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Improved Oil Recovery for Developed Oil Rim Reservoir Using Gas Blow Down Strategy (A Case Study of Cefa Feild in Niger Delta)

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Abstract— *One of the major production problems in the development of Oil rim reservoir is early water and gas breakthrough, thereby drastically reducing the production of oil which is the desired phase. The concept of concurrent gas and oil production is necessitated by the increased demand of gas in the gas market and also the production of gas provides room for additional oil recovery from the reservoirs. The aim of this research work is to improve oil recovery of CEFA oil rim reservoir in Niger Delta of Nigeria using gas blow down mechanism as to optimize and improve the production performance. A detailed geological reservoir static (permeability, Porosity, Water Saturation, Net-to-Gross) model with dynamic fluid and rock data served as input in setting up the dynamic model that was used for this study. The oil production rate and recovery factor as at the point of optimization process are 2000bopd and 25% respectively. After the analyses, considering different production scenario, the CEFA reservoir got the maximum oil recovery of 46%. In order to optimally develop the CEFA field reservoirs, it was recommended that 14 shut-wells should be opened, eleven (11) vertical wells should be drilled with five (5) completed on the gas zone and six (6) completed on the oil zone. Seventeen (17) horizontal wells should be drilled and completed below the current Gas Oil contact. The result also shows that higher group gas off take rate yield higher oil recovery and vice versa and a minimum gas group off take rate of 40MMscf/d should be applied, as any lower rate will yield lower oil recovery.*

Keywords— *Oil Rim production, Improved oil recovery, gas blow down, Reservoir.*

I. INTRODUCTION

Oil rim reservoirs are basically reservoirs with thin oil thickness ranging from 15ft to 25ft. These reservoirs contains substantial oil volume due to their large lateral extent despite the small thickness. The production of this oil from oil rim reservoir has been challenging over the years, hence recovery is usually minimal. Low oil recovery in oil rim reservoir is a phenomenon that entails the movement of gas and water into the well bore of a production well. This is as a result of the nature of gas and the variation of the density of water to that of oil.

Earlier development strategies for such reservoirs include placement of deviated wells and horizontal well to optimize production, but with the current need of reliable supply of gas to the Nigeria gas market, these reservoirs can be developed using the gas blow down mechanism to meet the target need of gas supply and also optimize oil production. The gas blow down method can also be considered as overall hydrocarbon maturation plans for oil rim reservoir.

The petroleum Industry is a high risk and challenging venture with a whole lot of uncertainties and very high consequences if a decision goes wrong. Hence for the maximum optimization of a field, the seismic data, individual reservoir parameters and well behavior has to be integrated and fully understood. It implies that a field development study will not yield good optimization plans, if one don't have a detailed understanding of the behavior of the wells in that field. Prior to production, the contacts are already defined, so strategies to develop wells in these reservoirs involve simulating the reservoirs to know the current contact, this helps in well placement as well as predicting what hydrocarbon to expect from such reservoirs.

Development strategies have been recommended in the past decades for oil and gas reservoirs based on the leads of a seismic interpretation and a defined geologic model. The strategies are not enough to get optimum recovery from the field. The most important part of a simulation study is to understand the behavior of the well that passed through/completed the reservoirs.

Development of oil rim reservoirs to achieve optimum recovery has been studied and reviewed by a lot of scholars: [2], [3], [4], [5], [1], [6], [7], using different development strategies which has been proposed and implemented. Result from these strategies varies for various reservoirs depending on the prevailing reservoir conditions and the size of the gas cap and the position of placement horizontal well.

In a work done by [2], in order to optimize the development of hydrocarbon (both oil and gas) resources, the gas cap and oil rim are produced simultaneously from the start of production. This can be done through a single well string in order to reduce cost. This is very effective for reservoir with active water drive mechanism. Also, improve oil recovery can be achieved by placing horizontal well close to the gas-oil-contact with a relativity large tubing size.

[3] tested three positions, one-third, centre, two-third positions from the GOC and concluded that the landing closest to the GOC (one-third position) yielded lowest Oil compared to the centre and two-third due to increased gas production. The two-third position yielded more oil than the one third while cutting more water.

[4] investigated the opportunities that intelligent completions provide for efficient oil recovery from thin oil column reservoirs. Oil production is maximized by using ICV control strategy which involves delaying gas and water

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breakthrough rather than controlling its production. Developing thin oil rim with intelligent completions in horizontal well will reduce drawdown and minimize coning and cusping. This strategy was deployed and additional 38% cumulative oil is expected.

