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Performance of the Petroleum Reservoir Under Waterflooding at the Petrochad Field in Mangara-Chad

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ABSTRACT

The Mangara petroleum field is made up of three superimposed reservoirs (C, D, E) with approximately 2500 m depth. These are unconsolidated sandstone reservoirs with an underlying active aquifer. The petrophysical properties of the reservoirs are relatively good as it's a self-sourced unconventional reservoir based on its organic richness characteristics unconventional resource opportunity as tight carbonate reservoir. Tank pressure is approximately 2900 psi, for an average temperature of 180°F. Of the 50 wells initially drilled, 23 are currently producing. The pressure is support by 04 injector wells, and daily production is estimated at approximately 12,000 bbl/d. To maximize oil production and minimize water production, the positions of injection wells were moved, which permitted to reduce the number of producing wells from 23 to 18. The result revealed that this scheme can maintained the pressure at desired levels of 2900 psi, until year 2040 and reversed the current trend in water production, which was 14,000 bbl/d. In the predicted scenarios, cumulative production will be maintain at 25,000 bbl/d with a daily production of around 18,000bbl of oil compared to formerly figure of 7000 bbl of water until 2040.

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1. Introduction

Exploration of oil in the Magara area in Chad began with the drilling of three exploration wells by the American company COTCO in 1978, follow by Exxon Mobil in 2003 until 2007 [1-4]. Exploration resulted in the discovery of oil in several superimposed reservoirs (C, D and E) in the Mangara block [3, 5]. Exploration operations continued with GEI firm from 2012, but only in reservoir C. This project was launch in 2013 for the simultaneous production of oil and gas, impregnated in a deposit of several superimposed reservoirs, with an estimated geological age from Upper and Lower Cretaceous [4-6]. According to Pinaeva [7] the aquifer is active only in deep reservoirs. However, for the case of Mangara the deposit is less deep and the aquifer is active, in which case according to Economides *et al.,* [8], the natural energy for the production of these reserves may be sufficient and acceptable. The entire found reserve can be exploited for economical purpose. At this level, the energy necessary for the recovery of petroleum can only be supported by an active aquifer boosted by the injection of water from the entire deposit [6, 9]. This option is advice, as the main source of water production is inlet and no need of extra resource. The study projects estimate a cumulative production of approximately 25,000 bbl/d until 2032 [2, 5, 6]. The objective of this work is to revise the initial water flooding scheme in order to minimize water production and optimize oils production. This will be done by examining the properties of the Mangara reservoirs water sources, the initial performance plan of the reservoir linked to primary recovery, water injection and aquifer.

2. Materials and Methods

2.1. Study Site

The Mangara field is located in the commune of Bémangra, in the south, approximately 450 km from the capital N'Djamena in the republic of Chad. Bémangra is in the department of Guéni, province of Occidental Logone, which covers an area of 8844 km^2. The province is subdivided into 04 departments and 21 communes. The Occidental Logone province in Chad has as capital Moundou town and borders with the Republic of Cameroon. This is the first site of the project. The map below shows the overall study area. The geographic coordinates are Latitude 8°58′60″N and 18°4′60″E (in DMS); Longitude: 18°4′60″ E.

