MASTER THESIS

CHARACTERIZATION OF RECOVERY MECHANISMS OF CRETACEOUS AND TERTIARY RESERVOIRS IN NORTH GULF AREA

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Affidavit

I declare herewith that this thesis is entirely my own work and that where any material could be construed as the work of others, it is fully quoted and referenced.

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Dedication

I would like to thank God Almighty for Amazing grace and blessings. This work is dedicated to my Family for their continuous support throughout my years of study, to the memory of my Grand Parents and all the others that have gone ahead of us.

"*God guard me from those thoughts men think*

in the mind alone,..." (Yeats, W., B.:1935)

Acknowledgment

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KURZFASSUNG

Ein allgemeines Modell für Lagerstätten ist wegen ihrer Komplexität unmöglich einzuführen, deshalb wird die Quantifizierung dieser Unsicherheiten ein bedeutender Teil des Lagerstättenmanagements. Trotz langer Operationsdauer von Erdölfeldern existieren häufig noch spät im Leben einer Lagerstätte maßgebliche Zweifel über wichtige Lagerstättenparameter. Das theoretische und praktische Verstehen dieser Parameter kann hervorragende Einflüsse und Auswirkungen auf eine erfolgreiche Zukunftsentwicklung der Lagerstätte haben. Unter diesen Parametern versteht man zum Beispiel relative Permeabilitäten oder das Maß an Anisotropie einer Lagerstätte. Im Auftrag des Erdölkonzerns TOTAL wurden zwei Erdöllagerstätten in Syrien und im Iran auf diese Parameter hin untersucht. Die Modelle dieser Lagerstätten wurden in der Simulationssoftware Eclipse aufgebaut und bestätigt, basierend auf dem aktuellen Wissensstand über das Feld. Auch wurde der Einfluss der einzelnen Parameter durch Sensitivitätsstudien evaluiert und interpretiert, dessen Ziel es ist, eine qualitative Idee von jedem Parametereinfluss zu bekommen. Die Untersuchungen und Ergebnisse werden in dieser Arbeit detailliert beschrieben. Weiters sind Empfehlungen für zukünftige Entscheidungen im Lagerstättenmanagement und der Entwicklung der untersuchten- oder analogen Felder enthalten.

ABSTRACT

Unique model for the reservoir in its full complexity is impossible to establish. Accounting and quantification of uncertainty is becoming a considerable part of reservoir management. Important amount of uncertainty concerning a number of reservoir parameters can still late exist in the life of field, notwithstanding the long operations time of oilfields. The theoretical and practical understanding of these parameters can have an eminent influence on the prosperous development and exploitation of the reservoir. These parameters are the relative permeability, the degree of anisotropy, to appoint only some. In the interest of the petroleum company TOTAL, two reservoirs in Syria and Iran were looked closely and unreliable parameters were recognized. The simulation sectors were established and confirmed with the software Eclipse. Sensitivities studies were performed on these parameters in order to appraise them, to bring out their meaning and to determinate their impact, based on the current status of knowledge about these reservoirs. The goal is to perform reservoir simulations for different values of the uncertain parameters with the purpose of getting a qualitative “idea” of each parameter influence. A detailed examination and issues of these parameters are described in the thesis. Besides recommendations for decisions in the future concerning the reservoir management and further field development for those reservoirs or another analogous reservoirs are inferred.

1. INTRODUCTION

The objective of this study was to understand the reservoir behaviour in an uncertain framework with the purpose of developing a regional data base of recovery mechanisms as well as of recovery factors. The dealt fields in this study are cretaceous reservoirs located in the North Gulf area.

The investigated reservoirs are the Shiranish reservoir in the SaZaBa field in Syria and the Asmari reservoir in the Haft Kel field in Iran. These discussed fields and reservoirs with specific static and dynamic data have been chosen as study source.

Although these two reservoirs have been putting on stream for more than 20 years, there was and still exists an important amount of uncertainty concerning a number of reservoir parameters. These two reservoirs could be considered as an analogue of other reservoirs located in the same study perimeter or outside. In case of development, the results obtained through this study could be helpful.

This study has the objective of drawing attention to these parameters by testing the reservoir behaviour for several values of these uncertain parameters and appraising their impact on production with a view to keep from failing decisions in the future concerning the reservoir management and further field development for this reservoir or another analogous reservoir.

This dynamic part of the study was conducted on the basis of preceding sections of the project which allowed characterizations of the depositional processes, description of facies, structural environments and records of the petroleum system. The main dynamic reservoir parameters influencing the production behavior were identified based on indications in the literature together with the geological and petrophysical understanding acquired about the fields.

The main dynamic parameters left doubtful have been made up based on in-house literature (historic studies). Reservoir simulation sector models were built with the simulator Eclipse based on these data. In order to confirm the simulation, a simple history match was carry into effect for cumulative production, reservoir pressure, water cut, gas oil ratio, to name only a few.

Sensitivities studies were performed on these parameters in order to determinate their impact and to make up a range of recovery factor. The goal is to perform reservoir simulations for different values of the uncertain parameters with the purpose of getting a qualitative “idea” of each parameter influence. The results obtained will be of interest in the constitution of the regional data base.

In spite of that, these results and further recommendations should be taken into account from a general view, since the simplicity of the model does not set aside for a detailed description of the field events.

2. SAZABA

2.1. FIELD LOCATION

The oil field SaZaBa is located onshore in the Northeast Syria closed to Turkey in the basin of Zagros Fold Belt. It is composed of three compartments (Said, Zurabeh and Babassi), which are probable in communication. [1]

The formation containing oil is the Shiranish (Upper Cretaceous: Maastrichtian), which is a fractured carbonate. The formation has two types of oil, one of them is active (the producible one) and located in the upper part of the formation (the pay zone: unit **A** and top of unit **B**) and the other one, less movable due to its high viscosity, density, high percentage of paraffin, asphalten, resin, and bitumen is located in the lower part of the formation (tight reservoir: bottom of unit **B** and unit **C**) and consists of Tar mat. Minor oil production is coming from the under laying Massive Limestone Formation in the Said structure. [1]

The geometry of the field is a wide structural anticline East-West trending. Its dimensions are approximately 20[km] long and 4[km] wide at top Shiranish Formation. The top of the Shiranish reservoir lies at 950[mss] TVD (True Vertical Depth) with an oil column of 200[m]. [1]

The first field which has been discovered is Said in 1977 followed by Babassi in 1978, and Zurabeh in 1979.The SaZaBa oil field was put on stream in 1983. [1]

The amount of original oil in place (OOIP) is estimated to be approximately 281[MMSm^3] (1.7[Bstb]), of which up to January 2002 only 5.058[MMSm^3] have been produced, resulting in a recovery factor of about 1.8[%]. [2]

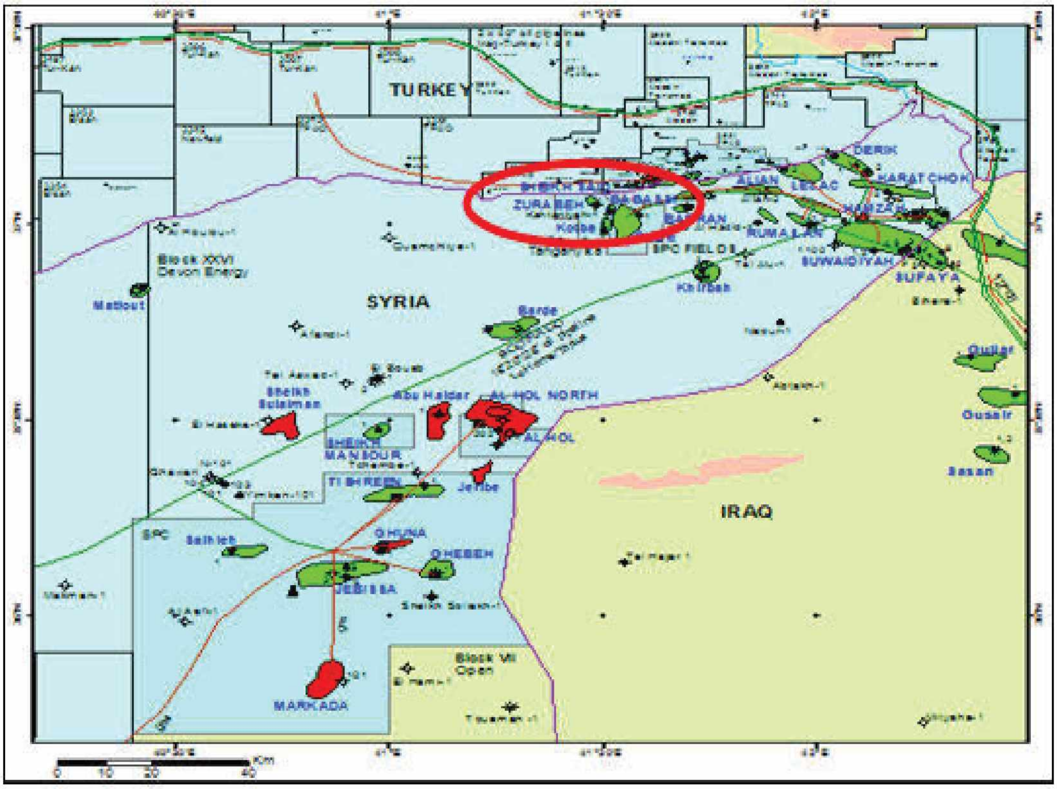

Figure 1: Field location of SaZaBa [3]

2.2. FIELD SEDIMENTOLOGY

The Shiranish formation is present over the whole field and strongly eroded below the Kermav Formation. In the study area, its thickness ranges from 250 meters in the South-western corner of the field, close to ZA-7 well, to less than 75 meters in the Southeast, South of Babassi structure. [1]

It has been possible to divide this formation into three main units, called **A**, **B**, **C** from the top to the bottom of the structure, based on Gamma Ray, Neutron and Porosity log correlation.

These members were deposited during two sedimentary cycles over the eroded Massive Limestone Formation.

During the first cycle, argillaceous and glauconitic and/or dolomite were deposited. These remaining limestones are representative of a first sedimentary cycle: a flooding surface, FS1, can be established within this interval.

The second cycle begins with the **C** unit erosion and detrital limestones deposition of the **B** unit. As a result of that, it is strongly eroded. The deposition of argillaceous and chalky like limestone follows these detrital limestones. These limestones are characterized by the presence of low energy environment structures (fine grains, SA-10 well) and have wackestone to mudstone texture. A flooding surface can be inferred from the highest Gamma Ray values encountered in the first quarter of the sequence. [1]

The regressive calcareous of the **B** and **A** units are encountered above this flooding surface. These limestone are mainly bioclastic (said of rocks consisting of fragmental organic remains) and gravelous with packstone to grainstone texture. They are representative of channel, bars, shore deposits, characterized by a high level of deposition energy and are highly porous and sometimes recrystallised or dolomitize. [1]

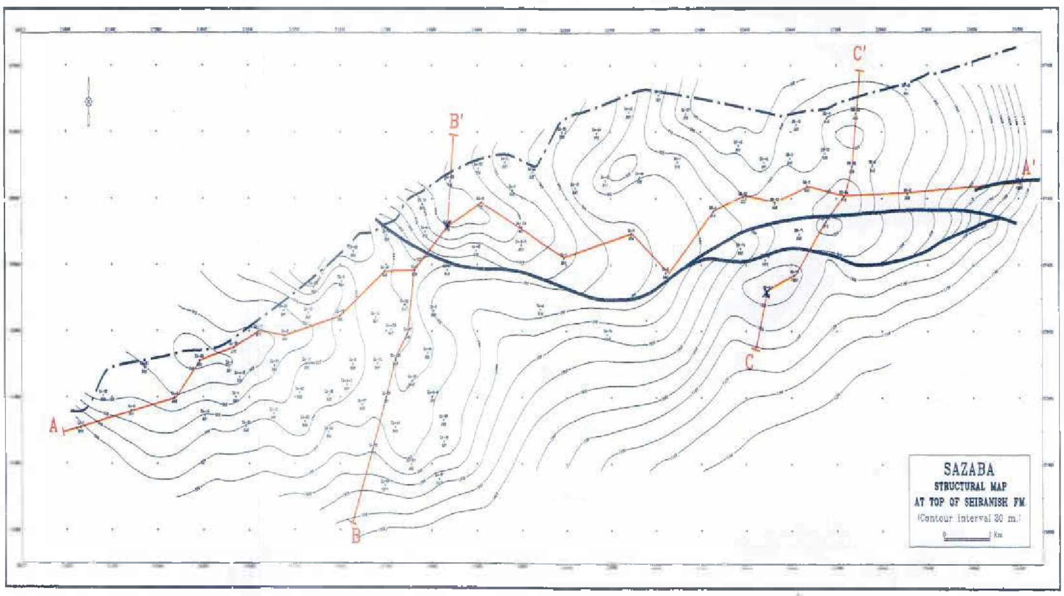

Figure 2: Top structure of SaZaBa at top Kermav Formation (Palaeocene) [4]

- <u>The **A** Unit</u>

  The **A** member is composed of grey to beige clean detrital limestones characterized on the Gamma-Ray curve by relatively low values.

  In this study area, oil bearing, the associated resistivities are high. In the uppermost part of this unit, some thin centimetric argillaceous beds may be present.

This member showing good reservoir properties is saturated by heavy oil and asphalt. The total thickness of this unit is very changing: from more than 100[m] in the Western part of the field to less than 20[m] Southeast of Babassi.

The decrease of the thickness is due to the erosion which occurred before the Kermav Formation.

The fractures, sometimes intensively, are occurring which are generally opened and vertical to sub vertical as observed on cores from SA-101, Za-2 and Za-1 wells. [1]

- The **B** Unit

It is composed, from base to top, of argillaceous and/or chalky limestones in which stringers of detrital limestones may appear. They seem to be more developed to the West of the field. Progressively the content of detrital elements increases with packstone and grainstone texture and it is difficult to differentiate the top of the member from the overlaying **A** one.

Its thickness ranges from 90[m] closed to the Turkish border in Zurabeh structure, to less than 40[m] Southeast of Babassi structure. [1]

- The **C** Unit

The **C** member is composed of light grey to brown tight argillaceous and glauconitic limestones having from a matrix point of view a very poor reservoir potential.

Its thickness shows a decrease from 88[m] in the Western part of this study area to less than 20[m] South of Babassi field. [1]

Formation	Units	Avg. Thickness	Lithology	Reservoir Quality
SHIRANISH	A	72 m 240 ft	Grey to beige clean detrital limestones with thin argillaceous beds	Good, where its matrix porosity is developed.
	B Upper	24 m 80 ft	Argillaceous and/or chalky limestones (wackestone to mudstone textures), changing to detrital limestone upwards	Good in upper part
	B Lower	25 m 83.3 ft		Tight in Lower part
	C	30 m 100 ft	Light grey to brown tight argillaceous and glauconitic limestones	Tight limestone, and Tar Zone
MASSIVE LIMESTONE		30 m 100 ft		Tight

Table 1: Formation lithology per layer

2.3. RESERVOIR GEOLOGY

The SaZaBa field bears two reservoirs, the Upper Cretaceous (Maastrichtian) Shiranish and the Middle Cretaceous Massive Limestone. Based on Gamma-Ray, Neutron and Porosity log correlations, the Shiranish reservoir was subdivided into three zones (from zone **A** at top, to zone **C** at base).

The base of the zone **B**, the zone **C**, and the Massive Limestone reservoir are considered as tight and poorly productive from a matrix point of view. The zone **A** and the upper part of the zone **B** are considered porous and oil producing. [1] [3]

The geological reservoir model was essentially taken over from Beicip-Franlab study (March 1995). It consists of a geological model construction, initialisation/history-matching, and simulation predictions. [5]

A quick seismic evaluation was initiated and the available seismic sections were provided. The shape of the structure is controlled by several seismic lines as well as by 98 wells spread over the field. [1]

17 key wells have been selected according to their distribution over the structure, the absence of faults, to their production and to the available set of logs. The clay content, the water saturation, the effective porosity and the lithology have been calculated over the whole Shiranish Formation. [5]

The structure of SaZaBa has been defined with the following data: Logs of 96 wells, 6 seismic sections restricted to the Eastern part of the structure, one structural map at top Shiranish from SPC (Syrian Petroleum Company) and one structural map at top Shiranish from Beicip-Franlab in 1992. [1]

The structure is faulted along its axial trend by an East-West normal fault which is duplicated in its Eastern part thus isolating a small compartment (see **Figure 2**). The origin of such a block can be created by a wrench movement along this main fault. [1]

The major fault network is quite well defined in the eastern part but underestimated in the western part. The minor faults have been seen but not correlated due to the lack of information.

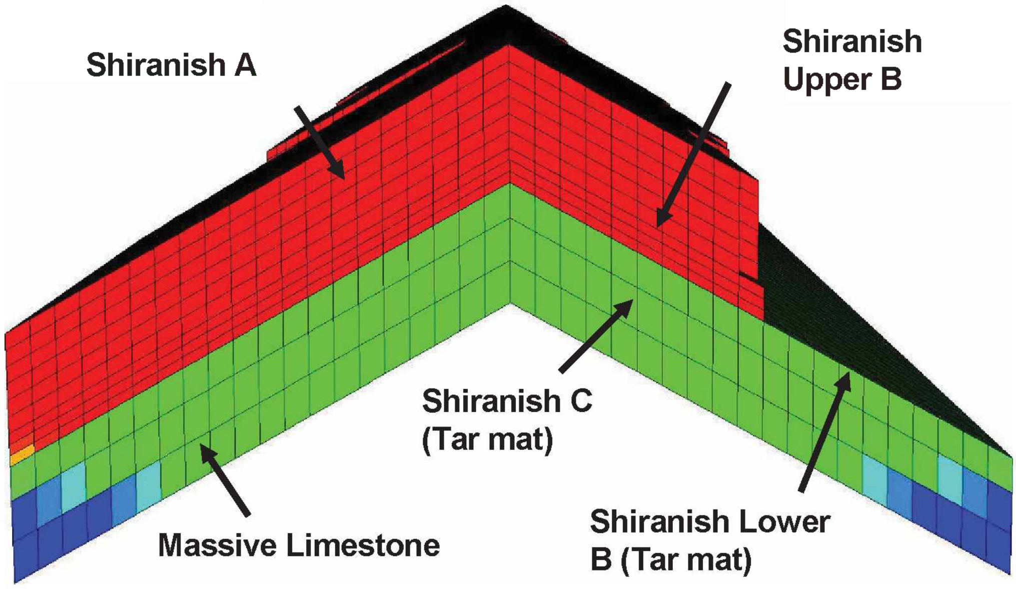

Figure 3: SaZaBa reservoir zonation

Formation	Thickness [ft]	Porosity [%]	Permeability [mD]	OOIP [MSm³]
Shiranish (A & Upper B Units)	320	20.4	16.9	281
Tar mat & Massive Limestone	200	16.5	Very poor	213

Table 2: Average reservoir properties filed wide [2]

The fractures have been evidenced on cores but not well characterised and quantified (No Formation Micro-Scanner log). Based on an anomaly detection procedure (the philosophy of this technique is based on the fact that the fractures are inducing local discontinuities in the rock which can be detected by one or more (to be more accurate) logs such as Calliper, the MSFL, the Sonic log, the Density log, the Neutron log and the DRHO (correction of the Density log)) a fracture log has been built for each of the study wells in the whole Shiranish section. [1]

Two fractures ratios (fractured heights over the thickness of the studied zone) have been calculated: one restricted to the Pay Zone and the other for the total Shiranish Formation.

These fracture ratio distributions show that the good producers are located along the faulted and fractured zones.

Most of the available logs were used for such calculations among which the MSFL, the DRHO and the Calliper ones seem to be the more reliable indicators.

It should be pointed out that the geological model of this 1995-study can be improved today. A more refined petrophysical description can be done. A more in-depth study of the fracturation network can be initiated.

The gas-oil contact (GOC) identified in well Sa-6 lies at 786 [mss] in the Western side of the field. In the Eastern side of the field (located in the small compartment), GOC identified in Bb-6 at 1056 [mss], restricted to the area. [1]

The origin of the oil-water contact (OWC) is not well identified from logs in the study area. Technical water (mud, completion fluid), water expelled from the lower part of the **B** member, and water coming from the Massive Limestone? In order to match the water contact in the model, the OWC was fixed to 1100 [mss]. [1]

Two types of hydrocarbons exist in the Shiranish: a movable one which is produced and a non movable one composed of asphalt and/or oxidized oil. The **C** member is a tight limestone (less than 12 % porosity) highly water saturated is considered as a very poor reservoir from a matrix point of view and it acts as horizontal barrier to flow regarding the communication within the field as filled up with non movable oil to develop a Tar mat. The base of **B** member is composed of limestones deposited in a low energy environment characterized by a very fine porous media. The connate water saturation is high due to the size of these pores, except in some local stringers of clastic material. A presence of Tar mat has also been evidenced. [1]

As a consequence the **C** member and the base of the **B** member are not involved in the Pay Zone.

The Pay Zone (**A** member and the upper part of **B** member) of the Shiranish Formation, which contains movable oil in its matrix porosity (the term of matrix is used from a petrographical point of view), shows very good average porosity values. They range from 15% which corresponds to a permeability of 1[mD] considered as a minimum for production of such viscous oil, to the South, to more than 23% to the North and to the West. [1]

The permeability test is only 5 times the core permeability, indicating a medium participation of the fractures to the oil flow. Neither the initial drilling damage nor the completion damage of the formation is indicated by the skin. [2]

The porosity-permeability relationship established by Beicip Franlab in 1992 from core data has been used to compute a permeability curve. This regression law [1] is as follow:

$$K = 10^{(17 \times PHI - 2.42)}$$

As previously for the porosity distribution the areas of better interest are located Northward and Westward of the field. The Permeability values range from 1[mD] to 30[mD]. [1]

Regarding to the communication within the field, the non reservoir layers Base of **B** unit, **C** unit and Massive Limestone might supply the Pay Zone with some water through the fracture network.

The oil is generally undersaturated, with a gravity of 19 °API and a viscosity of 31[cP]. [1]

There is not clear indication of significant pressure support from the aquifer and its volume, since that a considerable reservoir depletion of up to 80 [bar] from the initial reservoir pressure has been observed. Therefore no clear statement about aquifer presence can be at the moment.

In order to match the aquifer in the model, a bottom-water drive aquifer with a ratio of $W/N = 40$ has been taken. Where W is the volume of aquifer and N is the original oil in place. [2]

The production started in 1983 at 55 Sm3/d, at end March 2001 the oil production reached 1644 [Sm³/d] (10341 STB/d) with 96 wells (70 vertical and 26 horizontal), resulting in a recovery factor of 1.8%. [5]

The oil fluid parameters of the SaZaBa field are depicted in the table below.

	SHIRANISH	
API Gravity	[°API]	19
Viscosity at P_b	[cP]	31
Gas Oil Ratio (GOR) at P_b	[vol/vol]	36
Reservoir Temperature	[°C]	56
Formation Volume Factor (FVF) at P_b	[vol/vol]	1.13
Reservoir Pressure	[bar]	150
Oil Water Contact (OWC)	[m]	1575
Bubble Point Pressure (P_b)	[bar]	73
Compressibility above P_b, C_{ob}	[1/bar]	14.7E-5
Datum Depth	[m]	1475
Sea level	[m]	475

Table 3: Oil Field Fluid Parameters

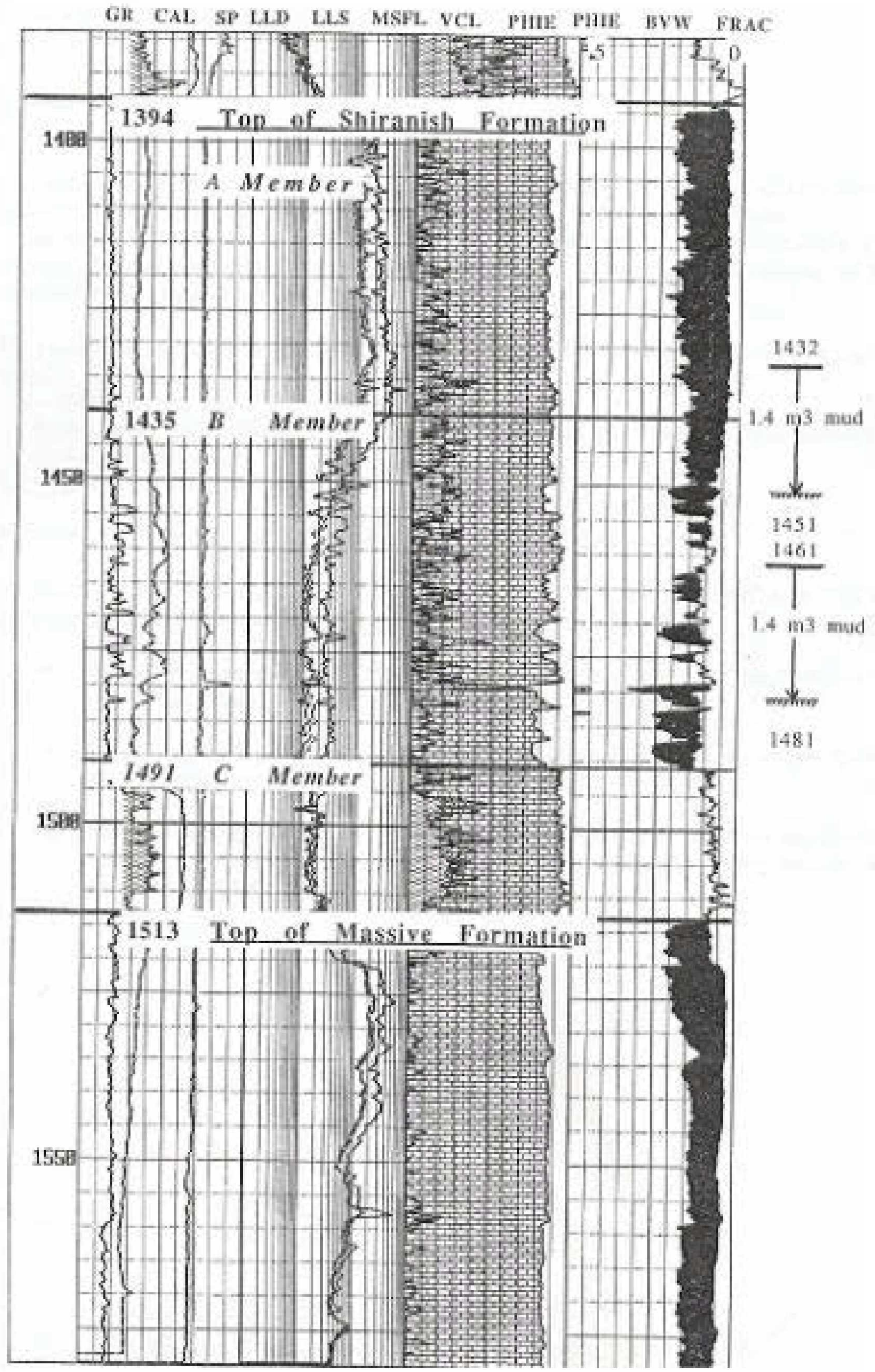

Figure 4: Log of the Shiranish formation from well SA-9 [1]

2.4. RESERVOIR MODEL

A sector model of the Shiranish reservoir was already available from an earlier reservoir study with the Athos simulator. As TOTAL deals with the Eclipse simulator, a new simulation model was built with the Eclipse simulator.

