Improving The Future Performance Using Simulation Method By Eclipse Software Program, The Habban Field (Block S2) Case Study.

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Abstract:

The solution gas drive system characterizes the decreasing reservoir pressure and increasing gas oil ratio, which requires searching for an appropriate development method to support reservoir pressure for the largest possible period. This study was performed on Kohlane sandstone and fractured Basement formations, which are the main producing formations in Habban field (bluckS2). The main objective of this research was to study the future reservoir performance with and without the optimization process by gas injection for a certain period 2008-2025 using the Eclipse program. In this research the simulation model has been built, by using petroleum programs, based on the data of petrophysical, seismic, PVT and etc..,. It was reached that at least 30 wells must be added which gives a cumulative oil production of 51.6MMstb, with a recovery factor of 10 %. Moreover, when restrictions on field oil production rate, with oil rate restriction of 10000 stb, the cumulative oil production in 2025 will be 48MMstb. Also when restriction on gas oil ratio GOR, it was reached that with GOR was 3000 scf/stb. and 5000 scf/stb, the cumulative oil production in 2025 will be increased from 46MMstb. to 53 MMstb. The effect of gas injection on the future reservoir performance was determined, and it was reached that gas injection leads to increase cumulative oil production in 2025 to 68 MMstb, when GOR was 5000 scf/stb with a recovery factor of 13 %, and when decreasing GOR to 3000 scf/stb the cumulative oil production will be 64 MMstb.

Keywords: Improving**.** Performance. Habban field**.** Eclipse program. Gas injection.

Introduction.

The different depletion drive system characterized low productivity with a decrease in the formation pressure. The Habban field (block S2) one of those fields that operate by solution gas drive system. In those systems, when the formation pressure was being lower than the saturation pressure, the gas begins to be released from the crude oil, which leads to the oil payment towards production wells. This additional natural energy resulting from the release of gas was limited, so it was necessary to find a technological facility in order to improve the performance of that field. Improving the productivity of these fields requires an intensive study of the properties of the oil reservoir and the properties of it was saturated fluid in order to determine the appropriate method to improve it was productivity. In this research presented a study of developing and improving the performance of Habban field sector S2 and predicting the effect of this improvement for an advanced period. The Habban field (block S2) which located in Al-sabatayn basin characterized by low permeability, high solution gas, absent water aquifer [1]. Habban field's previous characteristics made the method of increasing its performance efficiency through gas injection the best method. Achieving the objectives of this research required the use of a simulation method by used many special oil programs. Reservoir simulation was defined as the combination of principles of physics, mathematics, reservoir engineering, and computer programming in order to develop a tool for predicting hydrocarbon-reservoir performance under various operating conditions. Predicting the performance of the Habban field used the simulation method needed many different reservoir data that were processed by different oil programs. The performance data may include pressure data, production and injection data, well completion data, production and injection profile data...etc. The future performance of the reservoir was predicted with the history-matched models or with the initialized model in the case that the reservoir has no historical production. For a history-matched model, it was usually necessary to adjusting dividable well productivity index so that a smooth transition was achieved from the History-matching phase to the prediction phase [2]. The data needed to simulate a change the performance of the Habban field that was not available, such as petrophysical, reservoir static modeling and reservoir fluid properties data, were estimated by special oil programs, such as IP, petrel and PVT software programs. The estimated data used to achieved the goals of this research after it processed by Eclipse program [3]. The main importance of our research was in the used of petroleum software programs for estimating the realistic reservoir data (reservoir rocks and fluid data), and used these data to determine the future reservoir performance for a certain period by the reservoir simulation method.

Research Objectives.

1-Estimate and prepare the required reservoir data (rocks and fluid data) for Habana field that will be used for determining the reservoir performance.

2-perform a reservoir simulation and determine the History-matching between the simulation results and the observed field data.

3-Study the changes in future reservoir performance for the period from 2008 to 2025.

4-Determine the impact of the optimization process using gas injection on the future reservoir performance for the period from 2008 to 2025.

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2. Materials and Methodology.

Materials and methodology that include achieving our research objectives were the following programs (IP, PVT, PETREL, ECLIPSE). The IP program was used to study the petrophysical properties of the reservoir rocks, the PVT program was used to study the behavior of the reservoir fluid, the PETREL program was used to build the reservoir three diminution (3D) grig static model, The ECLIPSE program was used to building the reservoir simulation model to perform the history match study and to predict the reservoir performance with and without gas injection as a development scenario to optimize the production from Habban field.

2.1.Materials.

To conduct this study which was mainly concerning reservoir performance analysis of Habban field (block S2) and possibility of it was development a set of different data will be collected and used. The main data sets include Geological, Geophysical, drilling, Well logging, and Petrophysical data, as well as PVT, Well test and Production. These data were obtained from available data at OMV E&P operations Company Authority of Habban field. This study included four onshore wells (Kharwah-1, Habban-1a, Habban-2a and Habban-4) where were each well had a collection of data to be entered into the prospective study to improve the performance of the Habban field, from that data, the surface position and depth of wells, (Table1). There were two PVT analysis reports were available for Habban field. The first fluid simple was for Kohlan formation well Kha-1, the second simple was for Basement formation well Hab-1 (Table2). The saturation pressure and temperature data for Habban field showed in Table3. The separator laboratory data included separator pressure, temperature and oil density and oil formation volume at separator conditions, (Table 4) [4].

Table 1. Surface position and depth of wells in Habban field,

WELL NAME	X (m)	Y (m)	KB (m)	TD (md)
KHARWAH-1	697899.8	1695833.80	843.68	2752.34
HABBAN-1a	693382.00	1696498.00	815.67	3020.00
HABBAN-2a	695723.74	1696832.13	814.60	3204.00
HABBAN-4	694819.99	1695981.14	817.72	3285.00

Table 2.Chimecal composition of reservoir fluids in Habban field.

COMP.	Kohlan %	Basement %
H_2S	0	0
N_2	0.68	0.566
CO_2	1.37	0
C_1	45.9	43.067
C_2	8.47	8.331
C_3	6.58	6.539
Is-C_4	1.04	1.094
N-C_4	3.11	3.403
Is-C_5	1.03	1.22
N-C_5	1.47	1.824
C_6	2.17	2.314
C7+	28.18	32.62
M.W C_7+	187	193
S.G C_7+	0.8321	0.8231

Table 3. Saturation pressure and temperature of reservoir fluid.

Sample	Temperature (F)	Psat (psia)
Basement	200	3600
Kohlan	221	3365

Table 4. Separator laboratory fluid properties in Habban field.

	Pressure Psia	Temperature F	GOR Scf / stb	FVF bbl / stb	Oil density gm / cc
Separator	195	94	1137	-	0.781
Tank	14.7	60	125	1.72	0.815

2.2.Methodology.

Simulating the development of the Habban field block S2 required the use of many special oil programs. The simulation process methodology divided into two stages. The first stage is the preparation stage for the simulation process, where a petrophysical study of the field was carried out using the IP software program, and then the static model of the field was built by the Petrel program, after which the reservoir fluid characterization were studied. The second stage of the simulation process was to build a dynamic model of the Habban field block S2 by Eclipse software program that used in the study of the development of the Habban field block S2.

3. Results and Discussion.

3.1. Reservoir Petrophysical Properties Study Results.

The petrophysical study of Habban field was requested in this research to estimate the most important petrophysical properties which are porosity, permeability, lithology and water saturation. This study include 4 on shore wells which have been drilled into the basement rocks of Habban field block S2 (Khawrah,Habban-1a,Habban-2a,Habban-4). In those studies focus in the interpretation of lithology and properties of Shuqrah, Kohlan and Basement formations.

