production profile (Do nothing+LP)

The small disruption of the pressure history at the beginning was related to the interference from new production wells close to the observation well. No water production was observed until nowadays, which corresponds well to the history. The final HM result for individual wells are presented in the Appendix J. By running a "Do Nothing" case for production forecasting, the water breakthrough will be first seen in November 2011 at eastern wells. The plateau can only be extended by one year and a half, hence to maintain the plateau and the delivery capacity, further field developments such as infill wells, low pressure (LP) mode etc. should be considered (C.f. Fig.13 for the LP case with a RF of 81% and end plateau 2017), which will not be dicussed in this project due to the time limit.

The subsidence modelling results (map and total volume, until 2010) were presented in the Fig.14b below:

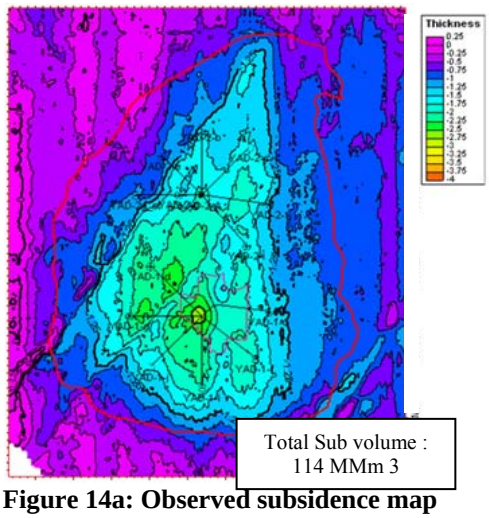

Figure 14a: Observed subsidence map

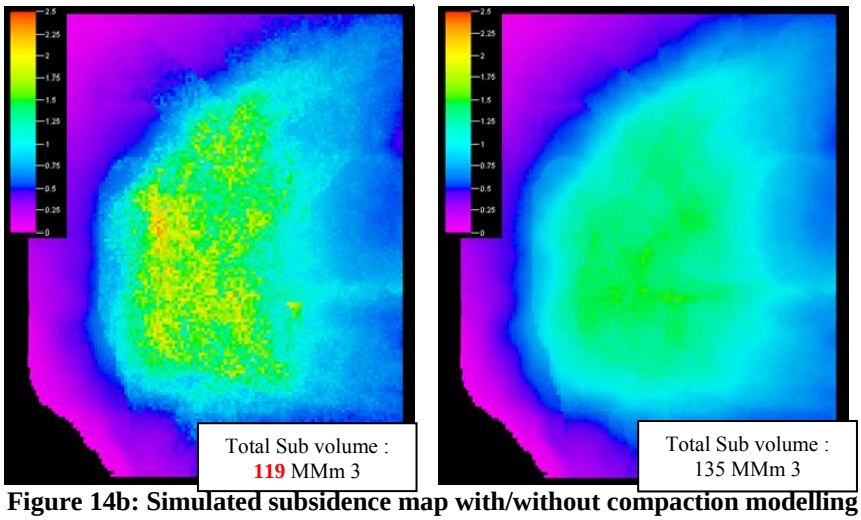

Figure 14b: Simulated subsidence map with/without compaction modelling

Assuming that the rock dilatation is negligible between the sea bottom and the top reservoir, the total subsidence volume could be approximated by the compaction volume, which matches well to the observed ones. Without rock compaction modelling, the compaction behaviour is homogeneous for each cell, therefore the subsidence depend only on the depletion and the thickness of reservoir, which corresponds well to the simulation result since the reservoir thickness increases from the west to the east; by contrast, with rock compaction modelling, the change in bathymetry that highly localized in the central west of the field (due to the facies distribution) was well captured. Nevertheless, on the NW border of the carbonate platform, the abrupt change could not be seen in the simulation result, which was due to the fact that the simulation model contains no information

above the top reservoir. Moreover, this subsidence modelling did not take into account other factors such as shear failure, which could partly explain why the simulated subsidence is slightly lower than the measured one.

The GWC rise modelling was greatly influenced by the compaction in the aquifer and the pore volume since smaller pore volume will result in a faster rise. The final match result is presented in the Fig.15 below:

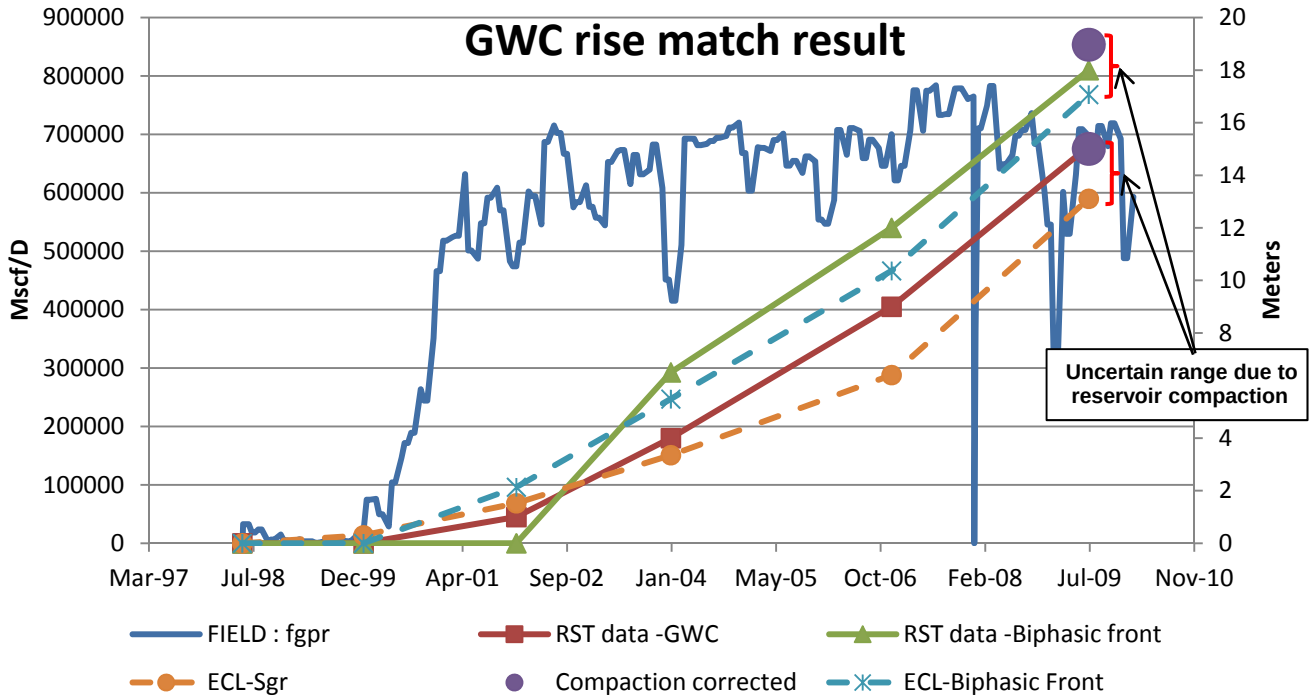

Figure 15: GWC rise matching result

We have to note that the Eclipse output did not take into account the cell movement (impact of subsidence caused by the reservoir rock compaction). Hence, on considering an observed subsidence of 1.9 meters at the observation well in 2009, a much better match could be achieved between the simulated GWC rise and the observed one (C.f. Appendix I for the result without GWC rise modelling). Moreover, Alpha is an atoll reef with the best facies distributed forming a ring, hence the aquifer would tilt the contact and therefore impact the WBT timing (C.f. Appendix I), which corresponds well to the GWC tilt evaluated by 4D interpretation.