The degree of complexity of the reservoir is a function of the amount and detail of information that could be obtained from the Athos data files.

The Eclipse model consists of 12 reservoir layers, 11 layers for the Shiranish and one for the Massive Limestone. Downwards, the layer 1 to 9 represent the Pay Zone (unit **A** and upper unit **B**) of the Shiranish Formation, the layer 10 represents the Shiranish Formation **B** (lower unit **B**: tar mat), the layer 11 correspond to the Shiranish Formation **C** (unit **C**: tar mat) and the layer 12 depicts the Massive Limestone Formation (tar mat), which could supply the water through the fractures network. The dimensions of the sector model are detailed in the following table:

	SHIRANISH	
Real sector length [m]	20000 4000 181	
Number of Grid blocks	[106] [40] [12]	
Average Length/Grid block [m/grid block]	X Y Z	190 100 15

Table 4: SaZaBa sector model dimensions

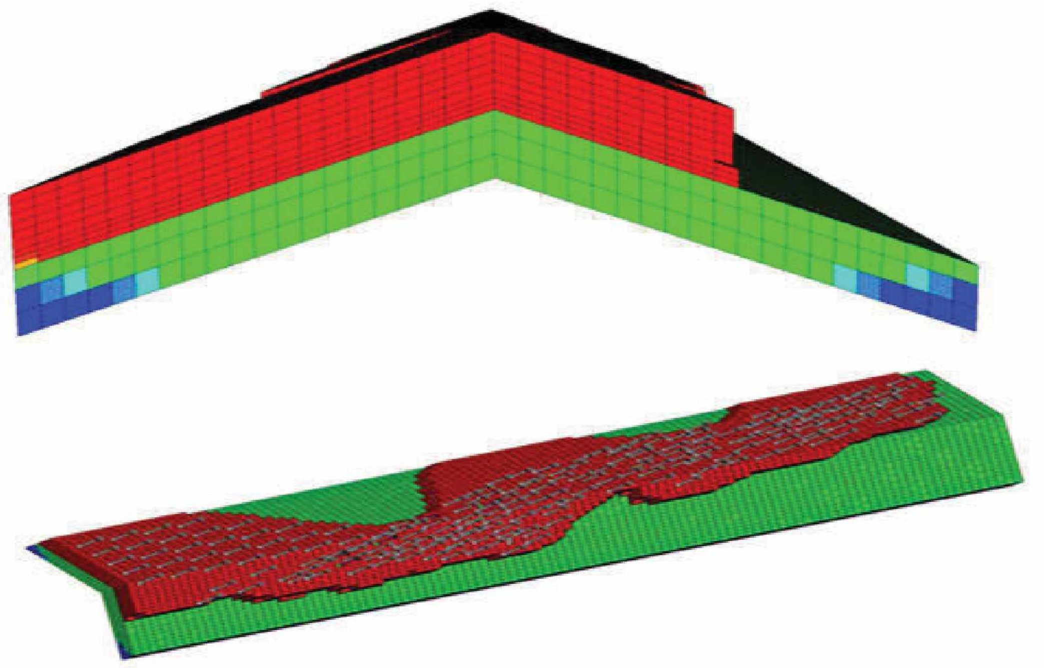

Figure 5: SaZaBa sector model side and total view

The model starts production on the first July 1983. It is history matched until 2001, the year from which the latest production data is available; for predicting purpose a forecast period until 1st March 2030 was chosen.

It has to be mentioned imperatively that the original model was build with the Athos simulator and contained production restrictions in the sense of a history file. Since the model is built with the Eclipse simulator some restrictions were removed to allow the model to produce freely and unconstrained for the purpose of sensitivity analysis, after the correct history match was assured (see **2.5**).

Thus it is quiet important to keep in mind that the cumulative productions resulting from the sensitivity analysis DO NOT correspond to figures (getting from the Athos simulator) that can be found in the literature.

Several operational conditions have been implemented in the sector model for the sensitivity analysis:

- The wells are put under an individual oil rate constraint which is different for all wells from 1983 to 1994. After 1994, some existing wells and the new vertical and horizontal wells have a new oil rate constraint which is of 20[Sm^3/Day] for the vertical wells and 50[Sm^3/Day] for the horizontal one.

- A minimum bottom hole pressure of 25[bar] for the vertical wells and of 40 [bar] for the horizontal one. The wells will be shut if the bottom hole pressure falls below this limit.
- The wells start and shut subsequently according to the indicated real production history. Approximately 100 of existing wells are on stream in 2001.
- There is no scheduled operation downtime for all wells at once.
- Duration of the simulation production time is 47 years.

The table depicted below gives an overview of the properties of the reservoir model SaZaBa (after matching the model).

Layer	H [m]	Porosity [-]	K (h) [mD]	$\frac{K_V}{K_H}$ [-]	Formation
1	12	0.20361	67.510	0.050	Shiranish A
2	12	0.20361	67.510	0.050	
3	12	0.20361	67.510	0.050	
4	12	0.20368	67.712	0.050	
5	12	0.20368	67.712	0.050	
6	12	0.20368	67.712	0.050	
7	8	0.20371	67.766	0.050	Shiranish Upper B
8	8	0.20371	67.766	0.050	
9	8	0.20371	67.766	0.050	
10	25	0.20118	Very poor	----	Shiranish Lower B
11	30	0.10	Very poor	----	Shiranish C
12	30	0.21318	Very poor	----	Massive Limestone

Table 5: Reservoir model properties

2.5. MATCHING THE HISTORY

Many runs were performed in order to obtain the best match for the scenario performed with the Athos simulator (especially for the wells schedule and the Dual porosity model).

It should be pointed out that a perfect matching was not the aim of this study. The goal was to obtain a model representative of the behaviour of the Shiranish reservoir in this area.

The best match was achieved using a set of data described below.

- Single porosity model in the Eclipse simulator instead of Dual porosity / Dual permeability model used in the Athos simulator.
- The critical gas saturation has been changed as well as the oil relative permeability.
- The values of the permeability have been multiplied by a factor 4. This suggests a relatively poor impact of the fracture network and the single porosity offers a good representation of the reservoir behaviour.
- A bottom water-drive aquifer has been used with a volume forty times the original oil in place.

As probably can be noticed all these input data are within the limits of a narrow interval with a high confidence. The results of the final matching which defines the yearly production and its cumulative values are, respectively, given in **Figures 6** and **7**. The results of matching the gas-oil ratio (GOR) and the water cut (WC) are also given in **Figures 8** and **9**.

The **Figure 8** shows a breakthrough of gas, from the model using the simulator Eclipse, just after the history was matching for a value of the critical gas saturation of 0.06, which is considered as a realistic value. The breakthrough of gas could be delayed if the critical gas saturation increases, but a higher value than the one used above will not be realistic.

In **Figure 9**, the produced water during the first ten years from model using the Athos simulator are not the computed figures but the measured rate of the called “technical water” (mud, completion fluid), involving “drilling” water expelled from the lower part of the **B** member, and water coming from the Massive Limestone.

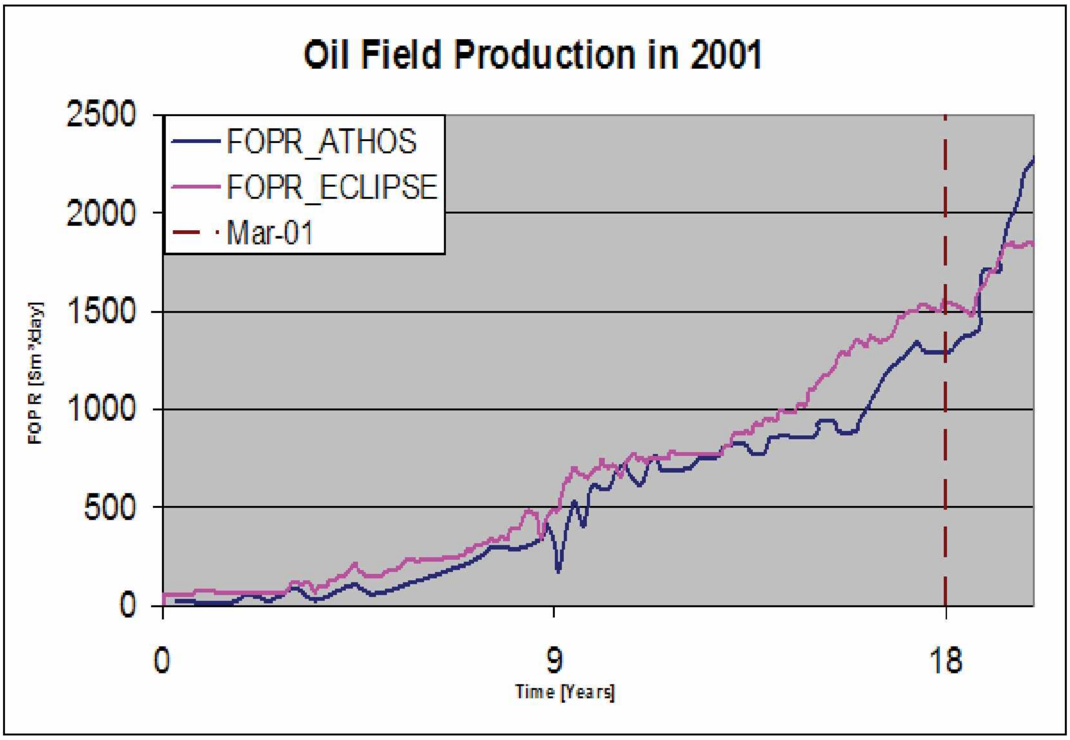

Figure 6: History match of the yearly production

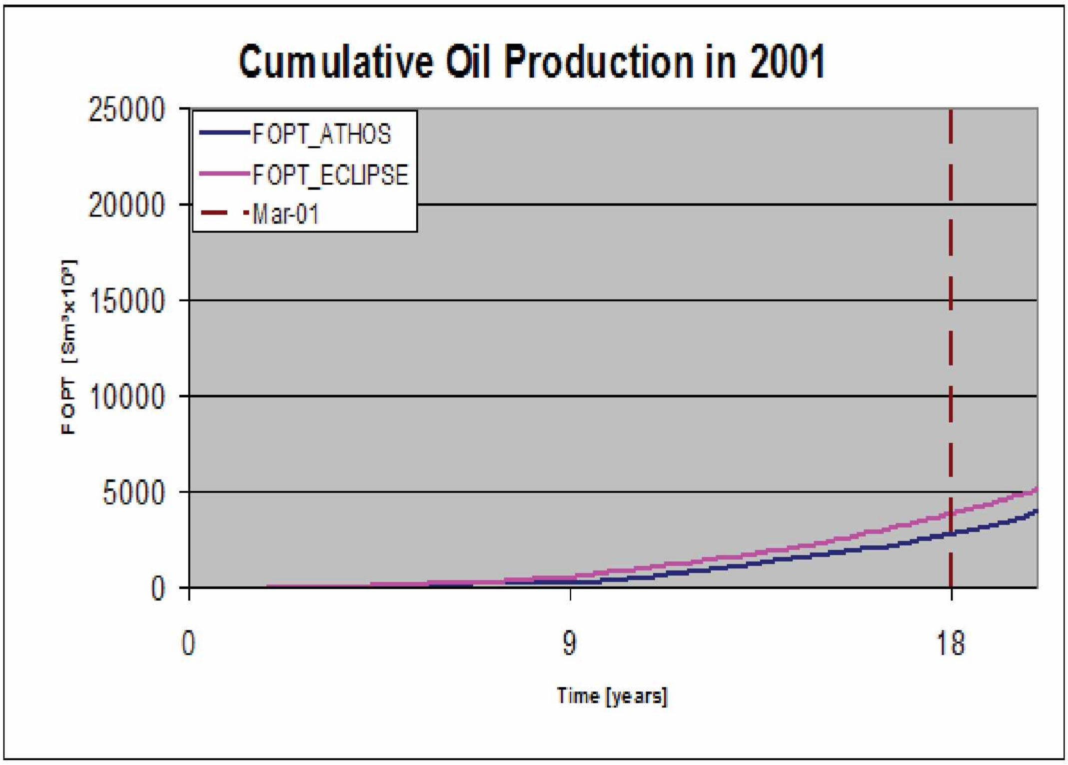

Figure 7: History match of the cumulative oil production

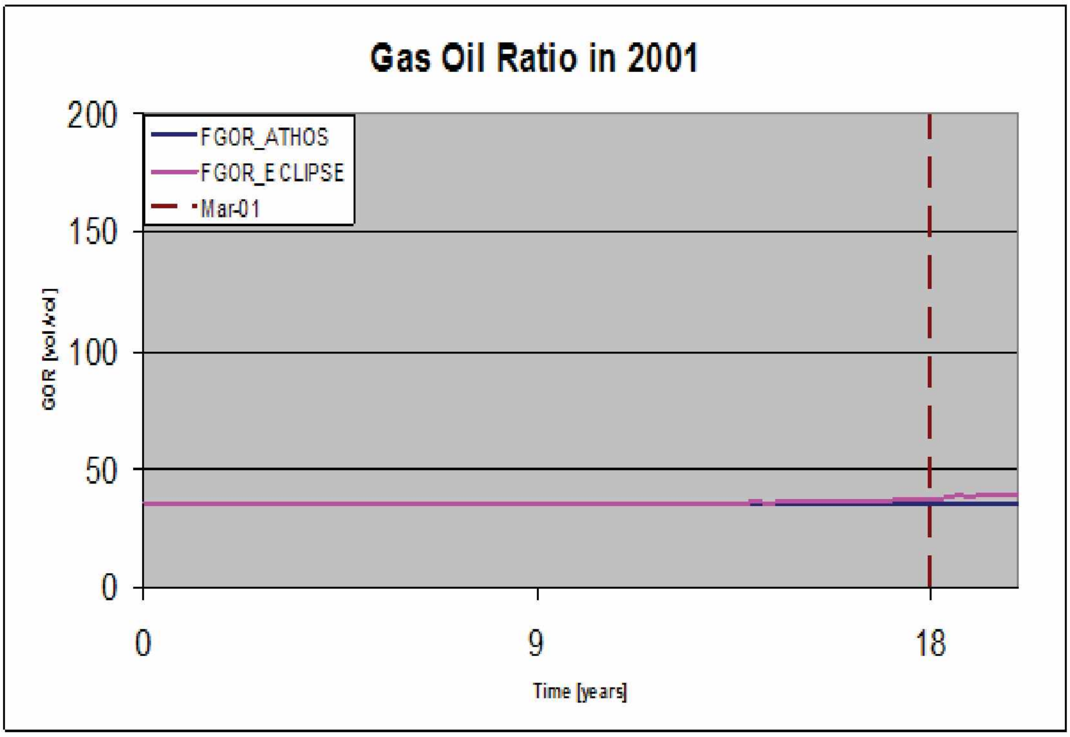

Figure 8: History match of the gas oil ratio

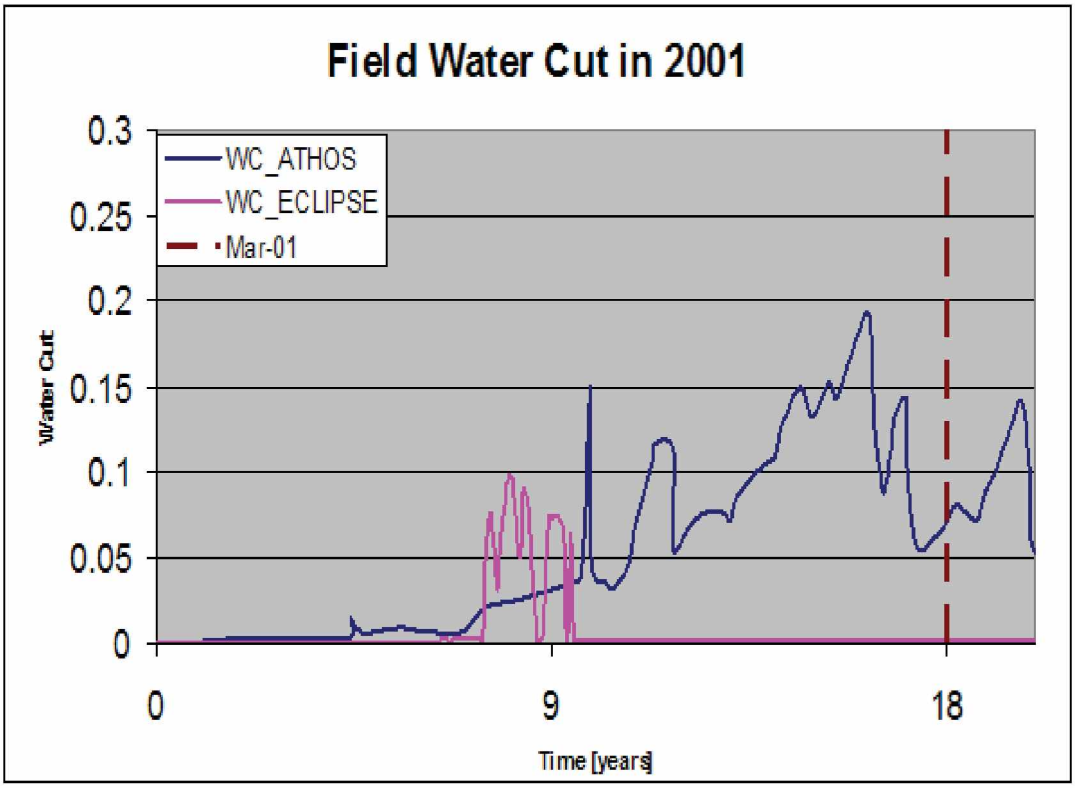

Figure 9: History match of the water cut

Formation	Thickness [ft]	Porosity [%]	Permeability [mD]	OOIP [MSm³]
Shiranish (A & Upper B Units)	320	20.4	67.6	281
Tar mat & Massive Limestone	200	16.5	Very poor	213

Table 6: Average properties field wide after matching

This Eclipse model can be considered as a good representation of Shinarish reservoir behaviour in this area and can be used for the following study objectives:

- To assess the main geosciences uncertainties
- To perform sensitivities analysis on these uncertainties
- To optimize the recovery factor using the EOR (Enhanced Oil Recovery) process(es) like steam injection and/or to develop features like highly deviated wells.

2.6. UNCERTAINTIES

The following uncertainties have been identified from the TOTAL in house literature:

(1) Matrix Permeability

(2) Aquifer Strength

(3) Fracture / Drain Network

(4) Horizontal Wells

(5) Steam Flood

2.6.1. Matrix Permeability

The matrix porosity-permeability relationship was established from core data and has been used to compute a permeability curve. The permeability values range from 1[mD] to 30[mD] and the model has a ratio of vertical permeability to horizontal permeability (K_V / K_H) of 0.05.

Gas injection is envisaged as a future EOR measure, thus there is expectation to find greater permeability values.

The permeability values of the blocks have been multiplied by 4 due to the heterogeneity of the formation in order to history match the production and the pressure and to obtain a permeability high enough to allow the oil to flow into the matrix.

It should be mentioned that in all of the runs vertical permeability was assumed to be equal to the horizontal permeability.

For the sensitivity analysis, two scenarios were considered; the first one was to divide the new matrix permeability by 2 and 4 respectively (low case) and multiplied by 2 (high case) to see the impact in the production and another scenario was to consider again the old permeability values (from 1[mD] to 30[mD]) and a Dual porosity model was adopted.

Since these permeability values are already high, only downside sensitivity was analysed.

2.6.2. Aquifer Strength

The presence and the force of an aquifer are quiet hypothetical and the presence of a tar mat at lower levels might significantly reduce its influence.

The aquifer's parameters such as its permeability, its volume, its nature (bottom or edge) are not defined in the TOTAL in house literature.

The led simulations show different depletions according to the size of the aquifer. It is quiet difficult to quantify the importance of these parameters in the absence of current data of pressure.

The base case model considers a Fetkovich bottom aquifer, the size of which has been set to $W / N = 40$. Where W is the volume of aquifer and N is the original oil in place. The aquifer properties are listed in the **table 7.**

For the sensitivity analysis, the size of the aquifer was increased from 40 to 250.

Datum Depth [mss]	Initial Pressure [bar]	Initial Volume [Sm^3]	Total Compressibility [1/bar]	Productivity index [Sm^3/day/bar]
1000	150	1.344E+10	9.6E-05	500

Table 7: SaZaBa hypothetical aquifer properties

2.6.3. Fracture / Drain Network

The fractures have only been evidenced on cores and detected based on anomaly detection procedure.

However, this could be explained by the lack of imaging techniques such as FMS log.

The fractures were included in the simulation model in the classical way by specifying a dual porosity model which is characterized by its flow regime that only allows flow from matrix to fracture and flow between fractures. The effective fracture permeability (the permeability values of the fractures cells are multiplied by the fracture porosity) was found in the history match of Athos model, being in the order of 1000[mD] in the horizontal and 10[mD] in the vertical direction.

The exact value of fracture porosity was not mentioned in the literature but could be evaluated from the book “Reservoir engineering en milieu fissuré” and has a value of 0.014[%].

A dual porosity and dual porosity/dual permeability (is characterized by its flow regime that allows flow between matrix and from matrix to fracture and flow between fractures) models have been performed.

The wells have been completed only for the Pay Zone due to the higher computational time and to avoid the convergence failures with the simulator.

For the shape factor, sigma, two cases were suggested: the theoretical one from Kazemi equation was equal to 0.19[1/m²] and two more realistic cases with 0.005[1/m²] and 0.001[1/m²], combined with the layers 10 and 11 plugged.

$$\sigma = C * \left(\frac{1}{l_x^2} + \frac{1}{l_y^2} + \frac{1}{l_z^2} \right)$$

Where $C = 4$, and l_x, l_y and l_z are typical X, Y, and Z dimensions of the matrix blocks. Matrix blocks have a value of: 8 x 8 x 8 [m]

The three different models which could be used in a simulator are illustrated in the figure below.

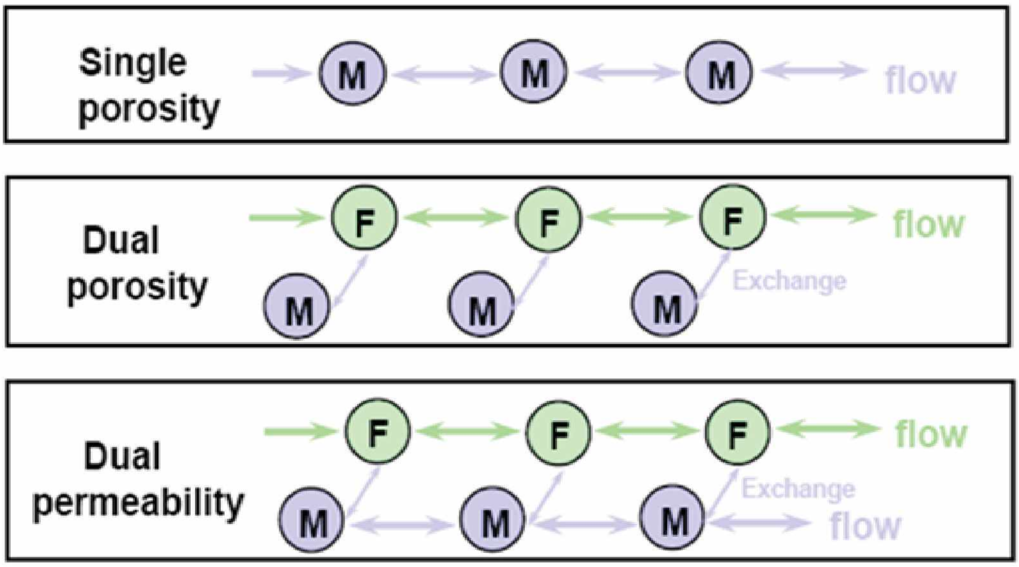

Figure 10: Single / dual porosity and dual porosity / dual permeability flow regime

For the fractured models, the lower B and C layers fractures might probably filled up with non mobile oil preventing water flow from beneath and therefore fractures permeability have been reduced significantly (1/1000) to simulate this issue.

2.6.4. Horizontal Wells

Up to date, 31 horizontal wells have been drilled using infill drilling method. Horizontal wells were considered from the beginning as a possible way to increase the productivity.

In the literature it is shortly mentioned that the horizontal wells strongly contribute to lower the high water production and allow the shut-in of near by high water formation volume factor of vertical wells as well as to increase the productivity of the field. Additional horizontal wells are drilled after the end of the history matching period in 2001.

There are enough good zones remaining in SaZaBa field to drill new wells and to obtain the desired well potential.

The base case contains 31 horizontal wells and 149 old vertical wells and 29 new vertical wells which have been drilled according to the remaining good zones of SaZaBa field after April 2005. For the sensitivity analysis, these 29 new vertical wells have been converted to horizontal wells at the same date. Some are completed in layer 3 and the others in layer 7.

2.6.5. Steam Flood

Steam flood has not been mentioned in the literature, thus it is assumed that no steam injection job has been performed up to date.

Steam drive as thermal recovery processes rely on the use of thermal energy in some form both to increase the reservoir temperature, thereby reducing oil viscosity, and to displace oil to a producing well.

Steam processes are limited to depths on the order of 3000[ft] because wellbore heat losses can become excessive. But insulated injection tubing can be used to reduce heat losses and increase this depth.

In this case, the steam injection starts in 2008 at a rate of 4000[Sm^3/d] in a sector model of the field. Although it is not practical to inject steam in the field near the critical pressure of steam, which is 3,206.2[psi] (critical temperature is 750[°F]), the injection pressure is 120[bar] (at a depth of 1500[m]) which is a bit higher as the pressure in this part of the field in 2008 with at the corresponding temperature of 324[°C]. A company did a pilot steam injection in a neighbour field showing the same reservoir characteristics a depth of 1500[m] and it seems to be successful.

A five spot pattern was represented; only one injector well and four producers with approximately 350[m] well spacing's. For the sensitivity analysis, this sector was naturally depleted (with 29 vertical wells) and the results will be compared with those of the same sector with steam injection.