Shuqra formation.

Shuqra formation can be characterized as several meters thick typically rarely argillaceous Limestone with very law primary porosity. So consider Shuqrah formation the top seal of the reservoir.

Kohlan formation.

In contrasted in Habban-2a the Kohlan formation in Habban-4 was relatively tight and shelly and does not contain field spathic sands with a good property as seen in Habban-2a. The section compress alternation of shale beds and argillaceous clastic layers showing grain densities higher than 2.7g/cc, most lively cased by heavy mineral assemblage. Average porosities are below 5% and represent bound water porosity only because of the high shale content. Nevertheless at the base of Kohlan formation (at 2098m MD) just on the top of Basement at 1m thick porous layer (PHIA = 15%) can be identified. This layer is hydrocarbons bearing (Sw= 24%) [1].

Basement formation.

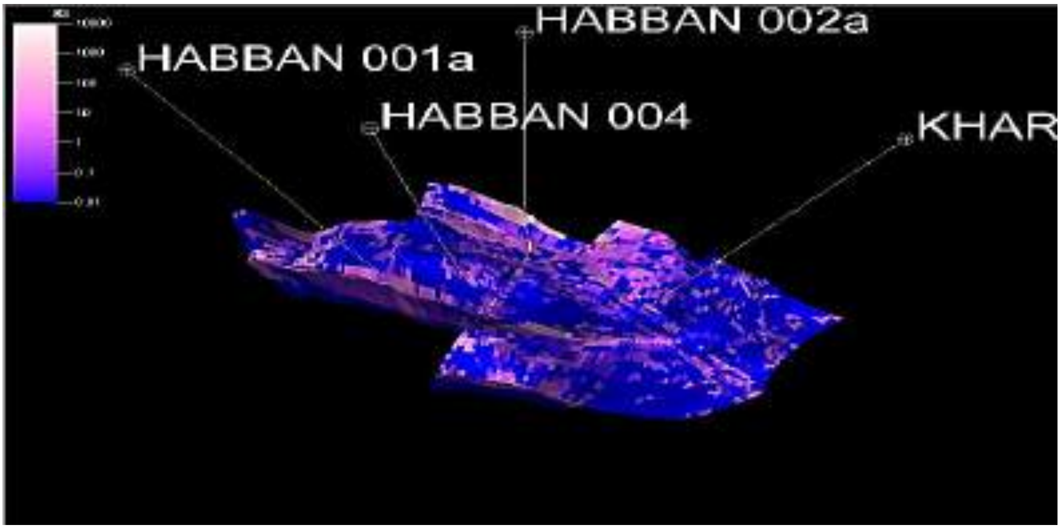
The Habban basement is set up as a metamorphic series, which was intruded by a granitic pluton containing:

- Felsites (mainly acidic meta with gneiss and shist texture).
- Basic metavolcanics and dykes (lamprophyres, amphibolites, cemented cataclasites)
- Strongly hydrothermally altered mafic and felsic rocks (chloritised gneiss)
- Granite (low potassium)
- Granite (high potassium)

The Habban field reservoir rock divided to two types of formations which are the lowest layer of Kohlan sandstone formation and the basement formation, the sand layer has good reservoir properties which overlaying the Basement which has poor reservoir properties, but it has good storage capacity. The Basement is a fractured metamorphic rock, which two types of fracturing, background fractures characterize the fractured basement reservoir with very low effective permeability of less than 0.001mD and fracture corridors with an effective permeability ranging from 0.01 up to 10mD, with a total porosity of 1.17% only. According to the results of this study, decide to select the gas injection as a development strategy to optimize the oil production from Habban field.

3.2. Reservoir Static Modeling Results.

This study was requested to build a reservoir static model 3D grid by petrel software programs that will be needed in the building of the reservoir simulation model. This study focus on selecting the region of the best sequence of Kohlan-Basement formations in which the largest distance and thickness of Kohlan formation, so selected the southern part of the Habban field to perform the simulation and development study, because the southern part was characterized by high oil saturation and high reservoir thickness, therefore the development scenario will be feasible [5]. The resulting 3D reservoir static model represents the geometry of the southern part of Habban field and the distribution of the Petrophysical properties within the southern sector, where each cell in the grid contain constant value of porosity, permeability, water saturation, etc. Figure1, showed the distribution of the fractured permeability within the southern sector.



The previous figure showed the distribution of the fractured permeability in the X-direction within the southern sector, as was seen the permeability distribution around Habban -2a, and Habban-1a represent a good quality productive zones, while around Khawrah-1 the resulted grid showed a poor quality productive zone, also good permeability distribution in the north of the reservoir because of the present of the high quality Kohlan formation as around the well Habban-2a.Generally, in the resulted 3D grid static model as shown in figure above could be read the Petrophysical properties for each cell with it was type (continuous or discontinuous), the depth and the coordinates at which the cell was located.

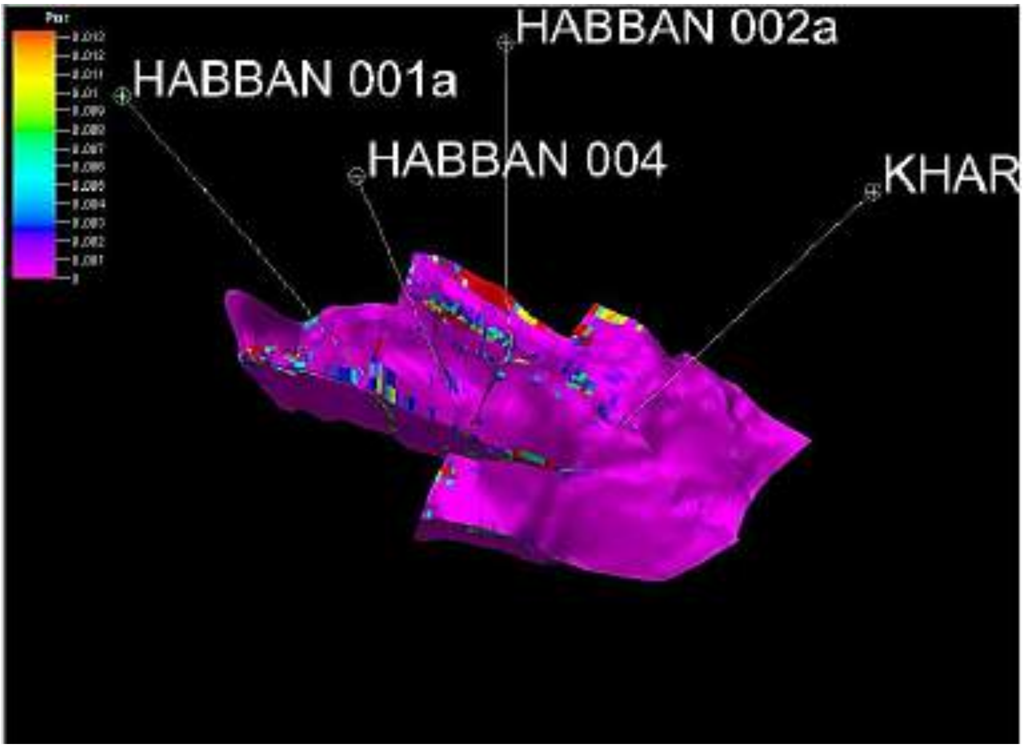


Figure 2.The distribution of the fractured porosity within the southern sector of Habban field.

