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Risk Mitigation in Development Drilling Through Improved History Matching by Incorporating Uncertainty Analysis with a Hidden Gas Cap

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Abstract

This research paper discusses the Field Development Plan (FDP) - 2020 of a brownfield which recommends drilling 3 infill producers to boost oil production. The study aims to address the mismatch in Gas Oil Ratio (GOR) in the existing model by incorporating uncertainty analysis in the simulation model. The methodology includes a top-down approach through the synthesis of the pressure-production behaviour, the evolution of GOR in wells/fields and the possible presence of a hidden gas cap. The findings of the present study demonstrate that by incorporating a small initial gas cap in the up-dip area of the field that any well has not penetrated, a significant improvement in GOR match and its early evolution in wells/fields are beautifully captured. The introduction of the initial gas cap has necessitated re-positioning and shifting of 3 infill producers away from the gas cap to maximise oil production. A novel two-pronged approach has been recommended for enhancing the water injection rate by 3-4 folds through a combination of a powered water injection system (already in place) and conversion of one of the existing injectors to a dump flooder on a pilot basis to ensure uninterrupted water injection in the field given the frequent power outages in the area.

Keywords: *Development Drilling, Risk Mitigation, Simulation Model*

1.0 Introduction

Uncertainty is inherent in every stage of oil and gas exploration and development. The ability to explore uncertainties is a valuable tool for understanding and evaluating risks and for developing better risk mitigation and decision-making strategies[1-12]. Many times, the simulation model when coupled with uncertainty analysis reveals a meaningful subsurface uncertainty that might have otherwise been overlooked[13-20]. It is for this reason that many Exploration and Production (E and P) companies have made it mandatory to include a section dedicated to uncertainty analysis in their FDP report.

1.1 Literature Review

Rose states that risk and uncertainty are inherent aspects of investing in petroleum exploration ventures. The tasks in serial exploration decision-making are to be consistent in dealing with risk and uncertainty and to perceive uncertainty realistically, reducing it where possible.

According to Øvreberg *et al*., an engineer's work is not done until a base-case prognosis is visible along with realistic upside and downside projections. Error bars are a useful tool for assessing project risk and can suggest further research, long-term testing, pilot projects or a phased (invest while you explore) development approach. A suitable basis for making an educated decision is only present once the uncertainties of each component and the

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overall level of uncertainty have been identified and their implications have been examined.

Rose opines that for a given prospect, geologists can assess the likelihood of key geological factors (reservoir rock, hydrocarbon charge, etc.) recognised as essential for an accumulation of petroleum to exist in the subsurface. His workflow improves the chance of success in terms of the size of accumulations or even finding them. The third consideration is the commerciality of the completed well and the accumulation discovered.

Haldorsen *et al*. felt the need for a detailed reservoir tomography by some known (e.g. seismic) or as-yet-undiscovered technology, which yields images of all faults, the correct structure map and geological architectural flow-unit and barrier details down to 1-m resolution on top of the reservoir characterisation research wish list to reduce uncertainty in long term profile forecast based on a dynamic simulation model.

In the Norwegian section of the North Sea, Jensen conducted a thorough investigation to determine the range of uncertainty in the long-term prediction for the developed Ekofisk and neighbouring fields (Eldfisk, Embla and Tor). To predict the various realisations, a large number of full-field numerical simulations were conducted. There was consideration of reservoir, operational and facility uncertainties. Simple statistical methods were combined with these findings to enable the estimate of probabilistic forecasts. Using Monte Carlo simulation, the production forecasts for each field were combined to create a single license.

Aitken *et al*., demonstrated the advantage of the combination of an Electrical Submersible Pump (ESP) and Gas Lift (GL) in energy saving and application for small diameter wells and developed workflow for hybrid artificial lifts to achieve the highest production rate from a network of multiple wells.

Vakeen *et al*., describe the surveillance and remedial activities that were implemented to monitor the aquifer rise and the associated water production to reduce the detrimental impact of water breakthrough on gas well capacity in a strong aquifer drive gas field.

Steagall *et al*., opined that the methodologies to quantify the impact of uncertainties are still not well established due to the number of variables that must be considered. The complete analysis usually depends on geological, economic and technological uncertainties that have different degrees of impact on the recovery process.

Al-Mugheiry *et al*., showed how a pragmatic approach remarkably improved oil recovery by converting oil leg injectors to aquifer injectors.

Williams *et al*., introduced Top Down Reservoir Modelling (TDRM) as a proprietary technology that has been developed by British Petroleum through extensive Research and Development and consists of a philosophy and tools that enable a faster and more robust exploration of uncertainty than has hitherto been possible. TDRM has been successfully applied to eighteen oil and gas reservoirs that range from the development appraisal stage to mature fields and has resulted in up to 20% increase in estimated net present value for the projects.

Williams integrated experimental design with field development planning. Experimental Design methodology, as a powerful and trusted method, makes it possible to choose simulator runs to obtain accurate probabilistic production diagrams using the least number of runs as well as to study the impact of uncertain parameters on the oil reservoir production profile.

As per Wolff, Probabilistic subsurface forecasting considers ranges of outcomes as strong subsurface uncertainties dictate an ongoing consideration of ranges of outcomes. A systematic approach based on probabilistic principles often including Design-of-Experiment (DoE) techniques provides the best auditable and justifiable means of forecasting projects with a suitable range of outcomes to consider.

Maureen *et al*., provided insight into the upcoming trends while concentrating on the practices and growing advancements in reservoir uncertainty modelling. The current workflows for probabilistic and stochastic uncertainty modelling, which are usually based on different numerical models are critically examined in this work along with the most advanced statistical reservoir uncertainty analysis approaches and the very recent development of embedding some artificial intelligence algorithms.

Hu *et al*., analysed several factors that have a great influence on model results through an analysis of the sensitive uncertain factors such as the lithofacies model, the variogram etc and ranked them in order of their impact on model results.

The study by Mahmood *et al*., constructed an advanced geological model of a giant Middle East oil reservoir using PETREL comprehensive interpretation and correlation processes based on the field data of 161 wells for detailed reservoir modelling before the final decision of the investment for de-risking further development of the oilfield.

A geological model was built by Jassam *et al*., for the Sadi reservoir, located at the Halfaya oil field in Iraq using Interactive petrophysics software for conducting interpretation and analysis of petrophysical properties such as permeability, porosity, shale volume, water saturation etc. The value of the original oil in place was calculated using this 3D-Geological model.

Chengxi *et al*., proposed a method for uncertainty analysis for power system dynamic simulation based on the Nataf transformation and Gaussian-Hermite quadrature which greatly reduced the simulation time for uncertain dynamic simulations while maintaining high accuracy.

Pratap *et al.,* analysed well pressure, production and injection data to resolve subsurface uncertainty regarding the reservoir continuity of producers with downdip water injectors. They recommended revamping of water injection by converting one of the injectors to a dump flooder utilising an overlying aquifer as a source of supply water on a pilot basis.

2.0 Brown Field History and the Field Development Plan 2020

A brownfield case history which supports the importance of uncertainty analysis in unravelling subsurface uncertainty is discussed. A national oil company awarded this field to a private player to boost production under a novel Production Enhancement Contract (PEC). The harsh contractual provision makes the venture economical only if the operator achieves a substantial incremental production over the BAU (Business As Usual) profile. Subsequently, the operator prepared a development plan in 2020 based on a simulation study. The main drawback of the study was that the evolution of the GOR trend in the field was ignored for matching. As a result, the prediction was over-optimistic both in terms of pressure and production profile,

Figures 1 and 2 show the stacking of producing reservoirs N-40 to N10 and above and the locations of producers and injectors in the field respectively. Production started from well #1 in 1999 from the N-20

Table 1. Exploitation Status of Producing Reservoirs in the Field

Exploitation Status of the Field							
Sand/ Reservoir	HCPV	STOIIP	Cumulative Production (MMSCM)		Recovery Factor, % of STOIIP		Remarks
	MMm^3	MMm^3	As of April 2011/Pre Water Injection	As of Aug 2021	As of April 2011/ Pre Wate Injection	As of Aug 2021	
N-10 & Above	0.96	0.76	0.060	0.121	7.9	15.9	
N-20	2.82	2.25	0.140	0.212	6.2	9.4	
N-30	0.84	0.67	0.056	0.094	8.4	14.0	Well #6 production distributed equally between N-30 & N-40
N-40	1.16	0.93	0.030	0.098	3.2	10.5	
Total	5.78	4.61	0.286	0.525	6.2	11.4	

Table 2. Depletion in reservoir pressure of producing sands in the field

Exploitation Status of the Field				
Sand/ Reservoir	**OWC m, MSL**	**Initial Reservoir Pressure, Kg/cm²**	**Bubble Point Pressure, Kg/cm²**	**Current Reservoir Pressure, Kg/cm²**
N-10 & Above	1962	205	139	100
N-20	1962	215	150	105
N-30	1970	210	160	150
N-40	2007	216	167	180

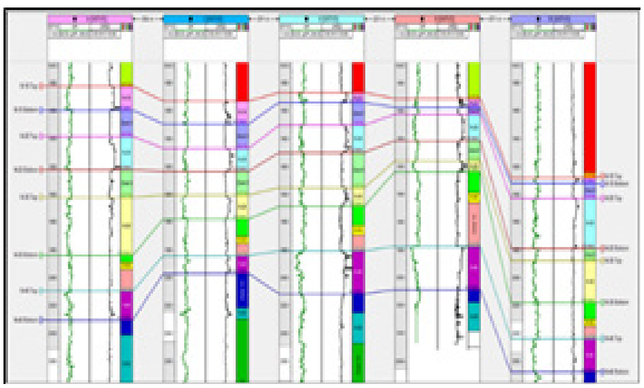


Figure 1. Well correlation panel showing the pay sands in wells #4, #1, #6, #9 and #15.

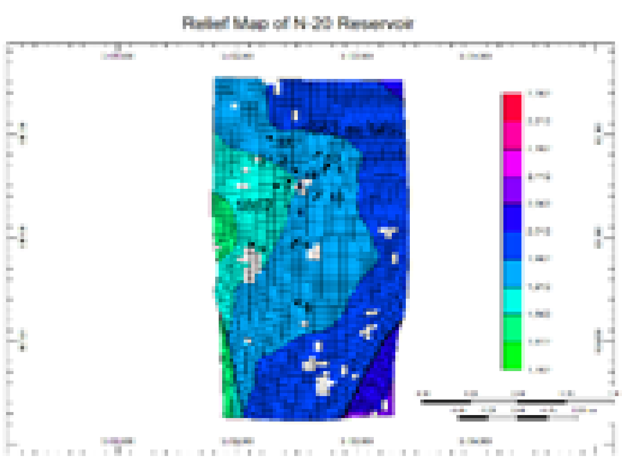


Figure 2. Relief map on top of major producing N-20 sand.