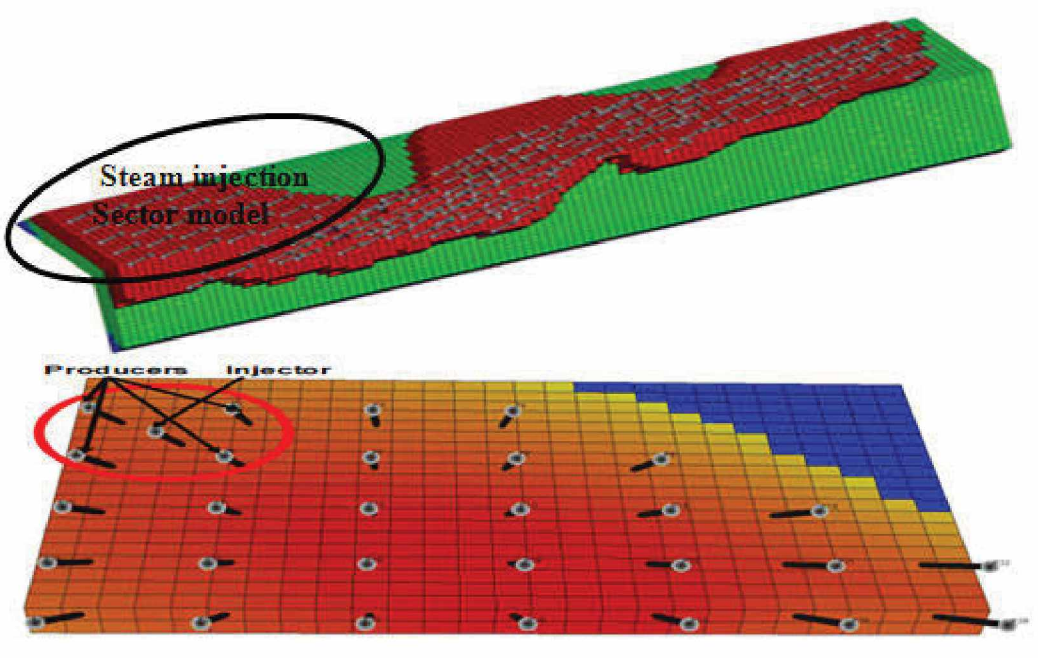

Figure 11: Steam injection in a sector model

2.7. RESULTS AND DISCUSSION

2.7.1. Reservoir Parameters

Uncertainty	Base Case	High Case	Low Case
Matrix Permeability	History matching value * 4	Values in whole field * 2	Values in whole field / 2
Aquifer Strength	Aquifer present (W/N=40)	Aquifer present (W/N=250)	---
Fracture / drain Network	---	Φ (fracture) ~ 0.00014 for a Dual porosity & Dual porosity/Dual permeability model σ=0.19 [1/m²]	Φ (fracture) ~ 0.00014 for a Dual porosity & Dual porosity/Dual permeability model σ=0.001 [1/m²] & σ=0.005 [1/m²] and layer 10 & 11 plugged
Horizontal Wells	176 vertical wells and 31 horizontal wells	149 vertical wells and 60 horizontal wells	---
Steam Flood	---	29 vertical wells and one injector	---

Table 8: Sensitivity analysis input data

For clearer illustration purposes and in order to better compare the results, two types of sensitivity analyses have been made.

One regards the reservoir aspects like matrix permeability and the different lift methods (different options are compared for just vertical wells and the same are applied to horizontal wells in another case), which will be evaluated, using a single porosity model.

The second sensitivity analysis evaluates the impact of the fracture/drain network using a dual porosity model and a dual porosity/dual permeability model.

- **<u>Sensitivity with single porosity model</u>**

The base case for the horizontal wells (using a single porosity model) is the horizontal wells case described in the reservoir uncertainties section.

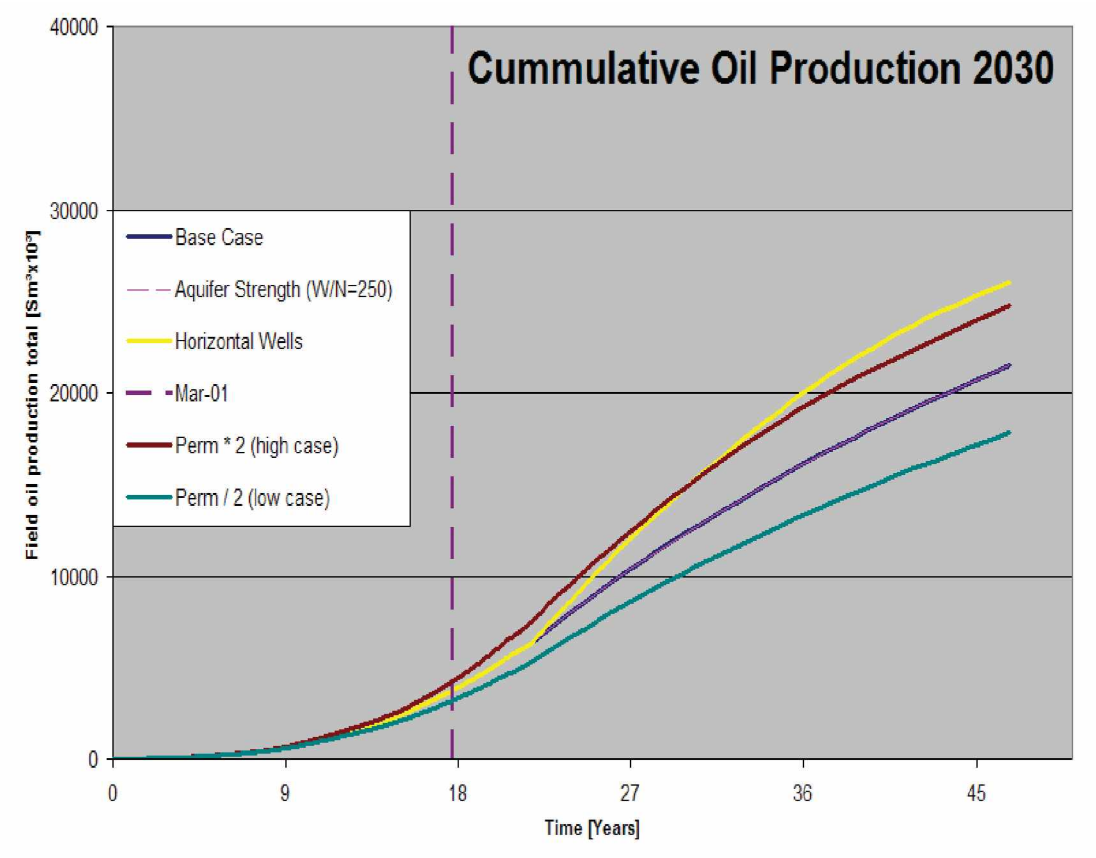

Figure 12: Cumulative oil production – base case and sensitivities

The figure above illustrates the simulation outcomes of the sensitivity study.

The main parameters to consider are the horizontal wells and the matrix permeability multiplied by 2 which have a strong influence on the oil production and on the pressure. The effect on the oil production is positive for both parameters, whereas the effect on the pressure is not beneficial as the field pressure is not supported by the bottom water drive aquifer due to the existence of the Tar mat (see **Figure 12**).

The horizontal wells have a significant and beneficial influence on the water cut whereas the matrix permeability multiplied by 2 as well as the horizontal wells have a negative on the gas oil ratio. This is probably due to the fact that the gas breaks out of the solution when pressure is below the bubble point conditions.

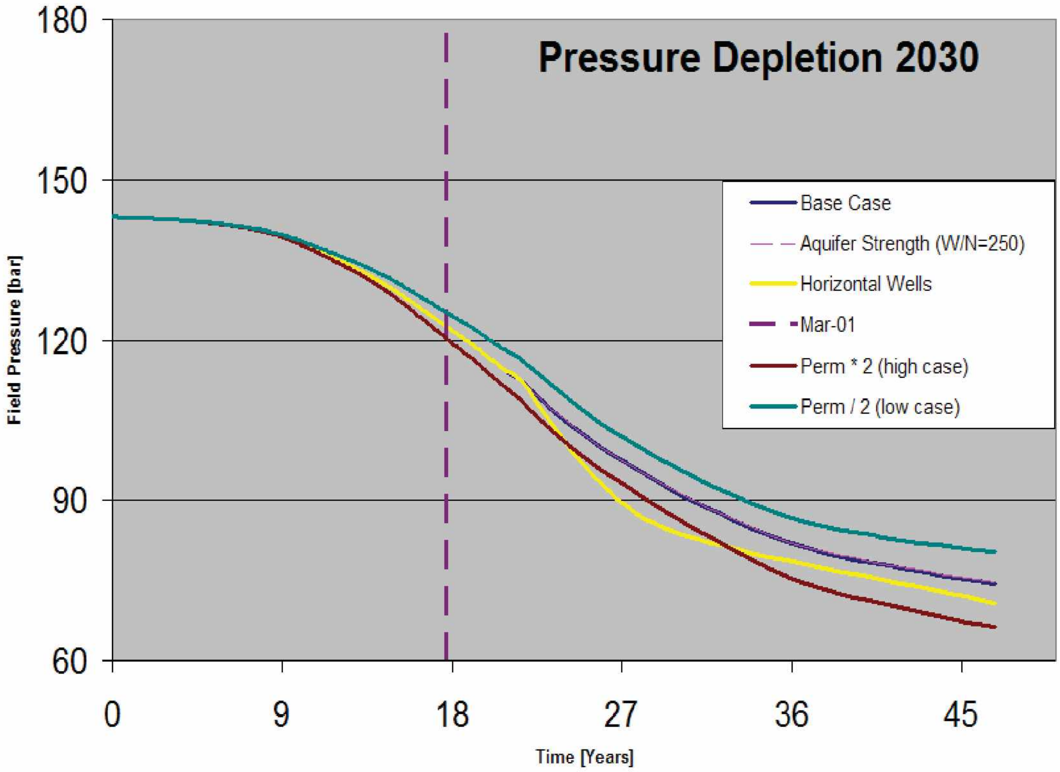

Figure 13: Pressure depletion – base case and sensitivities

All the others uncertainties namely the aquifer strength and matrix permeability divided by 2 have a poor influence on the cumulative oil production. The Aquifer provides a poor pressure support due to too low permeability in the bottom of the reservoir (Tar mat), thus the aquifer can not be effective and the results come very close to the base case ones.

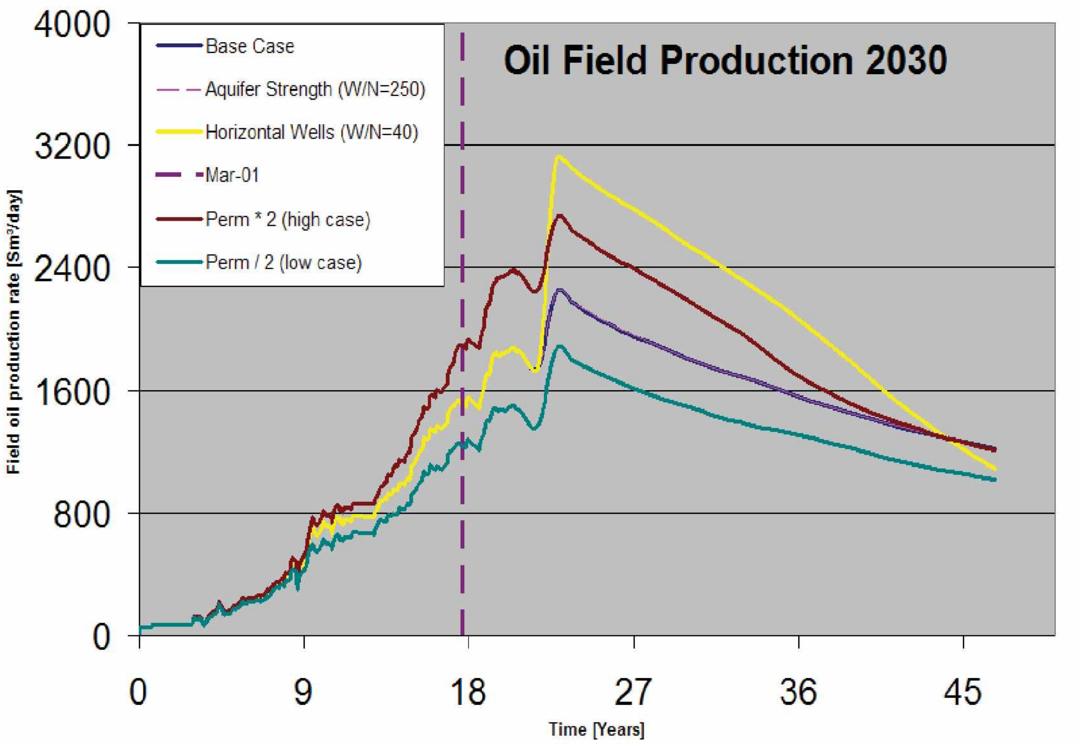

Figure 14: Oil production rate – base case and sensitivities

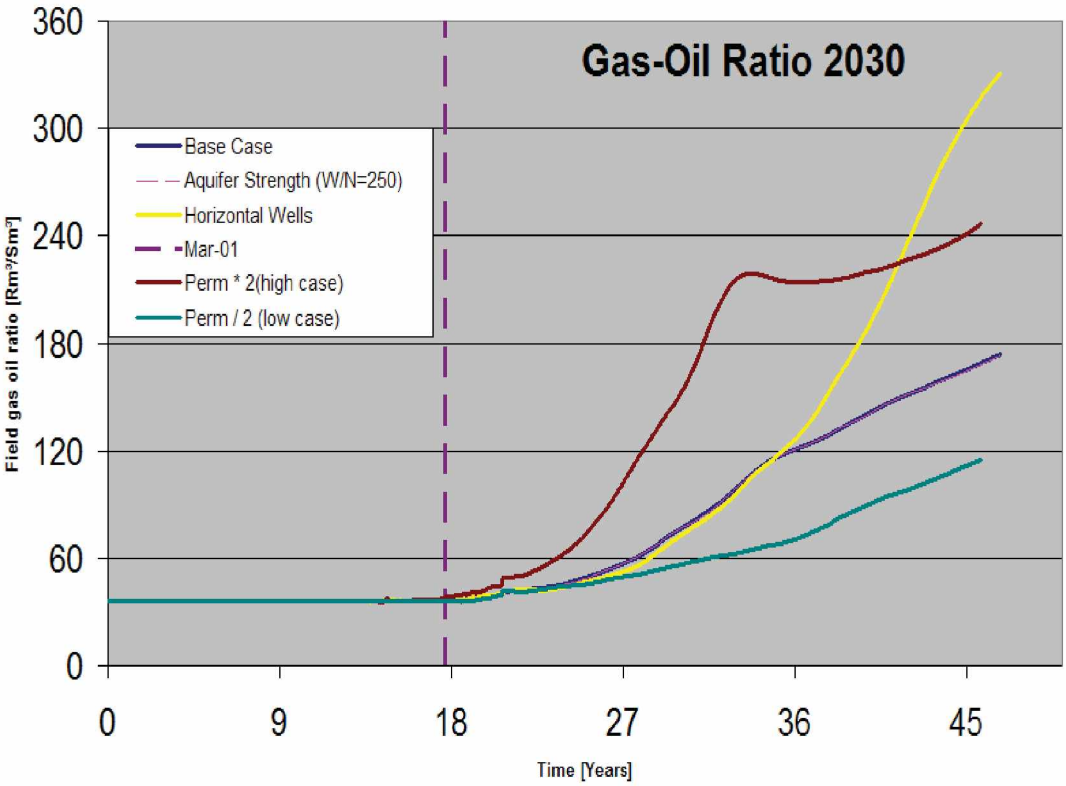

Figure 15: Gas oil ratio – base case and sensitivities

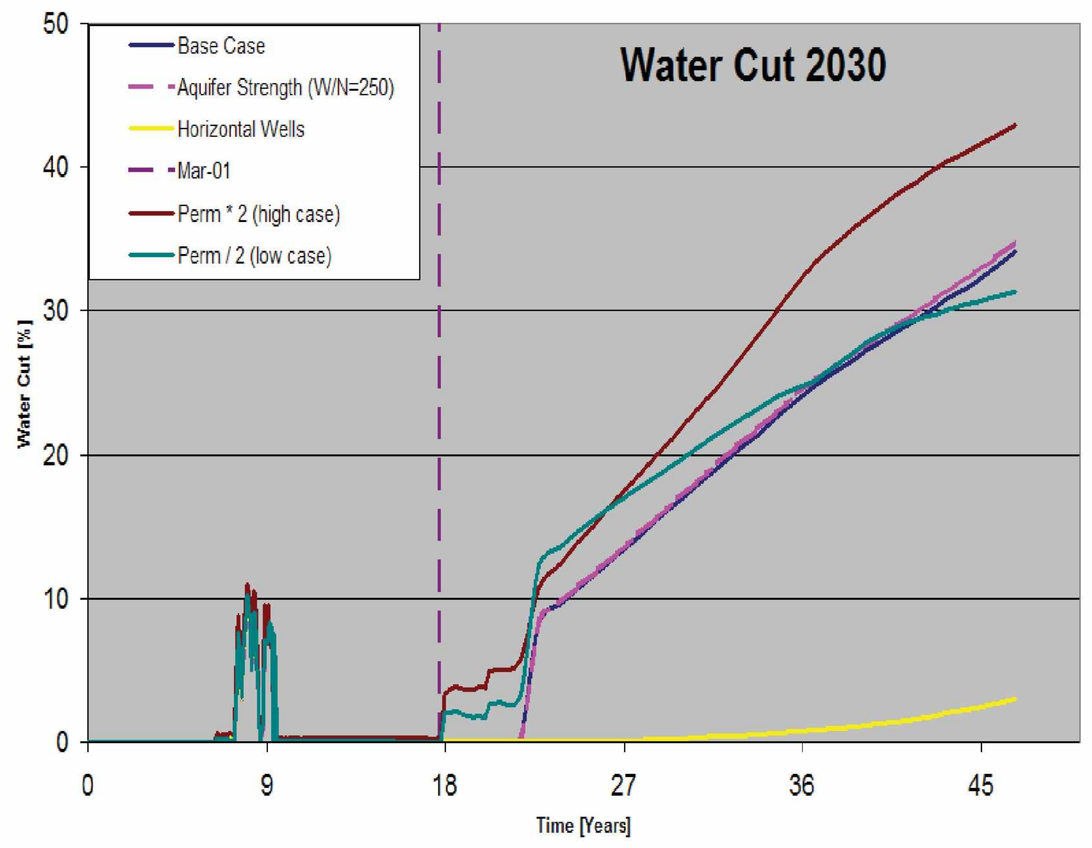

Figure 16: Water cut – base case and sensitivities

- <u>**Dual porosity, dual porosity/dual permeability models**</u>

The simulation results from the dual porosity model and dual porosity/dual permeability model are illustrated in the figures below.

The dual porosity/dual permeability model leads to a sharp increase in cumulative oil production but has a high field water production through the fractures network and a slightly decrease in amount of the produced gas.

The sensitivity analysis performed on sigma (shape factor) in order to get a more realistic case, leads to a small decline in cumulative production as well as in field water production, although it tends to increase the ratio of the produced gas to the produced oil.

The fact of considering that fractures are generally plugged by non movable oil in the tar mat areas (permeability fracture divided by 1000) reduces significantly the water cut but maintains the oil production.

The **Figures 17 - 21** below depict the impacts on the parameters as cumulative oil production, water cut, to name only a few, using another models namely a dual porosity and dual porosity/dual permeability models for the simulation.

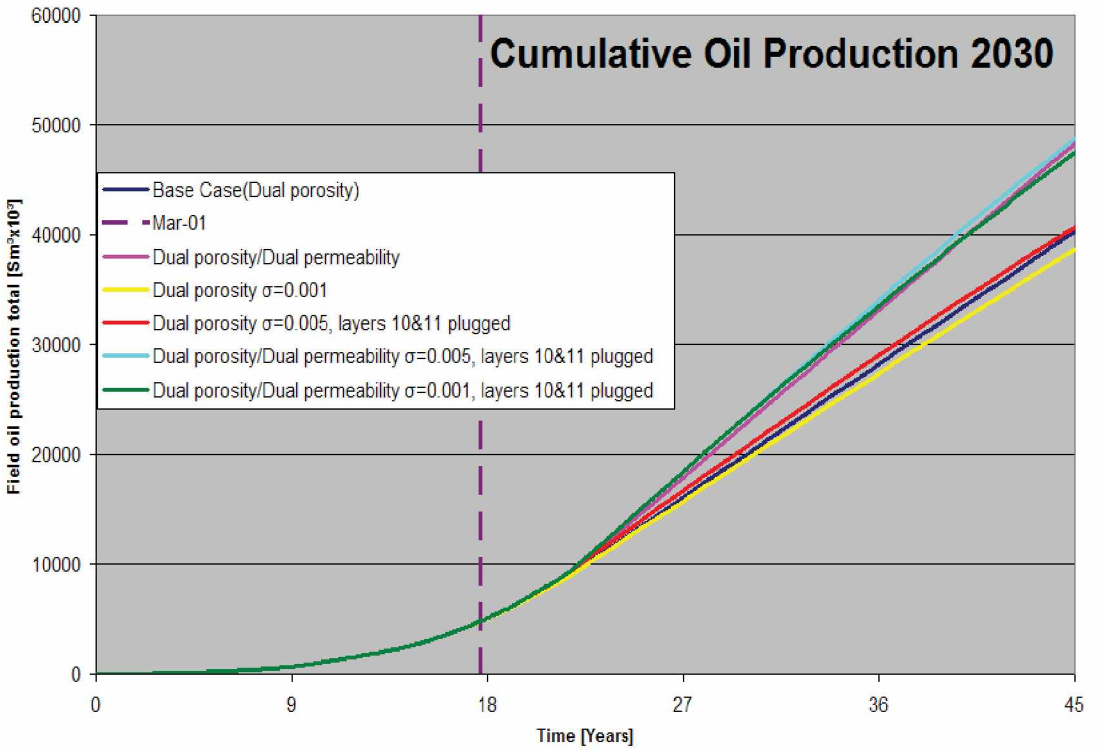

Figure 17: Dual porosity model – cumulative oil production – base case and sensitivities

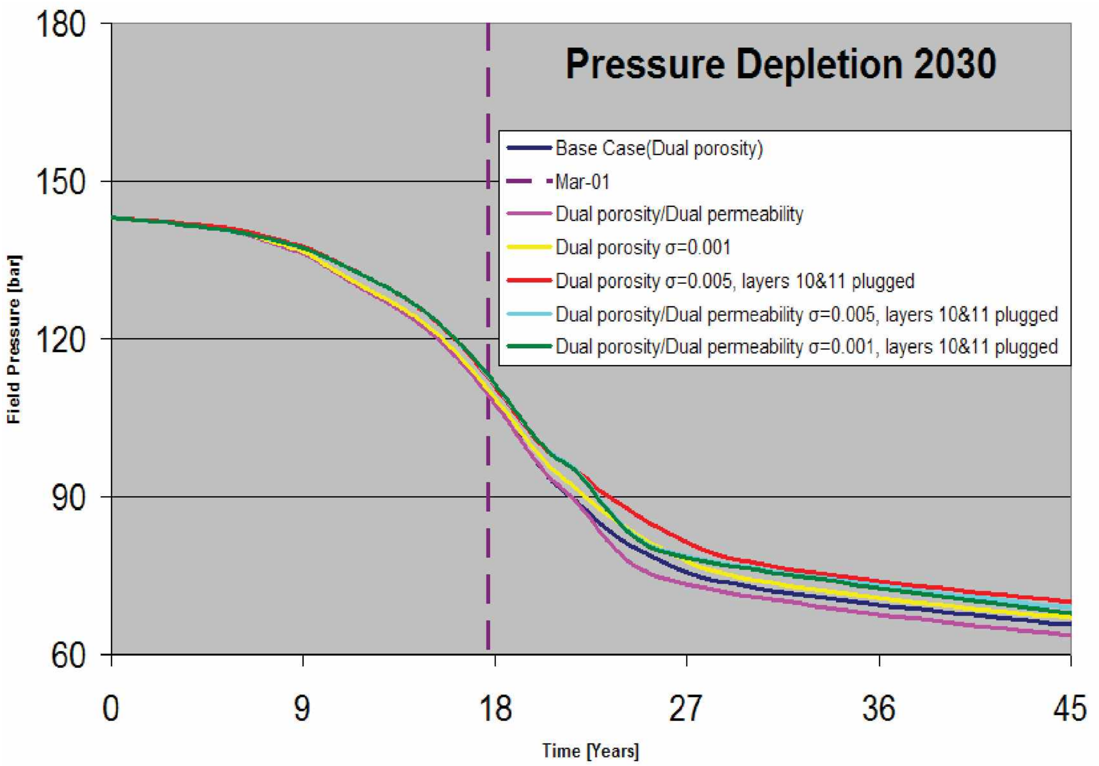

Figure 18: Dual porosity model – pressure depletion – base case and sensitivities

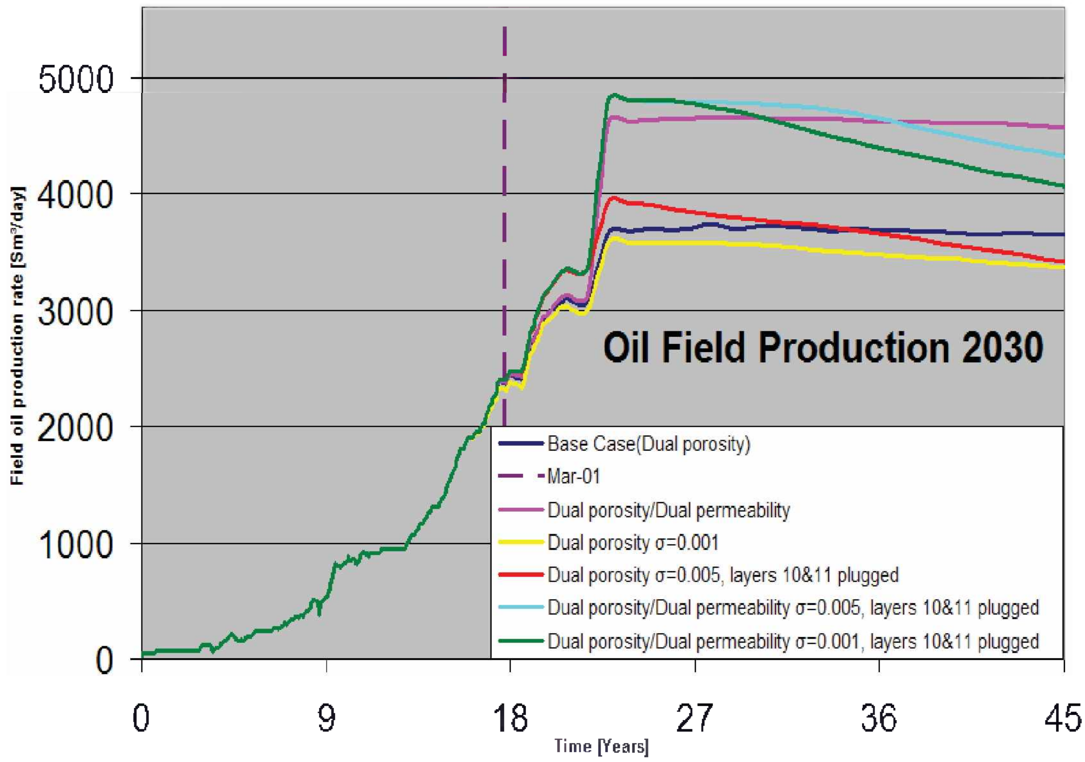

Figure 19: Dual porosity model – oil production rate – base case and sensitivities