The figure 2, showed the fractured porosity distribution show a good values around the wells (Habban-1a, Habban-2a) which mean a high storage capacity of oil bearing zones around these wells, while the model show a relatively low fractured porosity around Habban-4, as seen a poor porosity distribution around the well Khawra-1 and in the rest of southern part of Habban field because of the characterization and the complex structure of the fractured basement.

3.3-Reservoir Fluid Characterization Study Results.

A reservoir fluid characterization study of Habban field was performed to determine the fluid phases that present in the reservoir and to calculate the physical properties of the reservoir fluid such as (oil formation volume factor FVF, oil density, oil viscosity, gas-Z-factor, gas oil ratio GOR) that needed in the reservoir simulation study. Two equation of state models has was developed, one performed on the fluid sample that was obtained from Kohlan formation (well Khawrah-1) and the other was performed on the fluid sample that was obtained from Basement formation (well Habban-1a). For the two fluid samples was discussed the behavior of some of the most important fluid properties as which result from this study.

Figure 3, showed oil FVF versus pressure for the two fluid samples, the black color line for Kohlan formation fluid sample, and the red color line for Basement formation fluid sample.

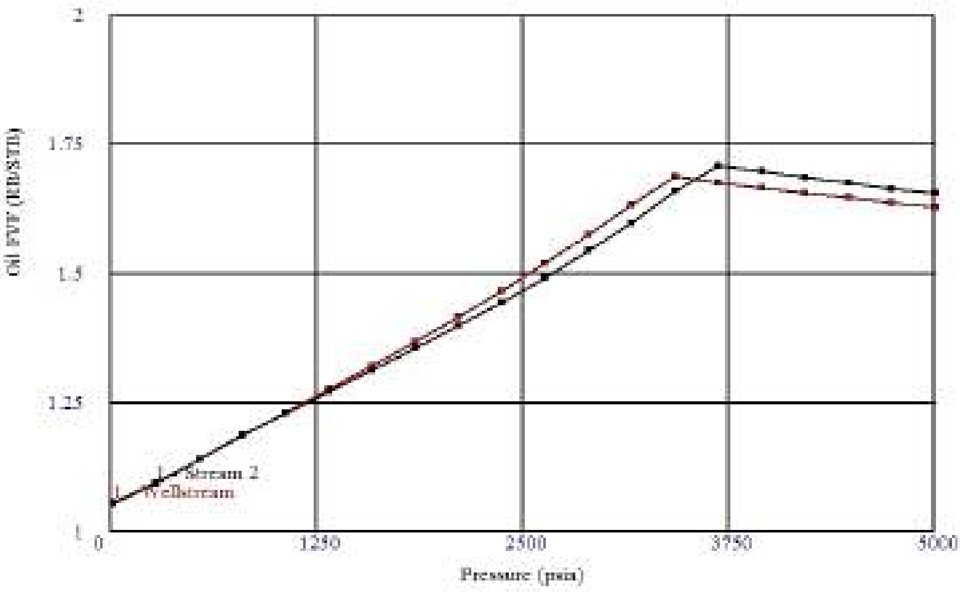


Figure 3**.** The relationship between pressure and oil formation volume factor.

The previous figure 3, showed that, as the reservoir pressure drop from the initial pressure, the reservoir fluid volume increase slightly, due to the expansion of fluid volume until the bubble point pressure (saturation pressure) had been reached which for Kohlan fluid sample was (3600psia) and for Basement fluid sample was (3365psia). Then below the bubble point pressure the reservoir fluid volume decreases with pressure drop, because of the dissolved gas liberation from the oil. Figure 4, showed the gas oil ratio (GOR) versus pressure, for Kohlan fluid sample (black color line) and for Basement fluid sample (red color line).

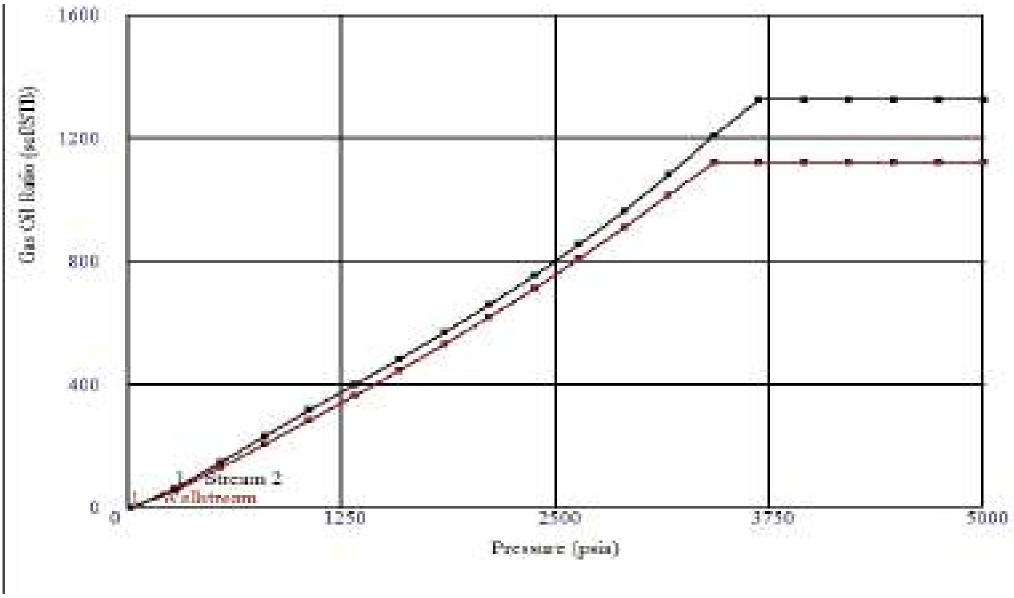


Figure 4. Relationship between pressure and gas oil ratio.

From figure 4, was seen, the gas oil ratio still constant when the pressure drop from the initial reservoir pressure to the bubble point pressure because at these interval the gas still dissolved in the oil, then below the saturation pressure the gas began to liberates from the oil when the reservoir pressure drops, this results in the decreasing of the gas oil ratio. As was seen in the previous figure the value for GOR for Kohlan fluid sample was (1262 scf/stb) and for Basement fluid sample was (1112 scf/stb). This results indicated that the reservoir fluid was live oil (contain high value of dissolved gas).

3.4. The history matching results.

History matching was done between the field data and the data that were extracted and prepared by the previous programs and prepared in the form of simulated files capable of creating a simulated model in the Eclipse program. The objective of the matching was to verify the validity and accuracy of the data that was extracted, prepared and processed to create a simulation model of the reservoir layers. A matching was made for many parameters such as downhole pressure, gas oil ratio and oil production rate. Figure 5, showed the results of the matching between the productivity data of the reservoir simulation process calculated by the program (the red dashed line) and the historical field productivity data (the green line). Noticed that the match was excellent between the mentioned data, which confirmed the accuracy of the simulation model, and therefore decided to adopt it to implement a correct future study of the reservoir performance.

Figure3.15. Field oil production rate History-Matching.

Figure 5. Matching the productivity data (the dashed red) versus the field productivity data (The green line).

3.5. Developing the Future Performance of the Habban field.

The history matched sector model has the following volumes of field in place [1].

Table 5. Initial oil and free gas in place.