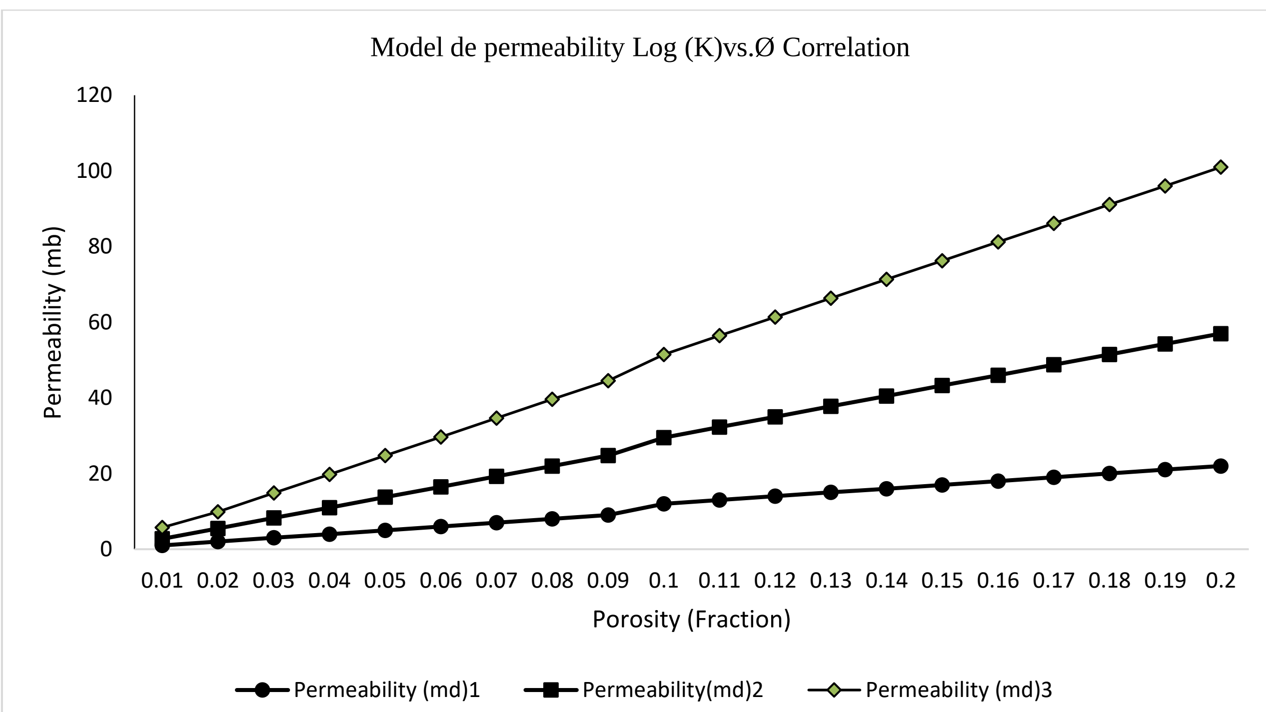


Figure 1: Evolution of permeability as a function of porosity of Mangara reservoir C.

2.2. Collection of Primary and Secondary Data

The main or primary data resulting from this research work are collected through interviews, observations and literature reviews. The transcriptions of the interviews as well as the presentation of the observations are treated according to Ahmed and McKinney [10].

Secondary data are obtained from the archives of public and parapublic institutions, companies and oil companies. These archives are selected for their direct involvement in the project and their participation in regulations or respect for the environment. They are used to support findings and analyses.

2.3. Analysis and Processing of Survey Data

The method adopted is a qualitative method of data collection, an interview technique for field engineers, which aims to collect information on a limited number of questions defined in advance [11]. For this study, the technique of collective interview made it possible to collect the impressions of operators, technicians and engineers specialize in the field of oil and gas exploitation at the Mangara field, then the managers involved in the operations. The information sought relates to the state of oil exploitation linked to the exploitation system, the overproduction of production water on the Petrochad (Mangara) Limited field. This involves collecting opinions on the causes of the influx of oil production water into the management system, locating water producing wells and taking stock of the decline in oil production. Precisely identifying the wells producing more than 10% of water at potential risk and propose a plan for closing wells found uneconomical.

To do this the development diagram of the reservoir were analyze, the petrophysical properties of the reservoirs to develop the cumulative production of the Mangara field and then make scenarios on different sensitivities relating to: (1) The mechanism of field recovery (2) The performance of the reservoir in producing oil and gas from 2014-2040; (3) the efficiency of oil recovery (4) The variation of the diesel ratio-GOR.

3. Results and Discussions

3.1. Lithology and Evolution of the Petrophysical Parameters of the Mangara Deposit

This work is essentially based on initial data from the Mangara field, which provides all the parameters to maximize the recovery of oils and gas at the lowest possible cost.

Fig. (**2**) below describes the evolution of permeability as a function of porosity in the Mangara reservoir. According to Bailey *et al.,* [12], permeability and porosity increase with depth of the wheel.

The paleoreliefs observed in the Magara oil field in Chad mark the moments of interruption in the accumulation of sediments in a primary geosyncline and to a lesser extent an intermediate platform or basin [12, 13]. The flooding of this basin could be due to orogenic or epeirogenic movements or its denudation (glyptogenesis), to the influence of external factors (physical, chemical and biological) [13]. Exposure and denudation at the Magara Oil Field would have formed over time with the creation of reliefs of variable shape, which, then, were buried under new cycles of sedimentation during marine transgressions. By supporting a new cycle of sedimentation (marine or continental), the relief would have transmitted its shape to the tectonic or sedimentary structure of the layers which cover it [10, 12]. The paleogeographic evolution of the land underlying the Magara oil field has experienced several moments of exposure or denudation caused by folding and uplifts in the Carpathian geosyncline, or by uplifts, faults and partially folding in the frontal zones and interior depressions. In relation to these paleoreliefs, different types of traps were formed where hydrocarbon deposits were discovered.