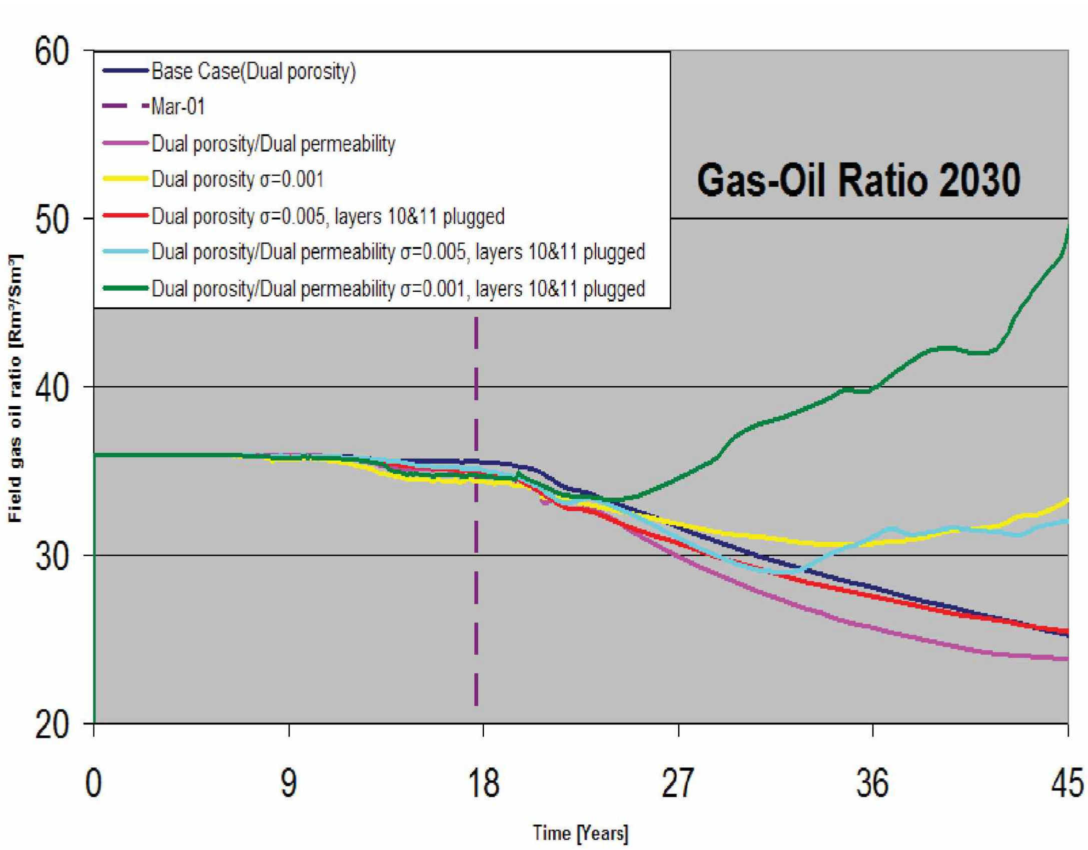

Figure 20: Dual porosity model – gas oil ratio – base case and sensitivities

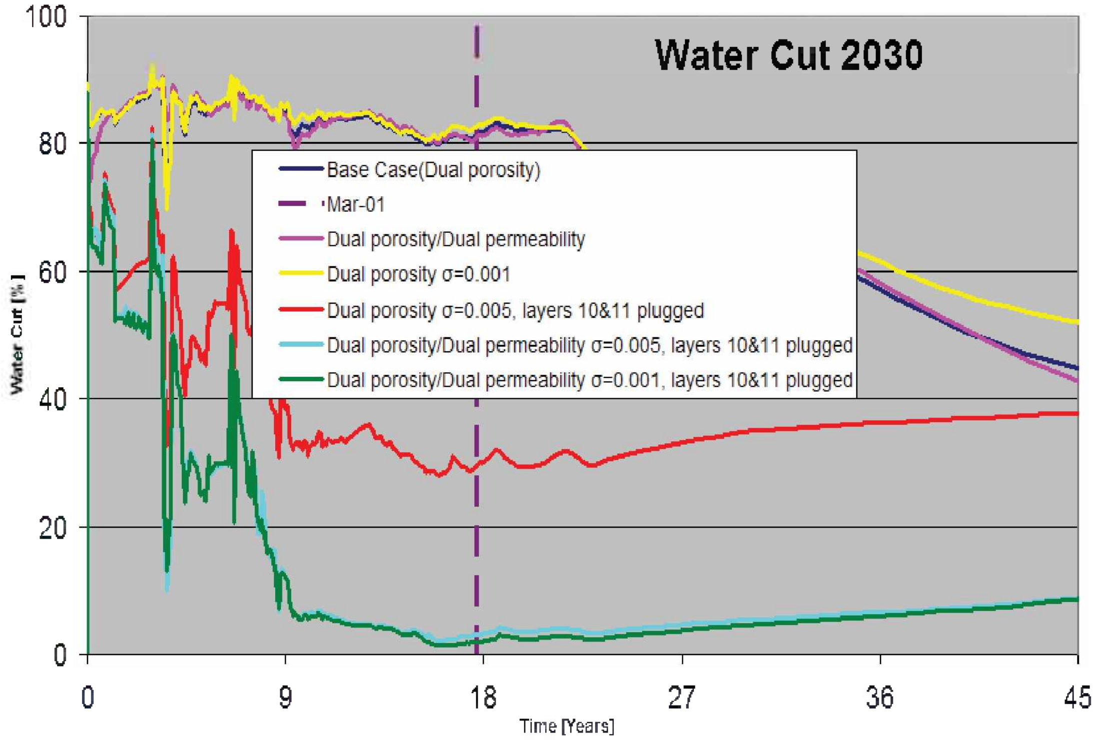

Figure 21: Dual porosity model – water cut – base case and sensitivities

OOIP [Bstb]	1.7		Np in 2030 (47 years) [MSm³]	RF [%]	WC in 2030 (47 years) [%]	Avg.reservoir pressure in 2030 [bar]
Base case figures	Base case		21.48	6.28	34.11	74.39
	High cases					
1 to 120[mD]	Matrix Permeability	K multiplied by 2	24.73	7.23	42.91	74.67
EOR process	Steam Flood (2005-2007)	One injector,production till 2012!	Convergence failure - model not running			
171 vetical wells & 31 horizontal wells	Horizontal wells	29 vertical wells converted in 2005	26.02	7.61	3.01	70.78
no fracture porosity	Fracture network(Φ=0.014% & σ=0.19)	Dual porosity	42.59	12.45	43.31	65.07
		Dual porosity/Dual Permeability	51.2	14.97	38.54	62.87
	Fracture network(Φ=0.014% & σ=0.005) layers 10 & 11 plugged	Dual porosity	42.85	12.53	37.93	69.31
		Dual porosity/Dual Permeability	51.51	15.06	9.13	62.02
	Fracture network(Φ=0.014% & σ=0.001)	Dual porosity	40.77	11.92	51.16	66.28
		Dual porosity/Dual Permeability layers 10 & 11 plugged	50.02	14.63	9.24	66.95
	Low cases					
aquifer (W/N=40)	Aquifer strength	aquifer (W/N=250)	21.49	6.28	34.73	74.67
	Matrix Permeability	K divided by 2	17.81	5.21	31.28	80.91

Table 9: Results overview SaZaBa

2.8. GENERAL CONCLUSIONS ON SAZABA

Two main parameters to consider are the matrix permeability, horizontal wells in the case of a single porosity model.

The matrix permeability has a significant impact on oil production in the part of the field with low fracturation.

Completed in pay zone matrix and with a K_v/K_h ratio of 0.05, horizontal wells have a strong influence on production even if they are completed in only one layer. Highly deviated wells that penetrate several layers should also be investigated.

In the dual porosity model and dual porosity/dual permeability model the theoretical shape factor sigma (σ=0.19[1/m²]) leads to a sharp increase in cumulative production with high field water production through the fractures network and to a slight decrease in the amount of produced gas, whereas more realistic figures namely σ=0.005[1/m²] and σ=0.001[1/m²] combined with the layers 10 and 11 plugged considering the fact that fractures are generally plugged by non movable oil in the tar mat areas (permeability fracture divided by 1000 or equal to zero), show a significantly reduction of the water cut but a maintenance of the oil production and an increase of the ratio of the produced gas to the produced oil.

Adequate aquifer support requires a minimum reservoir permeability to be effective. Aquifer provides poor pressure support, due to too low permeability in the tar mat (bottom of the reservoir).

Tentative tests using Steam Flood (EOR thermal process) did not succeed due to strong convergence failure and high time computation when using Eclipse dedicated package.

Other parameters have no or minor impact on cumulative oil production.

3. HAFT KEL

3.1. FIELD LOCATION

Haft Kel is a giant oil field and one of the earliest discoveries of Iran. It is situated in 10 miles in the North of Ram Hormuz and approximately 55 miles in the East of Ahwaz in the centre of the chain of anticlinal structure of Asmari which extends of Mamatain in the Southeast until Naft Safid in the Northwest. The producing formation is the Asmari Formation (Tertiary) of Oligo-Miocene age which is overlain by the Fars deposits of Miocene age which act as a seal for the reservoirs. The actual cap rock is predominantly anhydrite with a thickness of 80 to 140[ft]. The Asmari Formation consists of 900[ft] (the lower 300[ft] is quite marly) of well-fractured limestone in the Haft Kel area based on estimated true thickness in six wells. [6]

The geometry of the field is a strongly folded anticlinal structure about 20 miles (32[km]) long and 3 miles (4.8[km]) at the original OWC (Oil-Water Contact).

The folding of the Southwest flank is somewhat steeper than the Northeast flank due to Northeast direction of thrust which caused the folding. The Eocene and the Cretaceous rocks of Haft Kel are in pressure communication with Asmari Formation. The maximum initial oil column height was 2072[ft]. [8]

The Haft Kel oil field was discovered in April 1928 and was put on stream in 1929. [1]

The latest IOIP (Initial Oil in Place) is estimated to be approximately 1364[MMSm³] (8575[MMstb]) of which over 286.2[MMSm³] (1800[MMstb]) is believed to have been produced by the end of 1999. The expected ultimate reserves of around 318[MMSm³] (2000[MMstb]), the recovery factor is less than 21[%], the field is in its final stages of production. [9]

The structure of the top of the producing formation, Asmari limestone, is depicted in figure below.

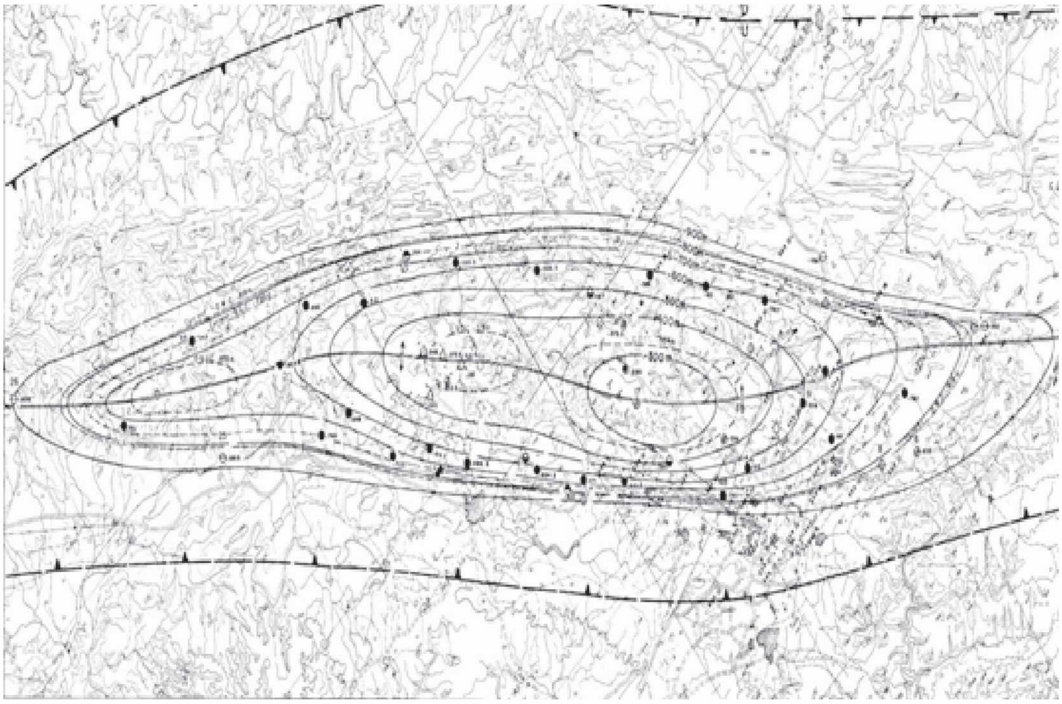

Figure 22: Haft Kel structural contour map on base of Asmari Formation [14]

3.2. FIELD SEDIMENTOLOGY

The Haft Kel lies between two fields named Naft Safid and Mamatain. The Naft Safid field is the deepest of the three structures and the Mamatain field the shallowest. It is believed that hydrocarbons after an upward migration to the Asmari, migrated Southeast-ward, filled the deeper Naft Safid before spilling into Haft Kel and then into Mamatain. [7]

The Haft Kel has three separate gas domes with initial Gas-Oil Contact (initial GOCs: 2170[ftss], 1015[ftss], and 1065[ftss]) at different elevations and an initial OWC at 3087[ftss]. A generalized cross section along the major axis of Naft Safid and Haft Kel is shown below. [6]

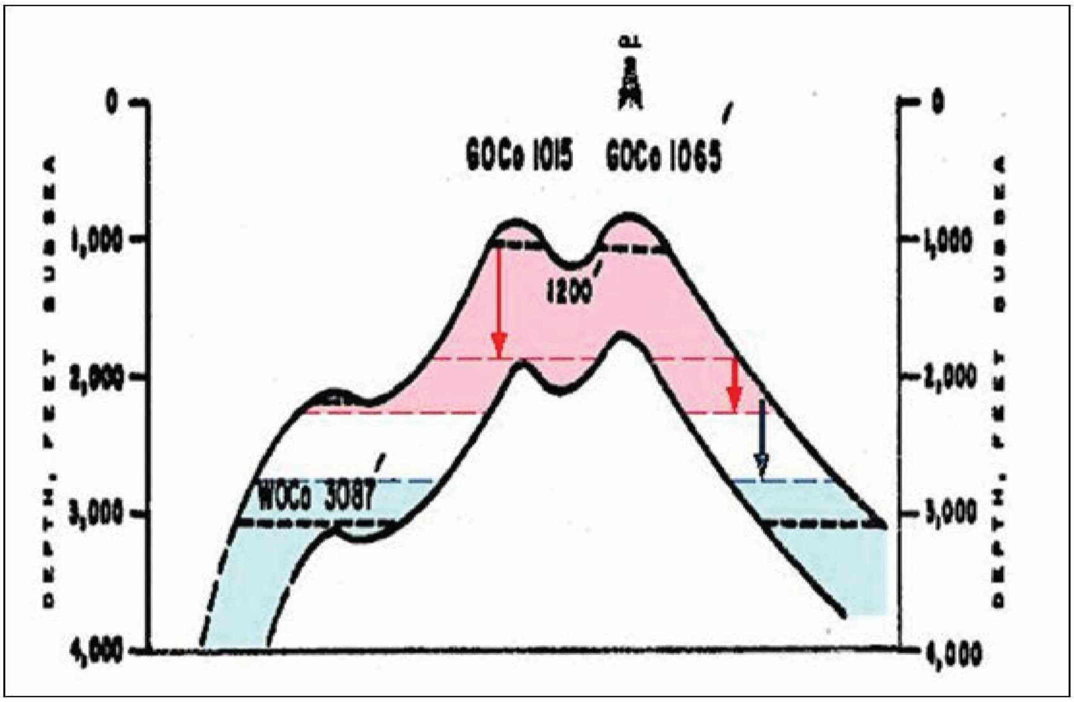

Figure 23: Haft Kel regional cross-section [14]

Based on estimated true thicknesses of Asmari in six wells, the thickness of the Asmari limestone is approximately 900[ft].

The Eocene and Cretaceous rocks of Haft Kel are in pressure communication with the Asmari Formation and contain similar oils as might be expected.

The Eocene rocks which are directly under the Asmari limestone, consists mostly of marl and marly limestone. The Eocene succession has an approximate thickness of 950[ft] at Haft Kel. From the Haft Kel Eocene samples, the porosities were generally 0.5[%] or less with the exception of the uppermost part of this formation where the limestone has a porosity of 9[%] and is thin. [9]

At Haft Kel, The middle Cretaceous consists mostly of Massive Rudist limestone with a thickness of 2000 – 3000[ft] of which only 1330[ft] has been penetrated at Haft Kel. The upper Cretaceous consists of marl and marly limestone with a thickness of 165[ft].

The oil contained originally in the lower section of the Eocene, 325[ft], and in the middle section of the Cretaceous, 185[ft] down to the original OWC, probably has contributed to oil production in Haft Kel. However, due to the very poor porosity (porosity of Cretaceous rocks) combined with the small size of the reservoirs (total Eocene and Cretaceous rock volume above the OWC being not so high) and consequently poor water displacement efficiency, their contribution might not be significant. [8]

The log quality in Haft Kel is usually poor due to some reasons mentioned below:

- Changes in hole diameter which affect all porosity tools making lithology and also the determination of porosity becoming quite questionable.
- Water saturation calculations affecting due to the deep invasion of drilling fluid lost into the formation.

All the intervals logged in the Haft Kel were invaded with water that's why it can be stated in general that petrophysical data are questionable. Therefore, the log calculated water saturations do not really represent the irreducible water.

A porosity relationship with the depth was developed in order to calculate the porosity using a more sophisticated method of log interpretations and with the aid of other geological and petrophysical information available. [12]

A well developed fissure system seems exist in Haft Kel, and because of such diversified interconnected system, the fluid contacts and the oil pressure do not vary appreciably from one end of the field to the other end.

The volume of fissures in the limestone is important from the point of view of its storage.

<table>
<tr><th>Formation</th><th>Average Thickness</th><th>Lithology</th><th>Reservoir Quality</th></tr>
<tr><td rowspan="2">A
S
M
A
R
I</td><td>600[ft]
180[m]</td><td>Limestone</td><td>Good</td></tr>
<tr><td>300[ft]
90[m]</td><td>Marly limestone</td><td>Good</td></tr>
</table>

Table 10: Formation lithology per layer

The full scale permeability, porosity and water saturation study of all core data available from all fields was done to develop correlations between these three parameters.

It should be mentioned that in all of the runs (with the Eclipse simulator), the vertical permeability was assumed to be equal to the horizontal permeability.

3.3. RESERVOIR GEOLOGY

The Haft Kel field bears one reservoir, the Oligo-Miocene Asmari. It is believed that the Eocene and Cretaceous rocks of Haft Kel are in pressure communication with the Asmari Formation and contain similar oils as might be expected.

Based on core and log information, the Asmari Formation in the Haft Kel field was divided into a nine-layer model.

The Haft Kel field has three separate gas domes; the initial oil pressure at the initial shallower GOC of 1015[ftss] was 1412[psig] and at the initial OWC of 3087[ftss] was 2092[psig]. The reservoir temperature at the initial shallower GOC of 1015[ftss] was 110[°F] and at the initial OWC of 3087[ftss] was 123.5[°F].

The field shows a moderate water drive (formation water specific gravity is 1.2 at 60[°F]) and is in pressure communication with neighbouring Naft Safid, in the Northwest, through the aquifer. Other drive mechanisms of this pool are solution gas drive (expansion of gas dissolved in the fluid: major in EOR processes), gas drive (expansion of gas cap: major in first recovery cycle) and gravity drainage (depending on the hydrocarbons density difference in the matrix and fracture system). [11]

Only a small area of the field was used in the simulation. This area and its sector model are depicted below.

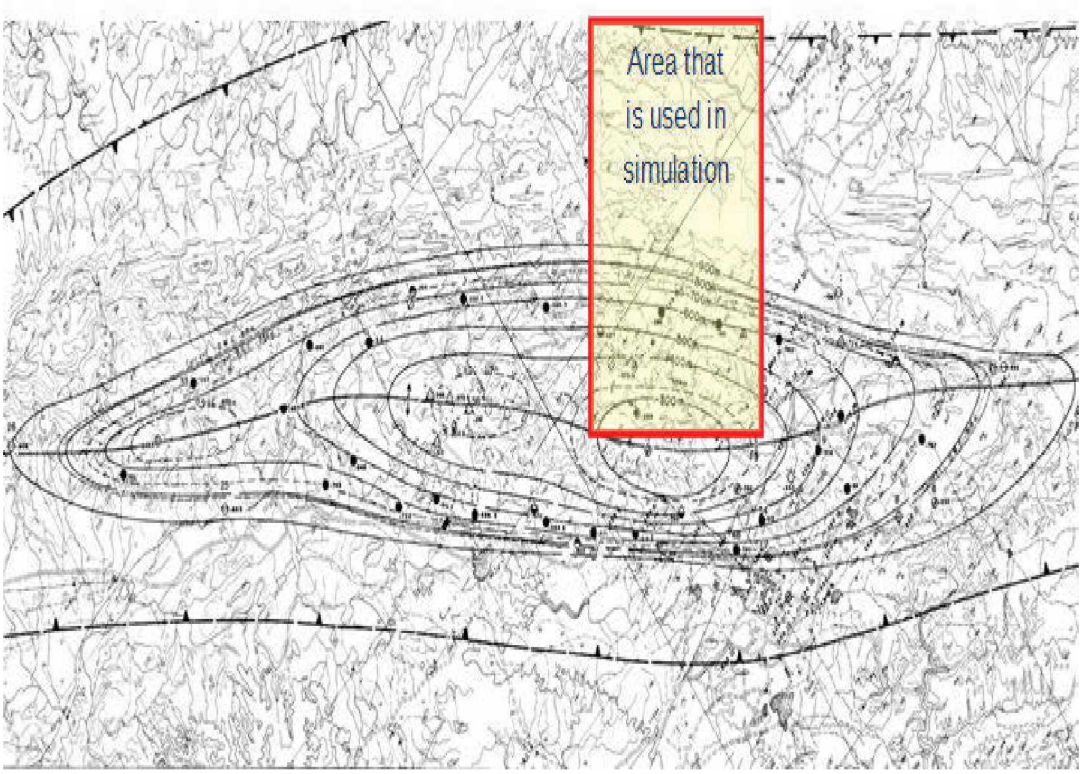

Figure 24: Sector model geometry [14]

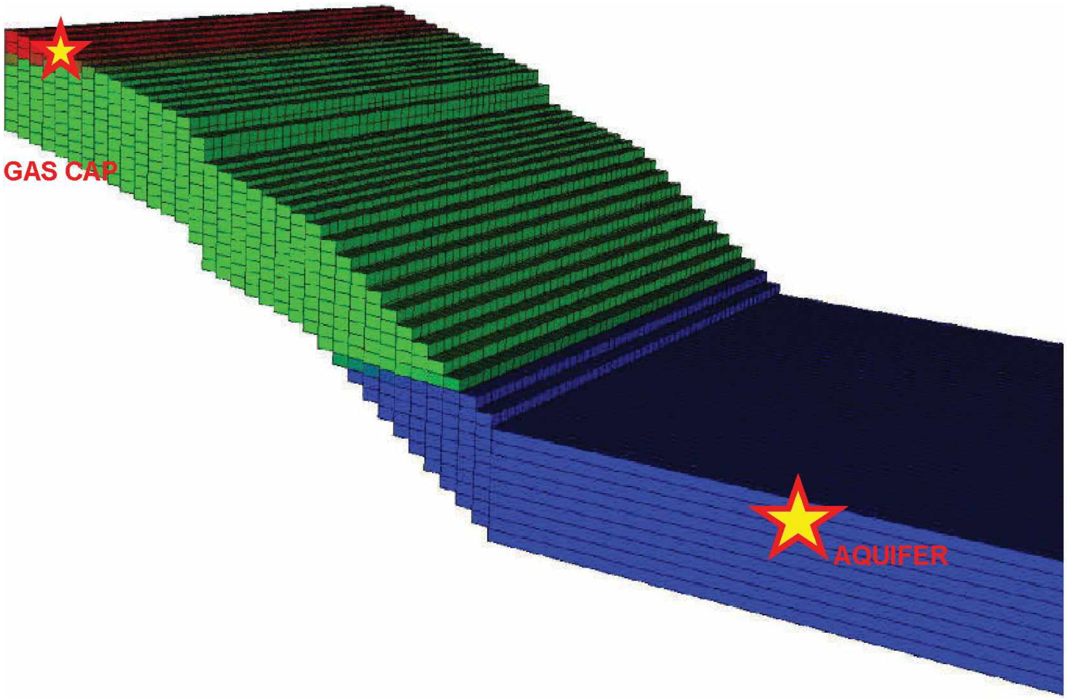

Figure 25: Sector model Haft Kel

Formation	Thickness [ft]	Porosity [%]	Permeability [mD]	IOIP [MMstb]	Initial Oil Reserves [MMstb]
Asmari	900	13	0.1	8575	2175

Table 11: Average reservoir properties field wide

The Haft Kel field seems to have a well developed fissure system. It was also of paramount important with respect to displacement efficiencies, to determine the spacing of the fracture as well as its density so that the block dimension can be estimated. Vertical fracture spacing is estimated to be between 6 and 13[ft] has been indicated by flowmeter surveys. This range coincides with the values calculated from the log interpretation of the water invaded wells. [8]

The porosity and permeability of the field were determined for 506 samples from well **M-28.** The Neutron log was calibrated with core porosity data. The rock type distribution (“Good”, “Poor”, Non-productive) was determined in well **M-28**.