Oil initially in place in southern sector (stb)			
	background fractures/matrix	fracture corridors	total
Kohlan	9.70E+07	1.04E+07	1.07E+08
Weathered zone	1.41E+07	1.07E+07	2.49E+07
Basement	2.25E+08	1.53E+08	3.78E+08
Total	3.37E+08	1.74E+08	5.11E+08

Free gas initially in place in southern sector (Mscf)			
	background fractures/matrix	fracture corridors	total
Kohlan	4.91E+05	1.52E+05	6.44E+05
Weathered zone	1.85E+05	5.12E+04	2.37E+05
Basement	1.26E+04	2.96E+03	1.56E+04
Total	6.89E+05	2.07E+05	8.96E+05

To investigate future developments of the Habban field, both depletion and gas injection had been investigated into detail used the history-matched simulation model of the southern sector by Eclipse program. For the depletion cases, it was assumed that the produced gas could be sold or injected in another reservoir. The gas injection cases assume the reinjection of the produced gas.

1. The future reservoir performance under natural drive mechanism (depletion).

Initially, the reservoir pressure was higher than the bubble point pressure in the main part of the field. Only at the gas oil contact (GOC), the reservoir pressure was equal to the bubble point pressure. When depleting the reservoir, the reservoir pressure drops below the bubble point pressure, thus liberating gas from the oil. Usually depletion gives low a recovery factor, especially when the reservoir pressure was close to the bubble point pressure. This was due to the liberation of gas, which migrates upwards and breaks through in the production wells. In this particular case, due to the low permeability, gas segregates slowly in the reservoir. The slow segregation together with the relatively small viscosity contrast can result in a favorable situation for depletion. Due to the low permeability of the background fracture system, the gas and oil segregate very slowly. Therefore, in the low permeability grid blocks, the gas saturation builds up whereas the gas segregates in the fracture corridor cell. Because of this behavior, it was possible to produce with a relatively low GOR, even if a large part of the reservoir is below the initial bubble point pressure [6]. Since the Kohlan was assumed to have a higher permeability, segregation of oil and gas does take place there. Therefore, when depleting the reservoir, the gas accumulates there and the gas cap expands. It was no surprise in the simulation model; the wells that experience gas breakthrough latest were the wells that either were down-dip enough to avoid the gas cap or were situated in places, where no Kohlan or fractures were present in the top of the reservoir.

- Improving the reservoirs performance by adding production wells.

To investigate the optimal well spacing, several cases were run with different numbers of additional wells. The wells were deviated with an angle of 45° and have an open reservoir section of 707m length (if the well does not extend below 2200 MSS). The wells were oriented almost parallel to Habban 2. (Figure 6). Unconstrained cases were run to increase the understanding on the processes on a field scale. Initially, cases were run with 55, 45, 30 and 25 additional wells besides the four already producing wells. In all cases, the wells were evenly spread over the central part of the sector model. The wells were placed in the central part of the sector, because the outer parts were relatively thin and have a larger structural uncertainty. All additional wells were assumed to start producing on 1

January 2009 and are constrained by a BHP of 1200 psi with a maximum oil rate of 3000 stb/d. The wells were shut in when a GOR of 5000 scf/stb was reached. The simulations were run until 2025. No constraints on production rate were taken into consideration. Of course, this was an unrealistic case. However, with the aim of investigating the well spacing, it suits it was purpose. When looking at the cumulative oil production for the cases 55, 45, 30 and 25vadditional wells, it was clear that the difference in recovery between 55, 45 and 30 additional wells was small (figure 7). The recovery factor in 2025 for these cases was about 10%. In this case, without production constraints, the optimal number of wells was about 30, which corresponds to a well spacing of about 650 m x 650 m. The results of these cases was listed in table 6.

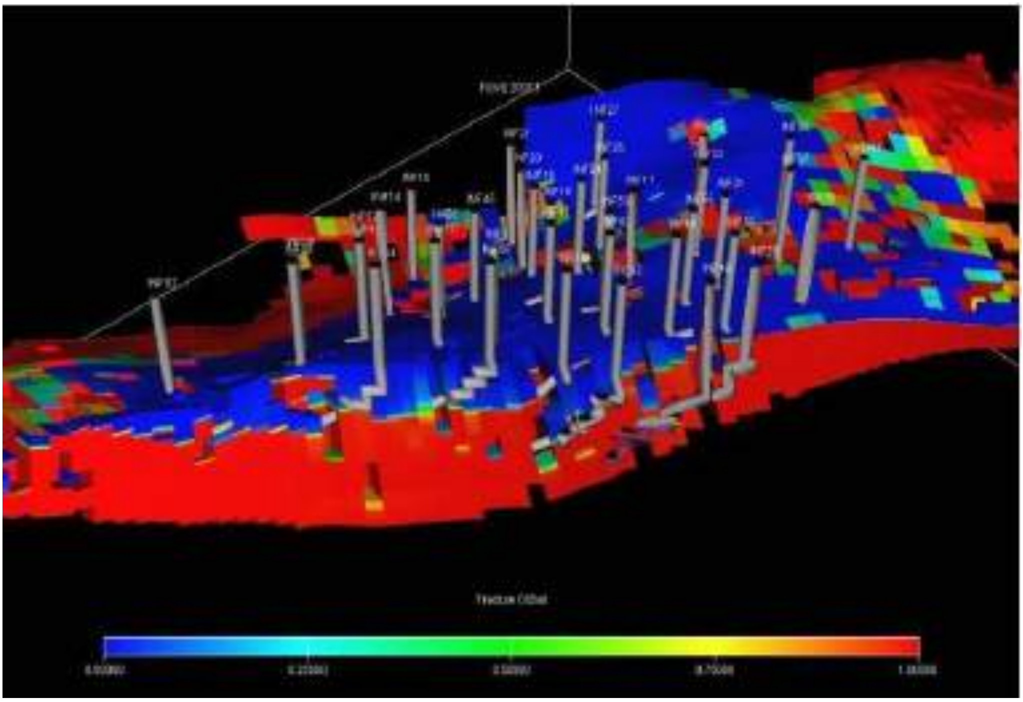


Figure 6. Distribution of suitable production wells.

Table 6. Effect of the number of additional well for recovery factor.

Case discretion	Cumulative oil production on 1/1/2025 (MMstb)	Recovery factor (%)
25 additional well	47.2	9.3
30 additional well	51.6	10.1
45 additional well	52.8	10.4
55 additional well	53.2	10.4