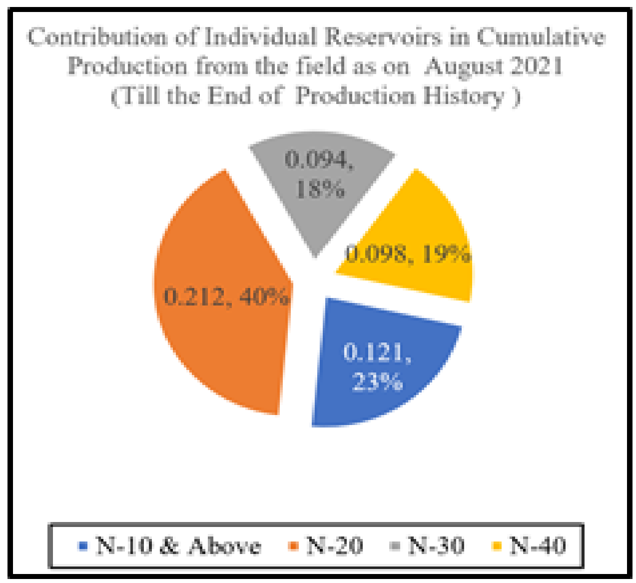


Figure 3. Reservoir production share as on August 2021.

reservoir. Subsequently, wells #3, #4, #5, #6 and #7 came into production from other reservoirs. The wells #3 and #4 were later zones transferred to upper reservoirs. Subsequently, wells #8, #9, #12 and #14 also came into production. Two producers (wells #3 and #8) were converted as water injectors in April 2011 and November 2014 respectively. In 2019, two more wells #13 and #15 were completed as injectors. Table 3 shows the drilling of wells and their status as producers/injectors with time.

The summary of the exploitation of various Bokabil reservoirs is shown in Table 1 and Table 2. As evident, the extent of pressure depletion in upper reservoirs (N-20 and above) is severe and alarming as compared to lower N-30 and N-40 reservoirs. These tables, Figure 3 and the supplementary Figure. S-1 and S-2 establish that the N-20

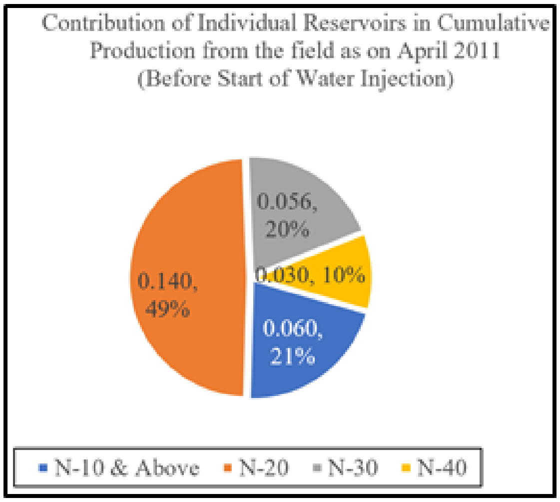


Figure S-1. Reservoir production share before inception of water injection.

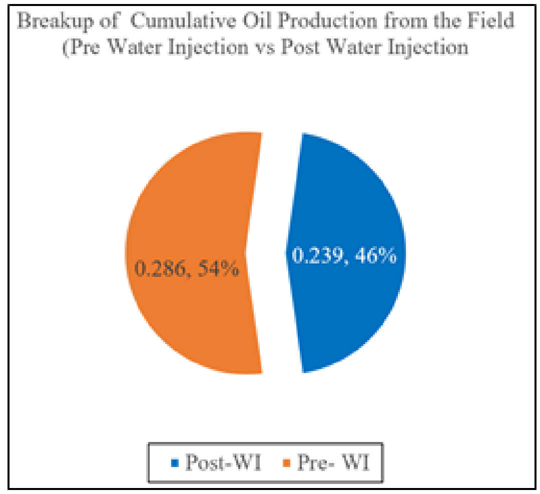


Figure S-2. Share of Production (Pre and Post Water Injection).

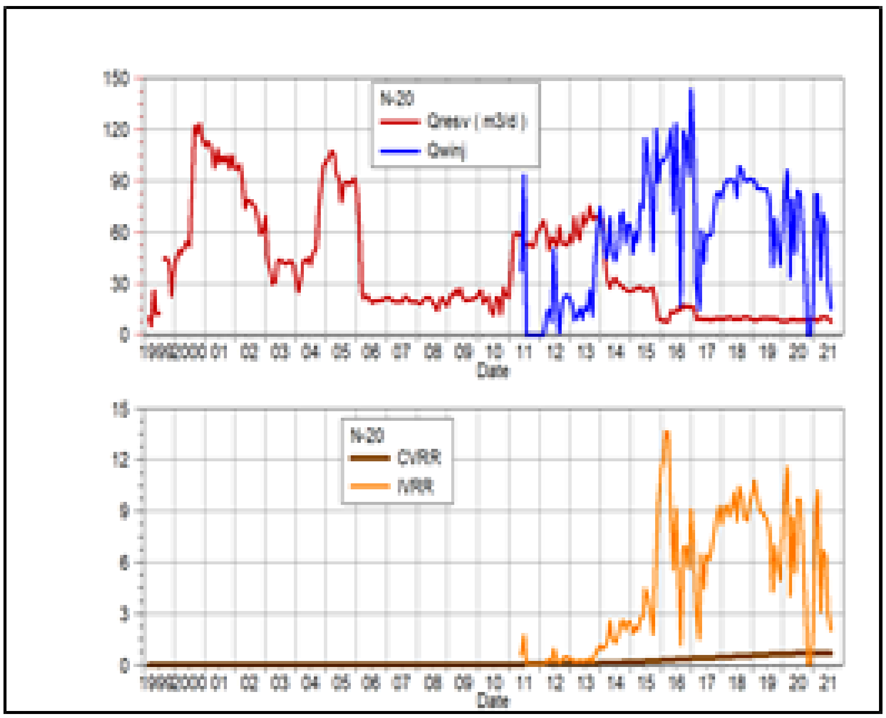


Figure 4. Voidage replacement in N-20 sand.

reservoir is the major contributor which is in pressure communication with the N-10 reservoir. Their current reservoir pressures are significantly below the Bubble Point Pressure (Pb). On the other hand, the bottommost N-40 reservoir is still above the Pb and is currently not in production. Producers in N-40 were prematurely zone transferred to upper sands without doing remedial water shut-off jobs to prolong production. Being the lowermost sand in the stack, the aquifer support is stronger than N-20 and N-10 reservoirs. The current pressure in the N-30 reservoir overlying N-40 is also reasonably good and close to Pb. From this reservoir as well, the producers were zone transferred prematurely to upper reservoirs. The recovery factor of the N-40 reservoir is only 10 % of

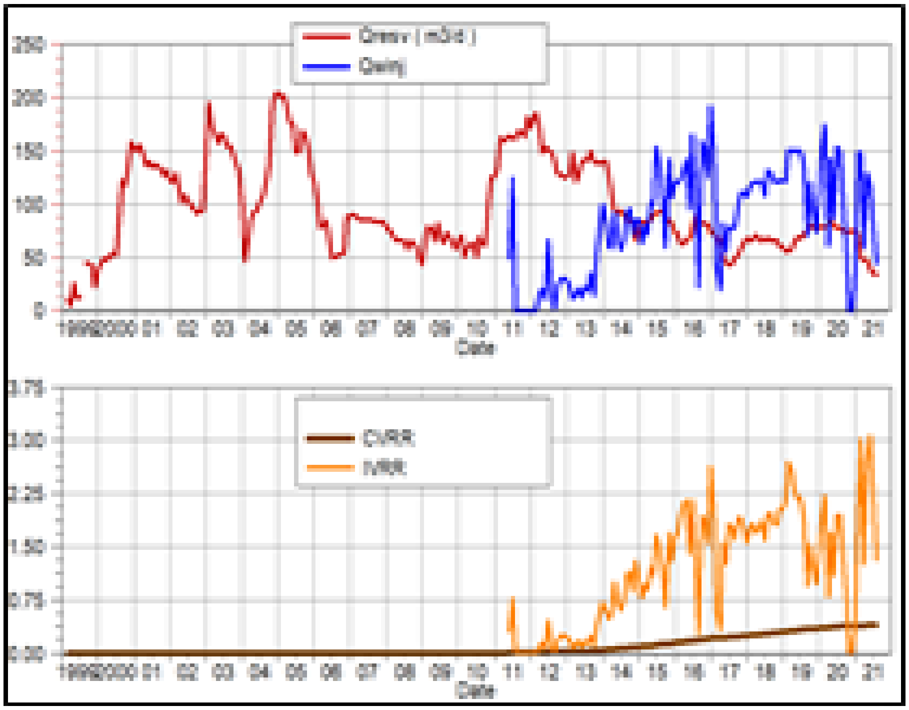


Figure 5. Voidage replacement for the field.

Table 3. Wells in different reservoirs put on production/injection with time

Well/Reservoir Production-Injection Start Summary							
Date Put On	Reservoir						Order as Production
Production/Injection	N-40	N-30	N-20	N-10	Above N-10	N-30 Equivalent	/Injection commenced
Mar/1999			Well#1				N-20
Aug/2000			Well#3				
Nov/2000				Well#4			N-10
Oct/2002				Well#5			
Jan/2003	Well#6	Well#6					N-30+N-40
Nov/2004		Well#7					
Nov/2010	Well#9						
Feb/2011			Well#8				
Apr/2011			Well#3	Well#3			N-10+N-20
Jun/2013			Well#6				
Sep/2015			Well#8				
Jun/2016	Well#3	Well#3				Well#12	N-30+N-40
Jun/2017				Well#1			
Aug/2017		Well#9					
Feb/2019		Well#15					
Apr/2019				Well#14			
Jan/2020					Well#13		Above N-10
Apr/2021					Well#14		

(Note: Water Injection related event is marked in blue font to differentiate it from oil production related event)

Stock Tank Oil-Initially-In-Place (STOIIP) whereas the recovery factor of the N-30 reservoir is 14 %. Both these reservoirs have somewhat better aquifer support and there is still bypassed oil in these reservoirs that can be suitably exploited using the combination of infill drilling and zone transfer of wells from the upper reservoirs where pressure has depleted significantly below the Pb. Pre-mature zone transfer of wells from N-40 and N-30 reservoirs to the major producing N-20 and upper reservoirs triggered rapid pressure depletion in upper reservoirs. The late and inefficient water injection system added to the woes as the quantum of water injection was not commensurate enough to arrest the decline in pressure. In other words, irrational exploitation and poor development strategy together led to low oil recovery from the field.

The water injection in the field started in 2011 through well #3. Subsequently wells #8, #15 and #13 were added as injectors. Figures 4 and 5 show cumulative and incremental voidage replacement ratios Cumulative Voidage Replacement Ratios (CVRR) and Incremental Voidage Replacement Ratios (IVRR) in major producing N-20 reservoirs and the field. CVRR is extremely low and the high reported IVRR (9 for the N-20 reservoir and 3 for the field) is exhilarated[13].

3.0 Review of Field Development Plan - 2020

In the meeting with National Oil Companies (NOC) in 2022, the operator emphasised the need to update

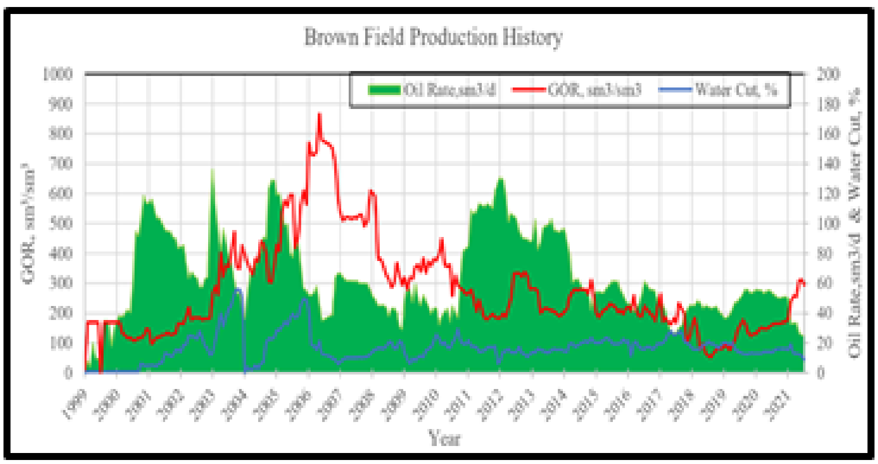


Figure 6. Field production history.