Synthesis & recommendations

During this phase, more data with a higher quality became available such as 4D seismic data, geomechanical measurements, RST and production data etc, based on which more advanced methodologies of reservoir interpretation could be applied.

By assuming a homogeneous reservoir model, pressure history matching is still achievable at the early stage of production, and several different scenarios were generated. However, without adding dynamic heterogeneities to the model, no match could be obtained for the entire pressure, GWC rise and subsidence monitoring history.

Those model refinements newly carried out are:

- Water induced rock compaction modelling (Geomechanical heterogeneity): which gives correlations between Cp/collapse pressure and Phi in the function of Sw change, and has important impact on field pressure profile;
- Rock Typing (formation heterogeneities): which has an important impact on the GWC rise modelling, rock compaction modelling and the IGIP estimation;
- GWC rise modelling (Saturation heterogeneity): through which the formation heterogeneity could be visualized, and it also has significant impact on the water production forecasting;
- Analytical aquifer modelling (Aquifer heterogeneity): which influences significantly the production energy distribution determination and hence the field pressure profile;
- Conductive Faults modelling (Sedimentary heterogeneity): which gives an estimation of potential water production related risk, and could help optimize the development strategy;
- Vertical flow barriers (Stratigraphic heterogeneity): which has a large impact on the early water breakthrough prediction, final recovery and production strategy.

The Alpha field is currently interpreted as a geologically heterogeneous carbonate reservoir under strong rock compaction drive and aquifer drive, with an aquifer volume of 4.9E+10 m^3 (edge analytical aquifer + bottom gridded aquifer). 9 different PGGs were identified by RT as the base of properties modelling. Its fault/fracture networks caused by karstic dissolution process were represented by two conductive faults located in the central east region.

Compared with our reservoir understanding obtained at the end of appraisal phase, the water bearing rock compaction above/below the GWC rather than the aquifer water influx is considered as the main production energy that dominates the dynamic behaviour. Different heterogeneities were increasingly seen, modeled and modified along the time through different studies, which make the interpretation result much more reliable.

Finally, the evolution of Alpha reservoir understanding could be summarized using the Fig.16 below:

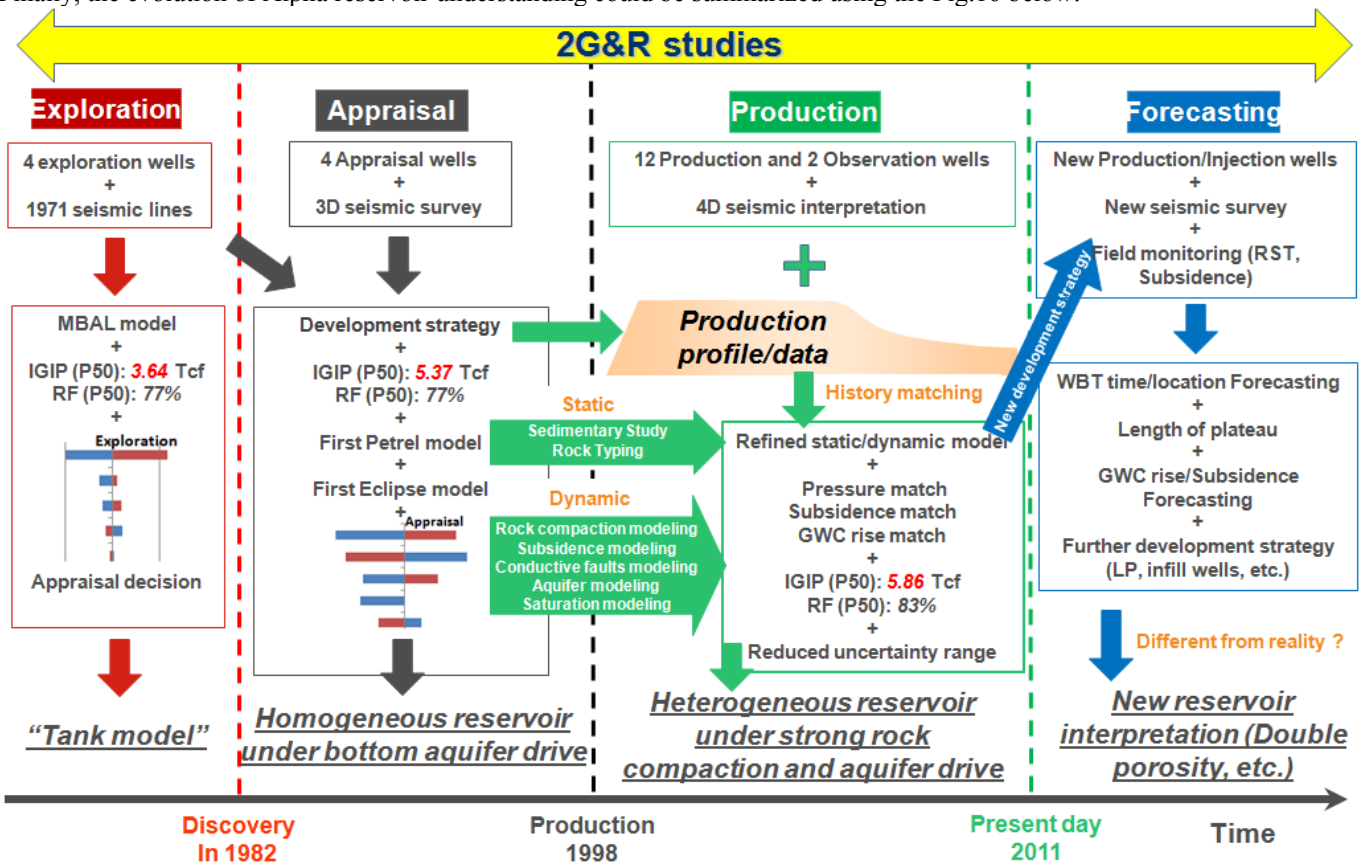

Figure 16: The evolution of the reservoir characterization and understanding

Since this project is a post-mortem study of the Alpha field dynamic behaviour, the following recommendations in terms of reservoir modelling, field development and monitoring were drawn for the analogue fields:

1) Subsidence extends to the eastern border on the map, hence a bathymetric survey covering a larger area towards the east should be carried out. The important rock compaction in the aquifer could be further confirmed if the subsidence could be observed in a larger area.
2) The rock compaction of Alpha field is difficult to be simulated by Eclipse since the simulator doesn't take into account the movement of cells and the stress redistribution. To better estimate the geomechanical effects such as subsidence, other software based on finite element analysis such as *Visage* should be used.
3) At least one more observation well should be drilled in the southern part of reservoir in order to better monitoring/modelling the GWC rise and to confirm the tilt of the GWC.
4) During later part of the field life, compression facilities will be required to maintain high well deliverability and achieve high recovery factors (LP mode).
5) If the average field compressibility (weighted by pore volume) calculated using the lab measured Phi-Cp relation for the core data and for grid data (Petrel) are not coherent (which is the case for Alpha), it was caused either by the porosity modelling mistake or by the weak representativeness of the core data. Therefore, special attention should be paid to the core data quality and the property modelling algorithme.
6) The development strategy is closely related to the petrophysical modelling. Different Phi-K laws, saturation laws or modelling algorithms leads to different models, which could totally change the field development strategy and

dynamic behaviour. Hence, more attention should be paid to the early stage works such as Rock Typing and facies modelling, in order to provide a reliable static model for dynamic modelling use in the future.