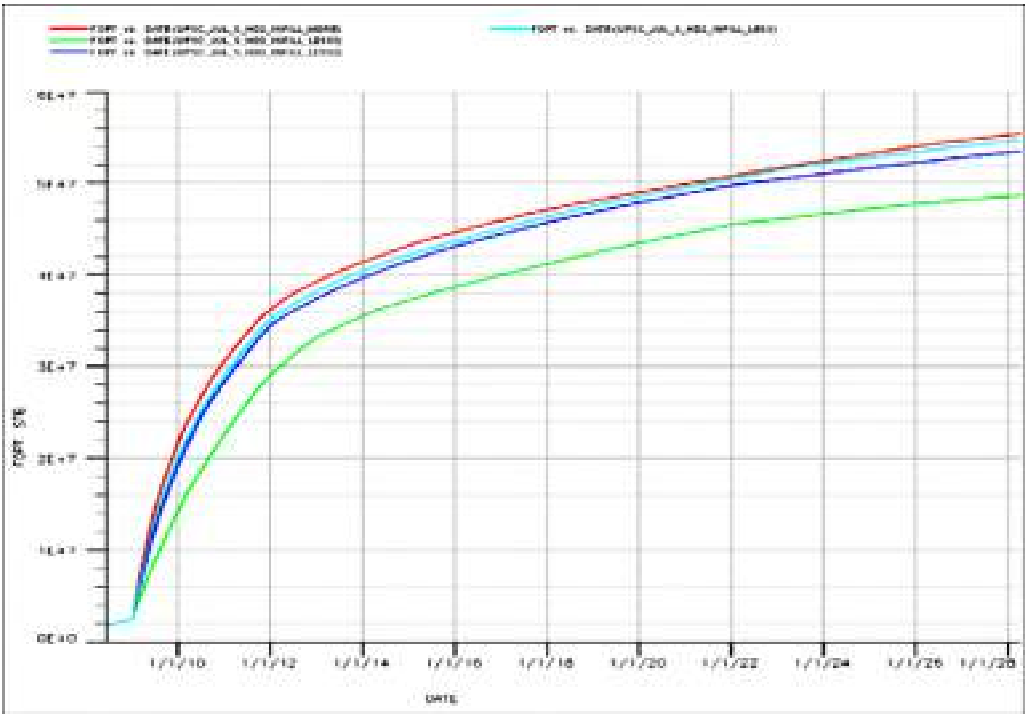


Figure 7. Cumulative oil production for the cases with 25 (green), 30 (dark blue), 45 (Light blue) and 55 (red) additional wells.

- Optimum production of additive wells.

Conservation of reservoir energy was an important issue when investing in oil and gas fields. In this research studied the effect of restricting and unrestricting the daily productivity of wells to maintain the natural reservoir energy depletion, as well determine the best daily productivity that most preserved the potential energy of the Habban field. Figure8, showed the relationship between the cumulative amount of oil production for 30 additional wells and time in several cases. The first case: the case of restricting the daily production quantity at 10000, stb/d, (the curve in green). The second case: the case of restricting the daily production quantity at 15000 stb/d, (the red curve).

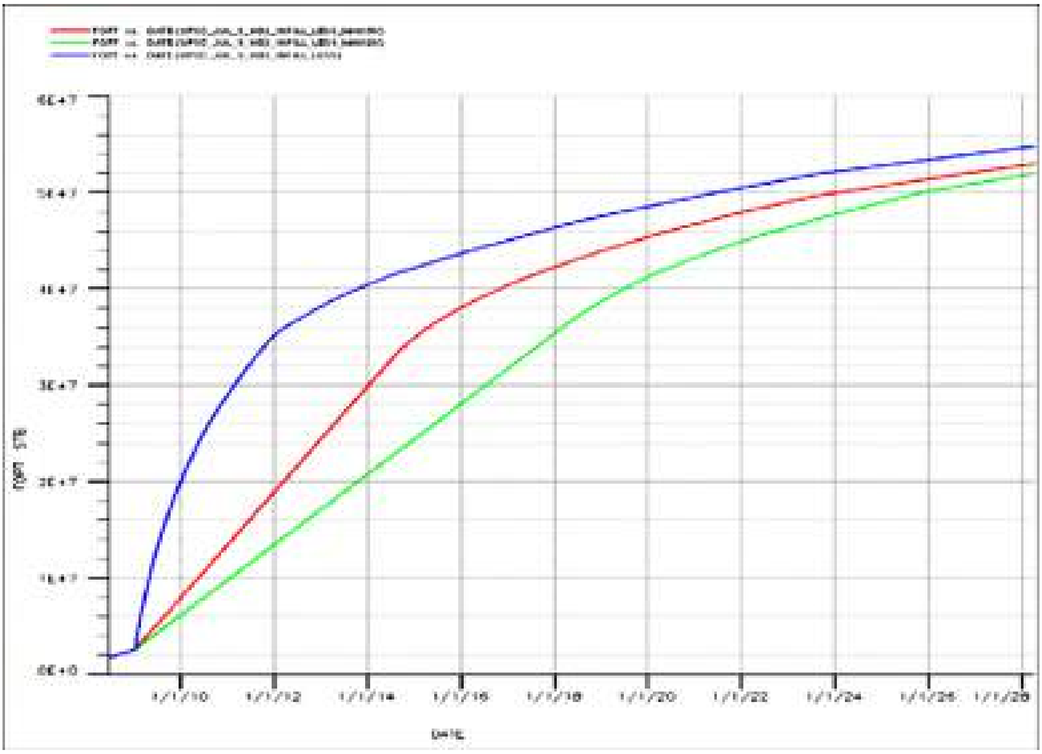


Figure 8. Cumulative oil production for 30 additional wells with 10,000 stb/d (green), 15,000 stb/d (red) and without field liquid constraint (blue).

The third case when the daily production amount was not restricted (the blue curve). It was observed that, in that event that the production quantity was restriction to 10000 stb/d, the cumulative production quantity has gradually increased until it reached 490 million stb/d, in 2025. Restricted to 15000 stb/d, the cumulative production quantity has also has gradually increased until it reached 490 million stb/d, in 2025. In the absence of restrictions on the amount of daily production, the cumulative production amount increased dramatically until it reached 520 million stb/d, in 2025. By comparing the curves in the figure find that, the cumulative production quantity and regularly in the first case and in the second case the production increased more than the first case, also in the third case, when no restrictions on the daily production, the cumulative production quantity increased more than the first and second cases. Explain that the increase in the daily amount of production in the third case over the second and first cases. Meaning that in the second and third cases, the reserve had been depleted significantly, and this led to a decrease in the natural reservoir energy. Also noted that the three curves converge in 2025, because that, the geological oil reserve, which was equal to 511 million barrels and the cumulative production in the three cases was close. Take advantage of that to determine the maximum daily oil production that should be not exceeded in order to preserve the self-propelled capacity of the reservoir. Therefore, the restriction to a production system at a rate 10000 stb/d, allowed obtaining the highest cumulative productivity and maintaining a stable natural reservoir energy until the end of the proposed production period 2025. Studied the effect of gas oil ratio (GOR) for the reservoir depletion energy.

2. Future improvement of the performance of Habban by gas injection.

The Habban field was distinguished by certain geological properties (low porosity, high residual oil reserves and high GOR) that made the method of future performance improvement by gas injection the best method. The depletion scenarios assumed that the gas was being sold or injected in another reservoir. This section was investigated the option of reinjecting the produced gas into the reservoir. The injection of gas may serve as pressure support to the reservoir, thus improving the ultimate recovery.

- The number and location of proposed injection wells.

One of the issues that must be resolved when investing in oil and gas fields through the injection process in its various forms was determined the locations and number of injection wells. Solution this issue by converting some of the proposed production wells to be added to injection wells. Where studied the absorption of each proposed production well separately and compared it with the absorption of Habban well 2, which had the highest capacity among the actual productive wells in the Habban field.
The result of study showed that eight of the proposed production wells can be converted into injection well, because their capacities were close to accommodating that Habban well 2. The wells proposed to be converted into injection wells were distributed on the two formations, of Kohlan (two injection wells) and the basement (six injection wells) as showed in figure 9.