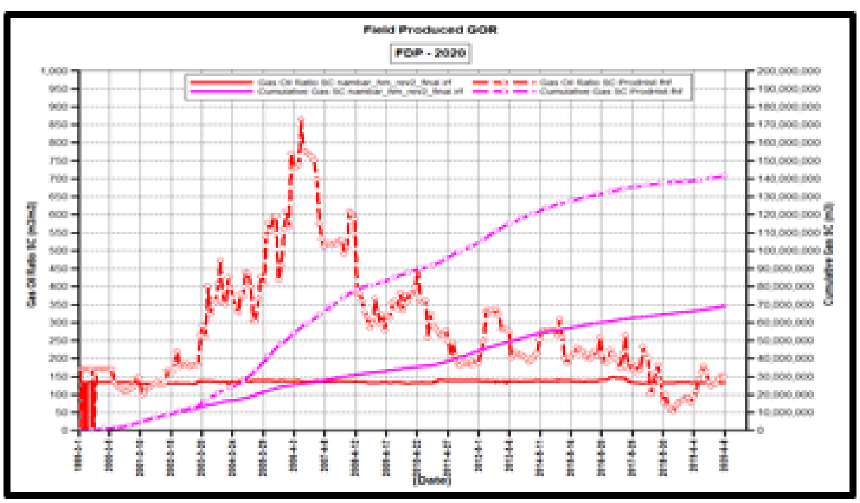


Figure 7. Comparison of GOR and Cumulative Gas Production (Historical vs Simulation Model).

and revisit history matching given the recent low Static Bottom Hole Pressure (SBHPs) and high GOR observed in wells and the following limitations and drawbacks in the existing model.

1. As there is no provision for simultaneous measurement of wellhead pressure and well injection rate at individual well heads of injection wells, the well level allocation of field water injection rate is non-realistic.
2. For the oldest injection well #3 completed in more than one reservoir, the injection rate was equally divided between all the recipient reservoirs in the simulation model which is non-representative.
3. The GOR match was ignored in the simulation model which is conspicuous from the fact that the historically reported field GOR in Figure 6 is much higher than the model field GOR and cumulative gas production as shown in Figure 7.

4.0 Description of Existing Simulation Model

CMG's IMEX Software of CMG Company for the simulation black oil simulator has been used for dynamic field modelling with a 31x66x104 cartesian grid system. The north-south and the east-west cross lines (three in

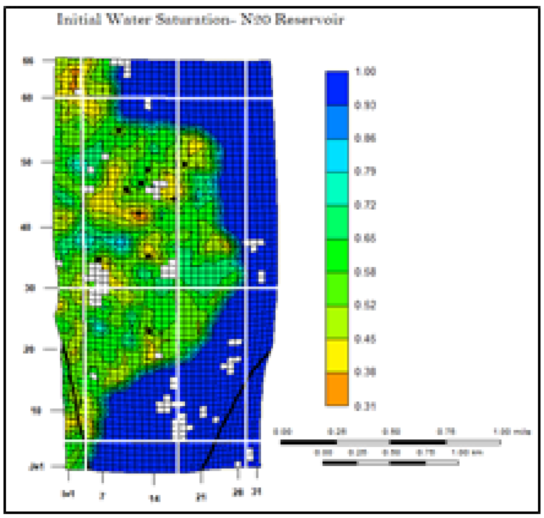


Figure 8. Simulation Grid with intersecting cross lines.

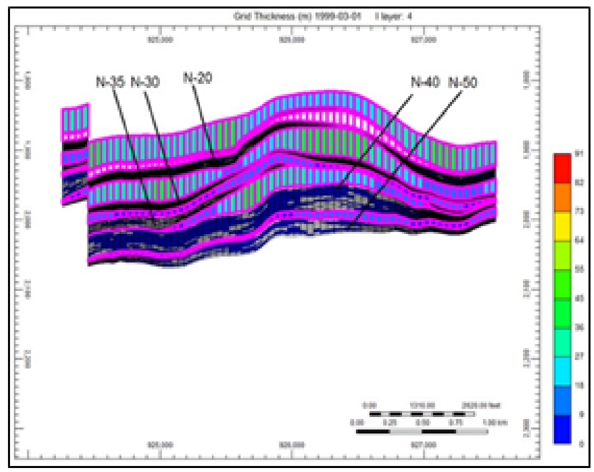


Figure S-3. Cross section along left north-south line showing spatial distribution of producing sands.

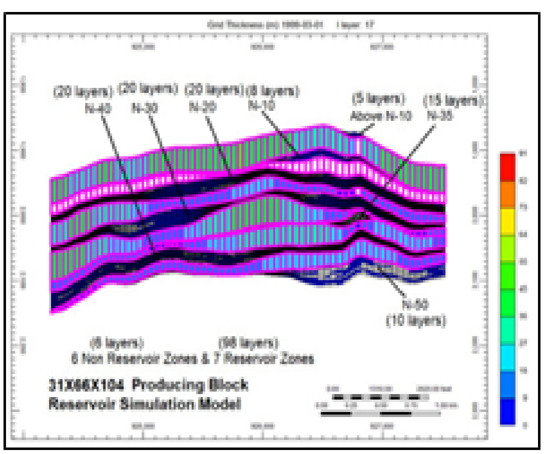


Figure 9. Cross section along central North-south.

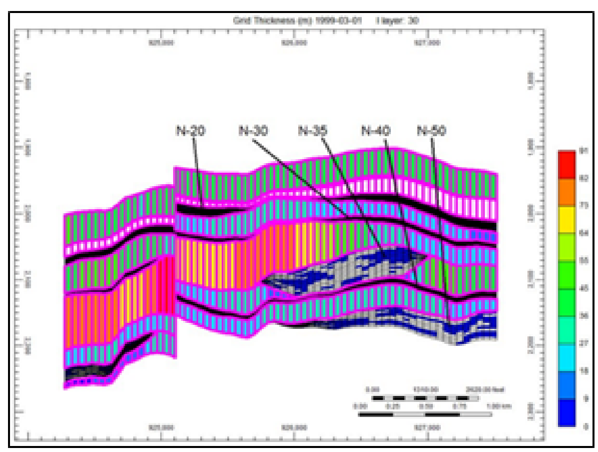


Figure S-4. Cross section along right North-south line showing spatial distribution of producing sands.

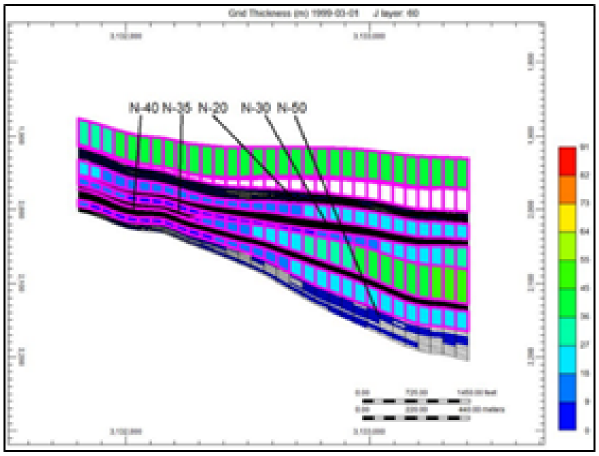


Figure S-5. Cross section along top east-west line showing spatial distribution of producing sands.

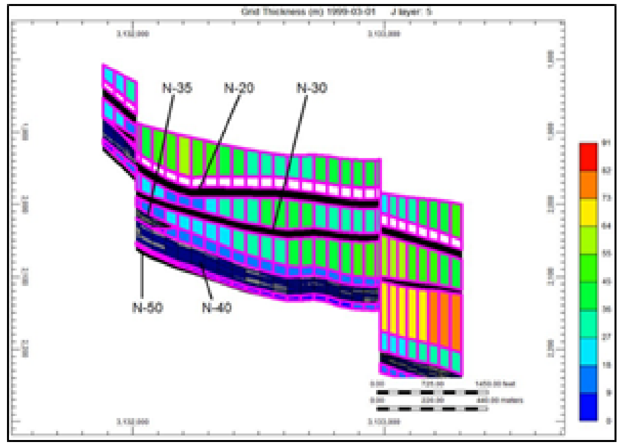


Figure S-7. Cross section along bottom east-west line .

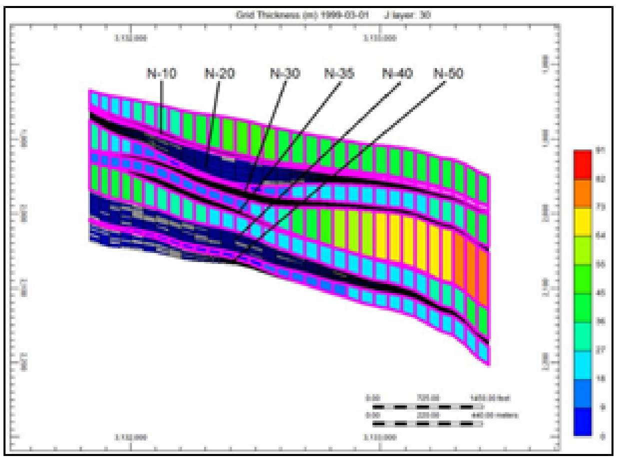


Figure S-6. Cross section along central east-west line showing spatial distribution of producing sands.

Scenario	Hydrocarbon In Place Volumes in Producing Reservoirs														Remarks
	N-10		N-20		N-30		N-35		N-40		N-50		Total		
	STOIIP	FGIIP	STOIIP	FGIIP	STOIIP	FGIIP	STOIIP	FGIIP	STOIIP	FGIIP	STOIIP	FGIIP	STOIIP	FGIIP	
	----------MMSCM----------														
FDP	0.745	0	2.2624	0	0.679	0	0.043		0.833	0	0.217	0	4.78	0	No Gas Cap
I	0.765	0	2.186	0	0.674	0	0.042		0.850	0	0.215	0	4.731	0	No Gas Cap
II	0.906	16	2.016	18	0.649	0	0.041	0	0.827	0	0.211	0	4.649	35	GOC ~ 1860 m

Figure 10. HIIP (Hydrocarbon Initially in Place) in simulation model.

each direction totalling six) are shown in Figure 8 along which vertical cross sections of the field have been depicted in Figure 9 and supplementary Figures (Figure S-3 to Figure S-7). They describe the spatial distribution of the producing reservoirs and the intervening non-reservoir shale layers shown as thick hatched lines. Figure 9 shows 104 vertical layers in the simulation model, of which 98 are reservoir sand layers and 6 are non-reservoir shale layers.

The average Pressure Volume Temperature (PVT) parameter with variable Pb was considered (supplementary Figure S-11). Based on the revised correlation of sand bodies, the reservoir layers N-30 and N-35 were together designated as N-30 and the reservoir layers N-40 and N-50 as N-40 respectively to bring consistency with the approach adopted by NOC.

5.0 Materials and Methods

The following analyses have been carried out during the study to develop a better understanding of the reservoir performance. A top-down approach finally culminated in an uncertainty analysis to explain field behaviour and de-risk future development drilling.