At Mangara the reservoirs are superimposed from 1989m to 2200m and based on this superposition, the permeability and porosity has experienced a remarkable growth of reservoir C (Fig. **2**). According to Ali *et al.,* [13], the reservoirs at high permeability are the source of the inflow of water and therefore excessive production of water from oil and gas production on the surface.

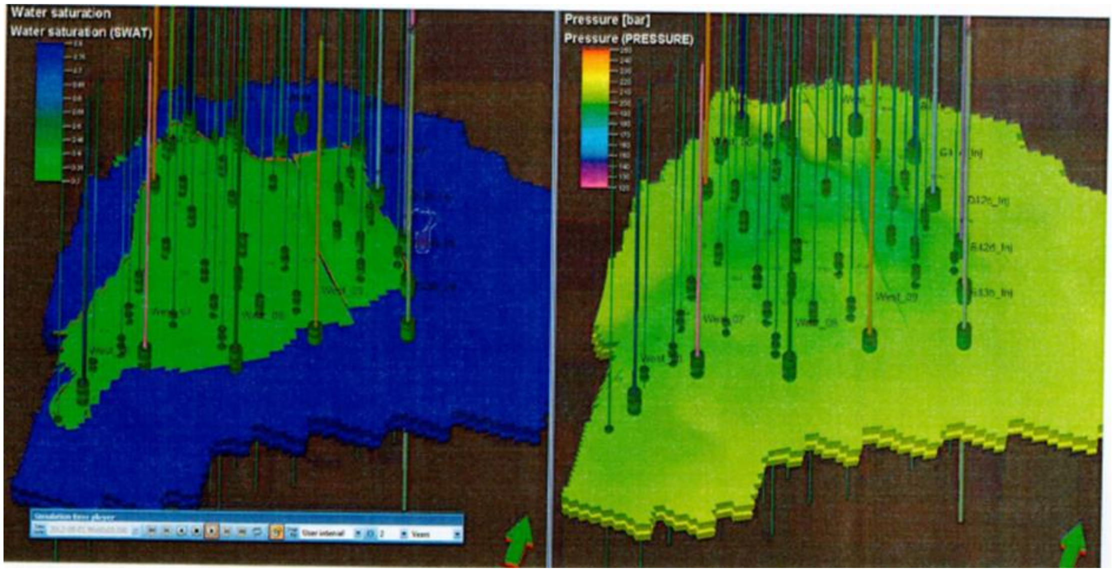


Figure 2: Flooding effect in Petrochad (Mangara) Limited field (Source. Exxon Mobil, 2011).

3.2. Evaluation of the Performance of Mangara Reservoirs

The recovery rate cannot remain high when the energy required for movement is adequate. The wells tested are Mangara 001 and 002 (Fig. **3**) completed in the C2 reservoir. This requires an appropriate selection of energy, whether natural (aquifer) or artificial (water injection). In this type of recovery, the efficiency of their drainage and the gas content in the oil is required.