The Asmari formation was divided into **7** stratigraphic units. For each unit the rock type distribution over **5** porosity classes was taken to be equal to that in well **M-28.** The rock type distribution in other wells could be determined with this assumption. The water saturation data for the well **M-28** were obtained from the relationship between porosity, permeability, water saturation and Archie rock classification established for the Gachsaran field. [8]

The average water saturations in each rock type in the various stratigraphic units in the other 17 wells were estimated on the basis of the average porosities per rock type per unit in these wells and the porosity as well as the water saturation data from well **M-28.**

Water-oil capillary pressure used in this study is the average of the five capillary pressure curves measured on Agha Jari cores at the reservoir conditions, with a connate water saturation of 20[%] and 3[%] instantaneous imbibitions.

The water-oil capillary pressure was purposely made optimistic in order to be sure that the water displacement was not penalized by any means.

After a study, the determined porosity, net to gross ratio, and water saturation were entered for good, poor, and dense rock by 40[ft] intervals through the 900[ft] Asmari thickness.

The matrix porosity has an average value of about 13[%]; the in situ permeability is very low, in most of the parts below 0.2[mD], the average is of about 0.1[mD]. There is an existence of higher permeable streaks with a value of 1[mD]. The permeability of the matrix blocks was obtained through a history matching process and ranged between 0.05 to 0.8[mD]. [7]

The estimated fracture porosity value is of about 0.4[%]. The net bulk permeability (product of fracture porosity and fracture permeability) was found by history matching being in order of 500[mD].

The irreducible water saturation is assumed to be 20[%] and 5 [%] for matrix and fractures respectively.

The wells of this pool present excellent indexes of productivity due to the network of fissures which crosses the totality of the reservoir and assures the fluids a good flow towards the producing wells.

The most promising method to get reliable results about the blocks size at first seems to be the flowmeter surveys run in producing wells. The degree of capillary discontinuity caused by smaller fractures is quite uncertain and they will not be detected by this method.

The height of the blocks has important effects on the final recovery as well as degree diffusion of gas which causes losses of oil in oil column. A block height of 15[ft] was found by history matching. [7]

Considerable numbers of fluid analyses are available for Haft Kel. They indicate lack of any significant variation of fluid properties; this could be attributed to the continuous convection processes taking place in this well fractured reservoir. The stock tank oil gravity is about 38[°API] (light oil).

Initial solution GOR (Gas-Oil Ratio) was about 400[scf/stb], the saturation pressure was linked to the initial reservoir pressure of 1412[psig] at the GOC (1015[ftss]). The initial in-situ oil viscosity was 0.78[cP] and initial oil formation volume factor was 1.81[rb/stb] at the GOC (1015[ftss]).

There is clear indication of significant support from the aquifer and its volume (17 times the reservoir size). [8]

The production started in 1930. In 1940, the production has been peaked at 200[Kbopd] and later declined to below 20[Kbopd]. The gas oil contacts in the Southeast and Central zones reached one another in early 1939. The field was shut-in from mid 1951 to end 1954 which has caused a pressure build up in the pool. The Naft Safid gas dome was used for the gas injection which commenced in 1976 when the oil column has reduced to 122[ft]. The production has caused a large movement in both the GOC and the WOC which moved downwards and upwards respectively in a uniform manner while oil column thickness increased to 400[ft] early by 1986.

The latest IOIP (Initial Oil in Place) is estimated to be approximately 1364[MMSm^3] (8575[MMstb]) of which over 286.2[MMSm^3] (1800[MMstb]) is believed to have been produced by the end of 1999. The expected ultimate reserves of around 318[MMSm^3] (2000[MMstb]), the recovery factor is less than 25[%], the field is in its final stages of production. About 31.8[MMstb] (200[MMstb]) is estimated to have been in the fractures. There are about 61 well locations on the field (most drilled before 1950) of which 46 wells entered the Asmari Formation in this field. Some location were not drilled, others did not reach the Asmari Formation. [9]

	ASMARI	
API Gravity	[°API]	38
Viscosity at P_b	[cP]	0.78
Gas Oil Ratio (GOR) at P_b	[Mscf/stb]	0.3956
Initial Water Saturation S_{wi}		0.2
Reservoir Temperature	[°F]	110 at GOC_i 123.5 at WOC_i
Formation Volume Factor (FVF) at P_b	[rb/stb]	1.181
Reservoir Pressure	[psi]	1412 at GOC_i 2092 at WOC_i
Oil Water Contact (OWC)	[ftss]	3087
Bubble Point Pressure (P_b)	[psi]	1426.7
Datum Depth	[ftss]	1015

Table 12: Oil fluid field parameters

3.4. RESERVOIR MODEL

Due to the availability of a sector model of the Asmari reservoir from an earlier reservoir study with the Eclipse simulator, no sector model was added or constructed.

The model is based on, for this purpose utilizable, information about the reservoir that has been gathered from various reports. The degree of complexity of the reservoir is a function of the amount and detail of information that could be obtained.

The model consists of 9 reservoir layers. All layers belong to the Asmari Formation, which contain light oil. The dimensions of the sector model are detailed in the following table:

	ASMARI	
Real sector length [m]	10000 5000 195	
Number of Grid blocks	[35] [50] [18]	
Average Length/Grid block [ft/grid block]	X Y Z	328 328 100

Table 13: Haft Kel sector model dimension

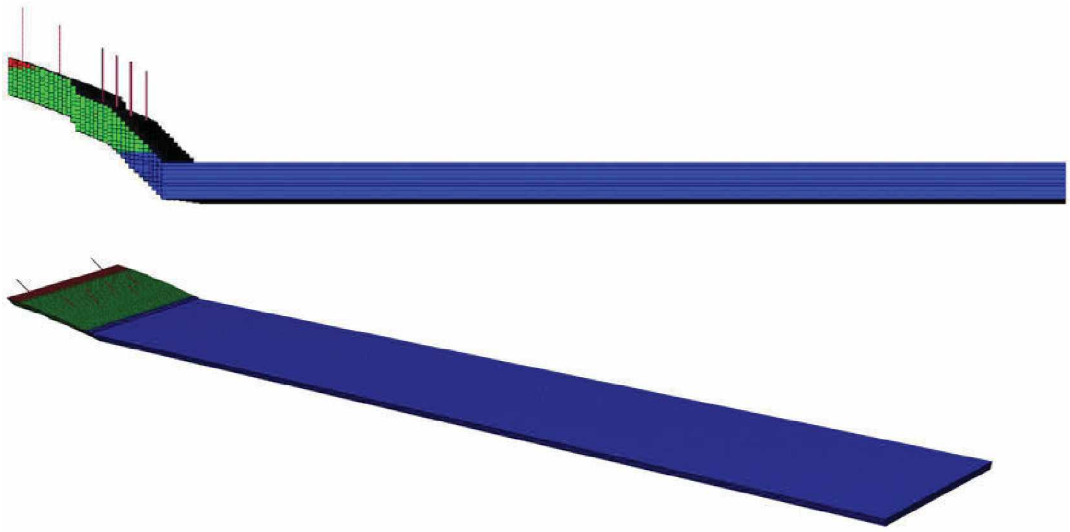

Figure 26: Haft Kel sector model, side and total view

The model is a dual porosity model with a fracture porosity of 0.4% and permeability of 500[mD]. The dual porosity/permeability model has been discarded due to low matrix permeability significantly limiting the matrix-matrix exchanges compared to the matrix-fractured exchange. The block height and matrix-fracture transfer coefficient (sigma) have been used as matching parameters and their values set at 15[ft] and 0.0005 respectively.

The model starts production on the first January 1930. It is history matching until 1999, the year from which the latest production data is available; for predicting purpose a forecast period until 1st March 2020 was chosen.

Thus it is quiet important to keep in mind that the target was not to match the history then it was ready matched as found in the in house literature, but to evaluate the respective efficiency of the capillarity and diffusion effect using different pressure maintenance schemes.

Several operational conditions have been implemented in the sector model for the sensitivity analysis:

- A minimum tubing head pressure of 125[psi] for the wells (vertical). The wells will be shut if the tubing head pressure falls below this limit.
- The wells start and shut subsequently according to the indicated real production history. Some of existing wells are on stream in 1999.

- The wells are put under a group target rate, where the cumulative well production cannot exceed 33000[bbl/day] of oil in the first fifty years and is then reduced to 8000[bbl/day].
- Gas injection maximum target rate is 3000[Mscf/stb] for the group of injection wells together.
- There is scheduled operation downtime for all wells for about two years (between mid 1951 and end 1952). This is the time when the field was shut-in.
- Duration of the simulation production time is 90 years.

The table depicted below gives an overview of the average properties of the reservoir model Haft Kel.

	H [ft]	Porosity [-]	K (h) [mD]	$\frac{K_V}{K_H}$ [-]	Formation
Matrix	100	0.13	0.1	1	ASMARI
Fracture	15	0.004	500	1	

Table 14: Reservoir model properties

3.5. DIFFERENT SCENARIOS ON HAFT KEL

Since the field effectively being subjected to both primary and secondary recovery is at the end of his life under the current development plan. It is an ideal candidate to investigate its potential for recovery by enhanced recovery processes. The Asmari

Formation is a tight and highly fractured shallow reservoir containing light oil with gas cap.

The aim for this study was the following:

- To evaluate the respective efficiency of the capillarity and diffusion effects using different pressure maintenance schemes (maintaining pressure with gas injection, normal depletion and enhanced depletion)
- To carry out sensitivity studies on different parameters (K, block height, sigma shape factor and reservoir depths).

The base case scenario (history until 1997 then production continuation with artificial gas lift) has been used only for model matching purpose and for the sensitivity analysis, three others scenarios have been developed and are described below:

- **Extended depletion** which consists of six oil producers. This option follow base case constraints until 1977, then depleted from year 1977 to 2020. The production constraints from the base case (GOR with a maximum of 0.65[Mscf/stb], WC with a maximum of 0.1[stb/stb]) have been changed in 1977 and others constraints (GOR with a maximum of 3[Mscf/stb], WC with a maximum of 0.7[stb/stb], and production rate with a minimum of 200[stb/d]) have been imposed to the wells. The artificial lift method (gas lift: 1000[Mscf/d]) has been used in this scenario in 1977.
- **Full depletion** is an intermediate scenario which consists of six producers which the production through natural depletion is optimized since the beginning. The gas lift (1000[Mscf/day]) starts from year 1960 till 2020. The production constraints are GOR with a maximum of 3[Mscf/stb], WC with a maximum of 0.7[stb/stb], and production rate with a minimum of 200[stb/d]. This scenario leads to **Extreme depletion** scenario following the full depletion schedule until 1980 when one gas producer (8000[Mscf/stb]) is open and ESP pumps are implemented to lower BHFP of oil producers.
- **Gas injection from the beginning** which consist of six producers and two gas injectors. The gas injection has been stopped between 1970 and 1976. No gas lift has been used in this scenario and the production constraints (GOR with a maximum of 3[Mscf/stb], WC with a maximum of 0.7[stb/stb], and a minimum oil production rate of 200[stb/d]) are different from the previous one.

3.6. UNCERTAINTIES

The uncertainties are related to the different scenarios mentioned above. The following uncertainties have been identified from the TOTAL in house literature:

(1) Matrix permeability

(2) Matrix blocks height

(3) The shape factor sigma

(4) Aquifer strength

These uncertainties have been assessed according to the three following scenarios:

- Extended depletion (mixed capillary and flow effect)
- Extreme depletion (promote flow effect)
- Gas injection (promote capillary effect through pressure stabilization)

3.6.1. Matrix Permeability

A dual porosity is used for the simulation. It is characterized by its flow regime that only allows flow from matrix to fracture and flow between fractures (see **Figure 8**). With disconnected matrix blocks this is assumed to be the best approach for the field and region under investigation!

The matrix permeability of the field was from core data and has been used to compute a permeability curve. The average permeability values is 0.1[mD], the existence of permeability streaks of about 1[mD] has been proved, and the model has a ratio vertical permeability to horizontal permeability (K_V / K_H) of 1.

Gas injection is envisaged as a future EOR measure, thus there is expectation to find greater permeability values.

It should be mentioned that in all of the runs vertical permeability was assumed to be equal to the horizontal permeability.

For the sensitivity analysis, each permeability value was the subject of modification and was multiplied by a factor of 10, in order to obtain permeability value which allows to flow into the matrix and from the matrix to the fractures.

3.6.2. Matrix Block Height

The most promising method to get reliable results seems to be the flowmeter surveys run in producing wells. Only the intersection of larger fractures was shown by the flowmeter surveys.

The dimensions of the blocks have important effects on the final recovery as well as degree of diffusion of gas which causes losses of oil in the oil column. In the base case model and different scenarios, the final block dimensions used was of 15[ft].

For the sensitivity analysis, the block dimensions were taken equal to 50[ft].

3.6.3. The Shape Factor Sigma

The shape factor sigma which is a member of the matrix-fracture transfer term equation plays an important role in a simulation (using the dual porosity) of fractured reservoirs.

A classical definition of shape factor proposed for example by Kazemi (SPEJ, Dec 76, 317-326) is the following:

$$\sigma = C * \left(\frac{1}{l_x^2} + \frac{1}{l_y^2} + \frac{1}{l_z^2} \right)$$

Where $C = 4$, and l_x, l_y and l_z are typical X, Y, and Z dimensions of the matrix blocks.

The shape factor sigma plays an important role in a simulation (using the dual porosity) of fractured reservoirs. In the base case model, the sigma value is of 0.0005 (obtained from the matching).

For the sensitivity analysis the sigma has been multiplied by 10 for high case and divided by 10 for low case.

3.6.4. Aquifer Strength

The field shows a strong water drive and is in pressure communication with the neighbouring Naft Safid field, in the Northwest, through the aquifer.

The presence and the force of an aquifer are well identified. The aquifer in this model is a bottom water-drive aquifer, which is seventeen times the reservoir size.

The led simulations show different depletions according to the size of the aquifer. It is quiet difficult to quantify the importance of these parameters in the absence of current data of pressure.

For the sensitivity analysis, the size of the aquifer was divided by 100.

3.7. RESULTS AND DISCUSSIONS

3.7.1. Base case and different Scenarios

Base Case	Extended Depletion	Full Depletion	Extreme Depletion	Gas Injection
Six oil producers & eight injectors	Six oil producers	Six oil producers	Six oil producers and one gas producer	Six oil producers and two gas injectors
Gas Injection	No gas injection	No gas injection	No gas injection	Gas injection
Artificial lift	No artificial lift	Artificial lift	Artificial lift	No artificial lift
Production constraints on Q_o, GOR, and WC	Production constraints on Q_o, GOR, and WC	Production constraints on Q_o, GOR, and WC	Production constraints on Q_o, GOR, and WC ESPs installation to lower BHFP	Production constraints on Q_o, GOR, and WC

Table 15: Base case and different scenarios models

The base case is the history case used to match the model. From the simulation outcomes, three recovery mechanisms have been involved in this model namely:

- Water drive which is major in the primary cycle, but a poor/moderate water drive is recommended in case of fractured carbonate reservoir.

- Gas drive which is major in the primary cycle. In our case due to the size of gas cap, it is of minor importance.
- Solution gas drive which is major in the EOR. It is a major driving process at the end of the reservoir life when the reservoir pressure drops below the bubble point pressure, the gas breaks out the solution and displaces the oil. This is the major recovery mechanism in our case.

The figures below represent the base case and the different scenarios mentioned above. The extreme depletion scenario has a significant impact on the cumulative oil production as well as the full depletion scenario.

The extended depletion scenario and the gas injection from the beginning scenario have a lower cumulative oil production than the base case whereas the gas injection from the beginning scenario has a beneficial influence on the reservoir pressure.

The base case involved some gas injection providing energy to the reservoir and therefore allows higher production than in extended depletion case.

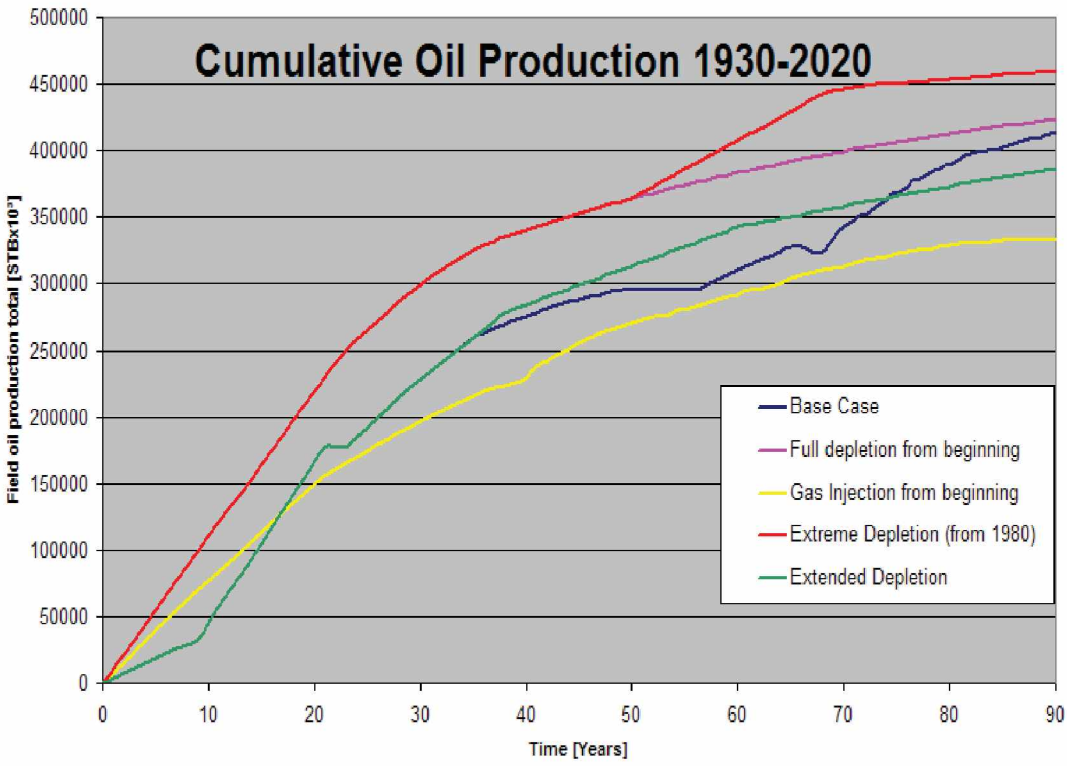

Figure 27: Cumulative oil production – base case and different scenarios

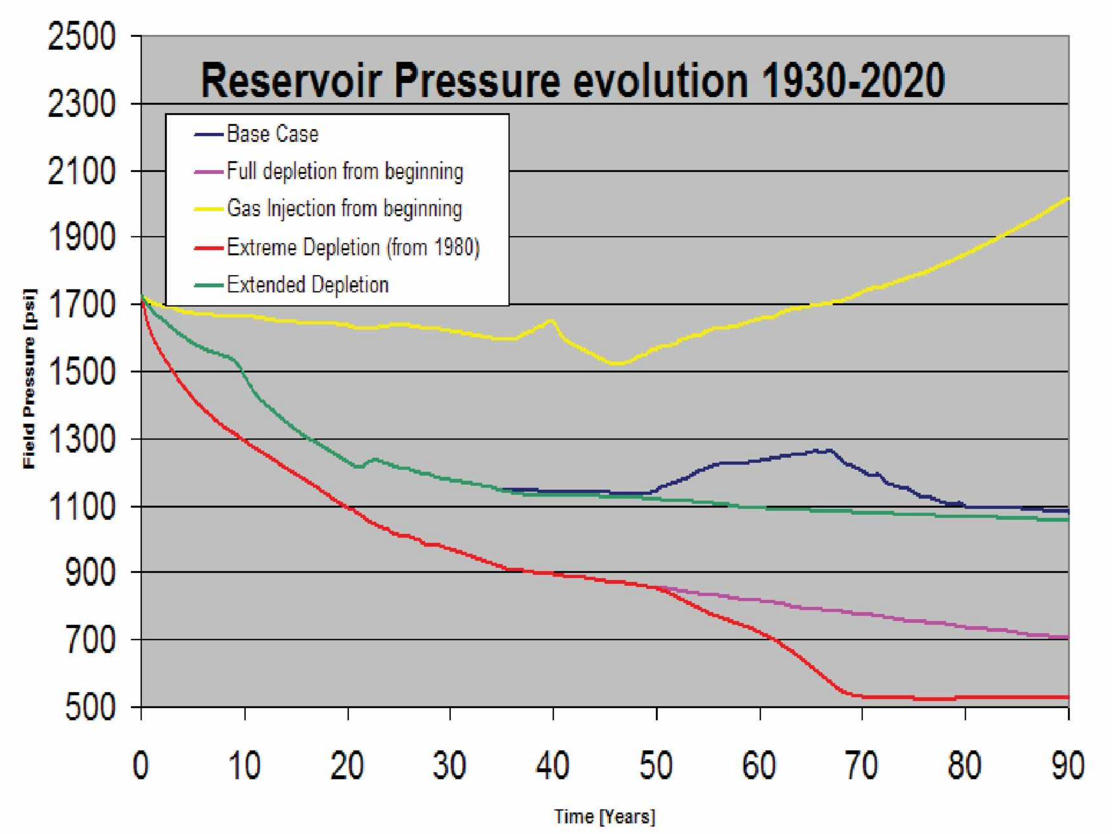

Figure 28: Field pressure – base case and different scenarios

In the extreme depletion scenario, oil is expelled from the matrix due to pressure difference between matrix and fracture. This scenario seems to be more efficient than the capillarity effect initiated by the gas injection scenario consecutive to low permeability and rather oil wettability.

Impact on matrix gas saturation is significant. The pressure drop generates gas liberation in the matrix block; some gas can remain trapped in the matrix due to the low permeability.

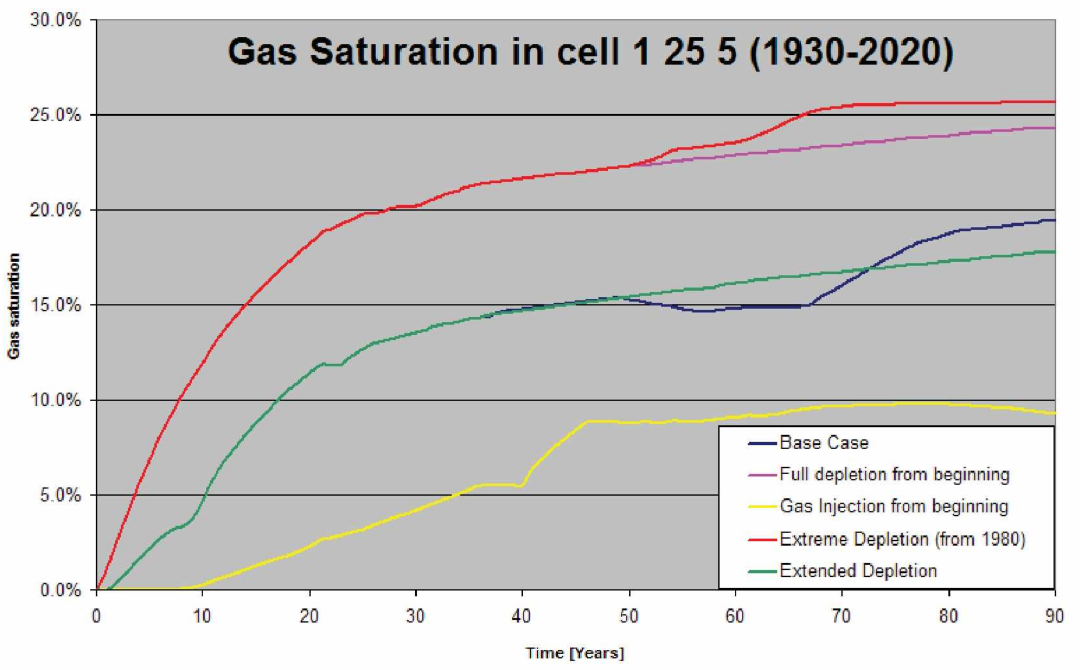

Figure 29: Gas saturation of cell (1 25 5) – base case and different scenarios

The rise of the water oil contact stopped and was reversed in the case of gas injection from the beginning, then the water saturation in the cell (26 25 5), chosen between the wells perforations and the OWC, is stabilized as illustrated in the **Figure 30**.