Conclusion

This report presents the results of a reservoir simulation study from exploration to production phase. The main objective of the project, i.e. synthesize the evolution of the reservoir interpretation and understanding along the time, has been achieved through integrated analysis of the field dynamic behaviour such as pressure, GWC rise and subsidence HM. Recommendations in terms of reservoir modelling, field development and monitoring were given at the end of each chapter, together with the synthesis of the field understanding evolution at different stages.

The accomplishment of this project contributes to extract experiences/lessons about the reservoir modelling and interpretation for a carbonate field: no matter which type of carbonate we are dealing with, the importance of water bearing reservoir rock compaction (derived from the plastic compressibility) and related early WBT problems should be taken into account from the very beginning where no signal is seen yet. Coherent models could only be constructed by integrating all available data. A wrong estimation of production energy leads to an incoherence from history and an overestimate of the final recovery factor.

In the future, the evolution of the field interpretation will certainly be continued given more available data source. For example, double permeability/porosity behaviour due to the fracture networks could become increasingly important and therefore dominate the field dynamic behaviour. Therefore, holding a dynamic point of view rather than a static one is quite important to understand and follow this evolution.

Due to the time limit, works such as 4D effects correlation and interpretation are not fully completed, which deserve a more detailed and profound study. Future works could be focus on the data acquisition such as core and fluid sampling from aquifer and full 4D seismic data (rather than 3 seismic lines) in order to better understand the 4D effect observed in the aquifer.

Nomenclature

ΔV_b : Change of bulk volume for each cell, m^3
DX : Change of X-direction length for each cell, m
DY : Change of Y-direction length for each cell, m
δL : Change of Vertical length for each cell, m
ΔV_p : Change of pore volume for each cell, m^3
ΔV_s : Change of matrix volume for each cell, m^3
δP : Change of pressure reference to the initial pressure for each cell, bar
Cpp : Pore compressibility, bar^{-1}
Cps : Matrix compressibility, bar^{-1}
V_s : Actual matrix volume, m^3
V_p : Actual pore volume, m^3
Φ : Porosity, %
C^{Oedo}_{pp} : Pore oedometric compressibility
C^{iso}_{pp} : Pore isotropic compressibility
C_s : Mineral compressibility for carbonate
α : Biot's coefficient
ν : Poisson's ratio

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2. R.Méhut et al.: "Alpha, Beta, Integrated Field Study 2007", TOTAL internal archive DGEP/GSR/VDG/AEO/08-080, 07/03/2008, Paris
3. L.Cantegrel et al.: "Alpha, Beta, Integrated Field Study 2010", TOTAL internal archive EP/GSR/VDG/2010-288, 26/10/2010
4. B.Caline et al.: "Alpha 2010, Updated sedimentary model integrating diagenesis", TOTAL internal archive DGEP/GSR/TG/ISS R10-24, 15/07/2010
5. J.Geertsma: "The Effect of Fluid Pressure Decline on Volumetric Changes of Porous Rocks", SPE 728-G (1957)
6. S. D. Joshi: "Cost/Benefits of Horizontal Wells", SPE 83621(2003)
7. P.Carles: "Alpha, under stress petrophysical measurements at different saturation state", TOTAL internal archive DGEP/GSR/TG/COP/LABO 03-67, 21/07/2005

Appendix A: Critical literature review (milestone & summary)

MILESTONES IN FRACTURED CARBONATE RESERVOIR UNDER COMPACTION DRIVE (ALPHA) STUDY
TABLE OF CONTENT

SPE Paper n°	Year	Title	Authors	Contributions
728-G	1957	The Effect of Fluid Pressure Decline on Volumetric Changes of Porous Rocks	J.Geertsma	- First to simplify the description of the pressure - volume relationship adapted to various types of reservoir rocks
83621	2003	Cost/Benefits of Horizontal Wells	S. D. Joshi	- Description of various reservoir applications of horizontal wells from primary recovery to EOR applications with cost benefit analysis
U.S.Geological Survey Bulletin 2208-E	2006	Eocene to Miocene Composite Total Petroleum System	C.J.Wandrey	- A systematical geological study of the Eocene to Miocene Composite Total Petroleum System
DGEP/GSR/VDG /AEO/08-080	2008	Alpha, Beta, Integrated Field Study 2007	R.Méhut et al.	- First to build an ECLIPSE reservoir simulation models and a Petrel model; - First to show the importance of the tilt of the GWC, and give recommendations for further works
DGEP/GSR/TG /ISS R10-24	2010	Alpha 2010, Updated sedimentary model integrating diagenesis	B.Caline et al.	- Generation of deterministic facies maps as input for the model; - Karst surfaces and cinerite level description; - Integration of diagenesis, facies and petrophysics to generate the Petro Geological Groups (PGG). The PGG are the base blocks for building the model.
EP/GSR/VDG 2010-288	2010	Beta-Alpha Field integrated study 2010	Luc CANTEGREL, Emmanuelle BRECHET, Claude GAPILLOU, Claire VIAUD	- A new simulation model that includes a new sedimentological model, new rock compressibility /subsidence modelling and a new history match using latest production data - An insight for the current understanding of the field behaviour.

SPE 728-G (1957)

The Effect of Fluid Pressure Decline on Volumetric Changes of Porous Rocks

Authors:

J.Geertsma

Contributions to the understanding of the compaction drive mechanism:

First to give a simplified theory with convenient experimental procedures to determine the deformation constant and to describe the pressure – volume relationship adapted to various types of reservoir rocks

Objective of the paper:

To obtain a better insight into the pressure – volume relationship for various types of reservoir rocks

Methodology used:

The reciprocal theorem

Conclusion reached:

1. Deformation phenomena in a purely elastic material of known porosity can be described by three deformation constants refer to repectively the rock bulk and rock matrix material;
2. For an isotropic porous medium built up of continuous homogeneous and isotropic matrix material, relations are established as a function of the elastic and viscous deformation constants of rock matrix and rock bulk material and porosity.
3. For practical purpose, pore compressibility can frequently be determined with sufficient accuracy from reliable measurement of the elastic and viscous deformation constants of the rock bulk material only.

Comments:

One of the most foundamental theory, which will help to better understand the active compaction drive mechanism that is happening in the Alpha field. It could also be useful for the carbonate compaction drive modelling since this paper gave explicitely the relationship in limestone reservoir (although under assumption of homogeneous and continuous matrix material).

U.S.Geological Survey Bulletin 2208-E (2006)

Eocene to Miocene Composite Total Petroleum System

Authors:

C.J.Wandrey

Contributions to the understanding of the naturally fractured reservoir:

A systematical geological study of the Eocene to Miocene Composite Total Petroleum System

Objective of the paper:

To describe the petroleum resources within the Eocene to Miocene composite total petroleum system in Beta, and to assess the quantities of hydrocarbon that have the potential to be added to reserves within the next 30 years

Methodology used:

Tectonic analysis, Stratigraphic Analysis

Conclusion reached:

1. The Eocene-Miocene Composite Total Petroleum System has produced the majority of the hydrocarbons in the central B Basin and I Delta. Structural traps are predominant, but stratigraphic traps are likely to be found in both ancient and modern delta environments.
2. Favorable elements of this petroleum province are suitable organic material, sufficient maturation, ongoing charging of reservoirs, short near-vertical migration paths and early trap formation.

Comments:

This paper provides very useful geological description about the stratigraphy, plate migration, source rocks, reservoirs, seals traps, timing, and petroleum information for the Eocene-Miocene Composite Total Petroleum System (within which the Alpha field is found), which is essential to understand geologically the formation and behaviour of the reservoir.