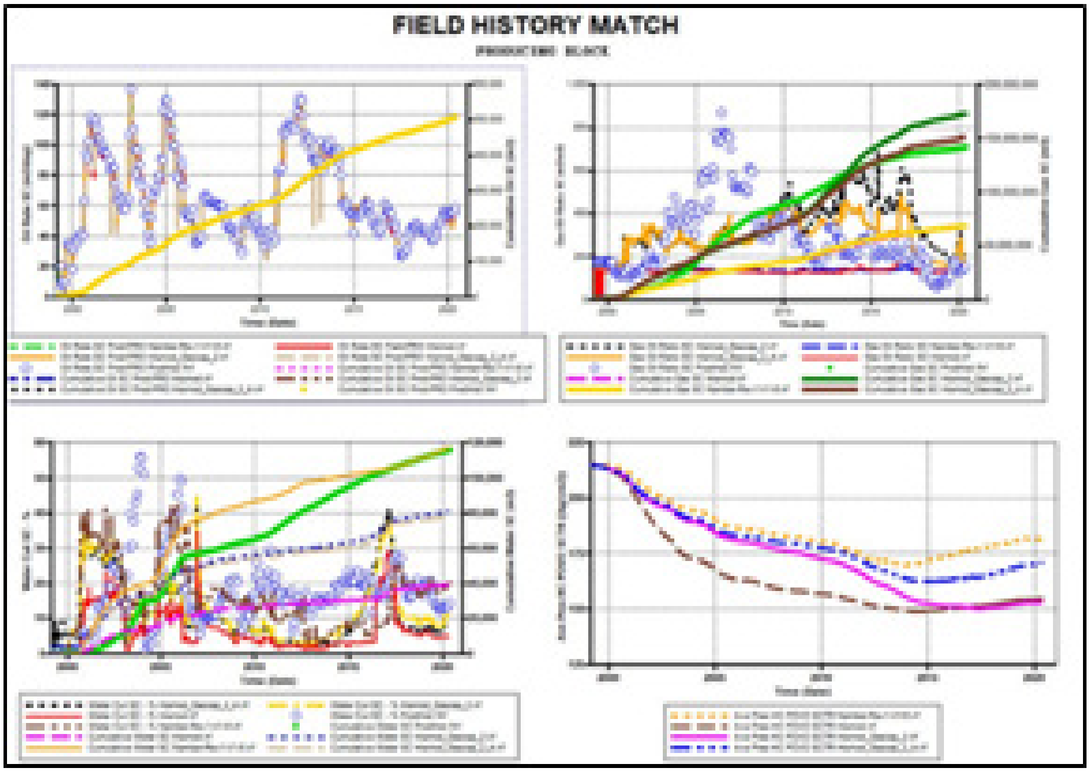


Figure S-8. History match of oil rate, GOR, WC and pressure for the field.

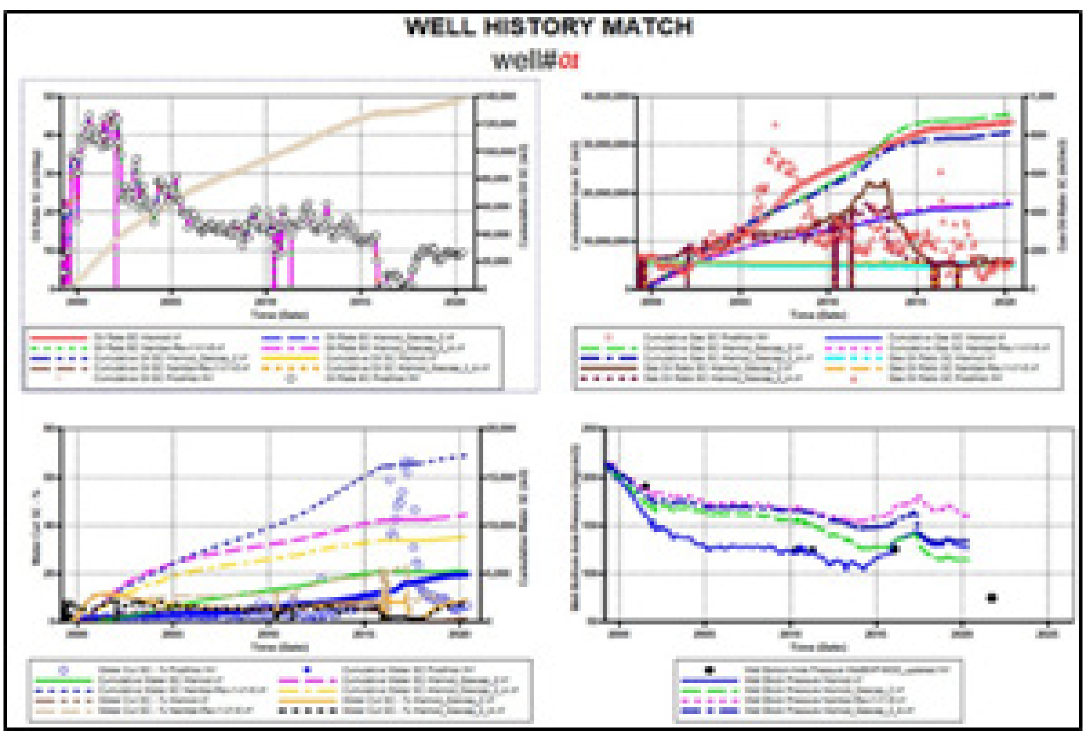


Figure S-9. History match of oil rate, GOR, WC & pressure for well #1.

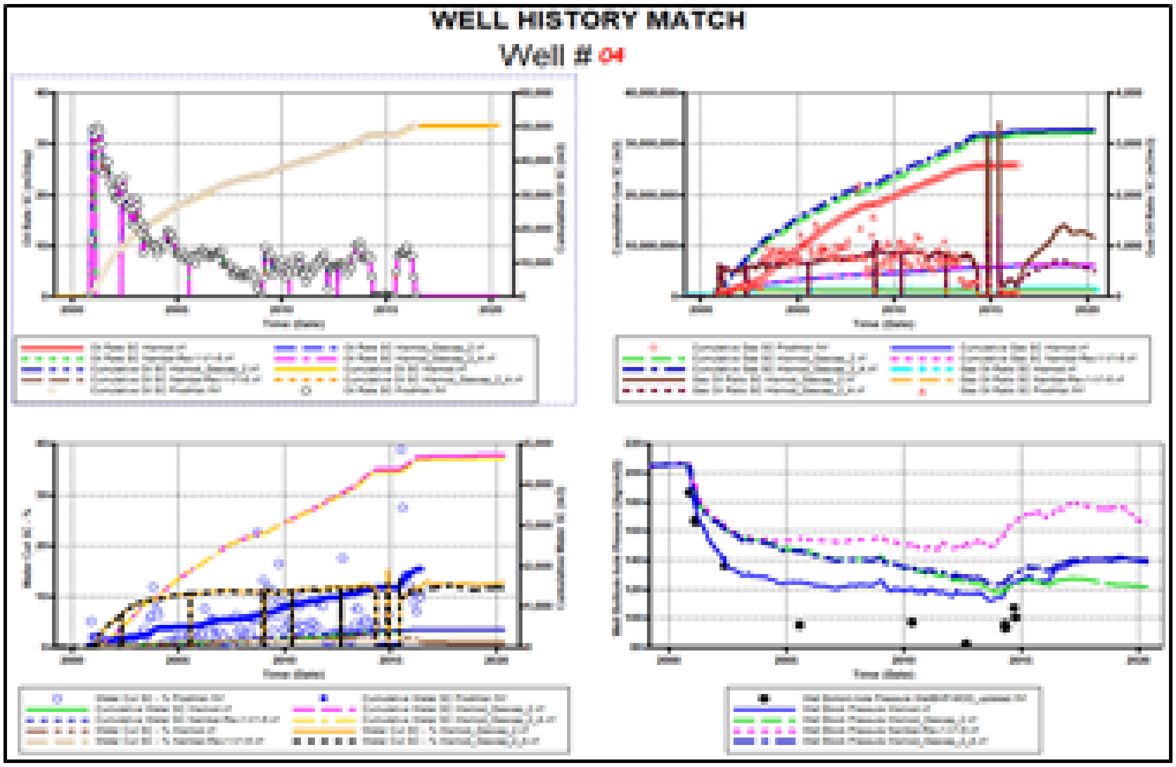
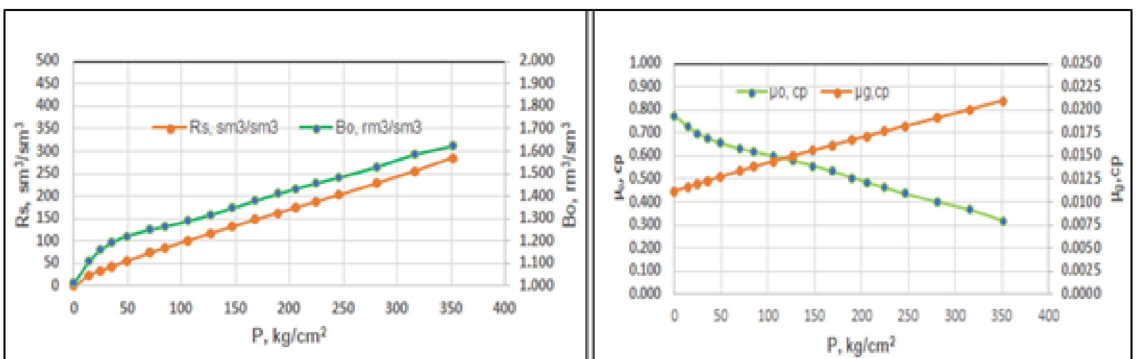
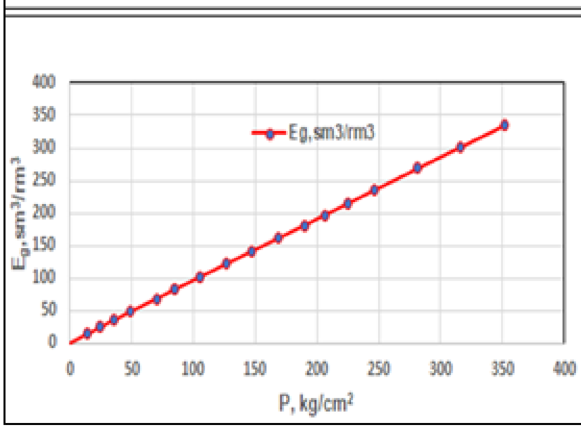


Figure S-10. History match of oil rate, GOR, WC & pressure for well #4.





Reservoir	P_b, kg/cm^2
Above N-10	140
N-10	140
N-20	150
N-30	150
N-35	160
N-40	168
N-50	176

Figure S-11. Average black oil PVT parameters and sand wise bubble point pressure.

1. Pressure depletion in the N-10 reservoir due to production from major N-20 reservoir and pressure depletion in the above N-10 reservoir due to production from N-10 and N-20 reservoirs to establish inter-reservoir pressure communication.
2. Excessive pressure depletion in N-20 and upper reservoirs that triggered gas cap gas expansion.
3. Structural position of the producers in the producing reservoirs and its bearing on the evolution of GOR in wells, reservoirs and the field with time.
4. Non depleted pressure in N-30 reservoir to establish non-communication between N-30 and N-20 reservoirs.
5. Limited production from N-40 reservoir with little depletion in pressure to establish non-communication between N40 and N-30 reservoirs.