[5] stated that despite the challenges encountered in placement of horizontal wells in a thin-oil column, additional oil recovery is obtained. However, significant oil volume is still left at abandonment. To effectively improve the recovery of oil rim, the horizontal well is placed very close to the gas-oil-contact either just above or below. The horizontal well is place just above the GOC to check the migration and loss of oil into the gas cap. High gas rate off-take is observed with this method and this is recommended where gas monetization is not an issue. In a situation where gas production is not needed, the horizontal well is preferably placed just below the GOC. [1] focused on maintaining gas supply and meeting contractual agreement. In the bid to producing the gas from oil rim reservoirs, additional oil volume is produced while producing the gas. Hence, development of these oil rims must be considered as part of the overall hydrocarbon maturation.

[6] stated that to economically develop oil rim, existing wells are side tracked at highly deviated angle to target by-passed oil in the field. Horizontal well is considered to be more effective in draining oil rim reservoirs because it has larger contact area (drainage area) with the oil column than a vertical well, also there is lesser pressure drawdown on the horizontal well when compared with the vertical well given the same start up rate, hence water breakthrough time is delayed in horizontal wells.

[7] in a study, gas injection above the oil water contact gave the highest oil recovery of 44% as compared to other cases of horizontal well placement which gave 29% oil recovery and water injection case which gave 33% oil recovery.

It is obvious that a wide variety of recovery factors ranging from as low as 3% to as high as 40% or more are obtainable from thin oil rim developments schemes around the world and in some cases the low recovery and hence poor economics have led to discontinuity of the targeted development. A key interest of stakeholders is an indication of an optimum recovery from such a development [8].

One of the major production problems in the development of Oil rim reservoir is early water and gas breakthrough, thereby drastically reducing the production of oil which is the desired phase. The placement of horizontal wells has been used to improve recovery from associated gas reservoirs, yet the expected recovery has not been met. Studies have shown that the gas blow mechanism is more effective method in developing oil rim reservoirs [9]. Therefore the study aimed at improving oil recovery from a developed oil rim reservoir (CEFA) in Niger Delta region of Nigeria using gas blow down mechanism.

II. Methodolgy

The study approach involves building a detailed static reservoir model which serves as input with other dynamic data to generate a dynamic model for sensitizing different development scenarios. Fig. 1 shows the flow chart for the methods adopted;

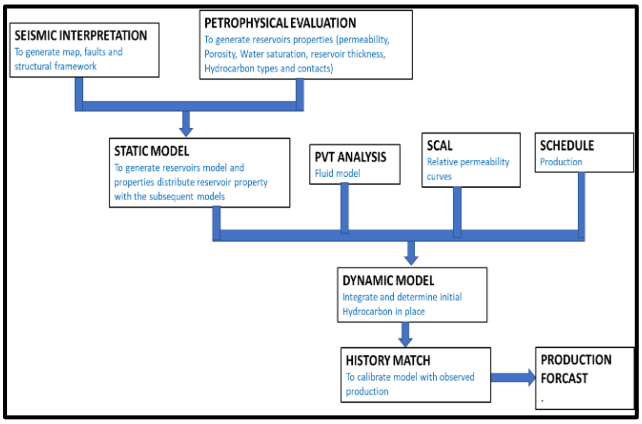

Fig. 1. Simulation Flow Chart

A. Seismic Interpretation

Wire-The data for the wells in the Field were made available which include: Well Header information, Fluid Column for the Hydrocarbon Bearing Reservoir, Time Picks and Maps (Fig. 2) and Structural Depth Map. The field fluid columns for the hydrocarbon bearing reservoir are 73563 and 200281 base case GRV (Acre. Ft**),** respectively for oil and gas.

In order to establish the lateral extent of the reservoirs across the field, reservoir sands were correlated across the wells that cut across the reservoir sands. These correlated sand tops were used as input in the synthetic seismogram process.

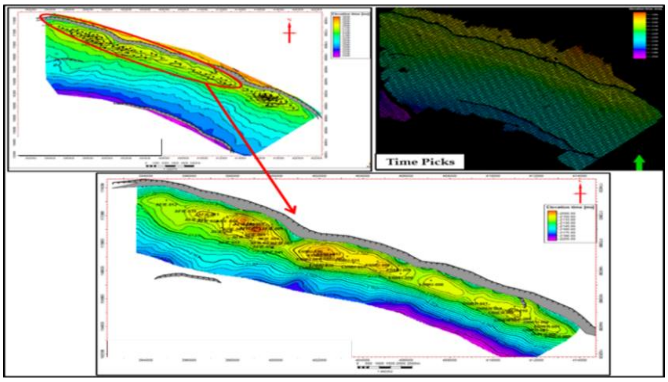

Fig. 1. Time Picks and Time Map

B. Petrophysics

The petro-physical evaluation was done to identify hydrocarbon bearing reservoirs as well as to study rock and fluid properties that are essential for the economic accumulation of hydrocarbon and its general characterization.