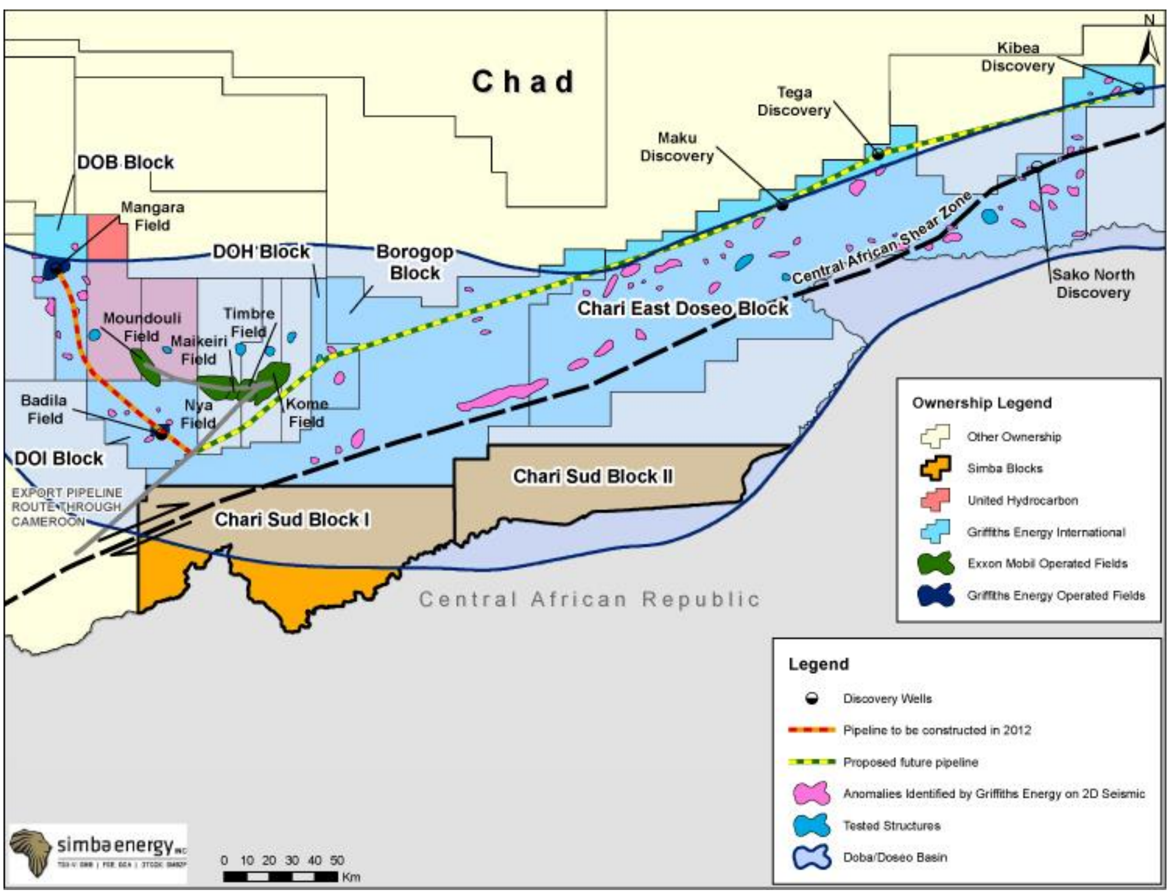


Figure 3: Location map of the Mangara field (Source: Simbaenergy 2012).

3.3. Field Recovery Mechanism

At the primary recovery stage, natural energy decreases rapidly as production falls [14]. The Fig. (**4**) indicates that, in thirty years, the reservoir is completely exhausted. The well will be flood by water from the aquifer, which will be produce on the surface. However, if the aquifer is active, there will be expansion of the aquifer. Production is good and the water produced will be proportional to the production of oils. As the water floods, pressure is maintained. Production is good and is accompanied by a significant quantity of surface water [12]. Rodney [15] presented the following characteristics for an oil reservoir fed by an active aquifer:

The reservoir pressure drop is generally very small. The Fig. (**4**) present the prediction of the evolution of the pressure as a function of time of a reservoir fed by an active aquifer and supported by the injection of water. In these reservoirs, several thousand barrels of oil can be produced for every 1 Psi pressure drop, due to the replacement of the volume of oil and gas coming from the reservoir with the volume of the water inlet. Although the pressure history is normally plotted as a function of time. Because the primary source of revenue is from oil production, if water and gas withdrawals can be minimized, then reservoir oil recovery can be maximized with a minimum drop in reservoir pressure. Accordingly, it is extremely important to reduce water and gas production to a minimum. This can be achieved by shutting down wells producing large quantities of these fluids, transferring their eligible oil production to other producing wells with lower water-to-oil or oil-gas ratios.

Case 1: If the deposit produced under its own energy (primary recovery), there is a decline in pressure from 200 bar to 10 bar around 2040 (Fig. **4**). Throughout this period, the recovery rate will not exceed 20% and towards at the end of this period no barrels will be produced.

Case 2: if the deposit is fed by an aquifer, there will be production but the pressure will decrease from 200 to 120 bar until 2040. During this period, water production is proportional to oil production.

Case 3: if the deposit is under water injection, the pressure is maintained at 180 bar until 2040. During this period, water production is much higher, i.e. 1.4 barrels of water for each barrel oil. Oil recovery by natural drainage rarely exceeds 30 to 40% as indicated by Bailey *et al.,* [12]. That is why other techniques have been implemented to improve recovery. The secondary recovery mechanism is based on the injection of fluids into the reservoir for an additional supply of energy.