Details	Field Production Injection Volumes - Simulation Model vs Production History										
Scenario	Dynamic Model					Historical Performance				Remarks	IMEX data file names
	Np	Gp	Wp	Wi	Pressure	Np	Gp	Wp	Pressure		
	MMSCM				Kg/cm^2	MMSCM			Kg/cm^2		
FDP	0.508	69	0.118	0.274	181	0.506	142	0.115	NA	No Gas Cap	Nambar-Rev1-V1-6.dat
I	0.504	68	0.039	0.274	155	0.506	142	0.115	NA	No Gas Cap	Hismod.dat
IIA	0.508	173	0.081	0.274	153	0.506	142	0.115	NA	GOC ~ 1860 m	Hismod_Gascap_2.dat
IIB	0.507	151	0.078	0.274	171	0.506	142	0.115	NA	GOC ~ 1860 m	Hismod_Gascap_2_A.dat

Note :
1. In Scenario-IIA, Gas Cap Size has expanded significantly. Free gas volume is 71 MMSCM at the end of History.
2. In Scenario-IIB Gas Cap Size has expanded to the extent of 58 MMSCM at the end of History. This results in lesser Gp of 150 MMSCM with higher field pressure of 171 kg/cm^2 at the end of history. Well#5 pressure match is significantly improved in this case, but at the cost of pressure mismatch in other significant producers.
3. In Scenario I, a secondary gas cap has formed with free gas volume of 22 MMSCM which eludes in FDP scenario as pressure is above bubble point.
4. The reported GOR is erratic but there is a definite trend showing presence of a hidden gas cap through which no well has been drilled yet. The likelihood of under reported GOR exists and hence possible expanded gas cap volume of 71 MMSCM is not ruled out.
5. In view of early & conspicuous trend of high GOR in Well#01 & Well#04, the new infill wells (A, B & C) in FDP do not hold merits due to high risk.
6. New infill wells E,H,J are proposed which are located away from Gas Cap and suitable for remaining oil exploitation from deeper reservoirs namely, N-30, N-40 & N-50

Figure 11. Comparison of pressure-production history (model vs actual field history).

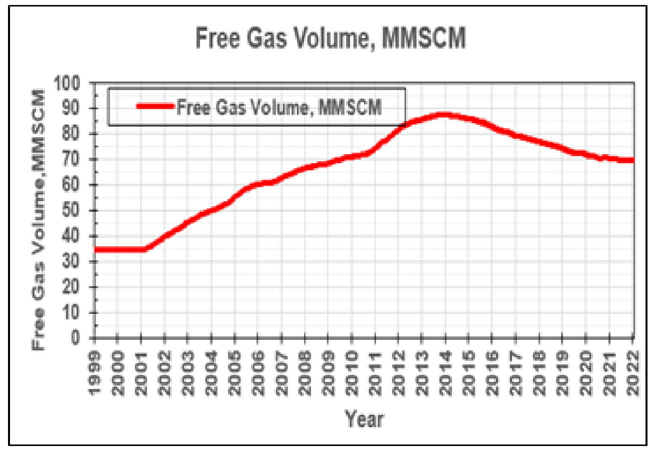


Figure 13. Gas cap expansion with time.

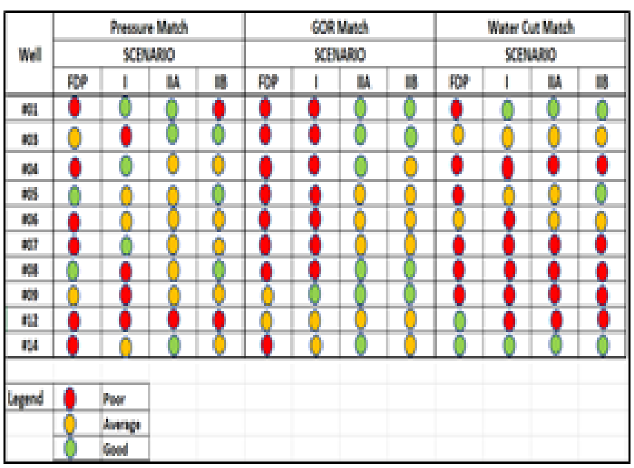


Figure 12. History match quality indices.

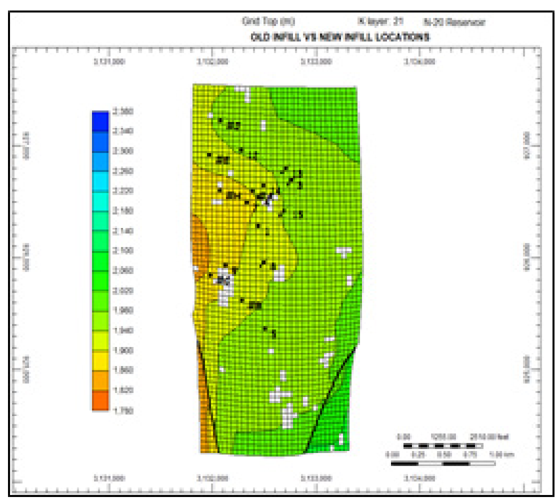


Figure 14. Locations of old vs new infill wells on top of N-20 reservoir.

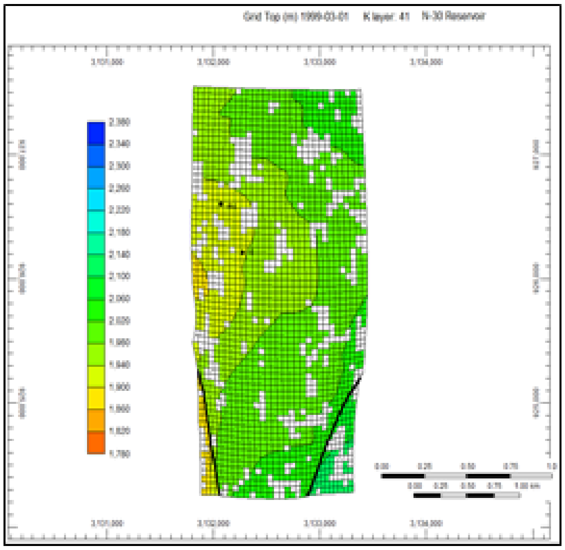


Figure 15. Location of infill well # H on top of N-30 reservoir.

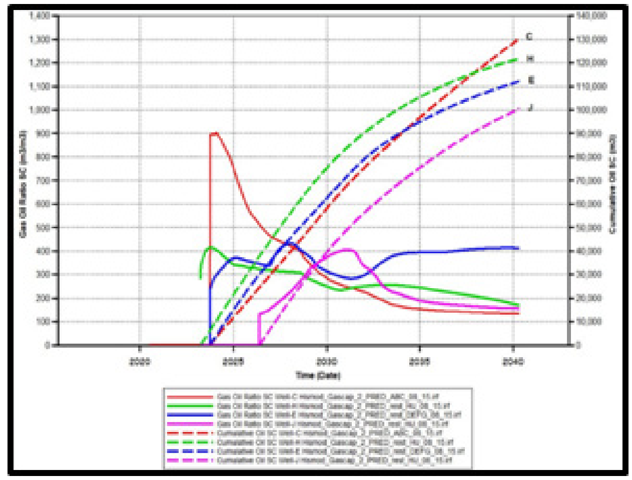


Figure 16. Performance of the best infill producers.

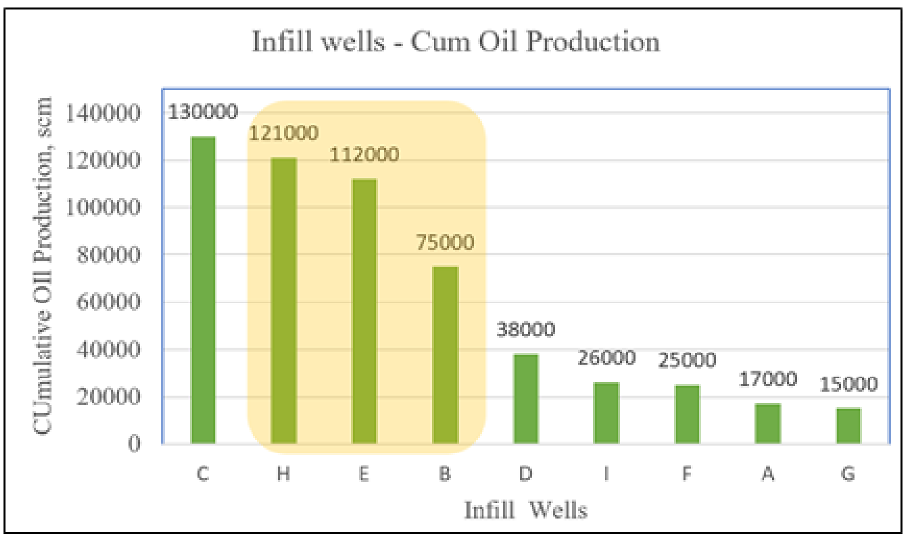


Figure 17. Three optimal producers based on high cum oil production and reduced GOR trend in the model.

6. Impact of uncertainty analysis of various parameters on the evolution of GOR in the dynamic simulation model.

6.0 Reservoir Pressure Depletion and Inter Reservoir Communication

Table 3 summarises historical well events as they came to production and injection. The last column shows the reservoir event in order of time to mark the commencement of production and injection. The n-20 reservoir was the first to be put into production in March 1999 through well #1 followed by the N-10 reservoir that came into production 1.5 years later through well # 4 in November 2000. N-30 and N-40 reservoirs came on commingle production through well # 6 four years later in January 2003. Injectors are shown in blue font in the table. Commingle injection in reservoirs N-20 and N-10 started 11 years later through well # 3 which had ceased to flow

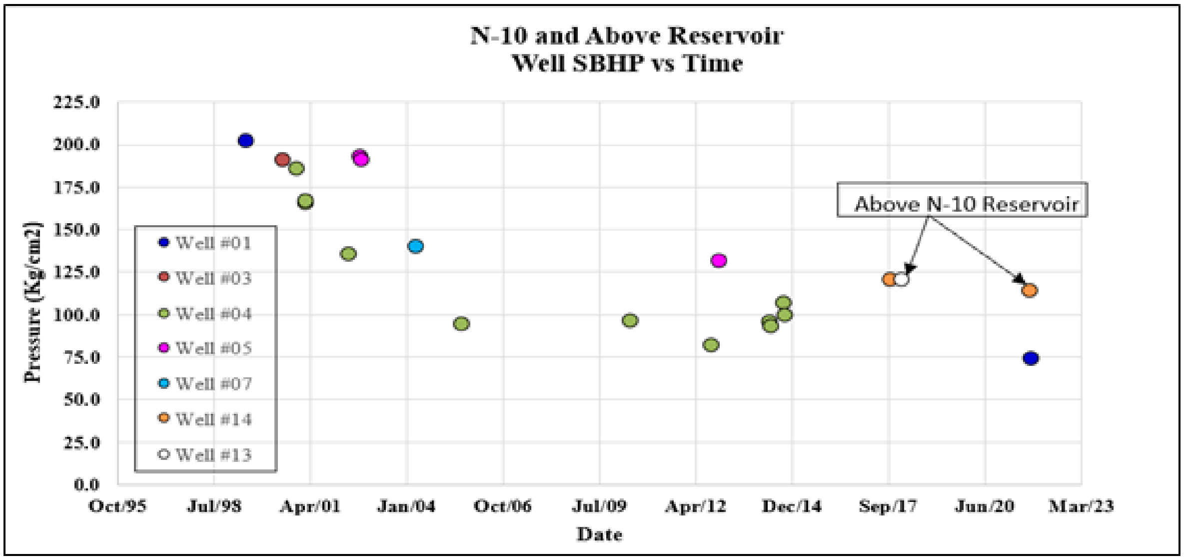


Figure 18. Pressure trend in N-10 and above reservoir.