The log suite consisting GR, sonic, density and resistivity curves were used in the evaluation of the reservoir properties, which includes, volume of shale (Vsh), porosity, water saturation, NTG and permeability. Table 1, shows the fluid types which were identified with the contact types. The sums and averages of petro-physical parameters and water saturation parameter, in-Situ and mud corrected fluid densities for CEFA Field were identified.

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TABLE 1. Fluid Contact and Types for the reservoir

Reservoir	Contact (ftss)	Fluid Type
A1	8056/8091	GOC/OWC
A2	8075/8108	GOC/OWC
A3	8587/8637	GOC/OWC
A4	8564/8648	GOC/OWC

C. Static Reservoir Modeling

This involved using the estimated Petro-physical data as input to generate the geo-cellular models. Sequential Gaussian Simulation is the modeling algorithm used for the distribution of continuous properties, while Sequential Indicator Simulation was used to distribute discreet properties across the entire 3D grid while honoring data input points. Porosity and Net-to-Gross were up-scaled using arithmetic average while permeability was up-scaled using geometric average. The model architecture was constrained by structural map interpreted from the 3D seismic survey provided. These fields are fault assisted anticline structure with a subtending growth fault trending approximately NW-SE which bound the fields to the North. It also has indication of strong water drive with flow from the bottom and flanks. The fields are separated by gentle dipping saddles with hydrocarbon accumulation at the crestal part.

The Petrophysical properties were geostatistically distributed across the grid. In line with geology of Niger Delta and in agreement with the seismic interpretation, the model revealed some growth faults together with simple antithetic and synthetic faults in the reservoirs. These constitute the main hydrocarbon trapping mechanism. Reservoir properties show a high variability within the lithological zones due to pronounced heterogeneity.

Fault modeling and pillar gridding

The faults were modelled and pillar gridded to generate 3D grids. The faults were modelled and quality checked with the depth converted seismic interpreted fault sticks for accuracy. A grid dimension of 50m by 50m was used in the pillar gridding process and the modelled Structure was quality checked with general geometry interpreted on Seismic by taking cross sections.

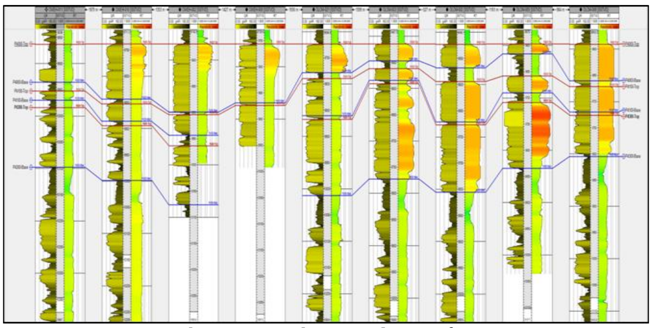

Fig. 3. Litho-Stratigraphic Correlation of Reservoirs

Stratigraphic modeling

The Niger Delta litho-stratigraphic units penetrated by the wells are the Benin and Agbada Formations. The Agbada formation, is characterized by multiple condensed paralliclithologic facie sequence of shale, siltstones and sandstones. Competent shale breaks of high sealing capabilities overly the reservoir sands. The interval is typically made up of alternating sand and shale sequence. The basal Akata marine shale provide hydrocarbon source for overlaying Agbada parallic sandstone reservoirs. The section is overlain by continental to shallow marine sandstones of the Benin Formation. The stratigraphy of the reservoir was established using Gamma Ray log and correlated it across the wells as seen in Fig. 3.

Structural modeling

Structural modelling of the reservoir was carried out with the depth converted faults and surfaces from seismic interpretation as input. This process was divided into five sub-processes, namely; fault modelling, pillar gridding, horizons making, zone making and layering. The faults were used to define breaks in the fault model generated grids. This was followed by pillar gridding which is the process in which 3D grids are generated. The vertical layering of the 3D grid was done with a process called make horizon. Fig. 4 shows the generated map with the gasoil contact and oil water contact. The porosity and permeability model was also generated.

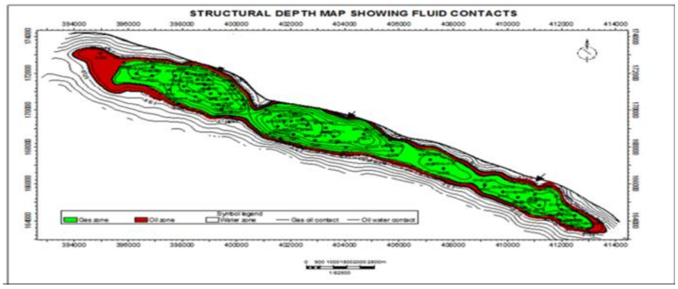

Fig. 4. Structural Map for the reservoir

D. Dynamic Modeling

The entire dynamic modeling procedure involves: Fluid Characterization (PVT analysis), Rock Characterization special core (SCAL) data analysis, Model initialization, History matching and Predictions sensitivities.