TOTAL DGEP/GSR/VDG/AEO/08-080 (2007)

Alpha, Beta, Integrated Field Study 2007

Authors:

R.Méhut, J-F.Mondy, F.Ribot, K.Samodro

Contributions to the understanding of the naturally fractured reservoir:

1. First to build an ECLIPSE reservoir simulation models and a Petrel geomodel for the Alpha field;
2. First to show the importance of the tilt of the GWC, and give recommendations for further works that could be done to confirm model parameters particularly aquifer permeability and to fine tune timing for development planning.

Objective of the paper:

Try to explain the slower than anticipated reservoir pressure decline which could be the result either of a larger in-place gas volume or a stronger aquifer activity than previously considered

Methodology used:

Sequential gausssian simulation (SGS), Properties upscaling, Leveret J function

Conclusion reached:

1. A new IGIP was estimated which matched in pressure and aquifer rise;
2. Water influx from a larger estern aquifer induces a tilt to the GWC which could be seen in ECL.

Comments:

Although the rock typing and facies modelling parts are fairly poor, this report provides very useful information to understand the slower than anticipated reservoir pressure decline due to either a larger IGIP or a stronger aquifer drive. Moreover, it clearly indicates an E-W tilt of the GWC rise. Therefore, more attention should be paid to aquifer modelling, IGIP assessment and GWC rise match for the Alpha field in my study.

TOTAL EP/GSR/VDG 2010-288 (2010)

Beta-Alpha Field integrated study 2010

Authors:

Luc CANTEGREL, Emmanuelle BRECHET, Claude GAPILLOU, Claire VIAUD

Contributions to the understanding of the naturally fractured reservoir:

1. A new simulation model that includes a new sedimentological model, new rock compressibility/subsidence modelling and a new history match using latest production data;
2. An insight for the current understanding of the field behaviour.

Objective of the paper:

To better predict the water breakthrough and to better modelling the subsidence by improving the existing model

Methodology used:

Facies modelling using random spatial distribution, HM, EST analysis

Conclusion reached:

1. Coral facies distribution, heterogeneous water rise and subsidence are the 3 main aspects that control the Alpha field behaviour;
2. The uncertainty on the water breakthrough timing remains very large and needs to be further investigated.

Comments:

The way they carried out this study could be used for my own study. It also indicates 3 main aspects which control the Alpha field behaviour and which should be given more priority in my project: 1) Coral facies distribution and its petrophysical properties; 2) Heteogeneous water rise from the east; 3) Subsidence and reservoir compaction.

TOTAL DGEP/GSR/TG/ISS R10-24 (2010)

Alpha 2010, Updated sedimentary model integrating diagenesis

Authors:

B.Caline, J.L.Cappelli, C.Mabille

Contributions to the understanding of the naturally fractured reservoir:

1. Generation of deterministic facies maps as input for the model;
2. Karst surfaces and cinerite level description;
3. Integration of diagenesis, facies and petrophysics to generate the Petro Geological Groups (PGG). The PGG are the base blocks for building the model.

Objective of the paper:

To characterize the reservoir heterogeneity of this carbonate platform focusing on the occurrence, origin and distribution of both highly permeable and tight carbonate beds

Methodology used:

Core and section description using Wellcad software, Core analysis

Conclusion reached:

1. Nine petrophysical geological groups have been defined, and the PGG have been propagated to the uncored interval;
2. Epikarst and island karst results in stratiform distribution of either enhanced matrix porosity/permeability or partial to complete cementation by calcite;
2. Permeability heterogeneity mainly results from early, shallow burial diagenetic overprinting, which is best developed in coral facies.

Comments:

This geological report of Alpha field sedimentology identified 2 main types of early diagenetic overprint: epikarst and island karst. These are essential informations of rock typing to understand the formation of the vertical fracture corridors existing in this field, which definitely has a significant impact on the water break through prediction.

SPE 83621 (2003)

Cost/Benefits of Horizontal Wells

Authors:

S. D. Joshi

Contributions to the understanding of the field development plan:

Description of various reservoir applications of horizontal wells from primary recovery to EOR applications with cost benefit analysis.

Objective of the paper:

To summarize the state of the art horizontal well technology and to review the economic benefits of horizontal wells.

Methodology used:

Field examples of different applications around the world

Conclusion reached:

1. Horizontal zell technology is a proven technology;
2. Horizontal wells have been used in a variety of primary, waterflooding and EOR projects.
3. Horizontal wells are utilized to reduce hydrocarbon finding cost and operating cost.

Comments:

Making development plan concerns the type of production wells that will be drilled. This paper listed the benefits and disadvantages of horizontal wells in different applications, and compared the vertical wells cost/benefits with the horizontal ones, which contributed a lot to the benefit/risk assessement of Alpha field development plan using horizontal wells.

Appendix B: Available data sources and parameters

Data source	*Concerned parameters*	*Specification*
DST campaign	k*h, k, h, Pi, Skin, T, Investigation radius	A-1 ~ A-4 A-a ~ A-d
PVT analysis	Gas composition, Sg, Viscosity, Bg, Z factor	A-1 ~ A-4 A-a ~ A-d
Well performance analysis	AOFP, n, C (Fetkovich)	A-1 ~ A-4
RFT	GWC, Pressure gradient	A-1 ~ A-4, A-b
RCAL	Phi, Kh, Kv, Grain density, Facies distribution, NTG	A-a, A-b, A-d A-1 ~ A-4
SCAL	FF, Swc, Sgr, Krw, Krg, Rock Cp, Leverett J function	A-1 ~ A-3, A-b, A-d
Wireline Logs	Phi, Sw, Matrix density, GWC, Rw, NTG, GRV	A-1 ~ A-4 A-a ~ A-d
2D seismic survey	GRV, GWC, Reservoir structure, Heterogeneities	Exploration
3D seismic survey	GRV, GWC, Isopach map, Reservoir structure, Heterogeneities	Appraisal
Brine analysis	Rw, Concentration	A-b

Table A1: Available data sources and parameters

Appendix C: Exploration & Appraisal phase data and results

Exploration	Max	Most likely	Min
Sw	15,00%	24,28%	30,00%
Phi	30,00%	27,25%	24,20%
Bg	0,00596	0,0061	0,00625
GRV	**5,28E+09**	**3,20E+09**	**1,44E+09**
NTG	1,00	0,95	0,80
IGIP m^3	2,26E+11	1,03E+11	3,12E+10
IGIP Tcf	7,98	3,63	1,10
GWC	1320	1320	1317
RF	90%	77%	50%
Reserve Tcf	7,18	2,80	0,55

Appraisal	Max	Most likely	Min
Sw	14,50%	20,13%	25,40%
Phi	28,50%	27,48%	26,20%
Bg	0,00596	0,00607	0,00625
GRV	**4,76E+09**	**4,50E+09**	**4,15E+09**
NTG	1,00	1,00	0,95
IGIP m^3	1,95E+11	1,63E+11	1,23E+11
IGIP Tcf	6,87	5,75	4,35
GWC	1320	1320	1317
RF	90%	77%	50%
Reserve Tcf	6,19	4,42	2,18