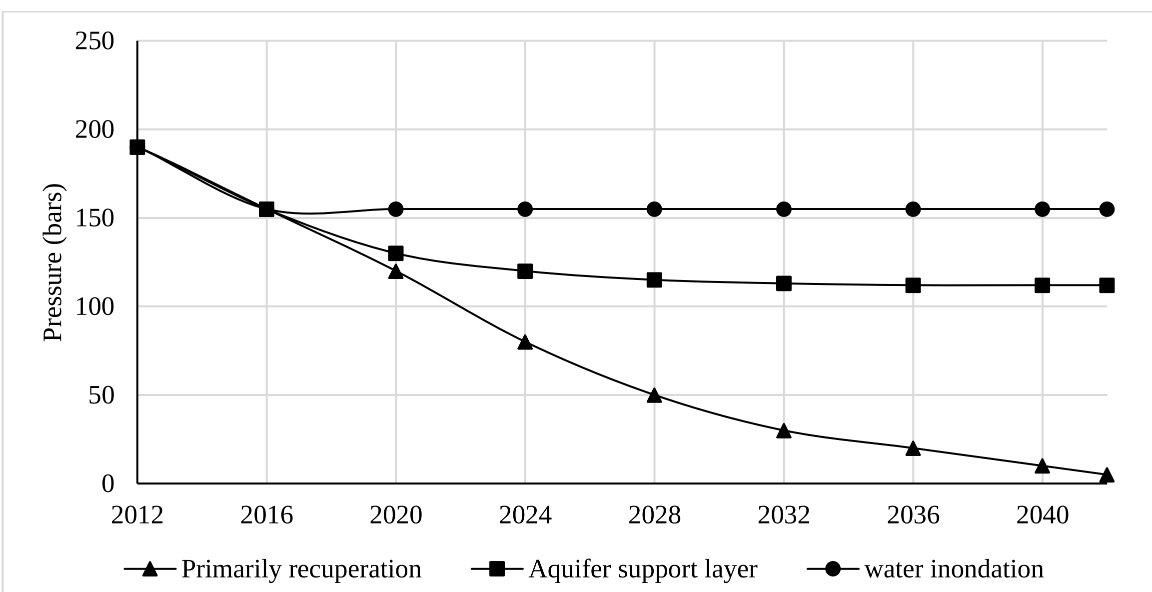


Figure 4: Curve representing the reservoir pressure drop as a function of time.

Currently in Mangara there is excess water production in structurally wells, especially in addition to the expansion of the aquifer, the entire deposit is under injection. This characterizes reservoirs fed by an active aquifer, which provides water inflows in a uniform manner; nothing can or should be done to limit these water inflows, as the water will likely provide the movement mechanism. Oil as efficiently as possible. If the reservoir has one or more layers of very good permeability, water can move through these more permeable zones [16].

Fig. (**2**) indicates the advance of the front, uniform because of the homogeneity of the reservoir.

3.4. Reservoir Performance

In the three cases in Fig. (**5**), the flow rates of the fluids decrease in accordance with the energies conferred. Over time (around 2040), the flow of oil from the aquifer support is equal and therefore the wells will be flooded and uneconomical supportable. The inflows will be excessive and in the case of the Mangara reservoir, the water can weaken the cement materials between the grains, which hold the formation in place, thus allowing the production of sand [17, 18]. As a result, wells where water production is high may have the lowest pressure drop across the reservoir at which sand production exists. This is the case observed in Fig. (**5**), when the deposit produced by its own energy or the oil flow is very low.

Similar to how water flow affects corrosion, produced water tends to form deposits in several ways; as water production increases, deposits form more quickly. When planning a water injection plan, the chemical composition of the injection water must be taken into consideration [19]. If the mixing of injection water and the formation leads to the formation of deposits, the latter can be considerably increased when injection water penetrates into the producing wells [20].