Material balance analyses was also use to estimate the oil in-place, evaluate the available energies and deduce aquifer parameters

PVT modeling

Reservoir fluid models were built for all reservoir levels using PVT experimental data as recorded in the laboratory report. Table 2 detailed the PVT parameter for the different reservoir level.

TABLE 2. PVT Experimental Data for the reservoirs

Reservoir	PVT Parameter					
	P_b (Psi)	Boi (rb/stb)	Rsi (Mscf/stb)	Oil Garvity (^{0}API)	Temp (^{0}F)	Oil Viscosity (cp)
A1	3600	1.24	0.76	32	150	1.15
A2	3630	1.22	0.65	29	155	1.17
A3	3650	1.23	0.63	28	157	1.17
A4	3670	1.22	0.61	28	159	1.18

SCAL Modeling (Rock-Fluid Property Modeling)

Relative permeability data helps characterize the simultaneous multi-phase flow of fluids in porous media. The results of the SCAL data from 18 core samples taken in the

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field were analyzed to generate end-points for relative permeability curves. An averaging and normalization of the available oil/water and gas/oil relative permeability data from the field SCAL has been carried out. This enabled the generation of relative permeability tables used for the simulation study of the reservoirs. The concept of rock types or Hydraulic flow Unit (HU) zonation was employed during the analysis in which Six (6) hydraulic units were identified namely: HU-1, HU-2, HU-3, HU-4, HU-5 and HU-6. Relative permeability tables were generated for the 6 hydraulic units. HU-1 represents the best reservoir quality flow zone while HU-6 represents the poorest reservoir quality flow zone.

Initialization

Initialization of the dynamic models provided the initial conditions upon which subsequent dynamic simulation scenarios were based. Input parameters include the static model, comprising the grid, water saturation, porosity, permeability and NTG. These data have been incorporated with other dynamic properties to obtain the dynamic model suitable for history match and prediction sensitivities.

The dynamic models of the reservoirs in fields have been initialized under hydrostatic equilibrium. The input equilibration data for the reservoirs is shown in Table 3.

TABLE 3. Equilibration data

Equilibration Parameters	Reservoirs			
	A1	**A2**	**A3**	**A4**
Pi (psia)	3733	3729	3720	3720
Datum Depth (ft)	8575	8567	8503	8503
GOC (ft)	8575	8567	8503	8503
OWC (ft)	8647	8647	8630	8630
Pc @ OWC (psia)	0	0	0	0

Well event modeling scheduling

In the well schedule, Well Specification, Well Connection Data, Production Well Control, Production Well VFP Table and Production Well Economic Limit were programmed for each run in the dynamic simulator. Schedule module in Eclipse® was used to prepare, validate and integrate production and completion data for use in dynamic simulation. Production data was entered on well basis while well trajectory and events (perforation, recompletion and squeeze operations) were defined. The schedule calculated well trajectory and connections of well with simulation grid based on geometrical grid and well information.

A. History matching

The history match process serves as a means of calibrating the reservoir models for prediction of sensitivities analysis. A black oil simulator (Eclipse 100) has been used to match the historical production data of the initialized dynamic models.

The simulator calculations have been constrained on reservoir liquid rate. Sensitivities were carried out on the following aquifer parameters (Table 4).

TABLE 4. Aquifer Parameters for the reservoirs

Complexes/Reservoir	Aquifer Parameters							
	Datum Depth (ft)	Pi (psia)	Perm. (md)	Porosity (fraction)	Total Compressibility (1/psi)	External Radius (ft)	Thickness (ft)	Angle of influence (deg)
A1, A2, A3 and A4 Reservoir	8647	3800	134	0.25	3.60E+06	9800	134	190

The history matching process has been carefully focused on matching oil production rate and water breakthrough time and trend. Cumulative water production volume and water rate trend over time were used as secondary history matching criteria.

E. Prediction Sensitivity

The dynamic models have been used in characterization of the historical performance, and in formulating drainage plans for the further development of the candidate reservoirs. Sequel to the realization of satisfactory history match, the reservoir models have been run in the predictive/forecast order as follows:

- *NFA (Do Nothing)* – allow existing producer at the end of history match produce to set economic and operational limits without implementing any well activities
- *Re-opening/re-completion* of existing wells where technically and economically feasible. This scenario also covers the short-term oil gain opportunities; sand clean out, gas lift optimization, well stimulation, etc
- *Infill wells* – horizontal and deviated/vertical well type; single well string/dual string completions to improve oil recovery.
- *Gas Blow Down* – additional oil recovery by gas cap blow down.