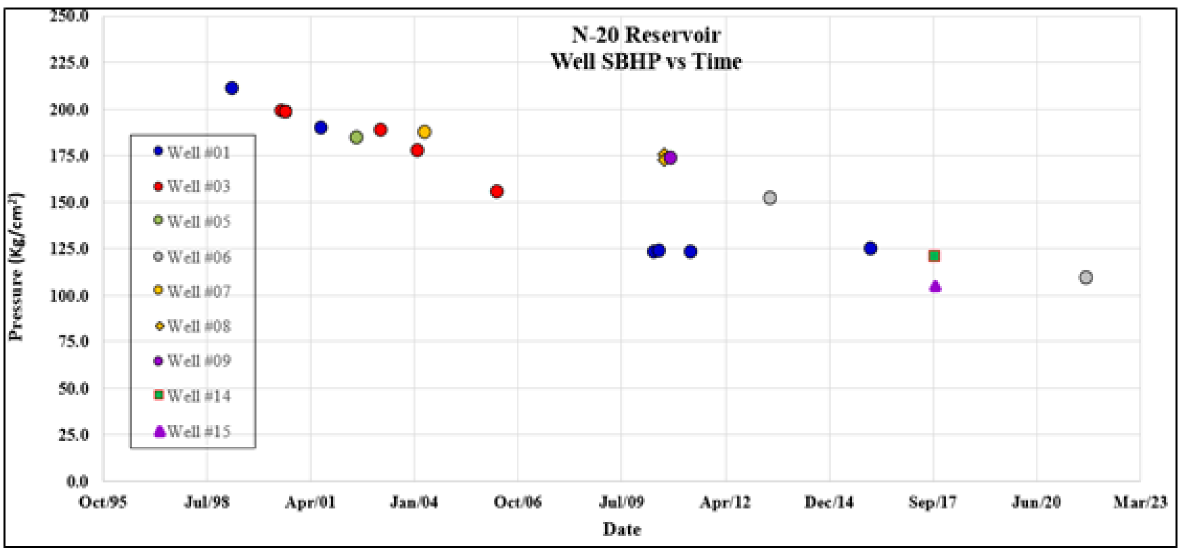


Figure 19. Pressure trend in N-20 reservoir.

due to a high Water Cut (WC) in the N-20 reservoir. Five years later, well # 3 was additionally perforated in N-30 and N-40 reservoirs and thus all four reservoirs were put on commingle injection from June 2016 in this well. Well # 8 was converted into a water injector four years later in 2015.

Figures 18-21 show measured SBHP in wells in respective reservoirs with time. The extent of depletion in the top two reservoirs (figures A and B) which together have contributed about 65% of total field production as of August 2021 is alarming. Their contribution is as high as 70% of the total cumulative oil production by April 2011. Another noticeable observation is that the recently drilled wells # 13 and # 14 are the only wells that have been completed in the above N-10 reservoir and both the wells show large depletion in pressure (Figure 18) indicating pressure communication with underlying N-10 and N-20 reservoirs. Also as shown in Table 1, the N-10 reservoir

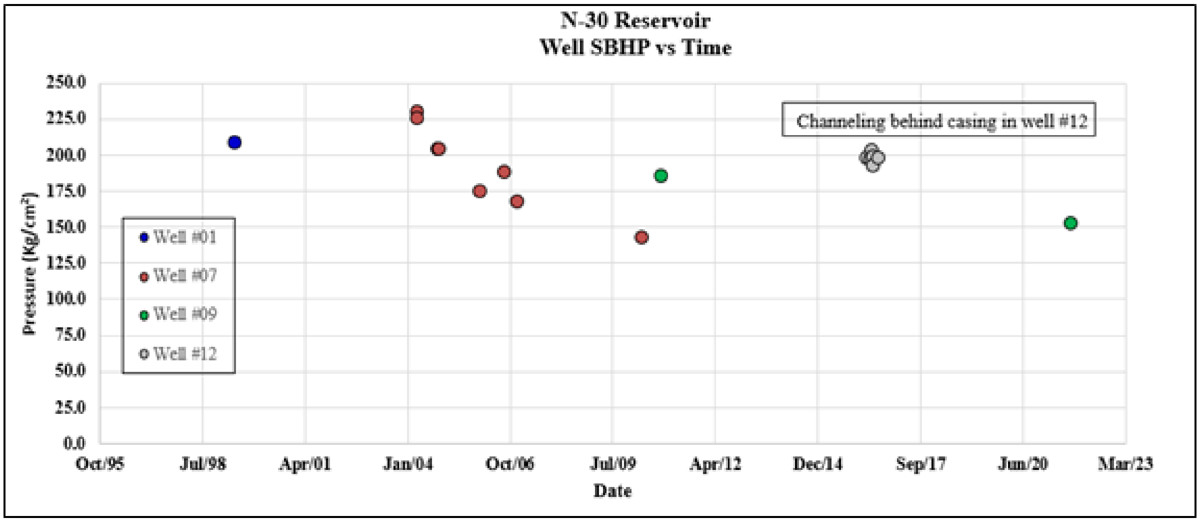


Figure 20. Pressure trend in N-30 reservoir.

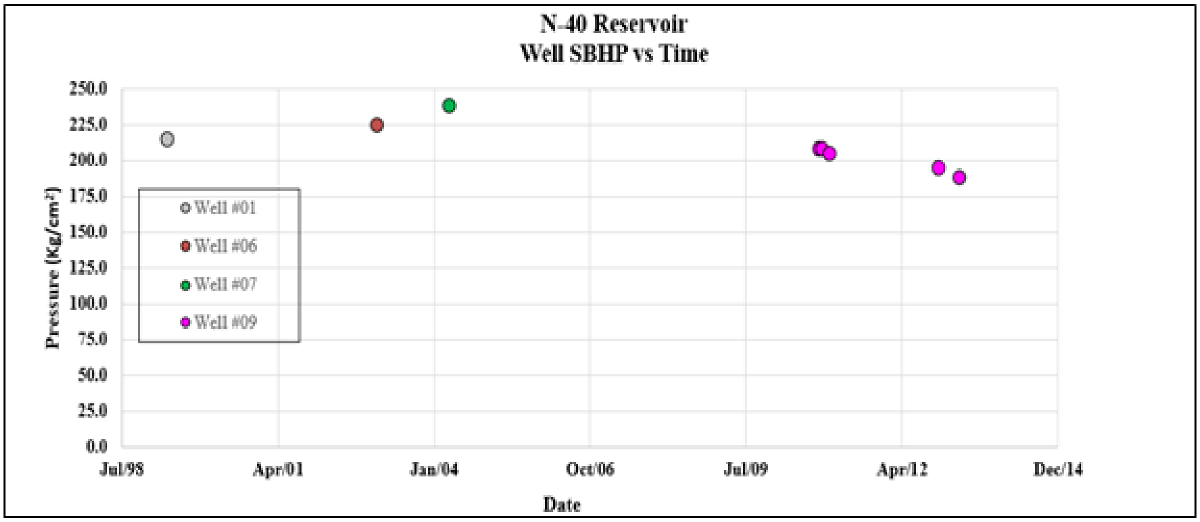


Figure 21. Pressure trend in N-40 reservoir.

came into production one and a half years later than N-20 in November 2000, but its pressure had already declined by 10 kg/cm^2. The lesser reservoirs (Above N-10 and N-10 reservoirs) which have the same initial Oil Water Contact (OWC) of 1962m Mean Sea Level (MSL) as that of the largest underlying N-20 reservoir are in pressure communications. They have limited aquifer support and have experienced large pressure depletion as compared to underlying N-30 and N-40 reservoirs (Figures 20 and 21). Their current reservoir pressures are in the range of 100-105 kg/cm^2 which is significantly below their Pb in the range of 139-150 kg/cm^2. N-30 reservoir with an initial OWC of 1970m (MSL) has current reservoir pressure of about 150 kg/cm^2 against its Pb of 160 kg/cm^2 whereas the N-40 reservoir with an initial OWC of 2007m (MSL) has current reservoir pressure of about 180 kg/cm^2 which is above Pb of 167 kg/cm^2. As deliberated later, the excessive rate of pressure depletion in N-10

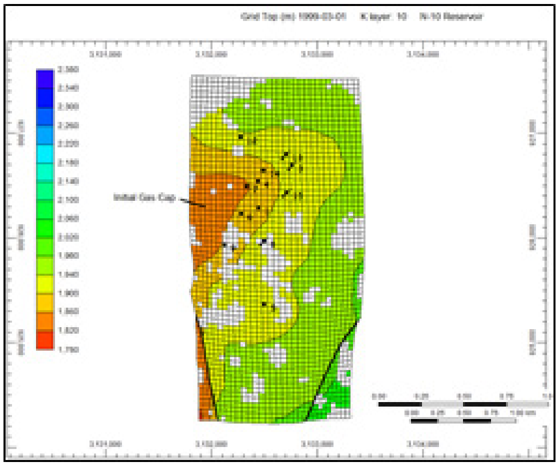


Figure S-12. Extent of initial gas cap in N-10.

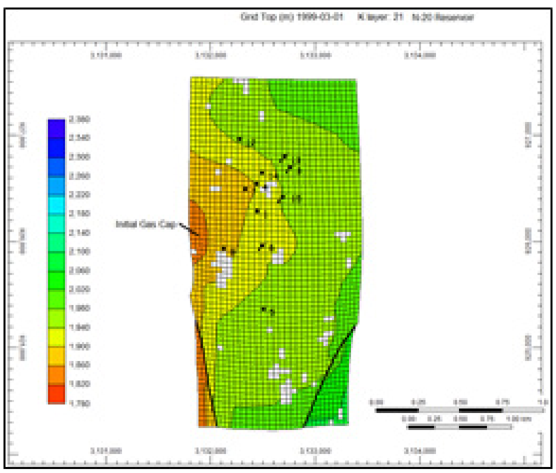


Figure S-13. Extent of initial gas cap in N-20.

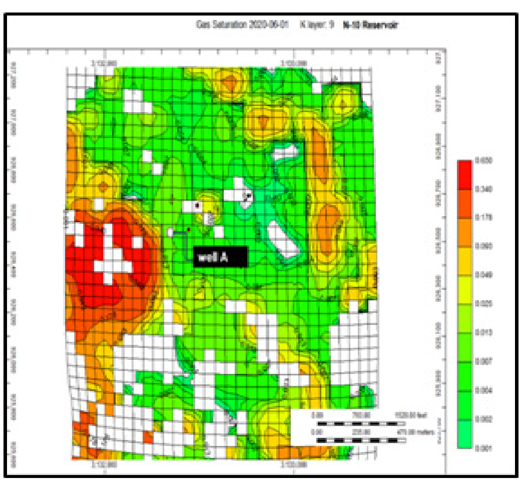


Figure S-14. Development of gas saturation around well A.