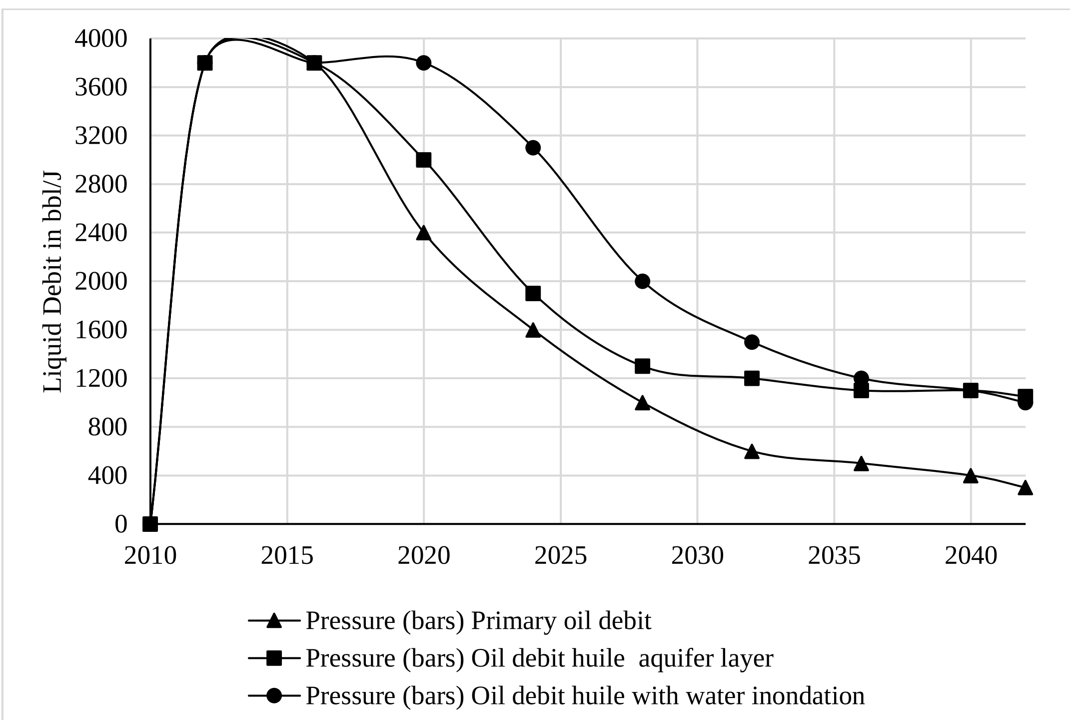


Figure 5: Curve representing the flow rate of the liquid as a function of time.

According to Fig. (**5**), between 2012 and 2018, all energies intended for assisted or unassisted recovery present a peak in high flow rates of more than 4000bbl/d. Nevertheless, after 2018 the decline in flow began. Particularly in primary recovery, all wells will stop producing around 2040. When water inflows are a result of reservoir mechanisms, water production can induce a significant reduction in accessible and mobile oil volumes in the reservoir [21].

However, reservoirs under water flooding or supported by aquifer activity have a flow rate around 800 bbl/d until 2040. However, the decline begins after 2018 and stabilizes after 2040.

3.5. Efficiency of Oil Recovery

The ultimate recovery of oils from reservoirs fed by an active aquifer is generally much greater than recoveries from other production mechanisms [14]. Recovery depends on the effectiveness of the water sweeping action. Generally, recovery decreases with increasing reservoir heterogeneity due to irregular water movement [12]. The advance of the waterfront is more rapid in areas of high permeability [22], resulting in a premature increase in the water percentage. As a result, water breakthrough wells reach their economic limits more quickly.

3.6. Ultimate Oil Recovery is also Affected by the Degree of Aquifer Activity

In a very active aquifer where the degree of pressure maintenance is good, the role of dissolved gas in the recovery mechanism is greatly reduced [23].

The ultimate oil recovery from reservoirs fed by an active aquifer is high, it is located between 35% and 75% original oil.

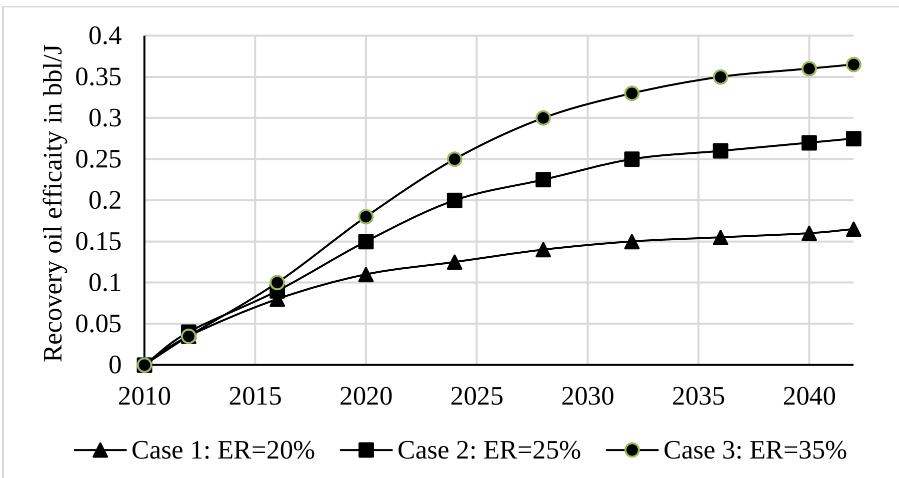


Figure 6: Curve representing recovery efficiency as a function of time.