Maps have been generated from the dynamic simulation results at the end of each prediction run using inputs of effective porosity models, sand thickness and oil saturation. The maps have been used in identifying insufficiently drained areas in the reservoirs and identify sweet oil spots in order to select new infill drill locations.

The following economic and operational limits/constraints have been used for the prediction runs; Minimum oil production rate of 50 stb/d, Maximum water cut of 95%, Minimum THP of 100 psia and Variable liquid rates (1000 - 2500 stb/d) for the NFA case - based on current wells' performance trend

The choice of horizontal/vertical wells for the infill wells was based on the following considerations:

- Sensitivity was carried out on horizontal well location in respect to the Gas-Oil-Contact in order to produce oil that will move into the gas cap in gas blow down scenario.
- Possibility of positioning well trajectory high in the attic region of the reservoir, thereby providing the maximum stand-off from the oil-water contact whilst maximizing reservoir contact and production. This will maximize oil recovery by delaying the onset of water production and maximizing the drainage of the attic oil volumes;
- Maintaining low drawdown during production, thereby reducing the impact of water coning.

. *Material Balance Procedure*

The reservoir fluid system was defined and PVT was modeled for each reservoir. Production history data were screened, formatted and imported into production history data section of the software. Also, reservoir static pressure history data were entered into the reservoir production history data section. Reservoir initial pressure and temperature were defined, and

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reservoir rock properties (porosity and fluid saturation) were entered into the reservoir input data. Rock compressibility was estimated from in-built correlation using connate water saturation, porosity and initial reservoir pressure. SCAL models were built with an in-built Corey correlation using connate water saturation, end-point saturations and exponent.

The analysis procedure is as follows:

1. Pressure and production data are entered on a Tank basis.
2. The matching facility in MBAL is used to adjust the empirical fluid property correlations to fit measured PVT laboratory data (Table 2). Correlations are modified using a non-linear regression technique to best fit the measured data.
3. The graphical method plot is used to visually determine the different Reservoir and Aquifer parameters. The Havlena – Odeh and the F/Et vs. We/Et straight-line plots of the graphical method were used to visually observe and determine the appropriate aquifer model and parameters
4. The non-linear regression engine of the analytical method was used in estimating the unknown reservoir and aquifer parameters and fine tune the pressure and production match. This is done for various aquifer models and their standard deviations from the actual field data are compared.

III Results and Discussion

After the analyses with seismic interpretation, petrophysical evaluation, static model, dynamic model, history match and other production data applied, the following was found.

A. *Seismic Interpretation (Horizon/Fault Interpretation)*

Horizons/Faults were interpreted across the field using the 3D seismic vintage provided for the study. Variance Edge seismic attribute was generated and was subsequently used to unravel the structural trend of the reservoirs, the interpretation was carried out to define the geometric framework of the field, the individual reservoirs and generate the top structural maps (Time and Depth) of the reservoirs in the field. Fig. 5 shows the depth surface deduced from structural interpretation.

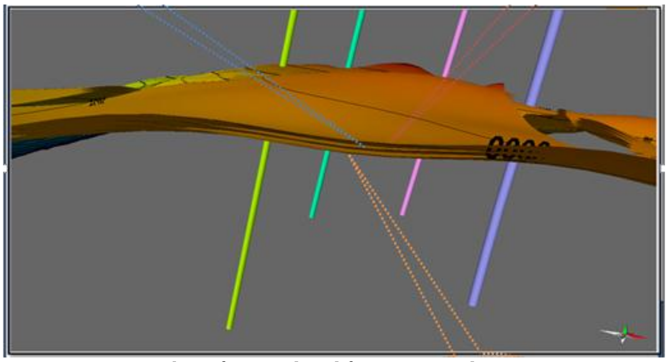

Fig. 5. Depth Surface, Deduced from Structural Interpretation

The average petrophysical properties for the reservoir levels is shown in Table 5.

TABLE 5. Petro-physical Properties for the reservoirs

PETROPHYSICAL PROPERTIES				
S/N	RESERVOIR	POROSITY	NTG	SW
1	A1	0.29640	0.96640	0.21360
2	A2	0.34960	0.82960	0.25053
3	A3	0.32410	0.85410	0.22705
4	A4	0.3242	0.85039	0.22702

B. *Field Production History*

The complex comprises the A1, A2, A3 and A4 reservoirs. The expectation STOIIP is 760MMSTB and 69Tcf of gas cap. Fig. 6 shows the historical production plots from the CEFA reservoir complex.