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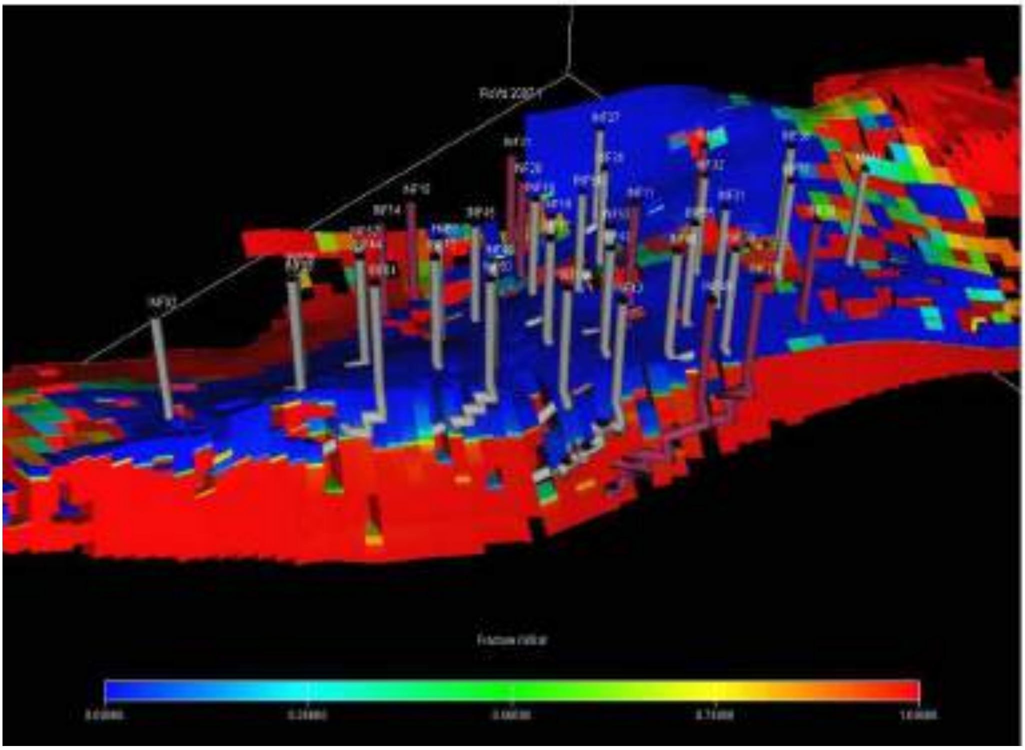

Figure 9. Distribution of suitable injection wells (red color).

This section investigated the option of reinjecting the produced gas into the reservoir. The injection of gas may serve as pressure support to the reservoir, thus improving the ultimate recovery. The first step in testing the possibility of injecting the produced gas was to test the injection capacity of the current wells. This gives an indication if it is possible to inject the required gas volumes. When assuming a bottom hole pressure (BHP) of 4000 psi to avoid exceeding the initial pressure too much, the following maximum injection rates could be achieved:

Habban 1 ~200 Mscf/d

Habban 2 >50,000 Mscf/d

Habban 4 ~600 Mscf/d

Kharwah 1 ~300 Mscf/d

The capacity of Habban 2 well was considered the highest intake among all the actual working wells in the Habban field. The amount of that capacity was approved as the amount of gas proposed to be injected into the injection wells during the supposed Habban field improvement process. These rates decline rapidly after the pressure builds up around the well. These figures had to be interpreted with care, since completion constraints were not taken into consideration. What can be concluded from these figures is that only wells that have a similar capacity to Habban 2 have the potential to re-inject the gas that was produced in the field.

- Effect of gas injection process on the productivity of Habban field.
To investigate the potential of gas injection, eight gas injectors were introduced in the unconstrained case. The wells were spread over the field and have the same orientation and depth as the production wells. The wells are injecting with a BHP of 4000 psi and a maximum gas injection rate of 50 MM scf/d. The wells start injection simultaneously with the 30 additional infill wells, on 1 January 2009. Initially, the eight injection wells were not able to reinject the produced gas volumes (figure10). This was due to the high initial production, which was caused by the unrealistic scenario.

Figure 10. Field gas production (green) and injection rate (blue).

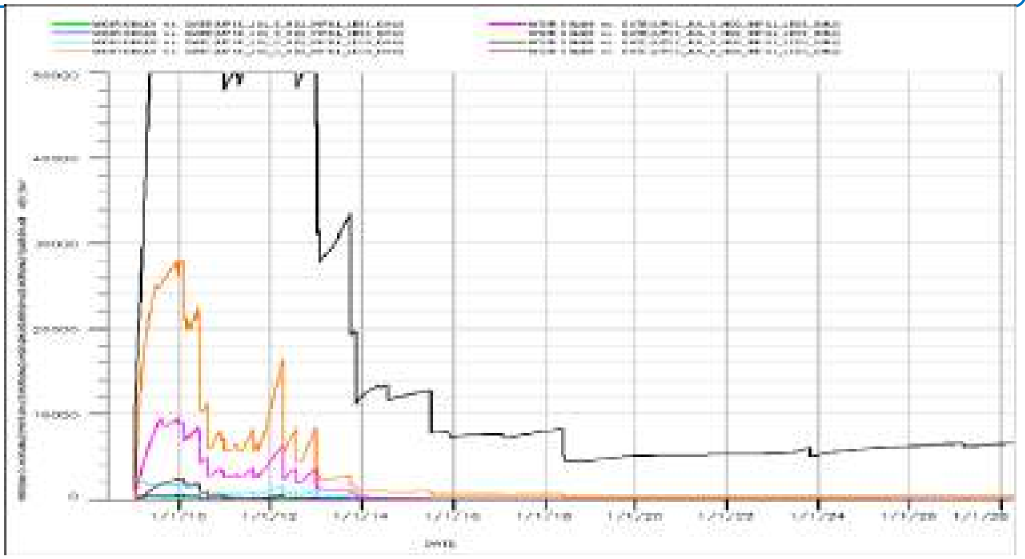

Figure11.The absorption rate of the proposed injection wells for the injected gas.

Figure 11, showed the distribution amount of the injected gas to the proposed injection wells during the improvement period. From the figure, noticed that the injection wells distributed on the Kohlan formation, on which only two injection wells were distributed, due to their small thickness, absorbed the highest amount of injected gas, because of their high filtration properties (porosity, permeability) compared to the basement layer (black and orange curve). Also, noticed a decrease in the absorption of injection wells distributed on the basement layer (other color curves). Concluded from this that, the largest proportion of injected gas was absorbed into the Kohlan formation, which made the oil extraction rate from this formation the highest.