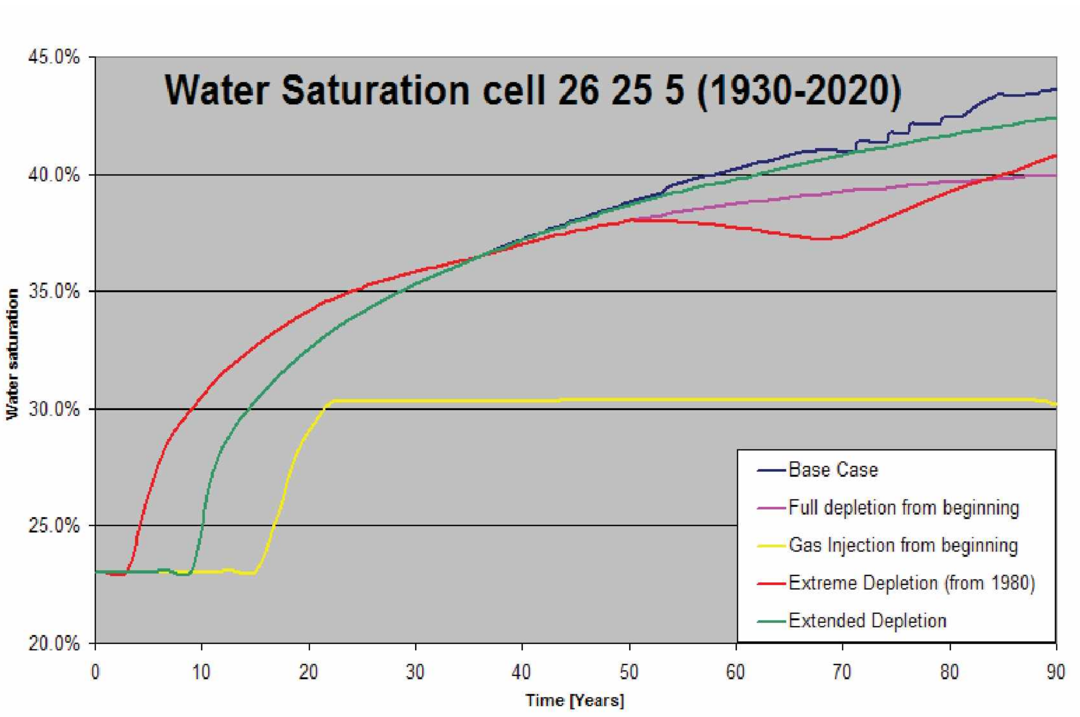

Figure 30: Water saturation of cell (26 25 5) – base case and different scenarios

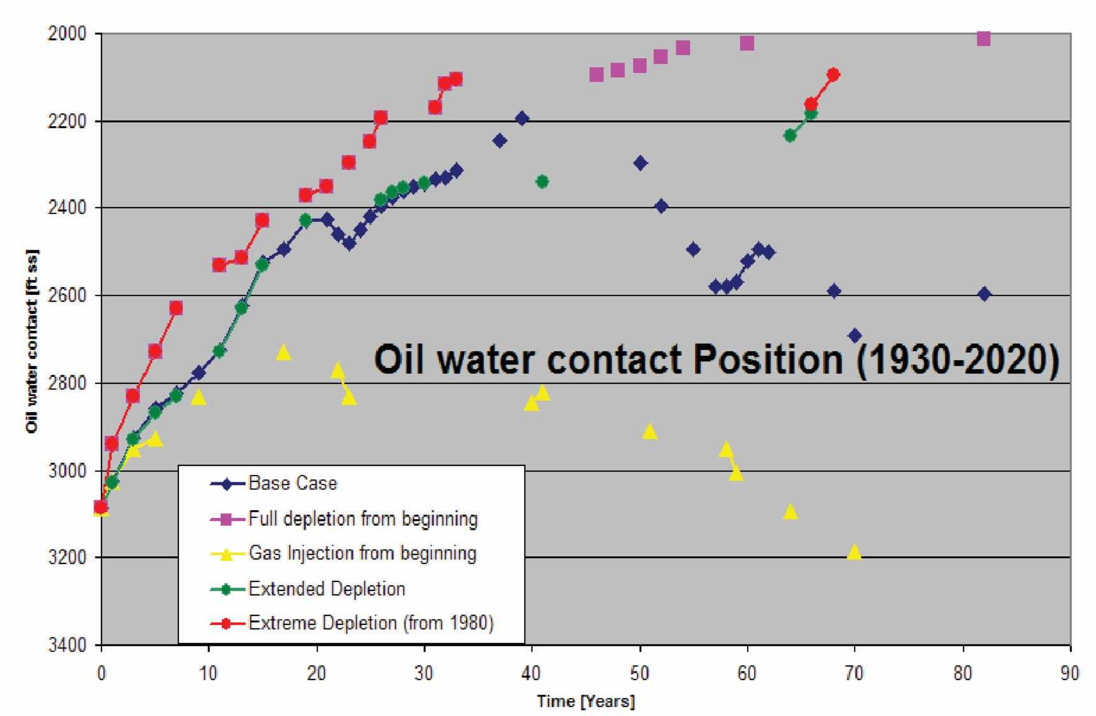

Figure 31: Oil water contact position – base case and different scenarios

The gas produced from the extreme depletion scenario leads to a sharp decrease in pressure and increase in oil production and water cut. This tends to lower the gas oil contact and stabilize OWC. The water production prevents OWC to rise suggesting that aquifer is rather moderate.

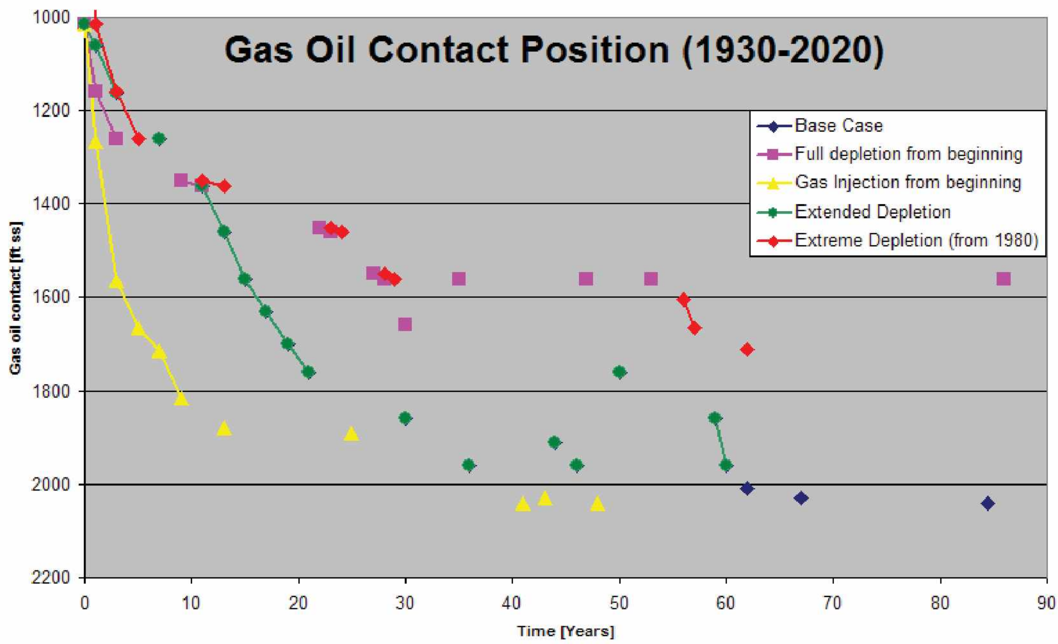

Figure 32: Gas oil contact position – base case and different scenarios

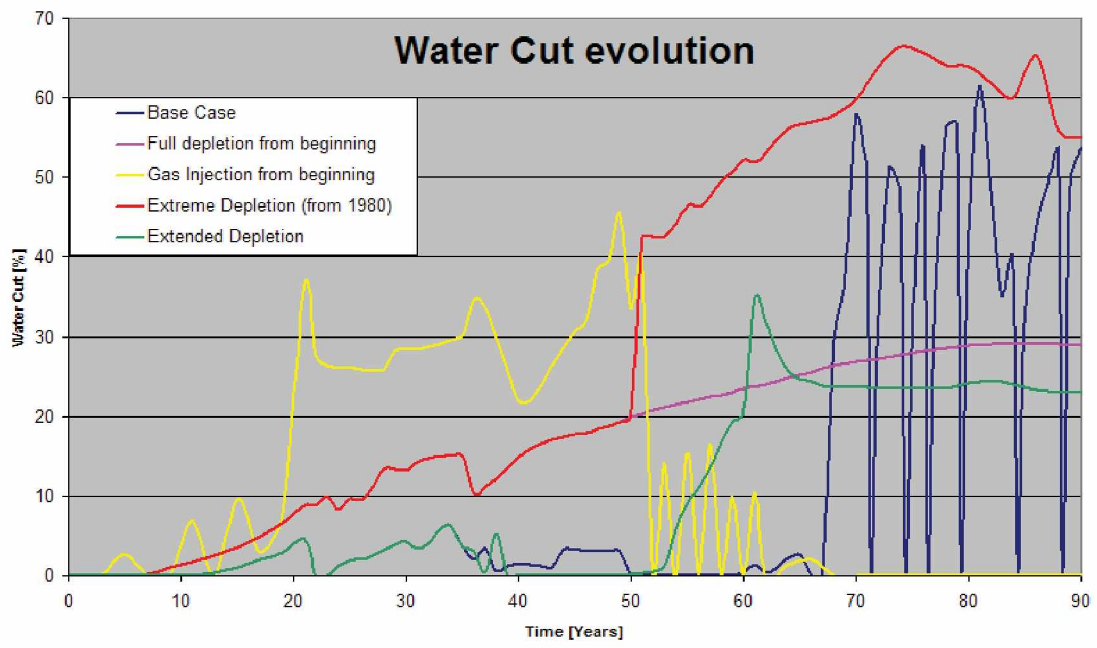

Figure 33: Water cut evolution – base case and different scenarios

Gas injection from the beginning involves a lot of well/perforations closure and reopening due to gas oil ratio constraint.

IOIP [BSTB] 8.575 Ultimate Reserves 2	Np in 2020 (90 years) [MSTB]	RF [%]	WC in 2020 (90 years) [%]	Avg.reservoir pressure in 2020 [psi]
Base Case	414.06	27.78	54.9	1077.95
Extended Depletion	386.61	25.93	23.02	1054.29
Full Depletion	423.6	28.42	28.9	706.51
Extreme Depletion	459.07	30.79	54.92	530.52
Gas Injection from the Beginning	333.85	22.39	0	2018.86

Table 16: Results of base case and different scenarios

3.7.2. Uncertainties assessment in Extended Depletion

Uncertainty	Extended Depletion	High Case	Low Case
Aquifer Strength	Aquifer present	----	Volume of aquifer divided by 100
Sigma (Shape factor)	History matching value σ=0.0005	σ * 10	σ / 10
Block height	History matching value, 15[ft]	Block height is equal 50[ft]	---

Table 17: Sensitivity analysis input data

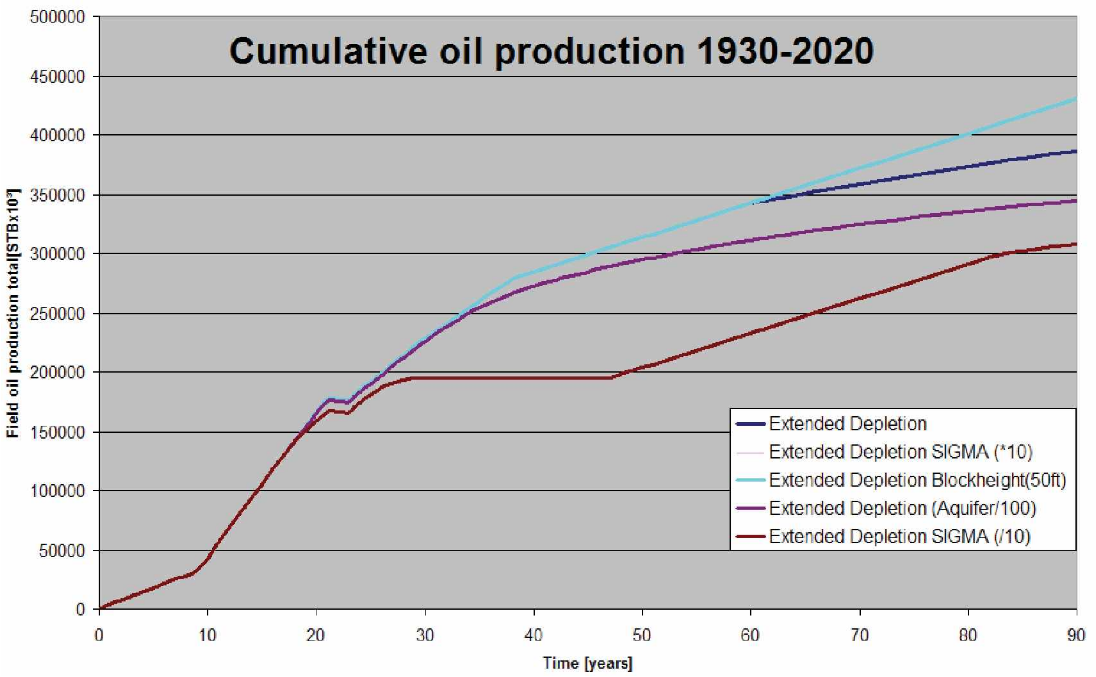

Figure 34: Cumulative oil production – extended depletion and sensitivities

Cumulative oil production for higher block height and sigma are the same as both are not affected by constraints put on production.

It should be mentioned that it was not necessary to perform sensitivity both on the matrix permeability and the shape factor sigma as the Eclipse program uses only the matrix-fracture transmissibility term in the dual porosity model, which is the product of matrix cell bulk volume, permeability of the matrix and sigma (matrix/fracture interface area per unit volume).

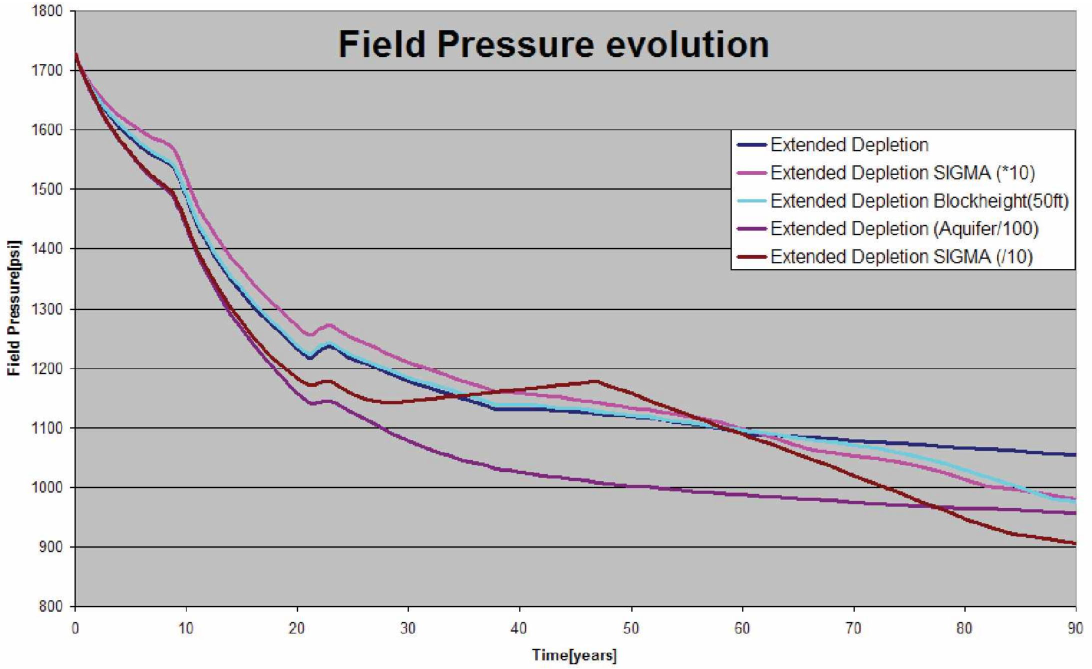

Figure 35: Pressure depletion – extended depletion and sensitivities

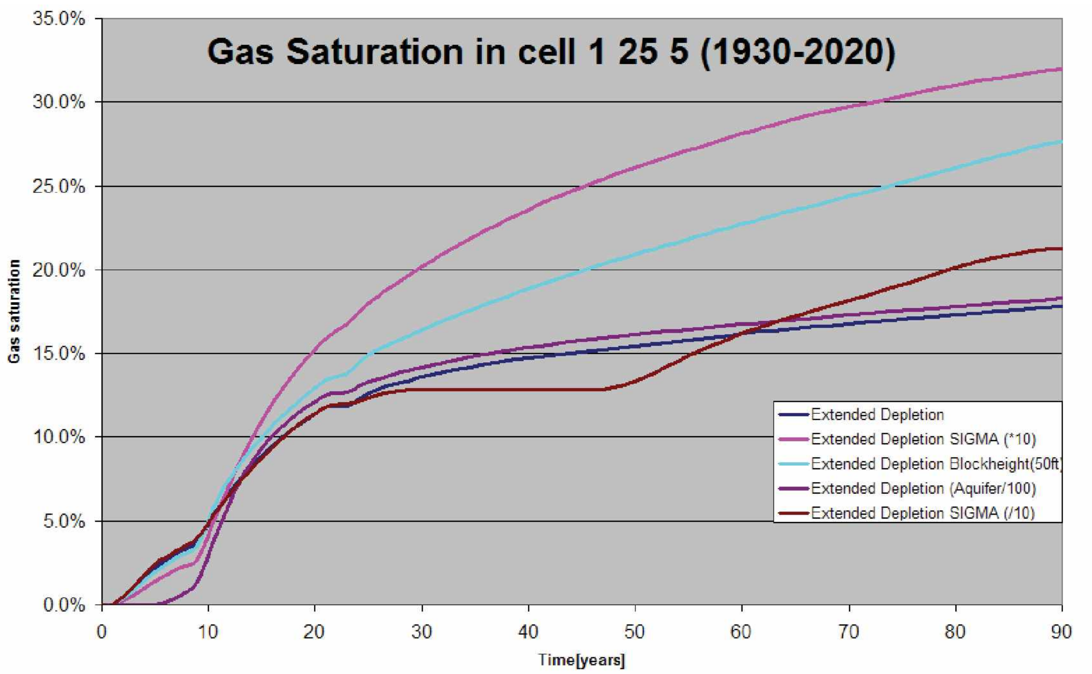

Figure 36: Gas saturation in cell (1 25 5) – extended depletion and sensitivities

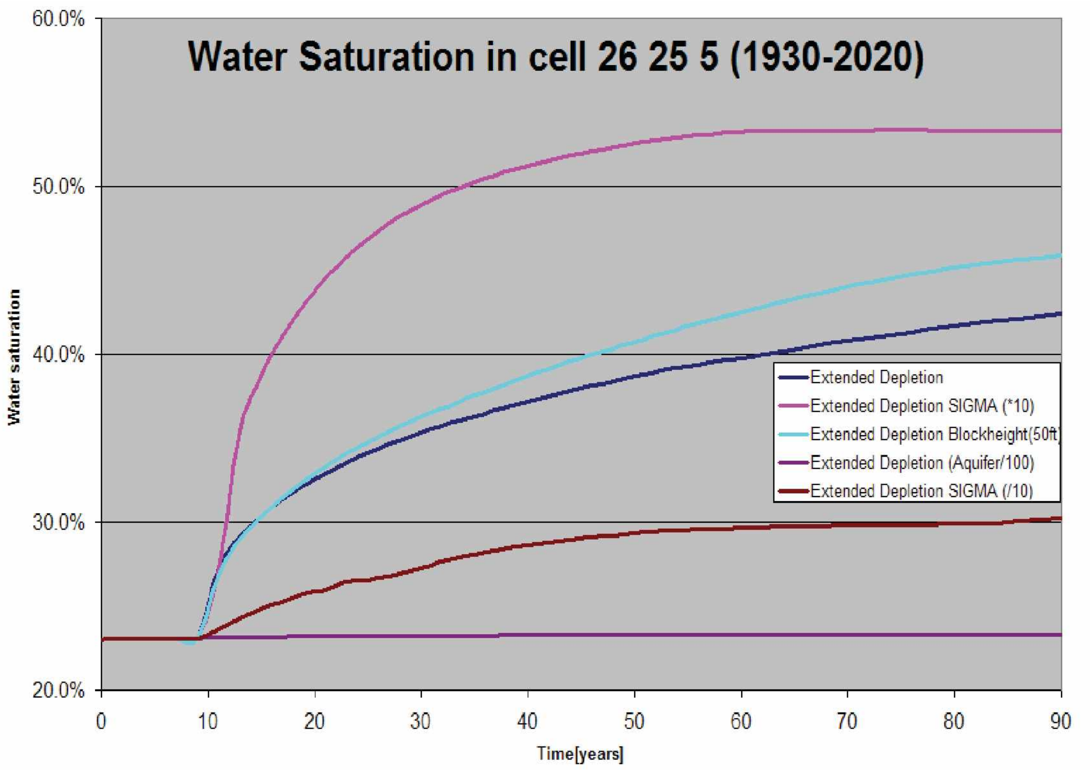

Figure 37: Water saturation in cell (26 25 5) – extended depletion and sensitivities

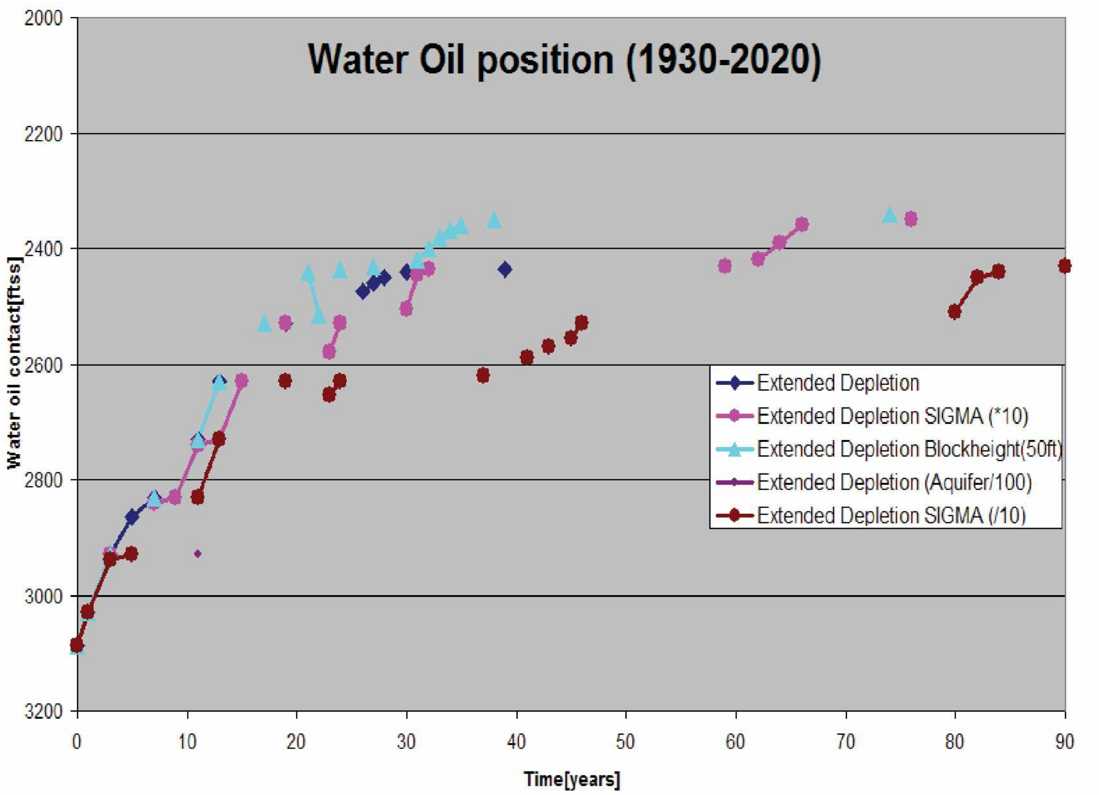

Figure 38: Water oil position – extended depletion and sensitivities

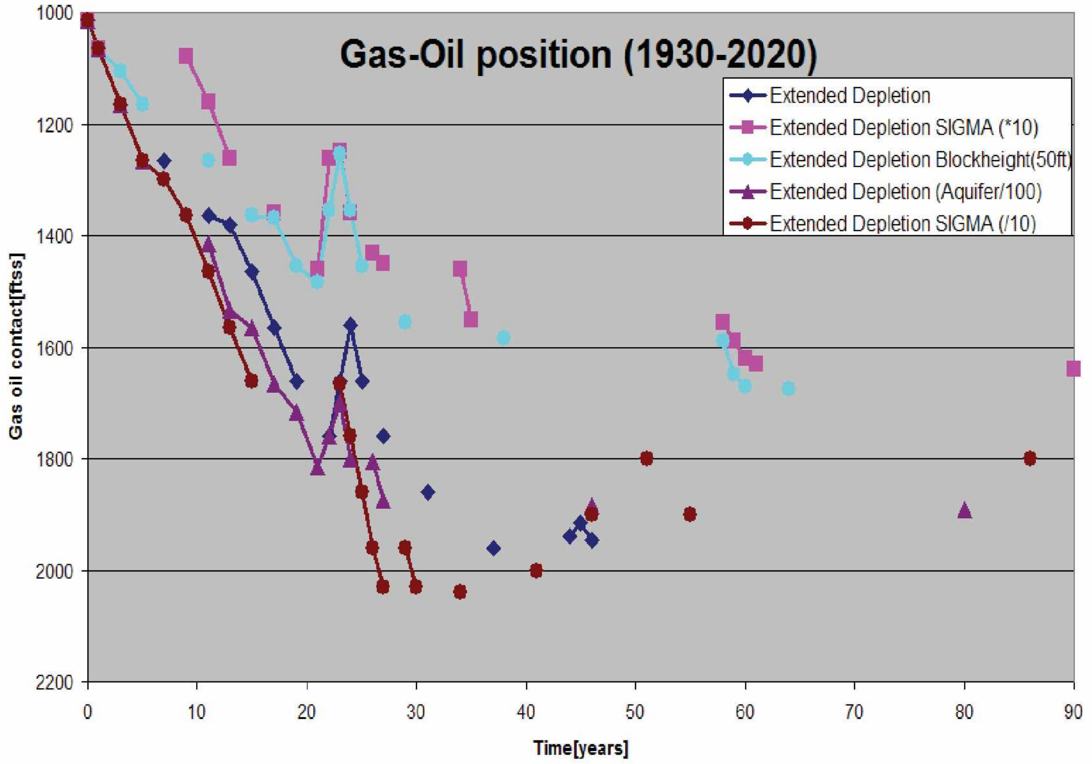

Figure 39: Gas oil position – extended depletion and sensitivities

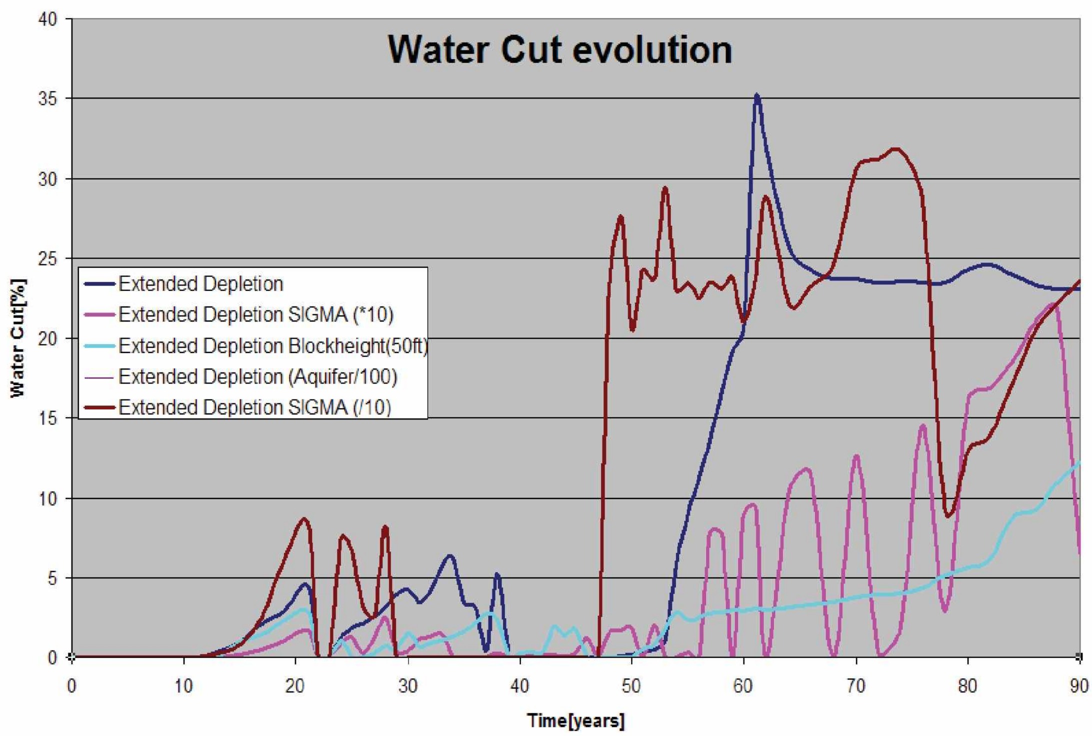

Figure 40: Water cut – extended depletion and sensitivities

Four main parameters have been considered for uncertainties assessment: matrix permeability, sigma fracture network shape factor, matrix block height and very poor

aquifer. The first two parameters sigma and matrix permeability having the same impact, a lower permeability or sigma coefficient tends to lower pressure reservoir and increase the amount of produced gas. The pressure decline results in better matrix gas saturation than even for the base case due to gas liberated but remaining trapped in the matrix.