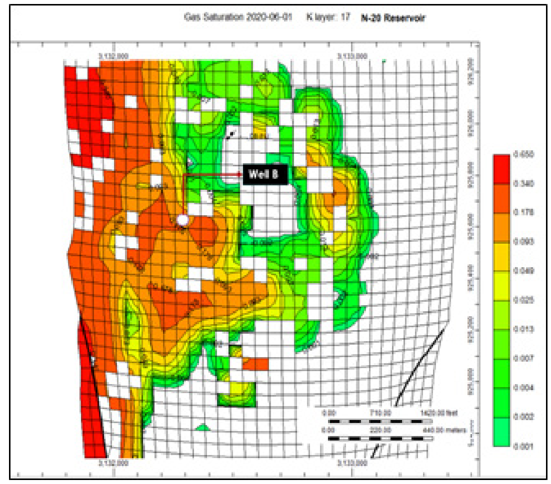


Figure S-15. Development of gas saturation around well B.

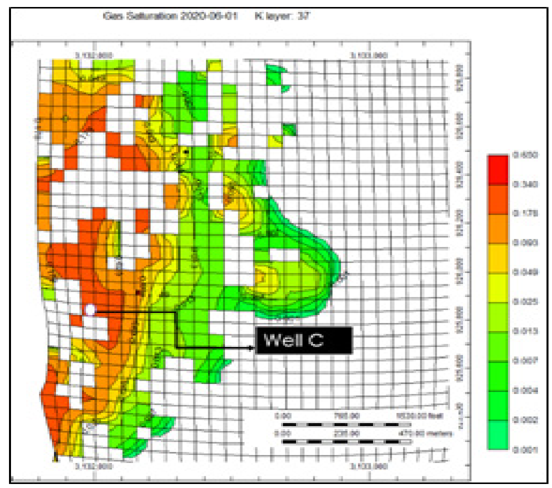


Figure S-16. Development of gas saturation around well C.

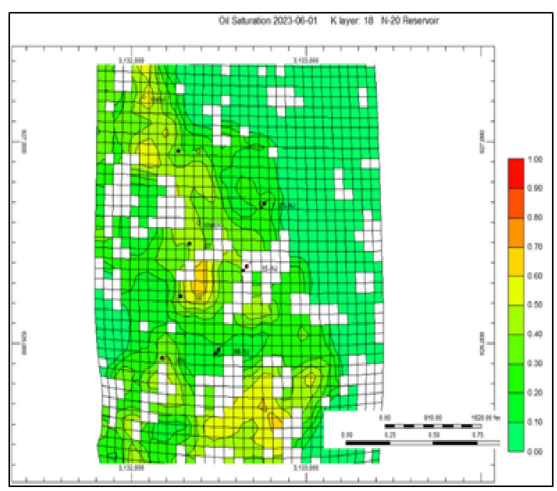


Figure S-17. Remaining oil saturation in 2023 (N-20 Reservoir).

and N-20 reservoirs triggered gas cap expansion and gas cusping in wells located structurally higher in the vicinity of the gas cap which led to the development of high GOR in the wells and the field in the early part of the history.

7.0 Incorporating a Hidden Gas Cap in the Simulation Model

Figure 10 shows Hydrocarbon Initially in Place (HIIP) for all producing reservoirs of brownfield. Three scenarios, namely FDP, I and II shown in the first column represent the FDP-2020 scenario and the two modified cases. Scenario I of the present study is a revision of the FDP-2020 simulation model without considering the initial gas cap after fixing some of the parameters more scientifically and rationally. However, in scenario II which considers the initial gas cap with Gas Oil Contract (GOC) at 1860 m MSL (based on sensitivity runs), a constant Pb of 190 kg/cm^2 has been considered for all the reservoirs based on review of all PVT studies. As is evident from Figure 10, introducing a common gas cap with GOC at 1860 m MSL results in the creation of a small gas cap with Free Gas Initially in Place (FGIIP) of 16 and 18 Million Standard Cubic Meter (MMSCM) for N-10 and N-20 reservoirs.

Figure 11 shows a comparison of produced fluid in the simulation model and actual production in the field. Unlike Figure 10, there are two rows for scenario II in Figure 11 to highlight how the matching of the pressure of remotely located well #5 which is completed in the N-10 reservoir adversely affects the pressure match in wells of the northern cluster. The possibility of limited or no communication between well # 5 and the northern main producing areas does exist. Given this uncertainty, the upper row of scenario II has been used for generating the Liner Top Packer (LTP) profile and the strategic placement of 3 proposed infill wells to reduce the risk of gas cusping and high GOR in the wells located in the vicinity of expanding gas cap.

As is evident from Figure 11, scenario I without an initial gas cap results in lower field pressure of 155 kg/cm^2 and somewhat captures the current low pressure in the reservoirs, but it adversely affects the pressure trend in the middle and the early period of production history. The most noticeable observation is that scenario I still suffer from GOR mismatch, and the cumulative gas production from the model is only 50% of the reported value in the field. The low field pressure results in the formation of a secondary small gas cap of 22 MMSCM albeit late in history, and the GOR match illudes the most notable producers # 1 and # 4.

The high GOR in producers # 1 and # 4 evolved as early as 2005 and could be captured only under Scenario II which also led to significant improvement in match of cumulative gas production in the model. Model gas production under scenario IIA exceeds the reported cumulative gas production from the field. A strong possibility of under-reported gas production does exist in the field as the produced gas has traditionally flared due to a lack of pipelines for transportation. Also, during the recent campaign measured well GOR was found to be higher than reported. On the other hand, scenario IIB with forced matching of pressure of well # 5 located remotely in the south by strengthening aquifer support from the south resulted in a closer match of reported cumulative produced gas in the field, but it also resulted in higher current pressure of 171 kg/cm^2 in the simulation model and adversely affected the pressure match of the wells in the northern part of the field. The mismatch of pressure and GOR trend in the remotely located well # 5 in the southern part may be attributed either to its complete separation from the northern part by a permeability barrier or limited connectivity due to the presence of possible low transmissibility region separating them. Remotely located Well # 5 is closed for production pending permission from the local authority due to legal issues and therefore has limited surveillance data. Supplementary Figures S-8 to S-10 show the history match plots for key wells # 01, # 04 and the field. Figure 12 shows the quality index of matched parameters for all the producing wells in the field. It is evident from Figure 12 that introducing an initial gas cap has significantly improved the GOR match of the wells without disturbing the pressure match under Scenario IIA. The WC match is also reasonably preserved except for well # 12 where high WC in the well is attributed to extraneous sources confirmed by water salinity data.

8.0 Gas Cap Expansion and its Impact on Proposed Infill Locations

The small gas cap in N-10 and N-20 reservoirs (Supplementary Figures S-12 and S-13) expanded with time due to pressure depletion to about 85 MMSCM by the year 2014 (Figure 13) which reduced to 71 MMSCM by mid-2020 under scenario IIA. The proposed infill locations A, B and C are shown in Gas saturation maps in supplementary Figures S-14 to S-16. Infill wells B and C fall within the expanded gas cap area and their performance in the modified scenario IIA is adversely affected. Well C, which is proposed for deeper N-30 and N-40 reservoirs also produces high GOR as a secondary gas cap has started developing even in the N-30 reservoir.

Alternate locations E, H and J (Figures 14 and 15) in the northwest area up-dip of well # 12 turn out to be better performers as they yield significant oil production (Figure 16) with reasonably lower GOR than the proposed infill wells A, B and C. Supplementary Figure S-16 and S-17 show remaining oil saturations around infill wells E, H and J in 2023.

9.0 Sensitivity Runs with Variable HIIP and Varying Bubble Point Pressures

Sensitivity runs with variations of uncertain parameters including P10, P50 and P90 estimates of HIIP (hydrocarbon initially in place) could not result in the evolution of observed GOR in the field despite considering a range of Ratio of Vertical and Horizontal Permeability (Kv/Kh) uncertainty from 0.1 to 0.01. Even variable Pb with depth could not match the evolution of GOR for the field and wells # 1 and # 4.

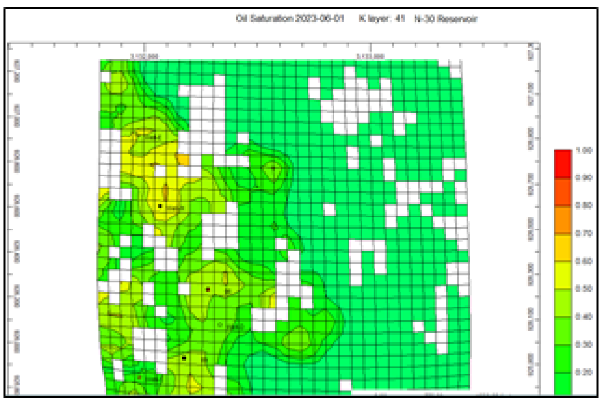


Figure S-18. Remaining Oil Saturation in 2023 N-30 Reservoir).

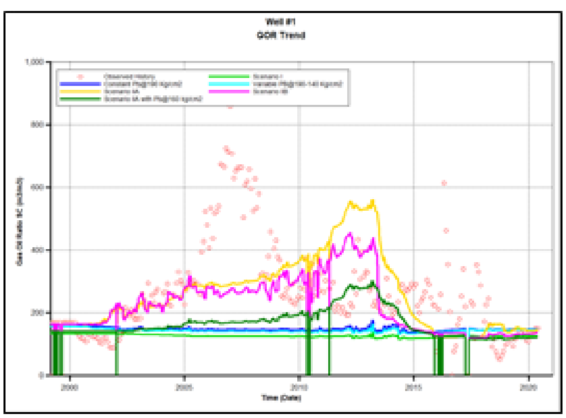


Figure S-19. Impact of hidden Gas Cap on GOR trend of well #1.

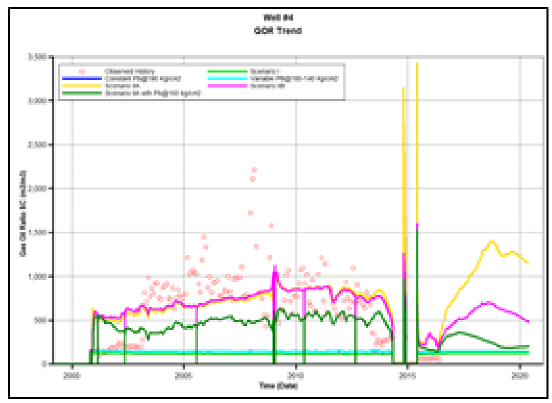


Figure S-20. Impact of hidden gas cap on GOR trend of well #4.

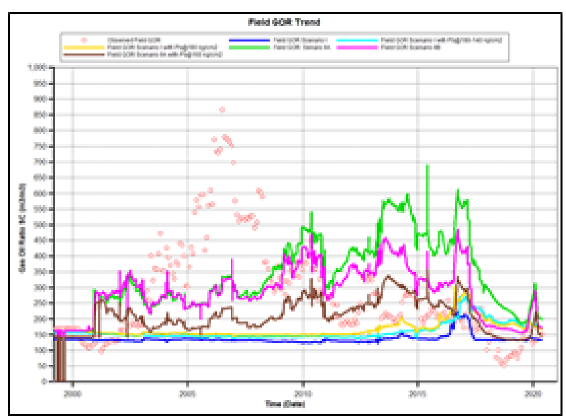


Figure S-21. Impact of hidden gas cap on Field GOR trend

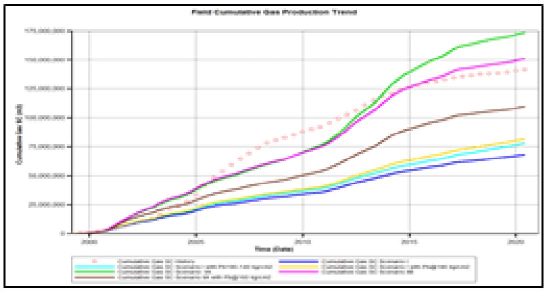


Figure S-22. Impact of hidden gas cap on cum gas Production.