Production from the field commenced in August 1965 from well M1and attained a peak oil production of *ca* 52,000 bopd in July 1970. A total of 52 wells have been completed on the reservoir complex. Oil production decline set in March 1973 as water production increased rapidly from about 17% in 1971 to 63% in 1996. As at December 2014, average oil production from CEFA reservoir complex was *ca* 3,000 bbls/day.

Cumulative oil production as at December 2018 is 194.72MMstb representing some 25% recovery factor at the end of history.

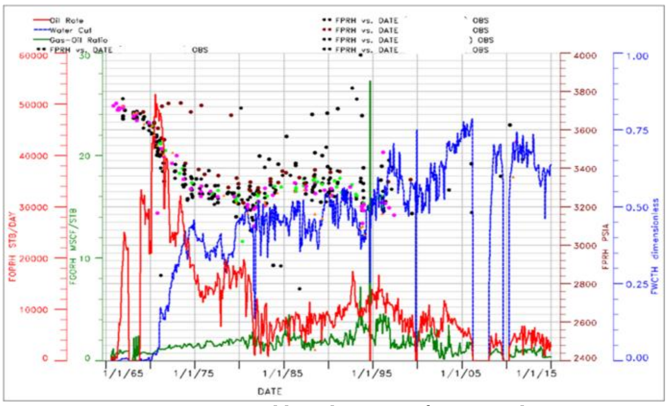

Fig. 6. CEFA Field Production Performance plot

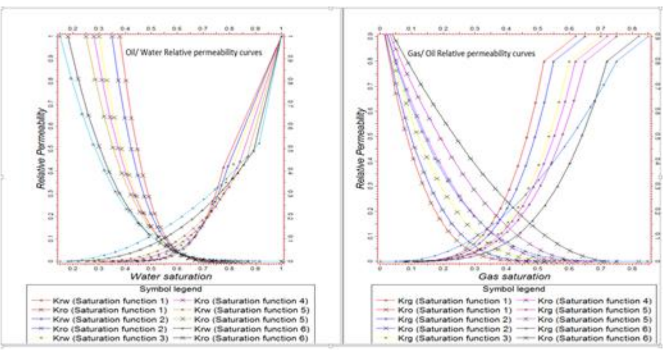

Fig. 7. Relative Permeability Curves plot

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C. SCAL Analysis

The results of the SCAL data from 18 core samples taken in the field were analyzed to generate end-points for relative permeability curves. Relative permeability tables were generated for the 6 hydraulic units. HU-1 represents the best reservoir quality flow zone while HU-6 represents the poorest reservoir quality flow zone. The end point values served as input data in generating Relative permeability curves for different permeability classes (Fig. 7).

D. Material Balance Analysis

MBal™ (Petroleum Experts) software has been used in carrying out material balance analysis of the reservoirs in the CEFA structure. This section of the report details the material balance analysis carried out on the A1, A2, A3 and A4 complex.

The various levels were initially carried as standalone reservoirs but findings from PVT, bottom-hole pressure and production data analysis depict that the reservoirs are all communicating hence the need to model the component reservoirs as a complex of reservoirs. The reservoirs are all saturated and have been modeled as such. There are fifty-four (54) production strings from 52 wells in the complex and the observed production data have been entered on well basis. All the reservoir levels have been connected together using transmissibility factors, these factors were regressed on to obtain suitable value used in matching the model. The result plots obtained from the reservoir A1 level is shown in Fig. 8.

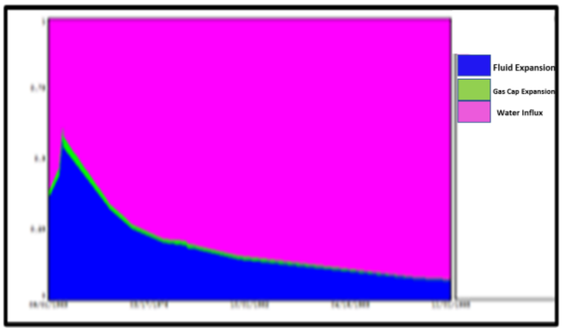

Fig. 8. Energy Plot for CAFA A1 reservoir

TABLE 6. Oil Volumes from Material Balance Analysis

Reservoir	STOIIP (MMstb)	
	Mbal	Static
A1	152.8	151.3
A2	232	230
A3	191	191
A4	132	134
Total	**707.8**	**706.3**

The result obtained from the analysis shows that water drive is the predominant drive mechanism. The oil in place obtained from the analysis and corresponding static volumes are shown in Table 6.