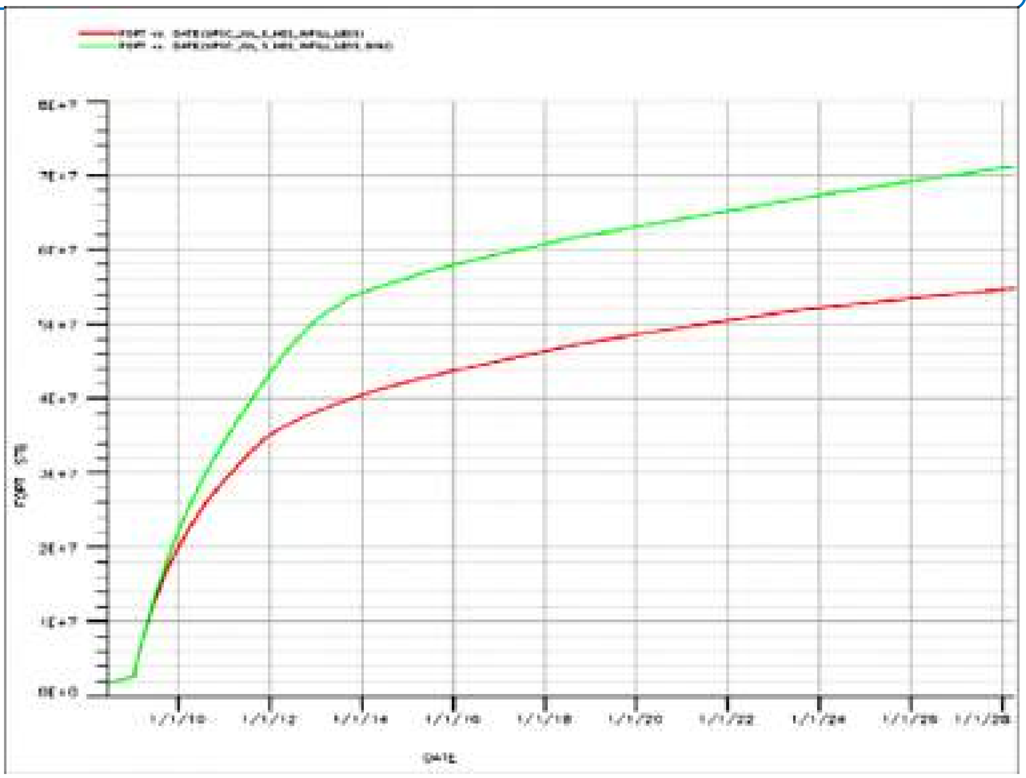

Figure 12. Cumulative oil production with (green) and without (red) gas injection.

One of the mechanism of increasing the oil recovery depended on the mixing of the injection gas with the oil, which leads to an increase in the reservoir pressure and a decrease the viscosity of the oil, and thus increase in mobility of oil in the direction of the production wells [7]. In order to clarify the impact of the future improvement process of Habban field by gas-injected method, studied the relationship between the cumulative of oil produced by gas injection and without the gas injection process along the improvement period. The average in the injection lines pressure was slightly higher than the reservoir pressure, as the average pressure in the injection lines was 4000 psi, while it was in the Kohlan formation 3356 psi. and in the basement 3600 psi. The result of the study showed in figure 12. Noticed from last figure that the cumulative production of oil produced by gas injection was 68 MMstb, with an increase of 16 MMstb, about the cumulative production of oil produced without improvement process, which was equals to **51.6** MMstb. The oil recovery coefficient because of the improved oil production process in the Habban field by gas injection increased by 13% at the end of the improvement period.

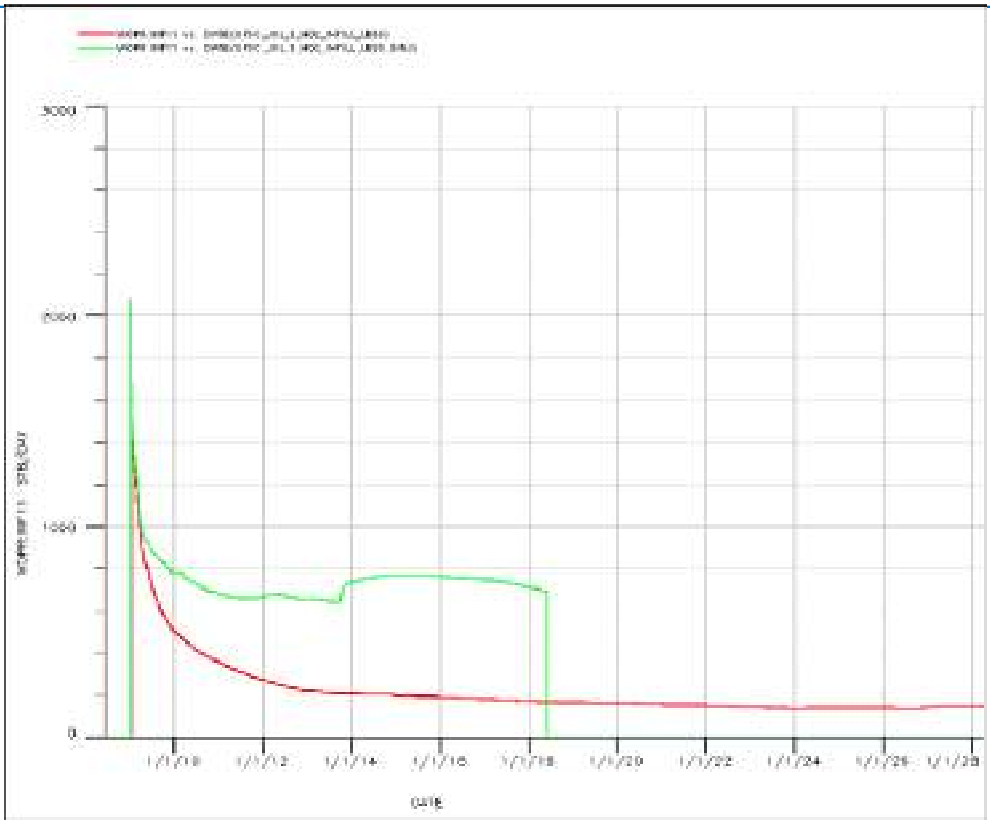

Figure 13. Well oil production rate with the breakthrough process (green curve) and without (red) gas injection.

The breakthrough process was defined as the arrival of the displaced fluid to the production wells. This process depended mainly on the formation of the displacement front, which in turn depended on the relationship between the kinetic of the displaced and the displacement fluid. This relationship was governed by the geological properties of the reservoir and the Petrophysicals properties of fluids inside it [8]. The distance between injection wells also had an effect on the breakthrough process. The smaller distance between the injection wells and the production wells, the breakthrough process time. It was useful to predict the time of the breakthrough process by predicting the end the impact of the injection wells on the improvement process. Figure 13, showed an example of a well that experiences good pressure support, but also a fast gas breakthrough. For this particular field case, the balance is favorable for gas injection. The production wells that benefit most from gas injection are the wells that are either far away (and down dip) from the injector or close by but have no direct highly permeable connection. For example, an injection well was injecting in the Kohlane, but a nearby well was drilled in an area where there was no Kohlane and was producing from the lower part of the well. By going through the differences well by well, it can be seen that the cause for an increase or decrease in cumulative oil production was a trade-off between pressure support and fast gas breakthrough. In general, the better the connection between the injector and producer was the better the pressure support but also the faster the gas breakthrough. Choosing a suitable production system for productive wells was very important during the investment of oil and gas field, by self or by optimization method. The optimum system for producing production wells aims to save reservoir energy in addition to ensuring a production system without technical problems such as the appearance of water or send in the product, hydrate formation during the production process, vibration of surface equipment and other problems that may lead to stopping the production process.

The optimal production of producing wells may not give the highest productivity of the well, in return it guarantees saving of the reservoir energy in addition to productivity without technical problems. In order to determine the optimum productivity of the Habban field when optimizing by gas injection during the period of improvement, by restricting the gas oil ratio. The effect of change of the GOR on the cumulative productivity of oil while the improvement process by gas injection, was studied, and compared with the effect of changing (GOR) during the work of the reservoir with its energy (depletion) without gas injection in order to determine the extent of the possibility of maintaining reservoir energy by decreasing the value of GOR, where the cumulative production quantity the changing the value of GOR as showed in figure 14. Noticed that, when decreased the GOR from 5000 scf/stb. to 3000 scf/stb while used gas injection, the cumulative oil decreases from 68 scf/stb to 64 (green and blue curves), and since the effect of GOR in the cumulative production of oil was small in this case, it was preferable that the amount of gas produced with oil equals 3000 scf/stb during the used of gas injection, the energy depletion of which had been improved the injection gas, while in the case of no used gas and relying on natural reservoir energy (depletion systems) the by value GOR was reduced from 5000 scf/stb to 3000 scf/stb, had a significant effect on the cumulative decrease in oil seen from 53 **MMstb** to 46 **MMstb** represented by the red and the light blue curves, respectively.