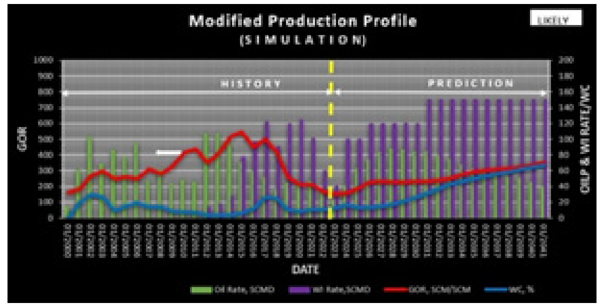


Figure S-24. LTP profile (Likely Case).

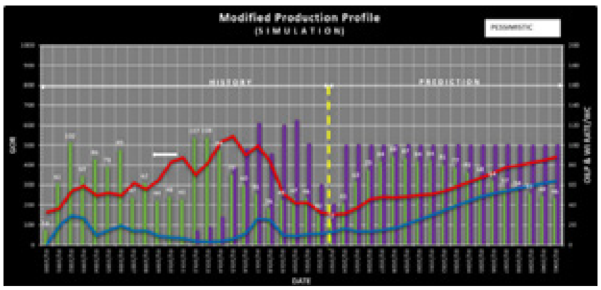


Figure S-23. LTP profile (Pessimistic Case).

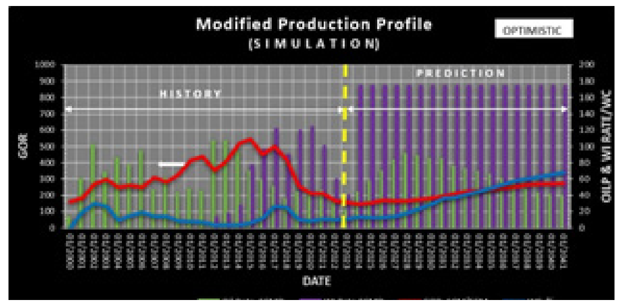


Figure S-25. LTP profile (Optimistic Case).

As is evident from supplementary Fig. S-19 to S-22, the scenario with a constant Pb of 190 kg/cm^2 could only capture the GOR evolution in wells and the field most satisfactorily. The top-down approach has helped in unravelling subsurface uncertainty that gets otherwise obscured if one ignores the surface signatures that are so obvious and conspicuous in the form of the evolution of the GOR trend in the field. This uncertainty study has honoured this trend and used it as a guiding tool to reveal uncertainty in the subsurface geological feature that impacts it the most. Out of all the uncertain parameters, the presence of a small initial gas cap was found to be the most effective in matching the GOR evolution in the field.

10.0 Limitations of the Methodology

The sensitivity runs made above may not have encompassed all the possible combinations of subsurface uncertainties and therefore may not construe to be the unique combination that would probably match the GOR trend in the field. However, the gas trapping that occurred during the first subsurface PVT sampling points towards a strong possibility of a gas cap present in the close vicinity.

11.0 Long-Term Production (LTP) Profile under Pessimistic, Likely and Optimistic Cases

The management is confident of jacking up injection rates significantly with the suggested remedial measures[13]. However, keeping in view the less-than-optimal field water injection rate in the past, three cases with a water injection rate from 100 to 175 Standard Cubic Meter (SCM) have been considered to generate an LTP profile (supplementary Figures S-23 to S-25).

The company aims to achieve a high injection rate of 175 SCM envisaged under the optimistic case as it jacks up pressure substantially resulting in reduced free gas in the reservoir and reduced cumulative gas production from the field (supplementary Figure S-26 to S-28).

Supplementary Figure S-29 shows a comparison of committed production gain vs field oil rate envisaged under the likely case. The envisaged incremental cumulative oil production catches up with the committed

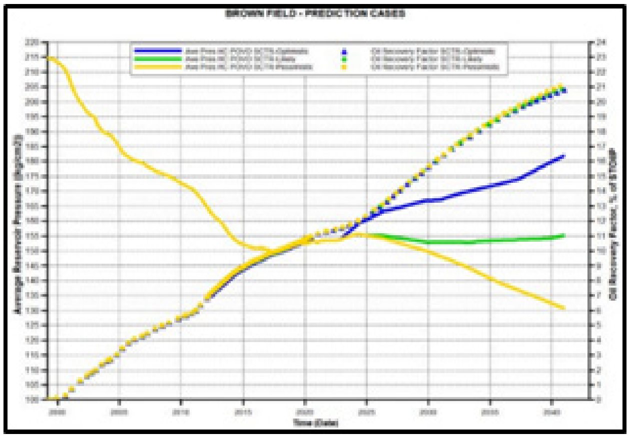


Figure S-26. pressure profile and recovery factor (3-cases).

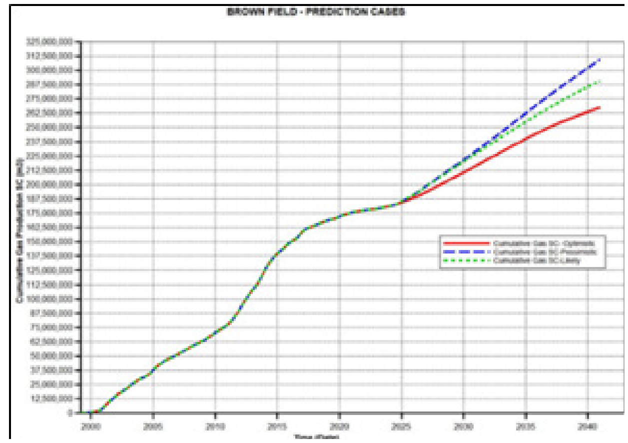


Figure S-28. Cumulative Gas Production under 3 cases.

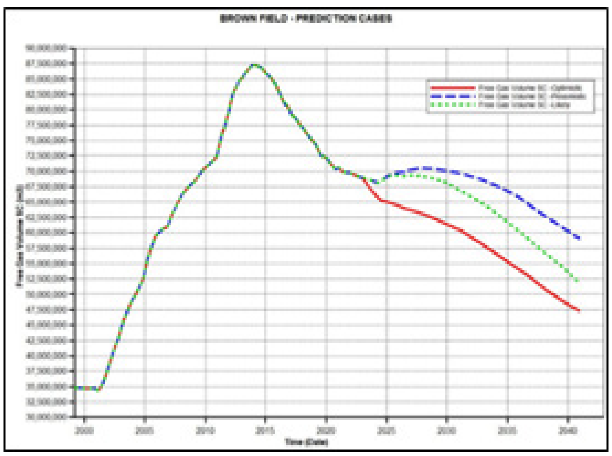


Figure S-27. Free Gas Volume with time (3 cases).

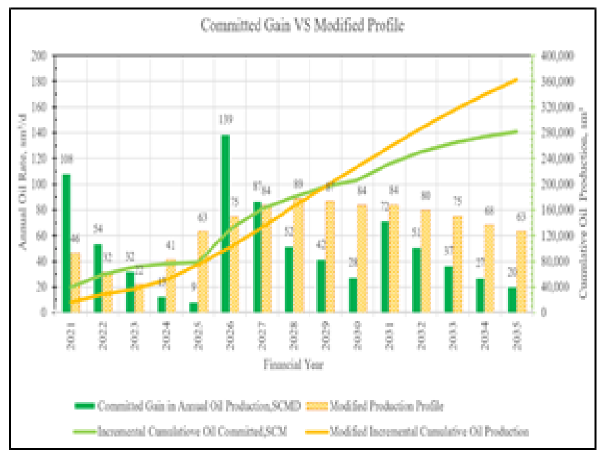


Figure S-29. LTP profile (Likely Case vs Committed Gain).

incremental cumulative oil production in the year 2028 and thereafter it substantially overtakes it with an additional oil production gain of more than 80,000 SCM by the end of the year 2035 over the committed value. Figure 17 highlights three alternate infill locations (shown inside the coloured rectangle) as they have high cumulative oil production and reduced GOR trend. Each of them will produce over 0.1 MMSCM by 2040.

12.0 Conclusions and Recommendations

A top-down approach has been used in unravelling a subsurface uncertainty using the evolution of GOR in the field with time which was not captured in the old simulation model. Though the case with hidden gas cap gas may not be the unique solution that can meaningfully capture the trend of GOR evolution, the very fact that during initial subsurface sampling of reservoir fluid of N-20 reservoir for PVT analysis in a well in the close vicinity of assumed GOC, the free gas was trapped in the sampler does indicate the presence of a gas cap. No other combinations of uncertain parameters like variable bubble point with depth and petrophysical parameters corresponding to P10, P50 and P90 cases of Oil Initially In Place (OIIP) estimates and endpoint relative permeability values could capture the early rising trend of GOR. Also evident from Figures A and B is the sharp decline in pressures in N-20 and upper reservoirs which are in communication that resulted in downward expansion of initial gas cap gas leading to gas cusping the producers close to it. Reservoir pressure decreased rapidly primarily because of high production rates (both oil and gas as cusping gas cap resulted in high gas production) in the wells close to GOC. The aquifer support was too weak to cope with the high withdrawal rate and as a result, a fast decline in pressure occurred. The field GOR came down subsequently because of low pressure prevailing in the reservoir during the later part of the history.

- Performance history of wells # 1 and # 4 and that of the field indicates the conspicuous presence of a small initial gas cap in N-10 and N-20 reservoirs through which none of the drilled wells has traversed.
- Significant improvement in GOR match in the modified simulation model also captures the prevailing lower pressure in the producing wells that have been measured recently post-handover of the asset to the company by the NOC.
- The southern area around well # 5 needs a review of the geological model to ascertain the likelihood of its complete isolation or partial communication with the main producing wells clustered in the north.
- The initial free gas volume of 34 MMSCM expanded to as high as 87 MMSCM BY 2014 and thereafter 71 MMSCM by the end of history.
- Out of three development locations A, B and C recommended for drilling in FDP-2020, the first two locations A and B yield too low oil production to be economically attractive. Well A which produces the maximum is also close to the gas cap tongue and produces high gas in the modified simulation model.
- There is a strong possibility that reported cumulative gas production is underestimated as the produced gas traditionally flared in the field.
- Alternate locations E and J are somewhat better placed in structurally lower areas in the north where apart from N-20, the deeper reservoirs N-30 and N-40 have relatively undrained with higher pressure. Location H is suitable for the exploitation of N-30 and N-40 reservoirs exclusively as it ensures the exploitation of relatively undrained deeper reservoirs in the area. They produced significantly lower GOR than previously proposed wells A, B and C.
- The revised simulation model considers jacking up of water injection rate by revamping the water injection plant and removal of skin in the injectors through acid stimulation. Addition perforations in wells # 8 and # 15 in the N-20 reservoir and conversion of well # 8 as a dump flooder for which approval from the NOC has already been obtained have been recommended.
- As the locations E, H and J are clustered in the northwest area, only one high-angle well has been sequentially recommended for drilling and completion starting from the deepest reservoir to be put on exploitation first. The upper reservoirs will be put into production later after their pressure is jacked up substantially.
- The likely case scenario envisages almost doubling of recovery factor from less than 12% as of today.
- 7" completion is recommended for the high angle well as it offers ease of sidetracking it in the future to the up-dip area to bleed and exploit gas cap gas as the gas monetisation process has been taken on priority by the Government of India with the establishment of National Gas Grid.

13.0 Acknowledgements

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