Table A1: Range of parameters at different stages for reserve assessment

Appendix D: Phi vs. Kh and Kh vs. Kv correlations

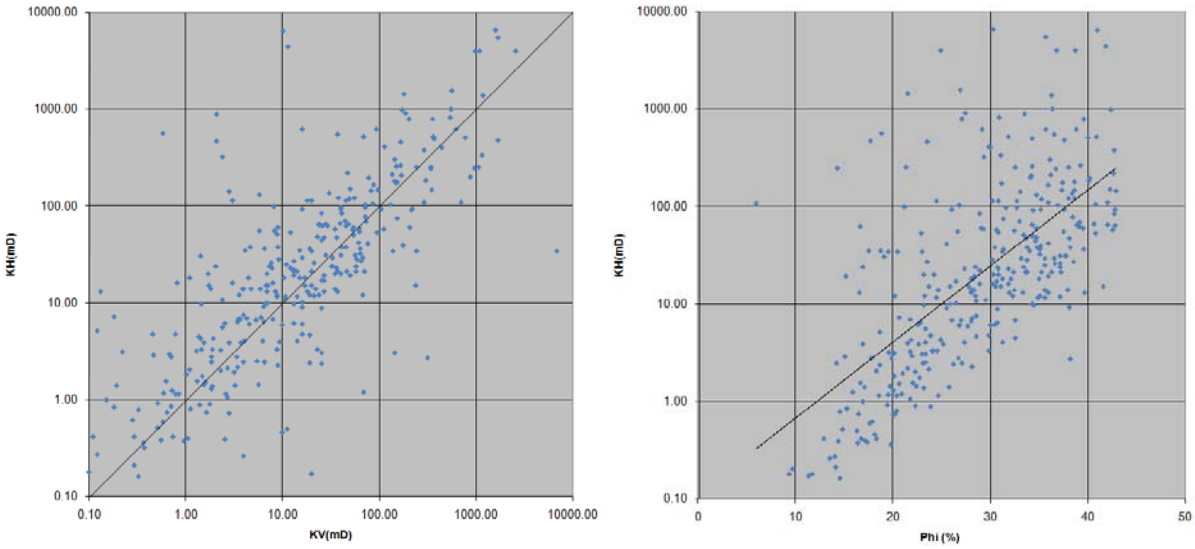


Figure A2: Phi vs. Kh and Kh vs. Kv correlations

Appendix E: Field permeability sensitivity analysis

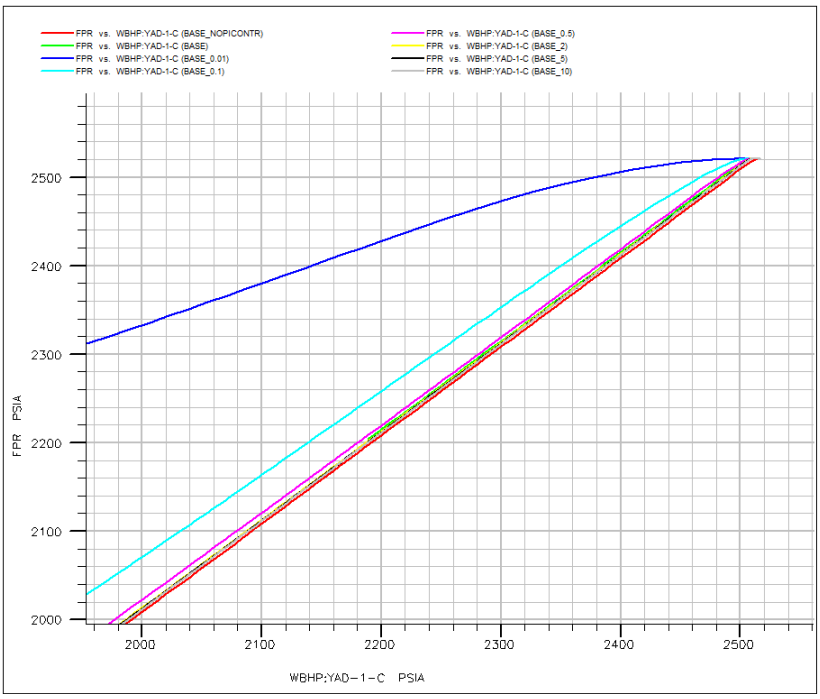


Figure A3: Field pressure vs. Bottom hole pressure for different field permeabilities

Field permeability sensitivity analysis showed an increase of pressure gradient between wells by plotting FRP vs. WBHP.

Appendix F: First 300 Bcf production HM

Scenario	Rock compressibility (1/psi), simple elastic model	IGIP (Tcf)	Aquifer model	Fracturation
1	2.0E-5	5.0	Bottom aquifer only	No
2	4.0E-5	3.9	Bottom aquifer only	No
3	2.0E-5	7.3	No aquifer at all	No

Table A2: Summary of the first stage HM result

Field pressure profile:

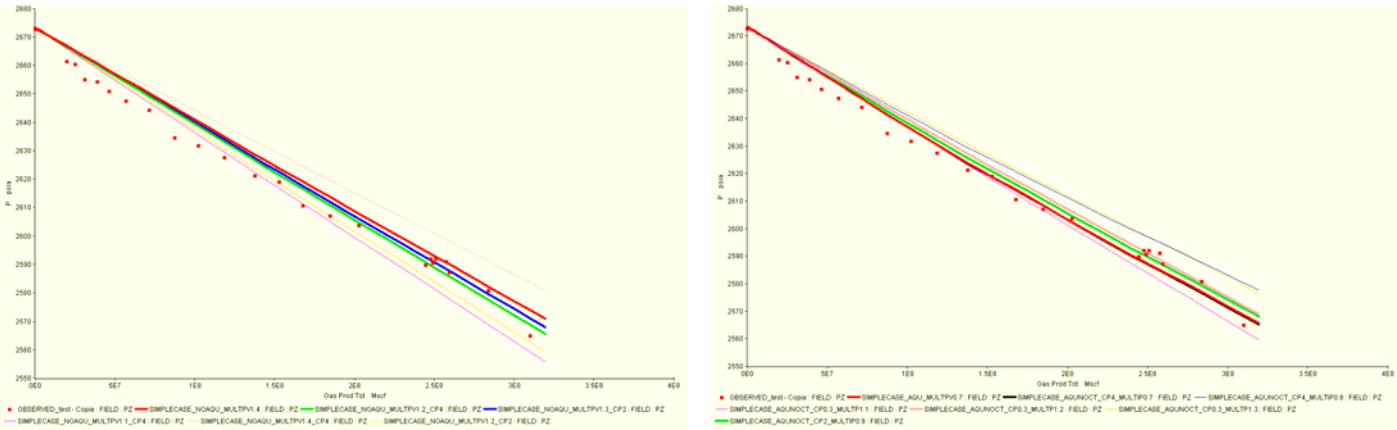
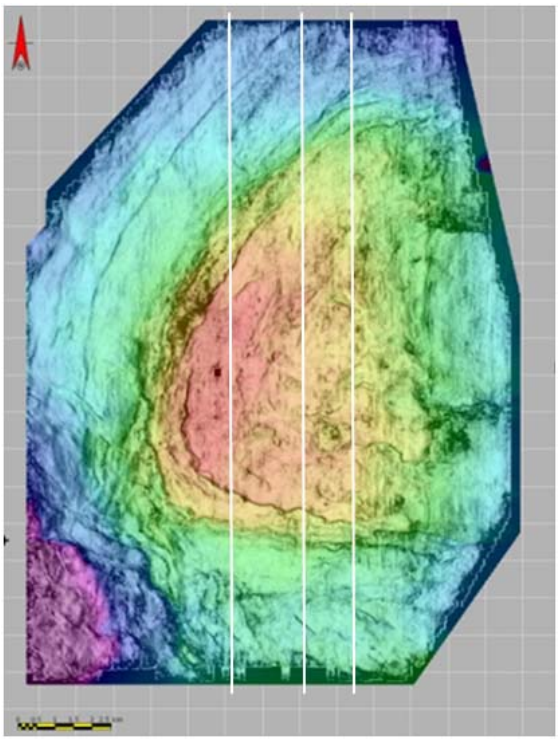