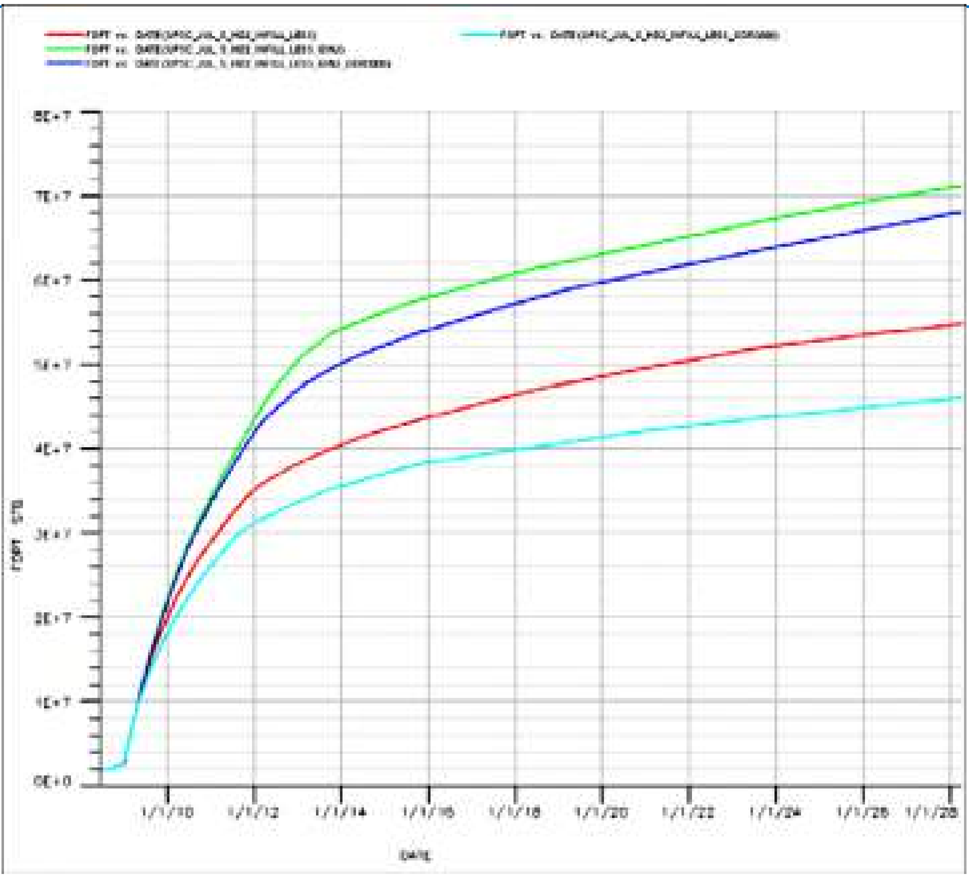

Figure 14. The gas oil ratio GOR versus the cumulative oil production, for depletion system (light blue curve 3000 scf/stb. the red curve 5000 scf/stb) and for gas injection system (blue curve 3000 scf/stb, green curve 5000 scf/stb).

Conclusions.

From the results of this research, concluded:

1-The reservoir rocks properties: background fractures permeability less than 0.001mD, fracture corridors permeability ranging from 0.01 up to 10 mD. Total porosity of fracture basement was 1.7% only, fracture porosity 0.6%, dissolution porosity 1.1%. Kohlan porosity was 15%, the water saturation equals 24%. The reservoir fluid properties: The fluid in Kohlan formation was characterized by density was 0.594 g/cc, the oil formation volume 1.71 bbl/stb, gas oil ratio 1252 scf/stb, stock tank oil API 43.7, stock tank oil density was 0.808 g/cc. The fluid in the fracture basement formation was characterized by : the oil formation volume 1.62 bbl/stb , gas oil ratio 1082 scf/stb, stock tank oil API was 42.4 , stock tank oil density 0.814 g/cc .

2- The history match between historical data and simulated data was in excellent case.

3- At least 30 additional successful wells for the southern part of Habban field and without restrictions on gas production, oil rate, etc., a recovery factor of 10 % (cumulative oil production was 51.6 MM stb) can be achieved within the study period from 2008 to 2025 by depletion drive mechanism alone, and with an oil rate constraint of 10,000 stb/d, the cumulative oil production was 48 MM STB, and when used a GOR constraint of 5000 scf/stb, the cumulative oil production was 53 MM STB.

4- With gas injection the recovery factor increase from 10 % to about 13 %, the cumulative oil production was 68 MM STB, and when used a GOR constraint of 3000 scf/stb, the cumulative oil production in 2025 was 64 MM STB.

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الملخص

يميز أنظمة الدفع بالغاز المذاب انخفاض الضغط المكمني وزيادة نسبة الغاز المنتج مع النفط، مما يتطلب البحث عن طرق تحسين مناسبة لدعم الضغط الطبقي لأطول فترة زمنية. أجريت هذه الدراسة على طبقة كحلان وطبقة صخور الأساس والتي تعتبر الطبقات الأساسية المنتجة في حقل حبان بلك إس2. الهدف الرئيسي لهذا البحث هو دراسة أدائية حقل حبان المستقبلية أثناء وبدون عملية التحسين عن طريق حقن الغاز لفترة زمنية (2008-2025) باستخدام برنامج الإكلبس. تم بناء نموذج محاكاة، باستخدام برامج نفطية اعتماداً على البيانات الجيوفيزيائية، الزلزالية و بيانات الضغط و الحجم و درجة الحرارة و غيرها. توصلنا إلى ضرورة إضافة ما لا يقل عن 30 بئراً. أثناء الإنتاج بنظام الاستنزاف إضافة في آبار إنتاجية يعطي إنتاجاً تراكمياً للنفط يبلغ 51.6 مليون برميل مع عامل استرداد بنسبة 10٪. علاوةً على ذلك، عندما تم فرض قيود على معدل إنتاج النفط، وجدنا أن تقييد معدل النفط البالغ 10000 برميل في اليوم، سيكون إنتاج النفط التراكمي عام 2025 يساوي 48 مليون برميل. أيضاً عند القيود المفروضة على نسبة الغاز للنفط المنتج من 3000 قدم مكعب قياسي/برميل الى 5000 قدم مكعب قياسي/ برميل، تزداد كمية النفط التراكمي في عام 2025 من 46 مليون برميل إلى 53 مليون برميل. تم تحديد تأثير حقن الغاز على أداء المكامن المستقبلي، وتم التوصل إلى أن حقن الغاز يؤدي إلى زيادة إنتاج النفط التراكمي في عام 2025 إلى 68 مليون برميل، عندما كانت كمية الغاز للنفط المنتج 5000 قدم مكعب قياسي/ برميل، بنسبة استرداد قدرها 13%. وعند خفض كمية الغاز للنفط المنتج 3000 قدم مكعب قياسي/ برميل، سيكون إنتاج النفط التراكمي 64 مليون برميل.

الكلمات المفتاحية: تحسين. حقل حبان. برنامج الإكلبس. نظام الاستنزاف. حقن الغاز.