For Mangara forecast, during water flooding the oil recovery efficiency is more significant and is continuously increasing until 2040. The recovery efficiency ranges from 0.32 to 0.38; this is the most suitable option today for starting wells when the reservoir has an energy defect or not. While the energy linked to aquifer activities has an average efficiency of between 0.16 and 0.24. However, during the entire primary recovery, the recovery efficiency is less and ranges from 0.1 to 0.18 until 2040.

3.7. Gas-Oil Ratio-GOR

The variation in gas-oil ratio is low during the life of a tank supplied by an active aquifer leads to a drop in oil production, this is particularly true if the reservoir does not initially have a gas cap. The pressure is maintained under the effect of water inlets. As a result, little gas will be released from the oil. This situation is also observed when the deposit is under water injection. While in primary recovery, Fig. (**6**) indicates a high gas content, which continues to increase until 2040. This is one of the reasons, which leads to the choice of the water flooding option. In this option, Fig. (**7**) indicates a low gas content, which is also approximately equal to the gas content if the deposit is under the support of the aquifer.

In the normal context of oil production in both cases it was necessary to wait until 2020 when the GOR will be greater than or equal to 500 STD/bbl for the deposit to be a candidate for gas injection into the producing well

[12]. In this case, the entire deposit was put under water injection very early on. For the case of the Mangara deposit as shown in Fig. (**7**), primary recovery releases a lot of therefore drop in oil production until 2040.

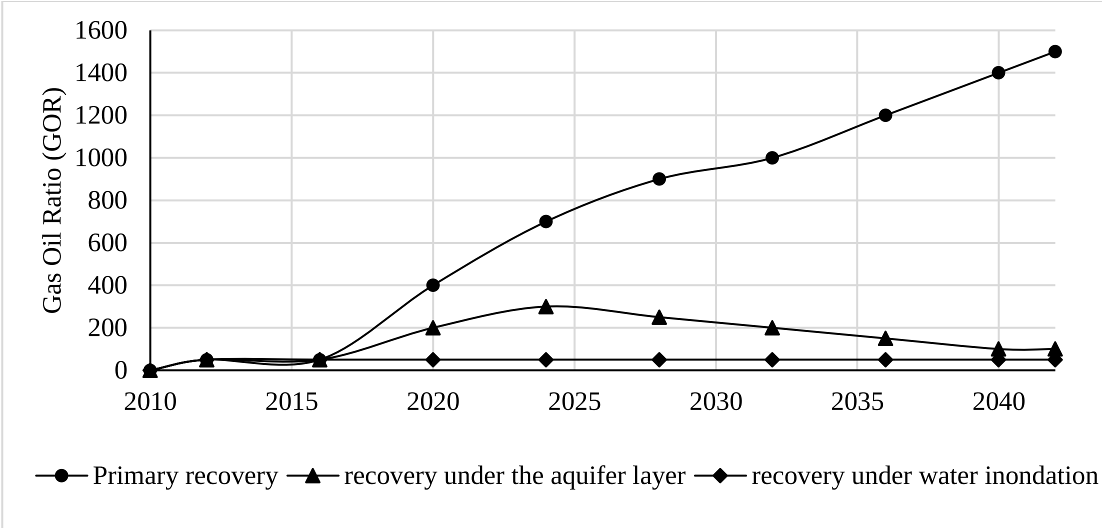


Figure (7): Curve representing GOR as a function of time.

3.8. Evaluation of Well Performance

3.8.1. Initial Developed Wells

Fig. (**8**) below summarizes the initial development wells (production, injection, observation and appraisal wells) on the Mangara site. Almost all of these wells are drilled at the roof of the reservoir. These are reservoirs with multiple interval bottom aquifers [2, 6]. About ten of the Mangara producing wells are on the outskirts of the anticlines (reservoirs) some of the injection wells are at the top of the reservoirs and therefore the percentage of water in the fluid (water cut) initially was 0% and is gradually reached 98% in January 2014. In this state of affairs, the well becomes uneconomic. Such a case leads to an abandonment of the management of certain wells, recommending their closure and drilling other wells nearby for some, resuming directional wells for others [15]. According to Simoneit *et al.* [16], injection wells located at the roof of the reservoir have a 98% probability of