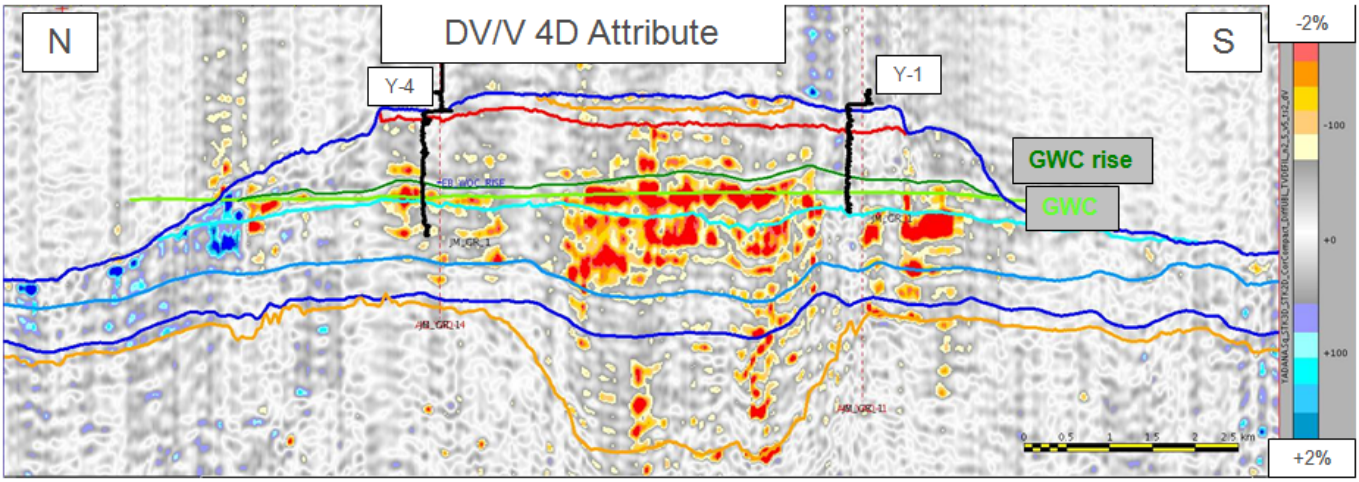
Figure A4: HM/sensitivity analysis without/with gridded aquifer only

The individual well match results for the first stage are not presented here due to the length limit.

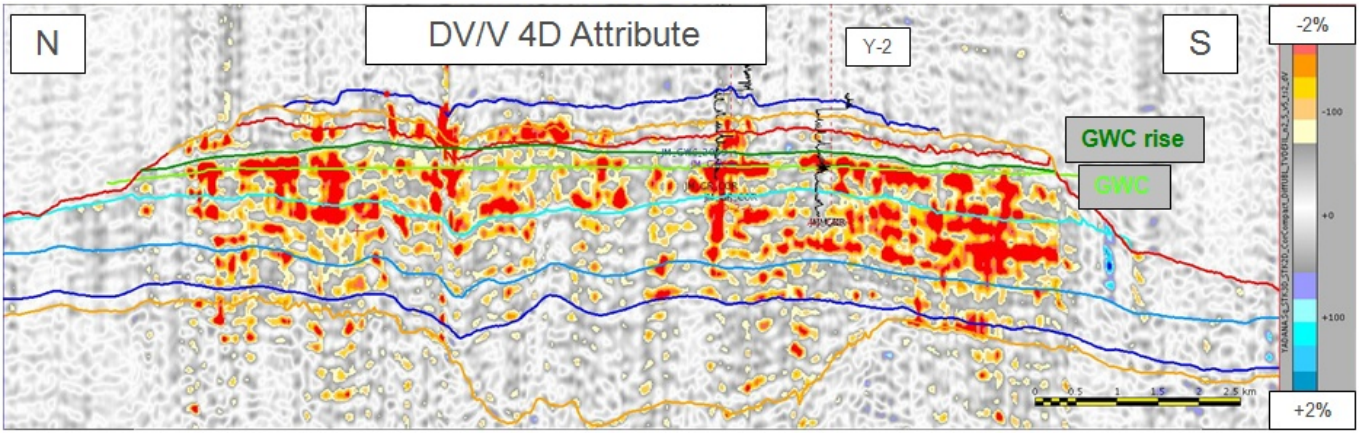
Appendix G: 4D effect



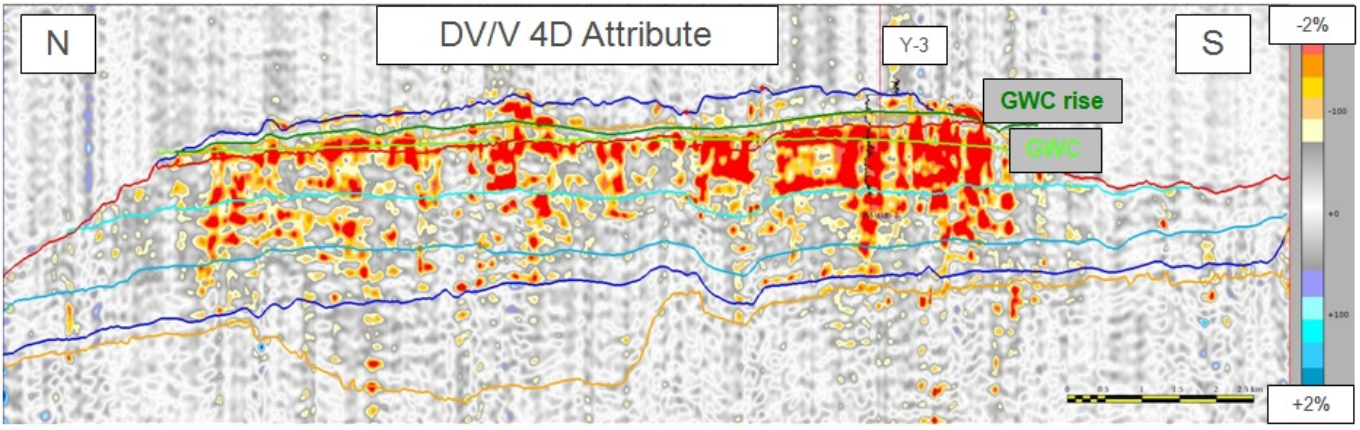
4D lines locations



West 4D line



Middle 4D line



East 4D line

Figure A5: 4D DV/V attribute & picking of GWC rise [3]

Explanation: The regions marked in red signify a decrease of the seismic wave velocity (propagation slower) which could be related to the water replacing gas or to the pore volume collapse, while the regions marked in blue signify an increase of the seimic wave velocity (propagation faster).