Increase block height from 15 to 50[ft] has a significant effect on gas saturation (better gas drainage) but lower on water saturation which is probably due to lower differential pressure (smaller oil water gravity difference).

Low aquifer support lead to a drop in oil production lower than expected. The water drive as recovery mechanism seems to have a relatively poor effect in the model as indicated by the ratio of only 17 between oil and water pool volumes (see **Figure 28** reservoir pressure difference between base case and low aquifer case).

IOIP [BSTB] Ultimate Reserves	8.575 2		Np in 2020 (90 years) [MSTB]	RF [%]	WC in 2020 (90 years) [%]	Avg.reservoir pressure in 2020 [psi]
Base case figures	Extended Depletion		386.61	25.93	23.02	1054.29
	High cases					
0.1[mD] & 1[mD]	Matrix Permeability	K multiplied by 10	430.25	28.86	6.52	979.48
Blockheight ~ 15[ft]	Matrix Block height	50[ft]	430.25	28.86	6.52	979.48
SIGMA ~ 0.0005[1/m²]	Shape factor SIGMA	SIGMA * 10	430.25	28.86	12.18	975.50
	PVT	Taking from another field			No results yet	
	Low cases					
Aquifer present	Aquifer strength	Volume divided by 100	344.50	23.11	0.00	957.52
	Shape Factor SIGMA	SIGMA / 10	308.2	20.67	23.56	906.46

Table 18: Results overview Haft Kel – extended depletion

3.7.3. Uncertainties assessment Extreme Depletion

Uncertainty	Extreme Depletion	High Case	Low Case
Aquifer Strength	Aquifer present	----	Volume of aquifer divided by 100
Sigma (Shape factor)	History matching value σ=0.0005	σ * 10	σ / 10
Block height	History matching value, 15[ft]	Block height is equal 50[ft]	---

Table 19: Sensitivity study input data

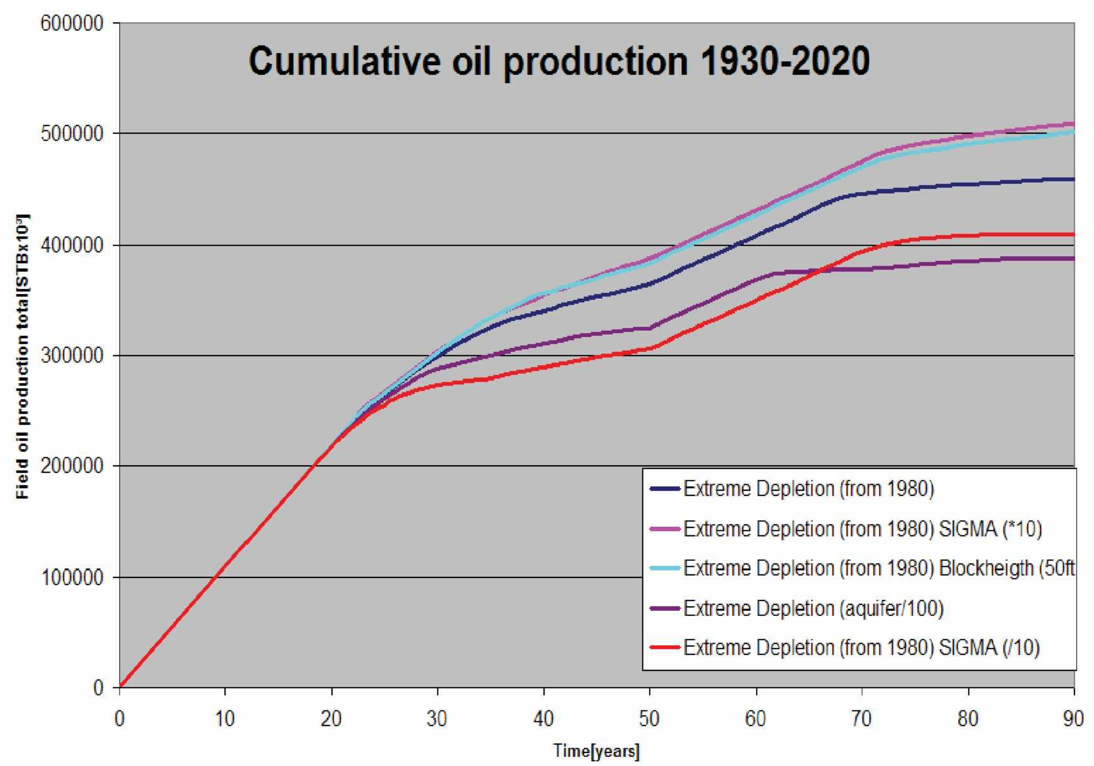

Figure 41: Cumulative oil production – extreme depletion and sensitivities

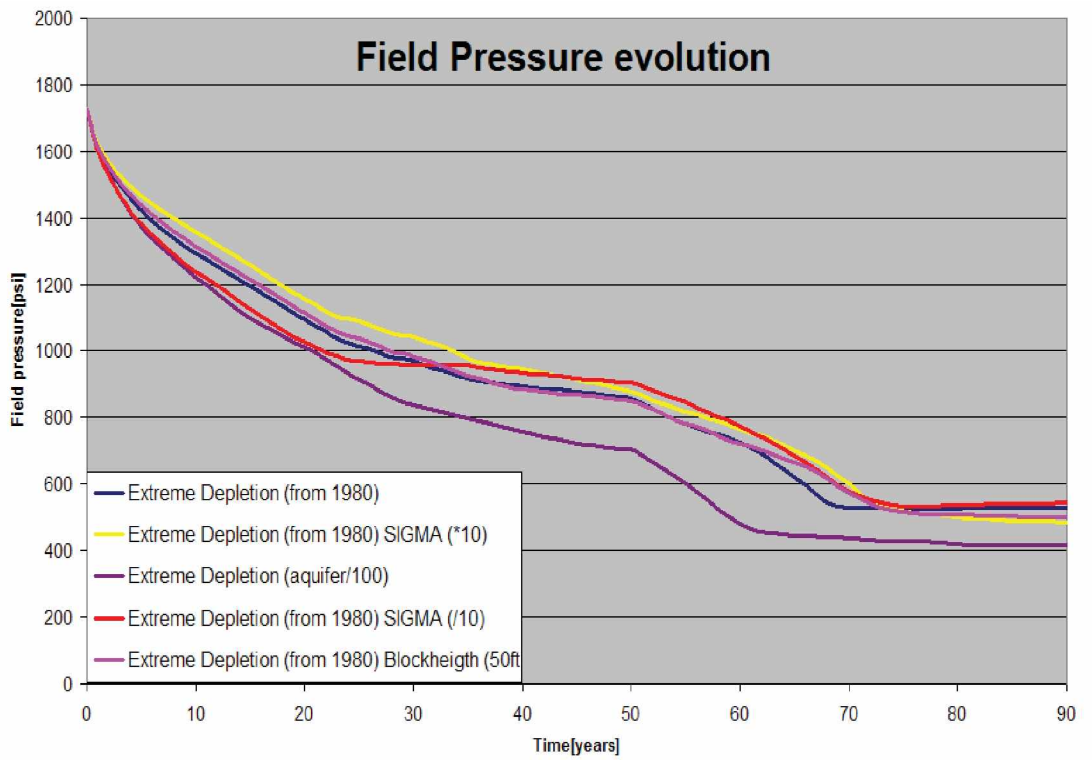

Figure 42: Pressure depletion – extreme depletion and sensitivities

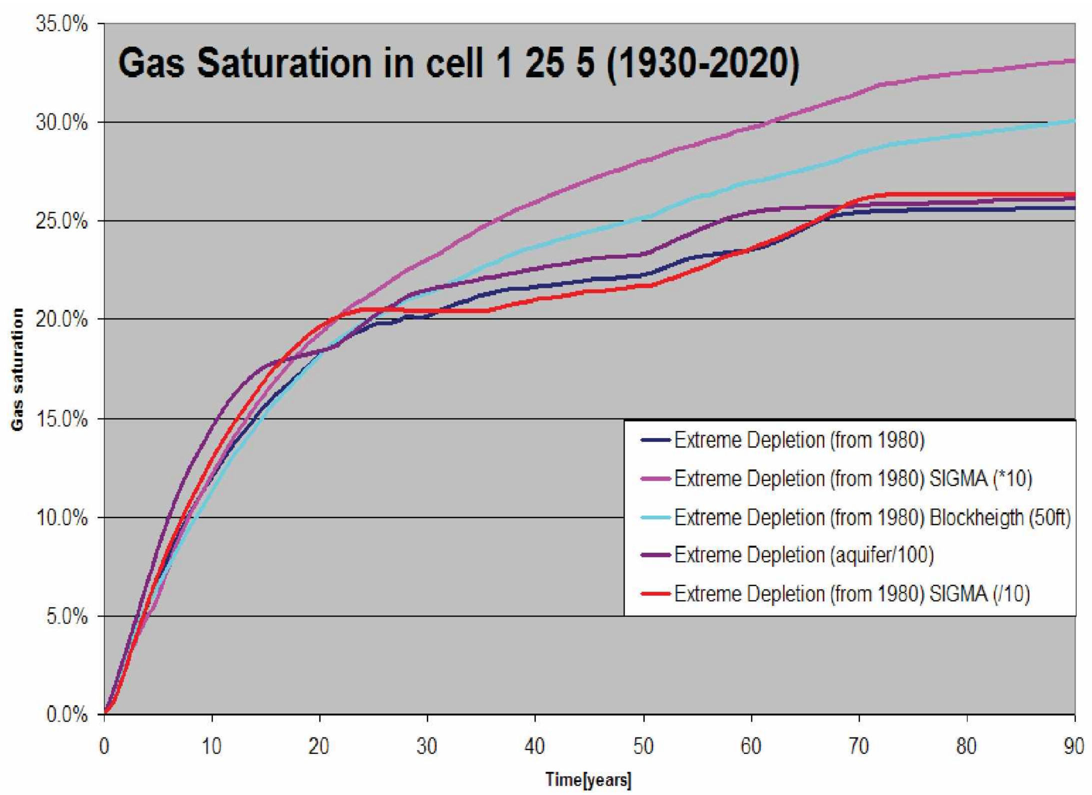

Figure 43: Gas saturation in cell (1 25 5) – extreme depletion and sensitivities

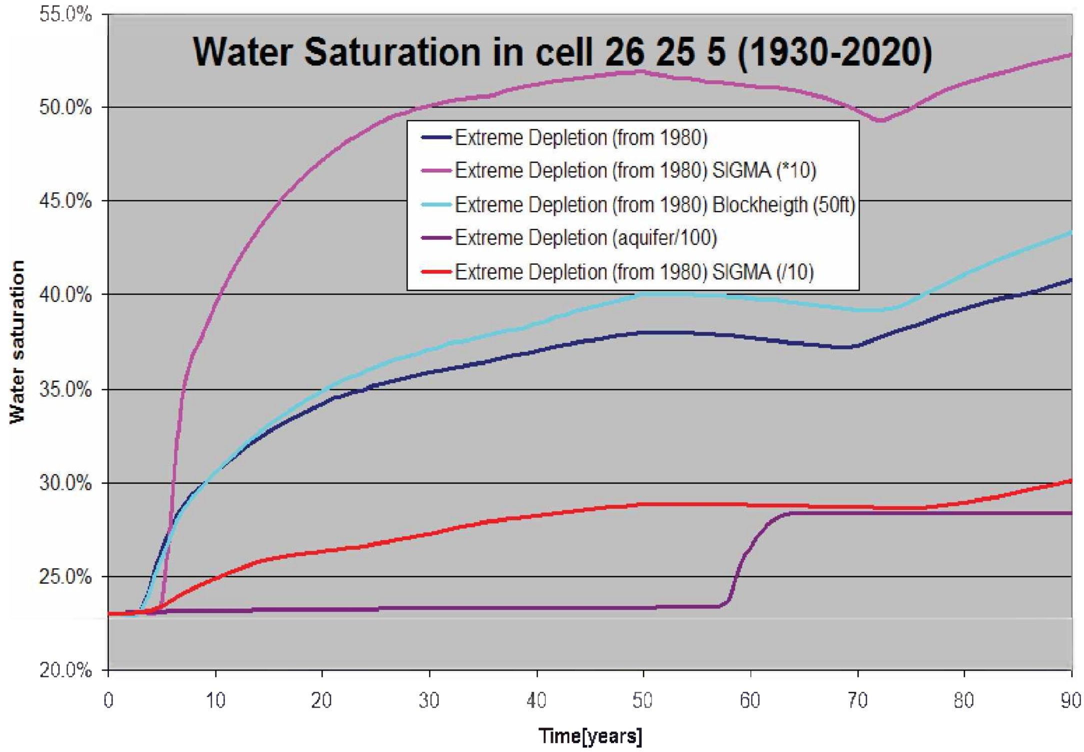

Figure 44: Water saturation in cell (26 25 5) – extreme depletion and sensitivities

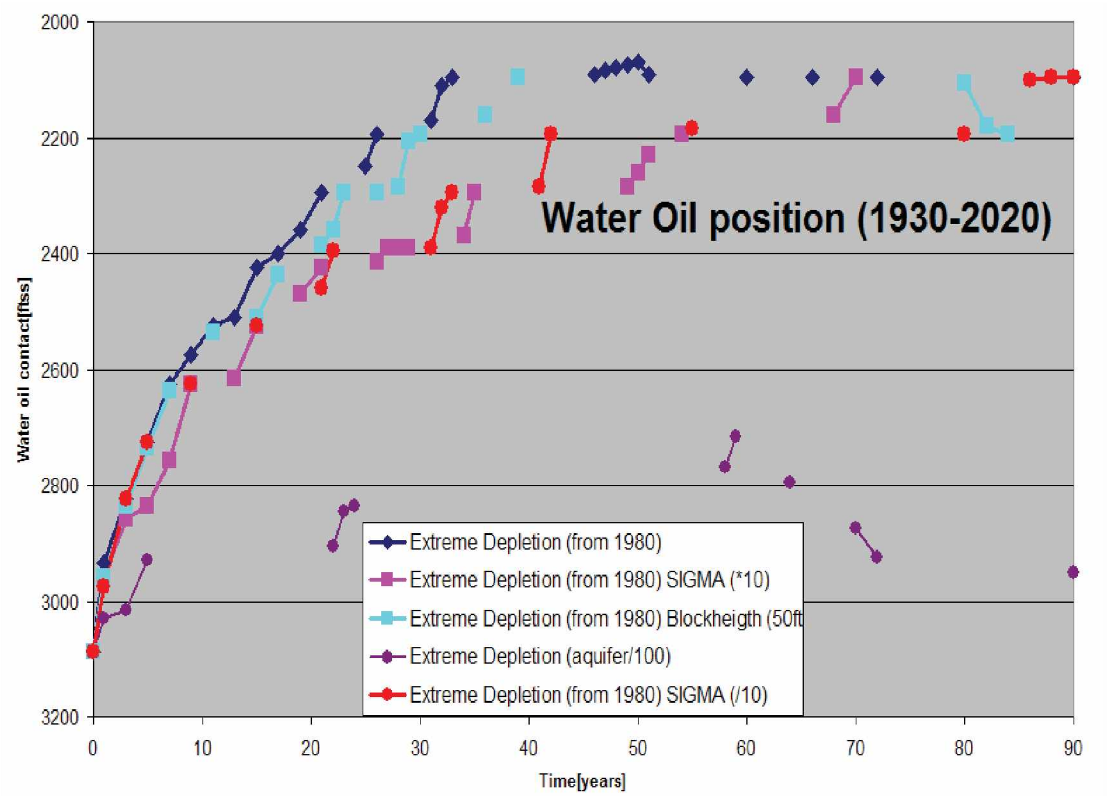

Figure 45: Water oil position – extreme depletion and sensitivities

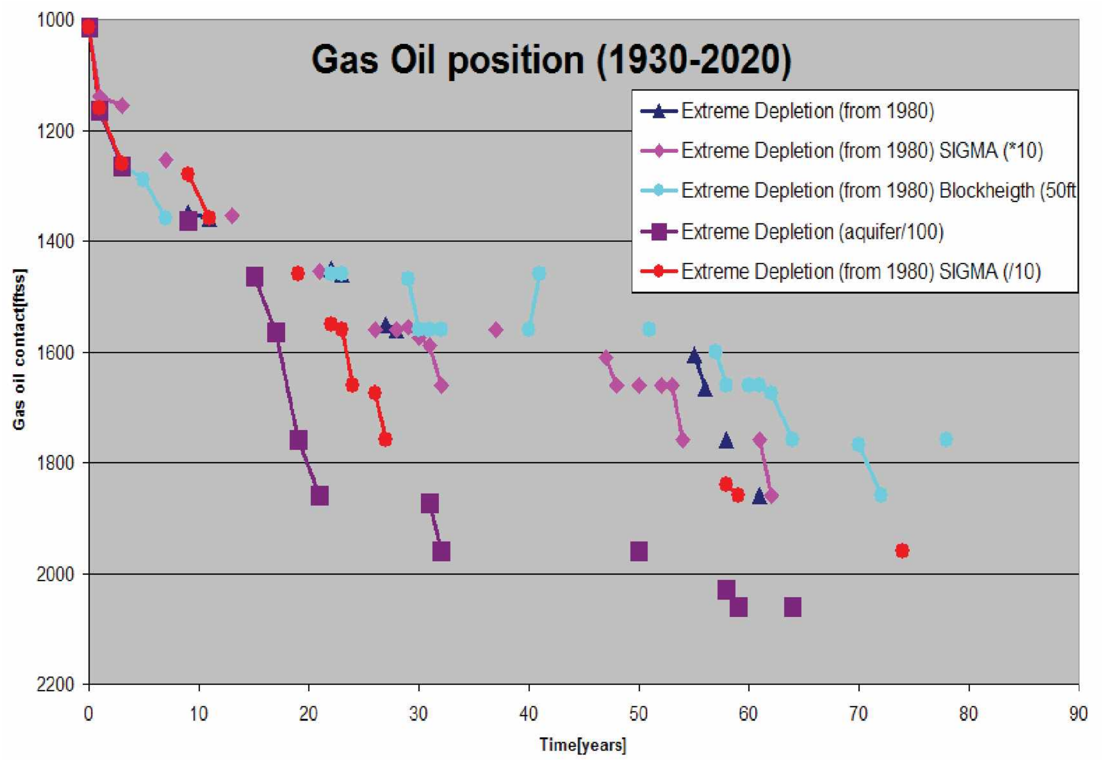

Figure 46: Gas oil position – extreme depletion and sensitivities

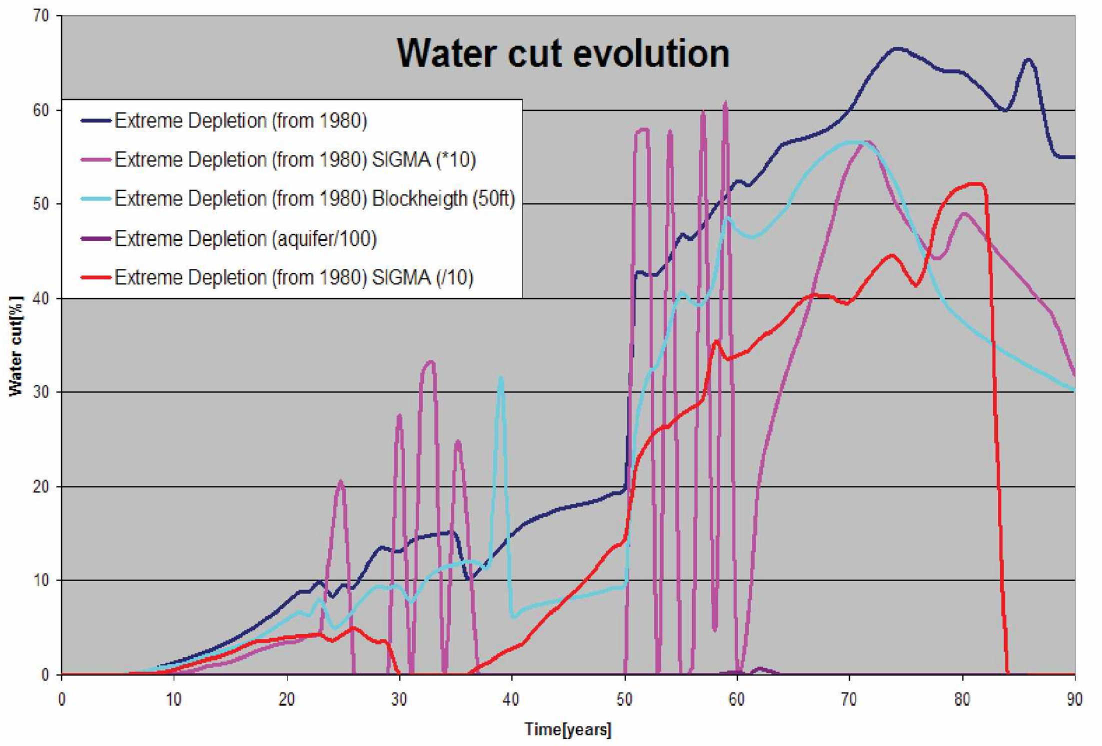

Figure 47: Water cut – extreme depletion and sensitivities

Four main parameters have been considered for uncertainties assessment: matrix permeability, sigma fracture network shape factor, matrix block height and very poor

aquifer, with the first two parameters sigma and matrix permeability having the same impact.

As for extended depletion case, a lower permeability or sigma coefficient tends to lower pressure reservoir and increase the amount of produced gas. The pressure decline results in better matrix gas saturation than even for the base case due to the gas liberated but remaining trapped in the matrix.

The block height plays an important role in the oil production in this model. It has a significant effect on gas saturation (better gas drainage) but lower on water saturation which is probably due to lower differential pressure (smaller oil water gravity difference).

Low aquifer do not provides a significant source of natural energy to aid in oil recovery. The water drive as recovery mechanism seems to have a relatively poor effect in the model (see **Figure 28** reservoir pressure difference between base case and low aquifer case).