From the results of material balance analysis, water influx is the primary drive and predominate drive mechanism for CEFA reservoirs. The initial volume of hydrocarbon obtained from material balance analysis and static model volume estimates were comparable.

E. Initialization

Reservoir model initialization has been carried out on the reservoir levels. The input data consist of; Pressure at datum depth, depth of fluid contacts (water-oil, gas-oil or gas-water contacts), capillary pressure data in the relative permeability tables and PVT data. Also, Reservoir distributive property model as defined by the static include, the water saturation, porosity, permeability and NTG models.

Equilibrated distributions of phase pressures and saturations at initial conditions have been established based on the input data. The equilibration data is shown in Table 7.

TABLE 7. Equilibration Data for the reservoirs

Equilibration Parameters	A1	A2	A3	A4
Pi (psia)	3733	3729	3720	3720
Datum Depth (ft)	8575	8567	8503	8503
GOC (ft)	8575	8567	8503	8503
OWC (ft)	8647	8647	8630	8630
Pc @ OWC (psia)	0	0	0	0

The oil in place volumes have been generated and compares favorably with the static (geological) model as shown in Table 8.

TABLE 8. In-Place Volume for Static and Dynamic Model

Reservoir	Dynamic Model		Static Model		%Diff	
	STOIIP (MMstb)	GIIP (Tcf)	STOIIP (MMstb)	GIIP (Tcf)	Oil	Gas
A1	153.8	9.91	152	10.27	1	4
A2	229.7	11.38	227	12.11	1	6
A3	202.8	0.34	200.6	0.32	1	6
A4	181.4	10.07	182.3	10.04	0	0
Total	767.7	31.7	761.9	32.74	1	3

F. History Matching

The dynamic simulation runs have been performed on Petrel RE platform using the Eclipse 100 simulator. The model was deployed to history match process; the results from the history match process are shown Figs. 9 and 10.

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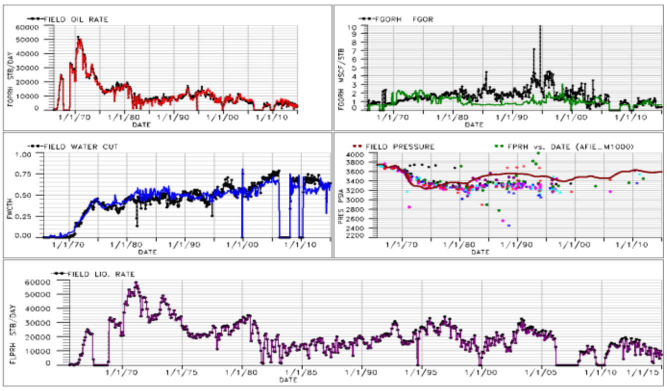

Fig. 9. CEFA Complex History Match Plot

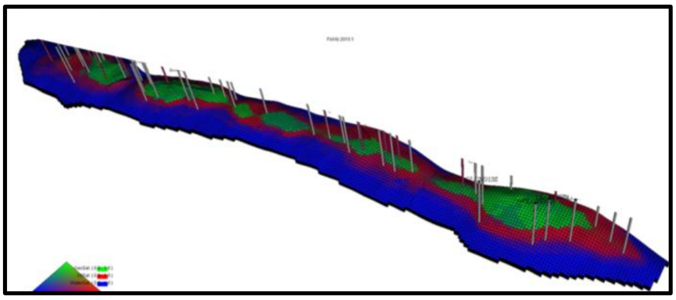

Fig. 10. CEFA Complex Average Ternary Saturation Plot @EOH

G. Prediction Sensitivity/Validation

Based on the acceptable history match models, prediction sensitivities haven been performed on the reservoir levels.

Four prediction scenarios have been considered. The detailed results are as follows

Case 1: No Further Action

A total of 12 well strings still on production at the end of history match have been used for the No Further Action (NFA) forecast case. Reserves from the case 1 scenario gave 28% recovery.

Case 2: NFA + Re-Opening of 14 Wells

At the end of the NFA case, 14 existing shut-in wells were re-opened based on recommendations from the Production Technologist and have been further used for prediction sensitivity alongside with the NFA case. Reserves from the case 2 scenario gave 30% recovery factor.

Case 3: NFA + Re-Opening of 14 Wells + 27 Infill Wells

Infill vertical and horizontal well was placed to target unswept oil accumulation. Sensitivity was carried out on well type, location, position a relative to the gas oil contact and off-take rate. Optimum results from the different set of combinations for the third scenario gave a maximum oil recovery factor of 43%.