Appendix H: Faults modelling

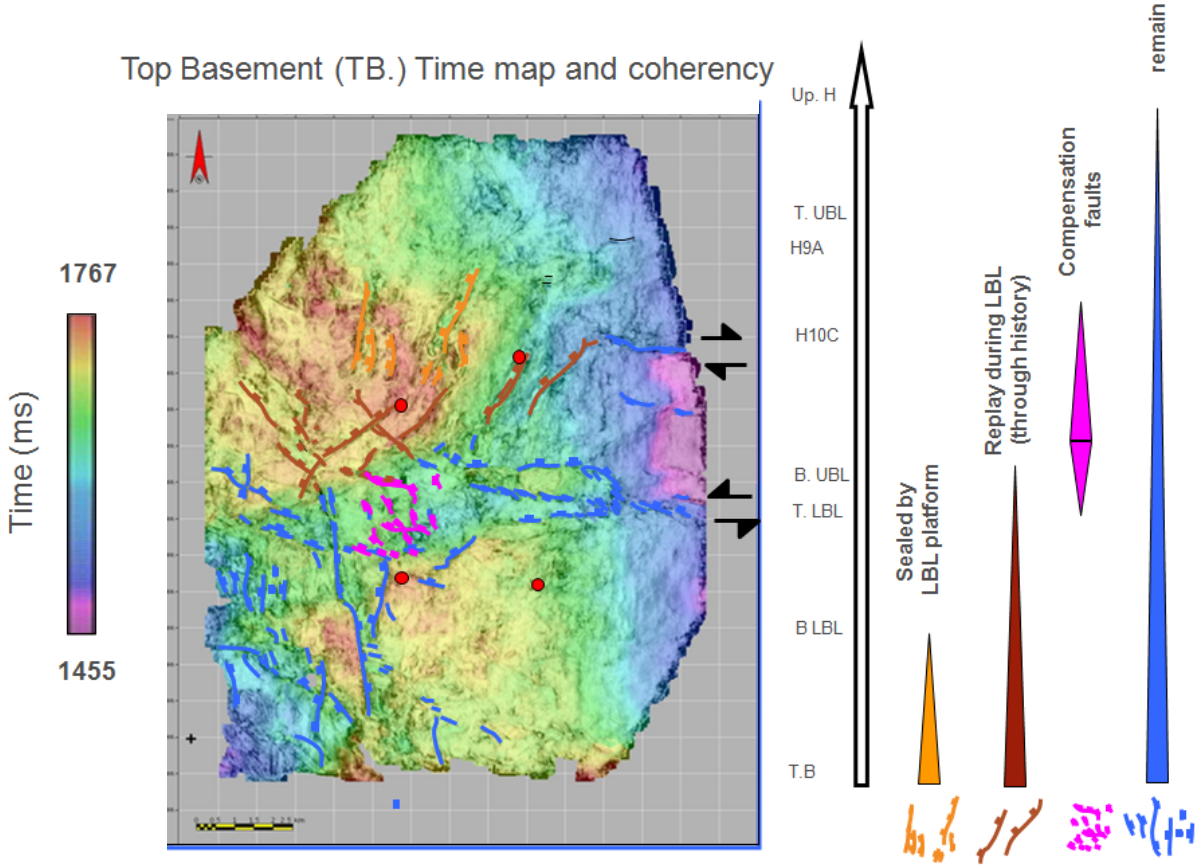


Figure A6: Fault activity summary

The fault systems (marked blue) stay active during the entire life of the platform potentially connecting reservoir and Basement levels & making hydrothermalism possible.

Appendix I: GWC rise modelling

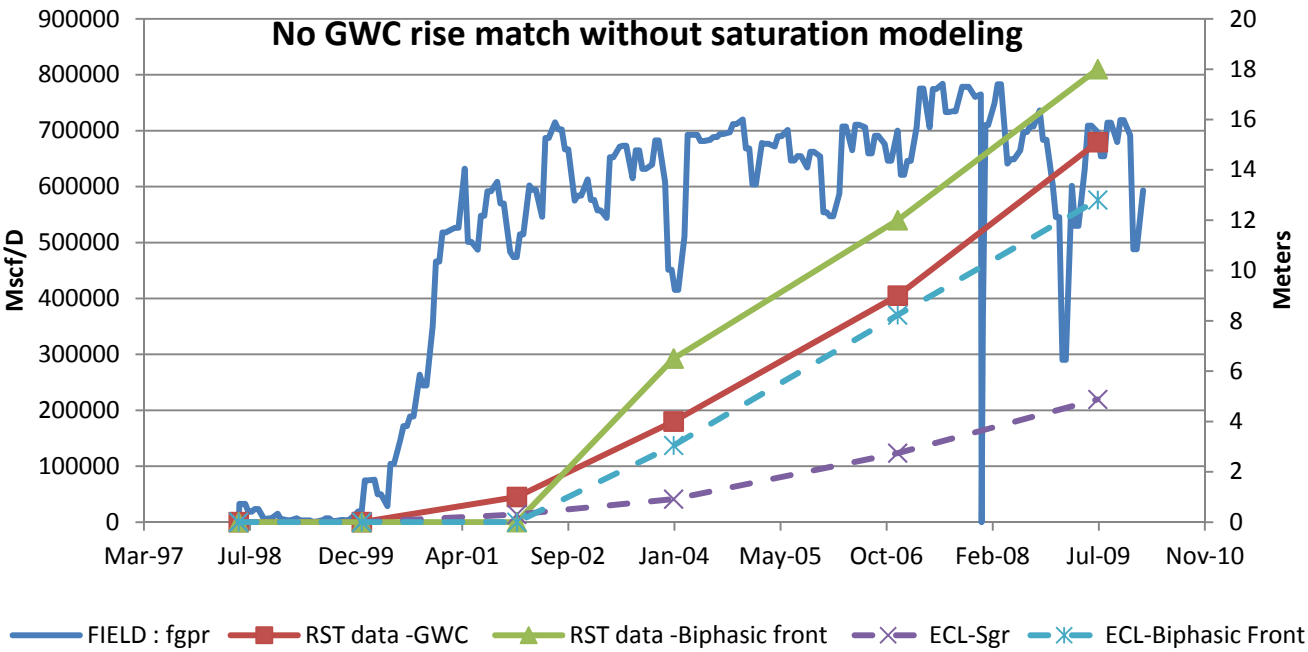
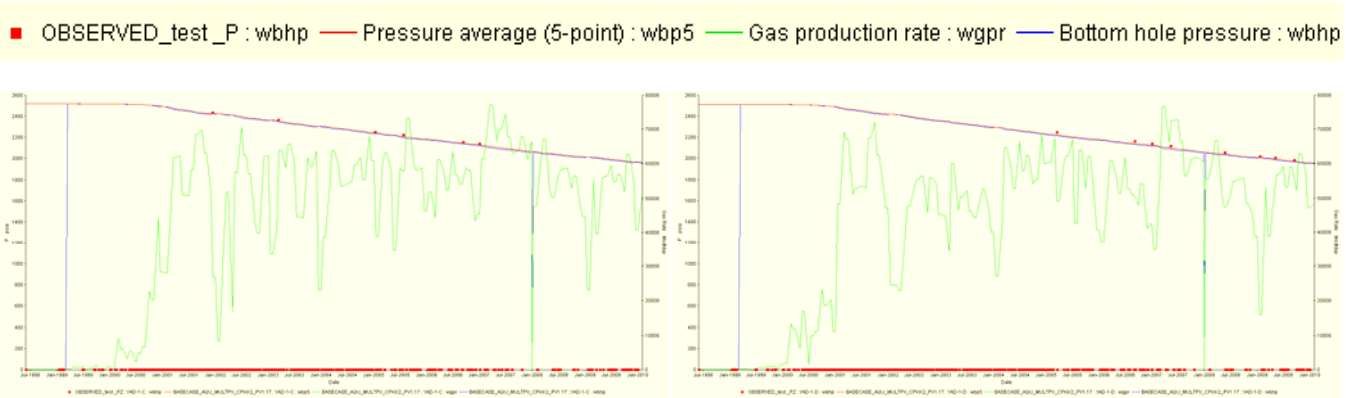