IOIP [BSTB] Ultimate Reserves	8.575 2		Np in 2020 (90 years) [MSTB]	RF [%]	WC in 2020 (90 years) [%]	Avg.reservoir pressure in 2020 [psi]
Base case figures	Extreme Depletion		459.07	30.79	54.92	530.52
	High cases					
0.1[mD] & 1[mD]	Matrix Permeability	K multiplied by 10	509.31	34.16	31.67	484.23
Blockheight ~ 15[ft]	Matrix Block height	50[ft]	501.86	33.66	30.22	499.65
SIGMA ~ 0.0005[1/m²]	Shape factor SIGMA	SIGMA * 10	509.31	34.16	31.67	484.23
	PVT	Taking from another field	No results yet			
	Low cases					
Aquifer present	Aquifer strength	Volume divided by 100	387.10	25.97	0.00	416.86
	Shape Factor SIGMA	SIGMA / 10	408.90	27.43	0.00	944.51

Table 20: Results overview Haft Kel – extreme depletion

3.7.4. Uncertainties assessment in Gas Injection

Uncertainty	Gas Injection from the beginning	High Case	Low Case
Aquifer Strength	Aquifer present	----	Volume of aquifer divided by 100
Sigma (Shape factor)	History matching value σ=0.0005	σ * 10	σ / 10
Block height	History matching value, 15[ft]	Block height is equal 50[ft]	---

Table 21: Sensitivity analysis input data

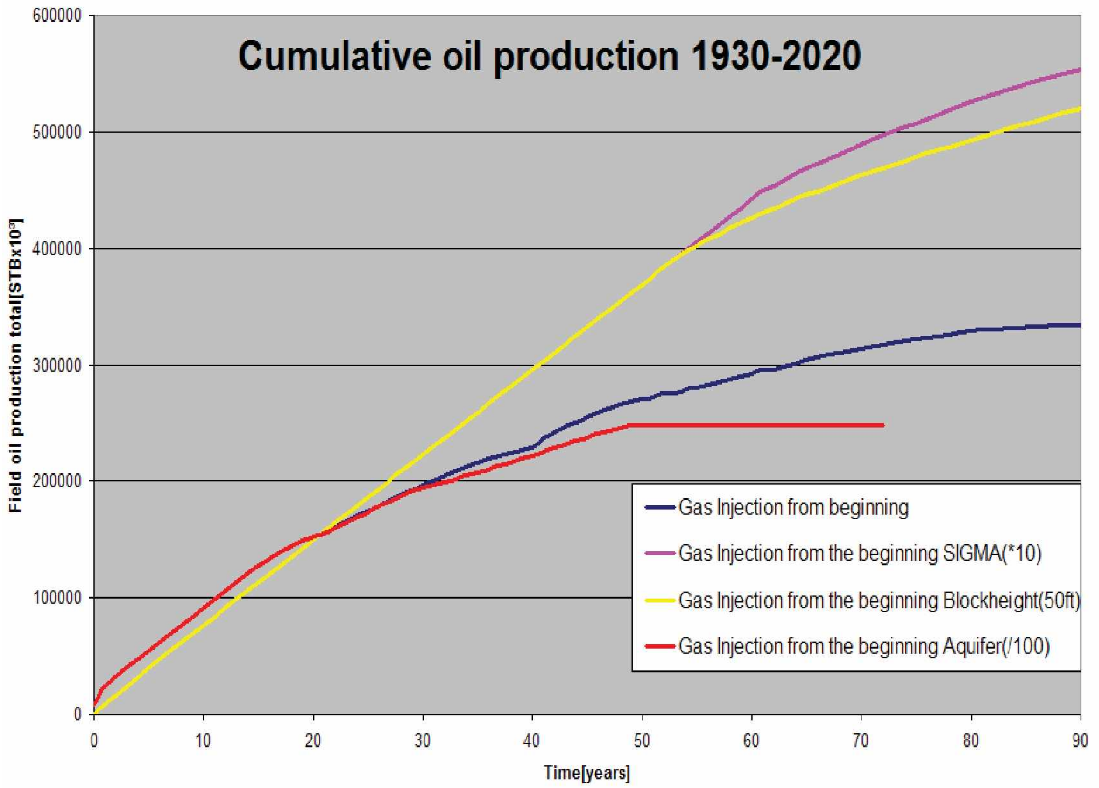

Figure 48: Cumulative oil production – gas injection from the beginning and sensitivities

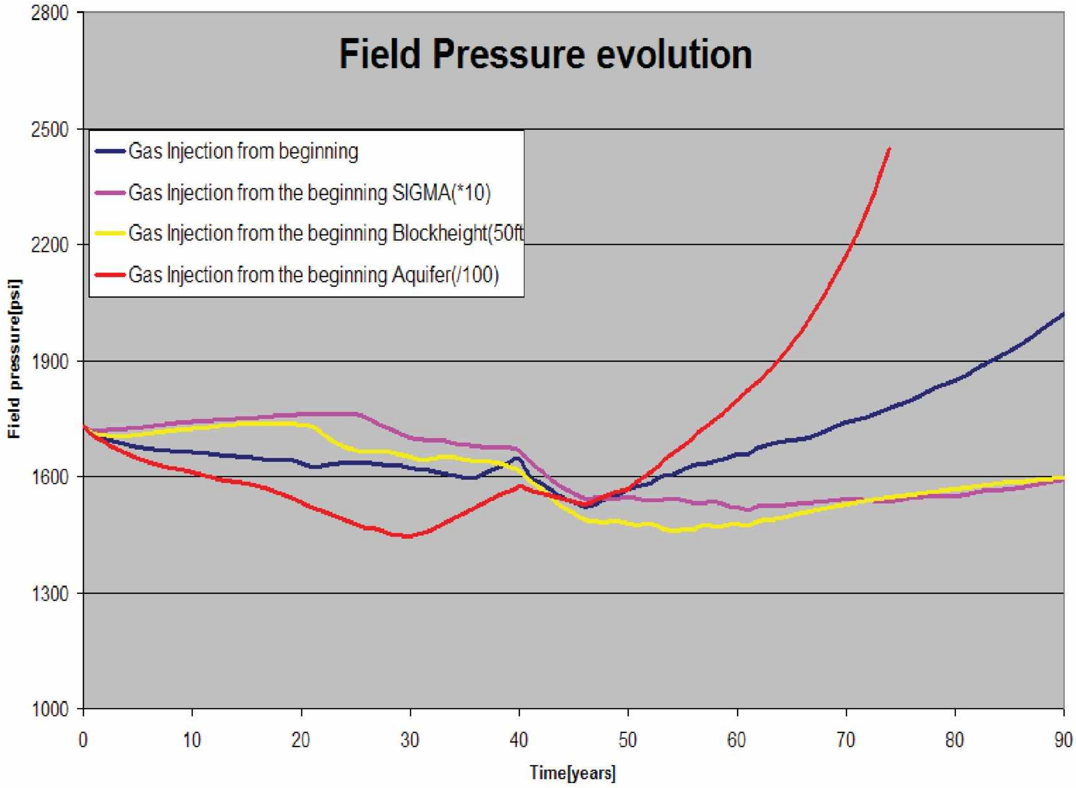

Figure 49: Pressure depletion – gas injection from the beginning and sensitivities

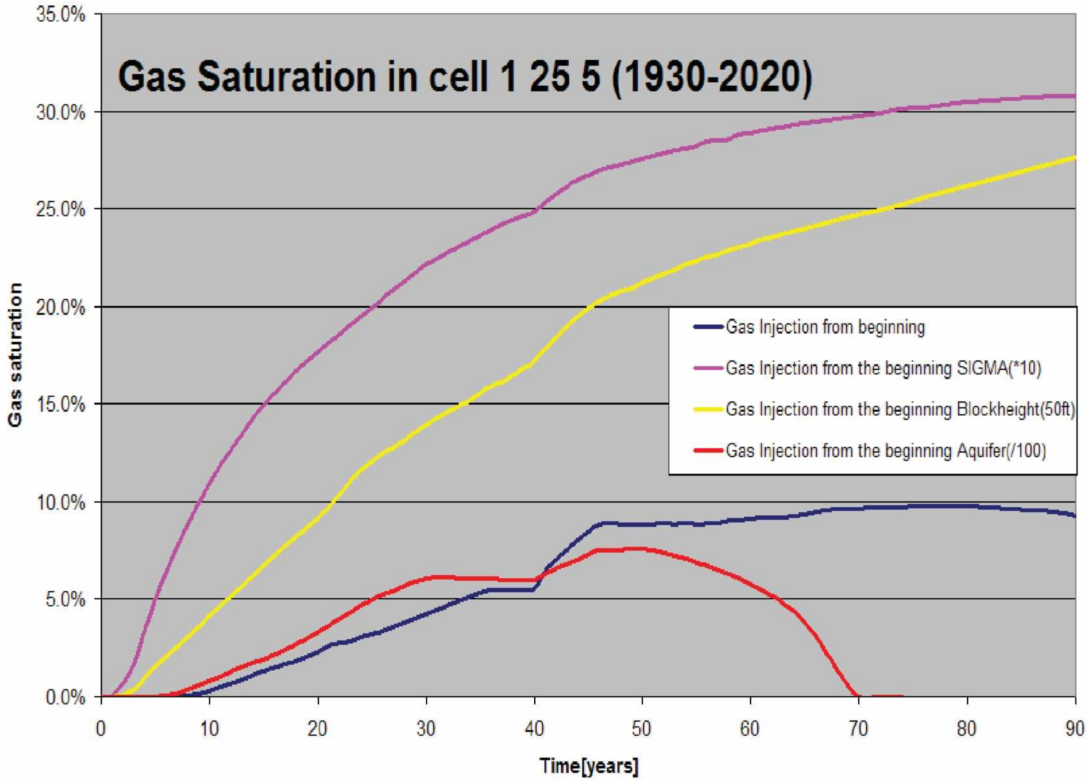

Figure 50: Gas saturation in cell (1 25 5) – gas injection from the beginning and sensitivities

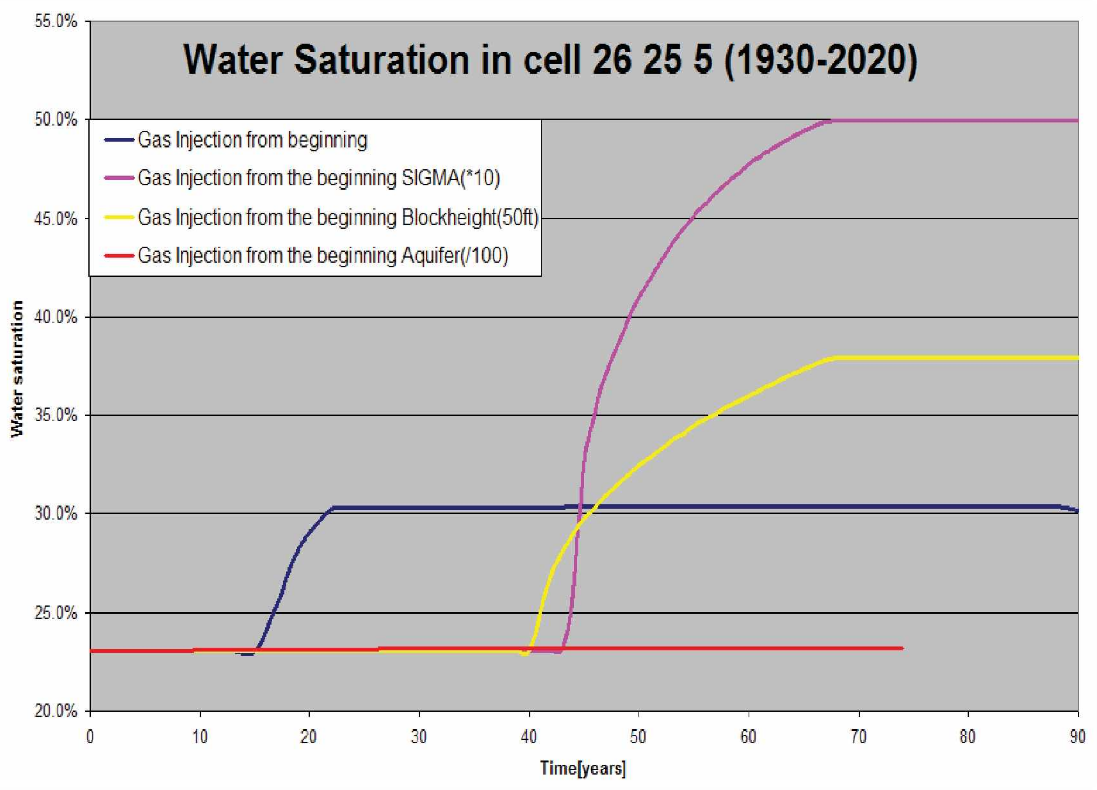

Figure 51: Water saturation in cell (26 25 5) – gas injection from the beginning and sensitivities

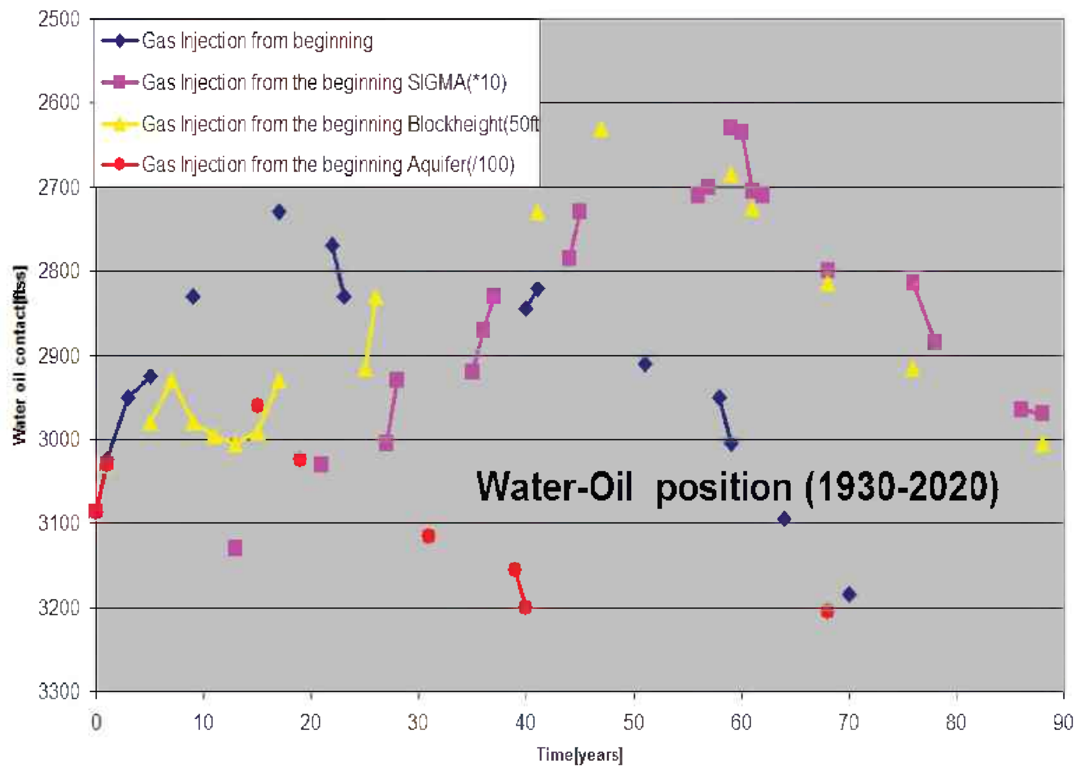

Figure 52: Water oil position – gas injection from the beginning and sensitivities

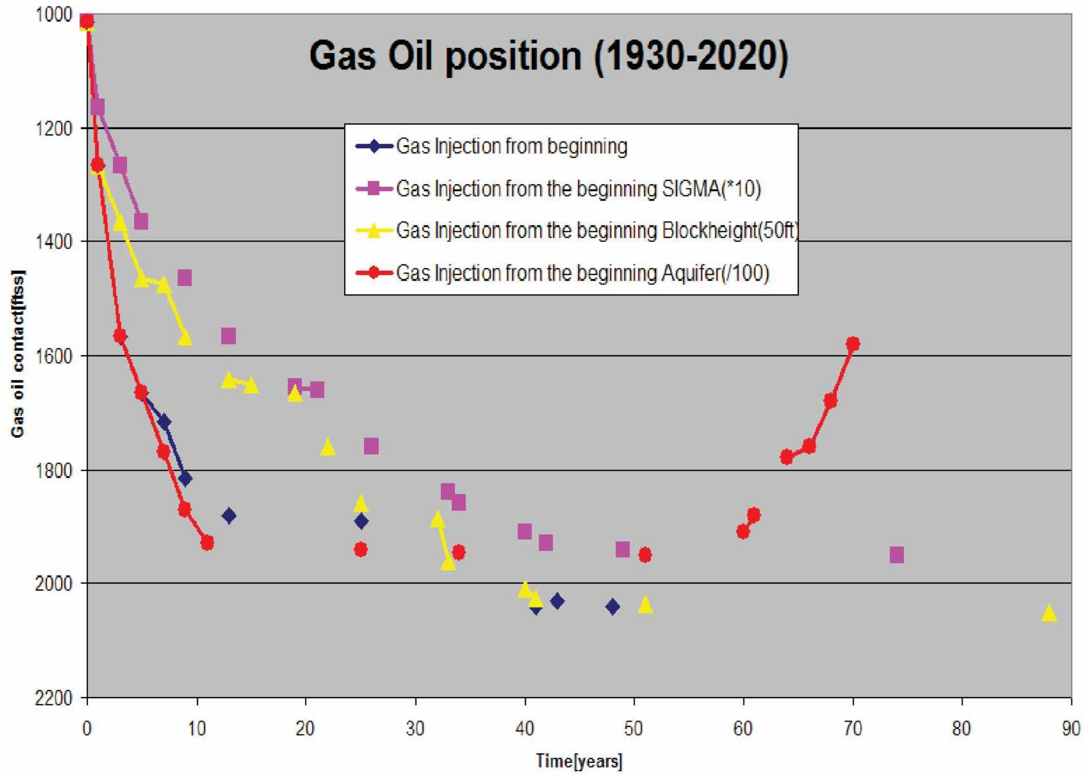

Figure 53: Gas oil position – gas injection from the beginning and sensitivities

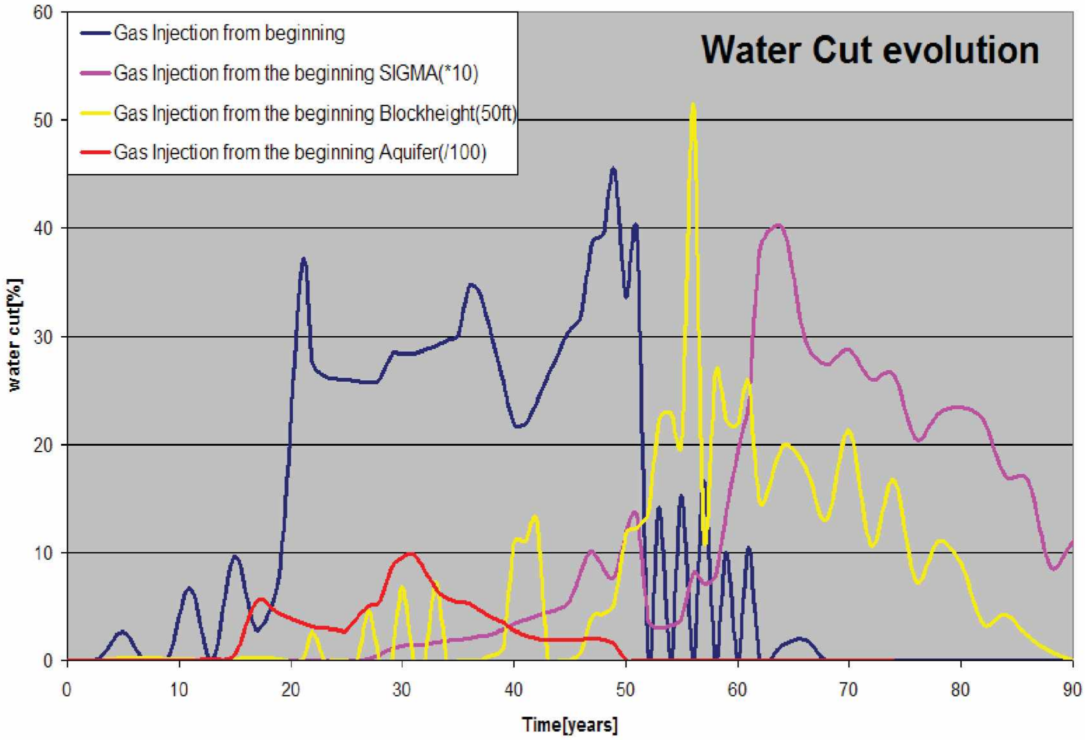

Figure 54: Water cut – gas injection from the beginning and sensitivities

Four main parameters have been considered for uncertainties assessment: matrix permeability, sigma fracture network shape factor, matrix block height and very poor

aquifer, with the first two parameters sigma and matrix permeability having the same impact.

The block height plays an important role in the oil production in this model. It has a significant effect on gas saturation (better gas drainage) but lower on water saturation which is probably due to lower differential pressure (smaller oil water gravity difference).

Compared to extreme depletion case, the gain in oil production with higher block height or permeability/sigma is far more important, highlighting capillarity forces rise when changing conditions. In terms of cumulative production, these cases are now equivalent whereas considering initial figures extreme depletion was more advantageous.

Low aquifer results in a rapid GOR rise leading to closing wells before the end of available production period.

IOIP [BSTB] Ultimate Reserves	8.575 2		Np in 2020 (90 years) [MSTB]	RF [%]	WC in 2020 (90 years) [%]	Avg.reservoir pressure in 2020 [psi]
Base case figures	Gas Injection from Beginning		333.85	22.39	0.00	2018.86
	High cases					
0.1[mD] & 1[mD]	Matrix Permeability	K multiplied by 10	516.2	21.51	11.18	1592.92
Blockheight ~ 15[ft]	Matrix Block height	50[ft]	520	21.51	0.00	1595.96
SIGMA ~ 0.0005[1/m²]	Shape Factor SIGMA	SIGMA * 10	516.2	21.51	11.18	1592.92
	PVT	Taking from another field	No results yet			
	Low cases					
Aquifer present	Aquifer strength (only for 64 years)	Volume divided by 100	248.33	17.23	0.00	2447.62
	Reduction of the injection rate	Injection rate divided by 2	312.20	20.94	0.00	1725.79
	Shape Factor SIGMA	SIGMA / 10	Convergence failure - model not running			

Table 22: Results overview Haft Kel – gas injection from the beginning

3.8. GENERAL CONCLUSIONS ON HAFT KEL

Four main parameters have been considered for uncertainties assessment: matrix permeability, sigma fracture network shape factor, matrix block height and very poor aquifer, with the first two parameters sigma and matrix permeability having the same impact.

Multiplying these parameters (matrix permeability and sigma) by ten, it results in sharp increase in cumulative oil production and in both matrix gas and water saturation. These cases can not be compared easily with block height case.

The block height plays an important role in the oil production in this model. It has a significant effect on gas saturation (better gas drainage) but lower on water saturation which is probably due to lower differential pressure (smaller oil water gravity difference).

A lower permeability or sigma coefficient tends to lower pressure reservoir and increase the amount of produced gas. The pressure decline results in better matrix gas saturation than even for the base case due to the gas liberated but remaining trapped in the matrix.

Low aquifer support lead to a drop in oil production lower than expected. Due to relatively poor water drive (seventeen times the volume of the reservoir).

In the extreme depletion scenario, oil is expelled from the matrix due to pressure difference between matrix and fracture. This scenario seems to be more efficient than the capillarity effect of the gas injection from the beginning scenario which is poor due to low permeability and wettability. Impact on matrix gas saturation is significant. The pressure drop generates gas liberation in the matrix block. The gas can remain trapped in the matrix due to the low permeability.

But when the permeability or sigma coefficient or the block height is increased, capillary forces tends also to improve and the difference between the two production strategies are narrowing and gas injection could even become better than depletion.

The gas injection scenario allows the pressure maintenance and thus gas saturation is mainly due to the capillary effect. The comparison of the gas saturation between this scenario and the extreme depletion scenario allows assessing these capillarity's effects:

- In cases matrix permeability (1[mD]) or sigma multiplied by ten and higher block height (50 ft), oil is mainly driven by capillarity.
- In the base case (0.1[mD] matrix permeability and 15[ft] block height, oil is driven by capillarity and solution gas drive.
- In case of lower permeability value (0.01[mD]), oil is mainly driven by depletion (very poor gas drainage, gas stems from gas brought out of the solution when the pressure falls below the bubble point pressure).

There are thresholds in term of oil mobility and block size (height) from which gas injection becomes an alternative to depletion.

As further works, capillarity forces should be evaluated more in details as well as reservoir depth uncertainty.

4. CONCLUSION

The fields studied are very different in term of development options, reservoirs properties and characteristics and encountered difficulties which are linked to the specificities of each reservoir.

Two parameters influencing the production behavior have been highlighted in both Shiranish and Asmari reservoirs. They are:

1. The importance of the knowledge of reservoir permeability, relative permeability, reservoir vertical transmissivity between layers and permeability anisotropy are decisive parameters driving the most the oil production rate. In order to moderate the development risks, it is strongly recommended to perform suitable core and log measurements with appropriate reservoir coverage to not only reduce the range of uncertainties but also to optimize the position of future producers in spots with favourable reservoir properties.
2. In case of poor aquifer support, it is advisable to implement pressure support in order to maintain reservoir take off and avoid reservoir pressure to drop below the bubble point and thus reducing well productivity.

In **SaZaBa** reservoir, two main parameters are to be considered, the matrix permeability, and horizontal wells in the case of a single porosity model.

The matrix permeability has a significant impact on oil production in the part of the field with low fracturation.

Completed in pay zone matrix and with a K_v/K_h ratio of 0.05, horizontal wells have a strong influence on production even if they are completed in only one layer. Highly deviated wells that penetrate several layers should also be investigated.

In the dual porosity model and dual porosity/dual permeability model the theoretical shape factor sigma (σ=0.19[1/m²]) leads to a sharp increase in cumulative production with high field water production through the fractures network and to a slight decrease in the amount of produced gas. More realistic sigma figures namely σ=0.005[1/m²] and σ=0.001[1/m²] combined with the layers 10 and 11 plugged considering the fact that fractures are generally plugged by non movable oil in the tar mat areas (permeability fracture divided by 1000 or equal to zero), show a significant reduction of the water cut but a maintenance of the oil production and an increase of the ratio of the produced gas to the produced oil.

Tentative tests using Steam Flood (EOR thermal process) did not succeed due to strong convergence failure and high time computation when using Eclipse dedicated package. This option should be deeper investigated, another simulator may be used for that.

Predominant parameters influencing the oil production behavior in **Haft Kel** based on three different scenarios are matrix permeability, sigma fracture network shape factor, matrix block height and very poor aquifer, with the first two parameters sigma and matrix permeability having the same impact.

Sensitivity runs illustrate a sharp increase in cumulative oil production and in both matrix gas and water saturation for higher matrix permeability values or lower sigma values. These cases can not be compared easily with block height case.

The sensitivity study concludes that block height plays an important role in the oil production in this model. It has a significant effect on gas saturation (better gas drainage) but lower on water saturation which is probably due to lower differential pressure (smaller oil water gravity difference).

Low aquifer support lead to a drop in oil production lower than expected. Due to relatively poor water drive (seventeen times the volume of the reservoir).

In the extreme depletion scenario, oil is expelled from the matrix due to pressure difference between matrix and fracture. This scenario seems to be more efficient than the capillarity effect of the gas injection from the beginning scenario which is poor due to low permeability and wettability. Impact on matrix gas saturation is significant. The pressure drop generates gas liberation in the matrix block. The gas can remain trapped in the matrix due to the low permeability.

But when the permeability or sigma coefficient or the block height is increased, capillary forces tends also to improve and the difference between the two production strategies are narrowing and gas injection could even become better than depletion.

As further works, capillarity forces should be evaluated more in details as well as reservoir depth uncertainty.

ABBREVIATIONS

Φ	porosity
°API	degree API
°C	degree Celsius
Bbl	barrel
Bstb	billion stock tank barrels
cP	centipoise
d	day
EOR	enhanced oil recovery
°F	degree Fahrenheit
ft	feet
ftss	feet sub sea
FVF	formation volume factor
GOR	gas oil ratio
k	permeability
k_h	horizontal permeability
kbopd	kilo (10^3) barrel of oil per day
km	kilometer
km^2	square kilometer
k_r	relative permeability
k_v	vertical permeability
m	meter
Mbbl	million (10^6) bbl
mD	milli – Darcy
Mscf	tausend (10^3) standard cubic feet
MMstb	million (10^6) stock tank barrel
$MMSm^3$	million (10^6) standard cubic meter
OOIP	original oil in place
OWC	oil water contact
Psi	pounds per square inch
Psig	pounds per square inch gage
PVT	pressure, volume, temperature
RB	reservoir barrel
RF	recovery factor
SCF	standard cubic feet
SG	specific gravity
Sm^3	standard cubic meter
Sor,w	residual oil saturation to water

STB	stock tank barrel
THP	tubing head pressure
TVDss	true vertical depth sub sea
Vol	volume
WC	water cut

CONVERSION FACTORS

		$\frac{141.5}{SG} - 131.5$	=	°API
Acre	×	4.05 E+03	=	square meter
Bar	×	14.5037738	=	pound per square inch
Barrel	×	0.1589873	=	cubic meter
Centipoises	×	0.0010	=	pascal - second
Cubic meter	×	6.2898108	=	barrel
Feet	×	0.3048	=	meter
Meter	×	3.281	=	feet
Mile	×	1609	=	meter
Milli Darcy	×	0.9869 E-09	=	meter squared
Pound per square inch	×	6.894757 E+03	=	pascal
Specific Gravity	×	999.996315	=	kilogram / cubic meter
Standard cubic feet	×	2.831685 E-02	=	cubic meter

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APPENDIX A