Case 4: Gas Blown Down Scenario

The number of wells considered for the gas blow down scenario is the same as been applied in the case 3 (NFA + Reopen + 27 new wells) with the optimal recovery.

Five (5) out of the proposed 27 infill wells was completed on the Gas cap, to produce the gas as well as improve oil recovery from the reservoirs.

Sensitivity analysis has been carried out on well off-take rates and energy balance of the reservoir complex.

Summary of performance results in Table 9 shows that a group target rate of 30 MMscf/d and below will result in losing oil as compared to the NO gas blow down case.

TABLE 9. Case 4 Prediction Results

Scenario		Gas Group off take rate (MMscf/d)	Incremental Oil Recovery (MMstb)	RF %
	No gas Blow Down (Optimum Case) 27 New Wells		134	43
Case 1	NFA + 14 Re-open wells + 5 gas wells + 6 vertical wells + 17 horizontal wells.	90	155	46
Case 2		85	155	46
Case 3		75	153	45
Case 4		70	153	45
Case 5		60	152	45
Case 6		50	150	45
Case 7		40	143	44
Case 8		30	133	43

The pressure depletion for the different gas off-take rates as compared to the No-Gas-Blow down scenario is shown in Fig. 11. The pressure depletion is still within tolerable pressure change range.

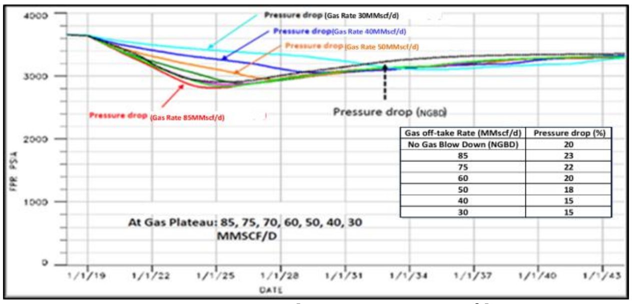

Fig. 11. CEFA Predictions Pressure Profile

The Summary of reserves from the four-case predictions scenario is shown in Table 10. The incremental oil production plots for the optimal Gas-blow-down case and No-Gas-blow-down case is depicted in Fig. 12. It can be found from Fig. 12 that the additional oil produced using gas blow down mechanism is 155MMstb as to compare 134MMstb for no gas blow down strategy, which is a very huge success.

TABLE 10. Summary of Reserves

Scenario	Activity Description	Cum Oil Prod @ End of History (MMstb)	Incremental Oil Recovery at end of prediction (MMstb)	DUR	Recovery Factor (%)
Case 1	No Further Action (NFA)	195	18	213	28
Case 2	NFA + Re-opening of 14 wells		33	228	30
Case 3	NFA + Re-opening of 14 wells + 27 new well (9 Vertical well + 18 Horizontal wells)		134	329	43
Case 4	Gas Blow Down: NFA + 14 Re-open wells + 27 new wells (5 gas wells + 6 vertical wells + 16 horizontal wells).		155	350	46

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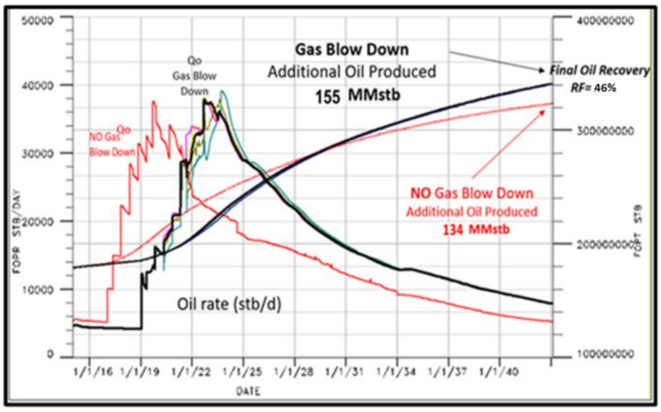

Fig. 12. CEFA Complex Gas Blow Down vs No Blow Down production plot

IV CONCLUSION

The development of thin oil rims with associated large gas cap reservoirs presents series of challenges that ranges between by-passed oil accumulation due to gas cap expansion and water influx and Regulators constraints (wells with HGOR should be shut-in) to preserves the energy of the reservoirs. In this study the CEFA oil rim reservoir fluid and rock properties have been described using combination of field, reservoir and production data.

Predictions sensitivities has been carried out with different combination of production conditions to estimate recoverable reserves from the field. The results from prediction analysis shows that the gas blow down scenario gave a significant additional recovery of 155MMstb of oil with the same set of operation conditions (number of wells and pressure drop), when compared to the No-Gas-Blow down development scenario with incremental oil recovery of 134 MMstb, besides the additional gas recovery.

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