Figure A7: No GWC rise match without GWC rise modelling

Figure A8: Simulated GWC rise tilt

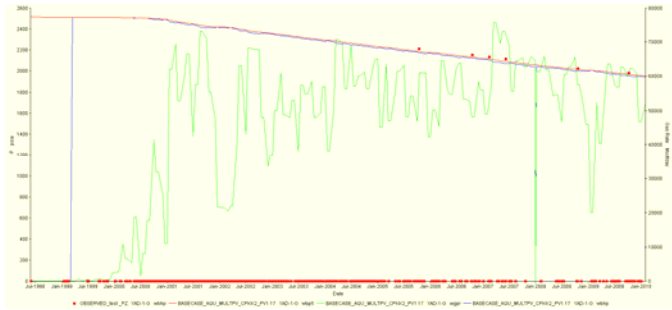
Appendix J: Final HM results for each well



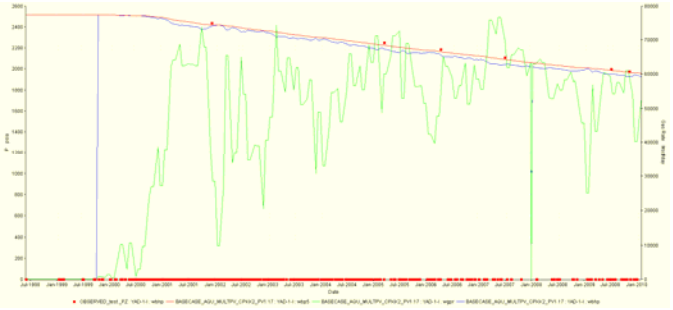
A-1-c

A-1-d

A-1-f



A-1-g



A-1-i

A-1-j

A-2-b

A-2-c

A-2-e

A-2-f

A-2-g

A-2-i

Appendix K: Geomechanics measurements

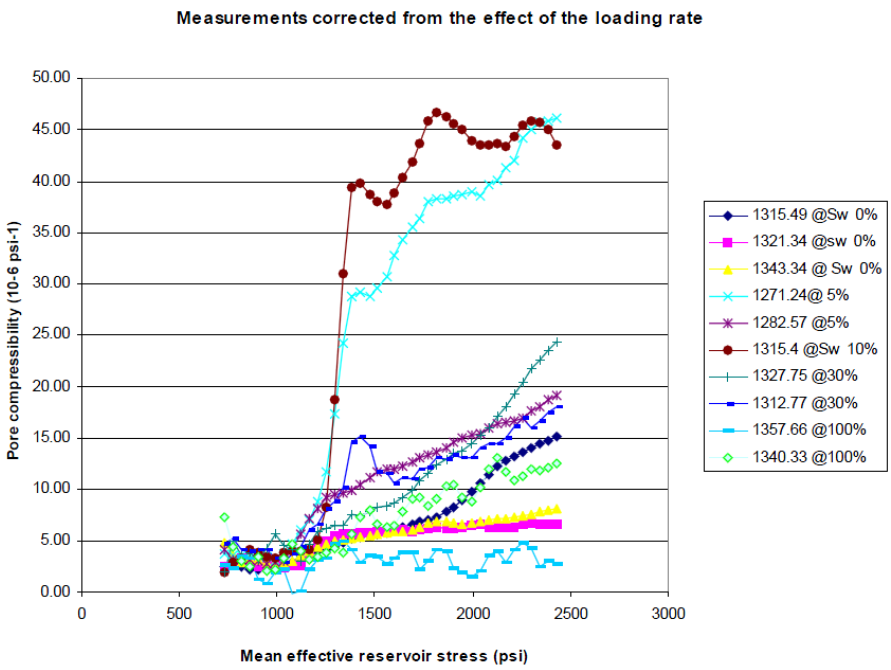


Figure A9: Measurements corrected from the effect of loading rate and oedometric conditions

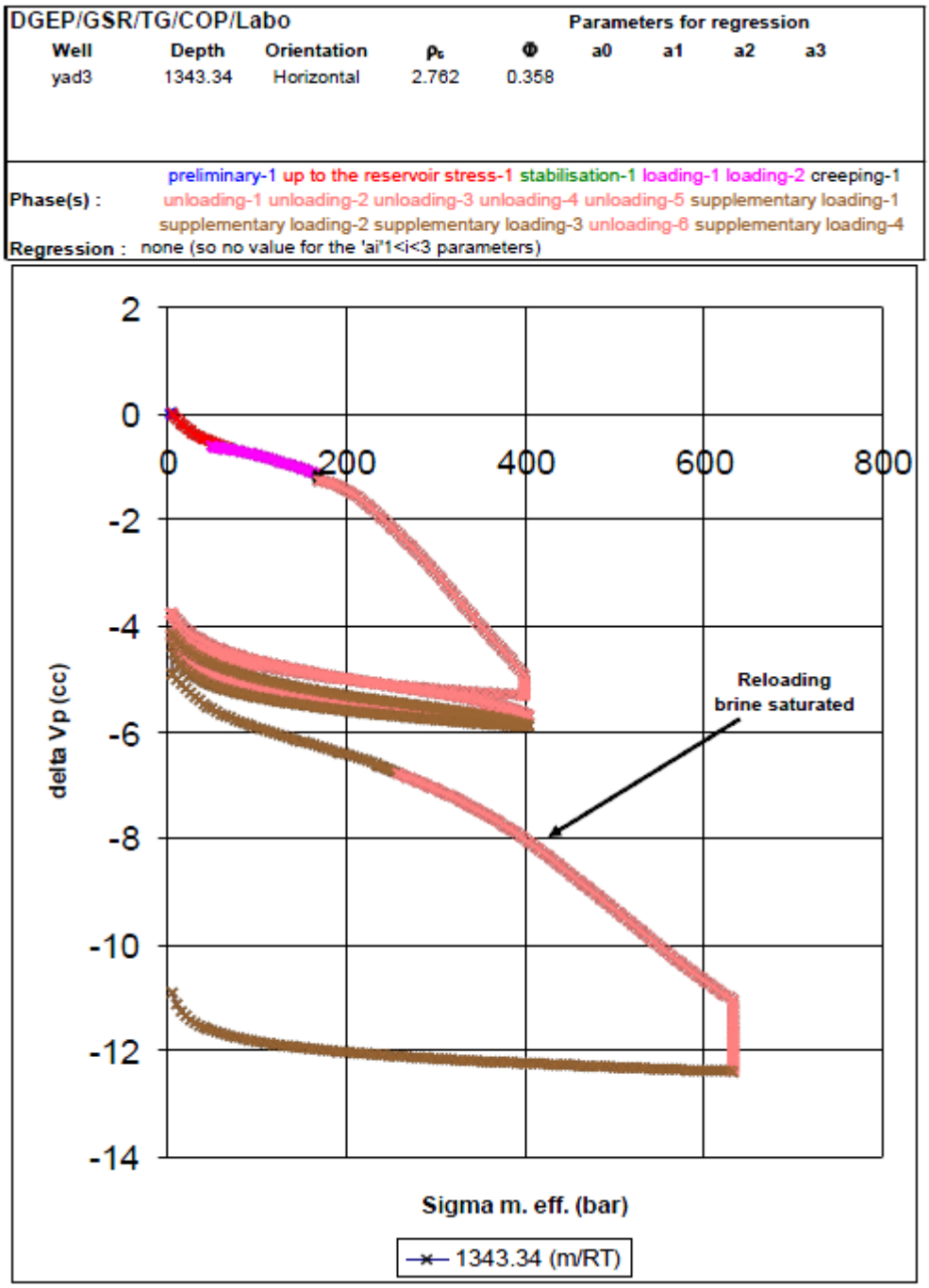


Figure A10: Example of test graphs