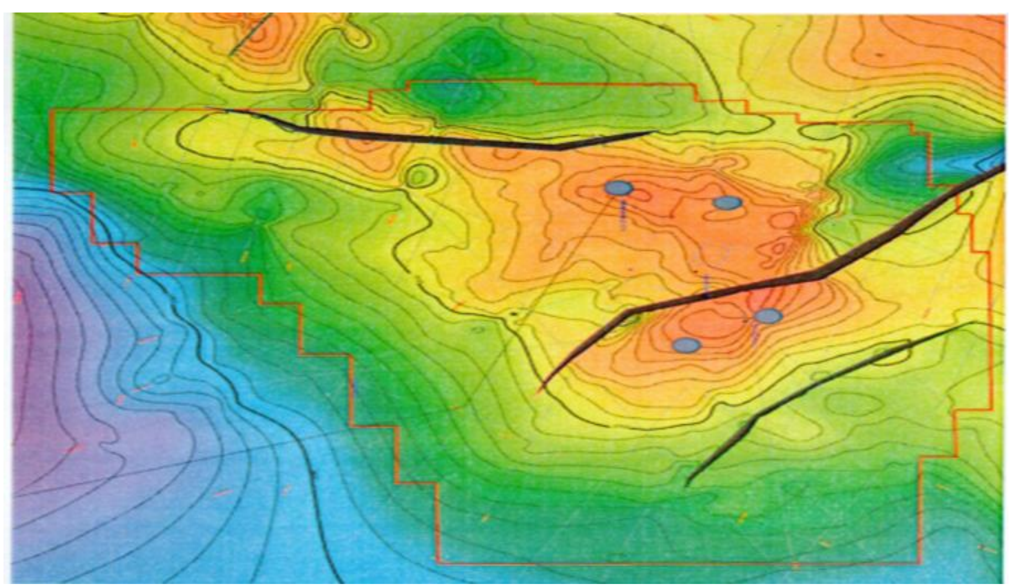


Figure 8: Initial development well map of the Mangara field (Glencore Limmited 2020).

flooding the producing wells at the reservoir wall. In Mangara the conventional injection structure is not well respected according to map 2, only a "five spot (an injection well surrounded by four producing wells)" is found in zone C. Here again in Mangara the reservoirs are slightly inclined, the injected water takes the previously preferential direction towards one of four producing wells and therefore the percentage of water in this well is high. Beyond all this, the water cut varies from one well to another or from one field to another. This situation has allowed several authors to develop correlations in this direction. Among the most widespread correlations, can be cited: the method of Salehi-Shabestari *et al.,* [24] based on laboratory data and modeling of their results, the method of Olabode *et al.,* [25] based on experimental data. Schneider [26] applied the material balance equation to predict water production performance as a function of time after water breakthrough.

3.8.2. Current Planning of Development Wells

Fig. (**9**) below plans the different positions of the producing and injector wells in accordance with the studies carried out on the different reservoirs of the Mangara field. The planimetric and topographical reading tells us that most of the producing wells are located near the Guéni River on surface view and close to the aquifer in the porous environment. The first reason for the proximity of the wells to the Guéni River is to facilitate the injection of water into the reservoir and reduce the cost of all operating operations. While the second reason is to support secondary recovery dray (water injection) by an aquifer expansion mechanism. As the Mangara reservoir is slightly inclined towards the aquifer, the injection will be done directly into the aquifer to strongly encourage the expansion of the latter, therefore avoid the breakthrough of water, and produce below the critical flow (a water flow rate cannot be achieved unless the producing well is flooded). One of the options is to resume and complete these producing wells into multi-branched wells through the C2, C3, C4 and D1 reservoirs, which are well superimposed, and close to the aquifer. It is in this well planning system that a production forecast can be developed in accordance with the different horizons as indicated in Table **1**. In Fig. (**4**), with the PETREL software, we vary the positions of the injection wells for the efficient maintenance of the pressure, maximizing the recovery and therefore for the efficiency of the scanning according to the conventional configurations of planting the injection wells (five spot: one injection well in the middle of four producing wells; Seven spot: one injection well for six producing wells; Nine spot: one injector for eight producers). This configuration was not approximated; however, we adapted it in accordance with the stratigraphy of the reservoir and its dimensions. Usually injection pressures are maintained below ground fracturing pressures (0.2 bar/meter) Khan [27]. According to Aziz *et al.,* [28], water injection involves the implantation of the injection device. The cost of the cubic meter of water injected increases with the injection pressure [29, 30], and especially the time between the start of the injection and the significant increase in oil production [31-33], which time determines the benefit of the injection is which can be more than a year.

Table 1: Interpretation of Fig. (9) for the development of the Mangara field.

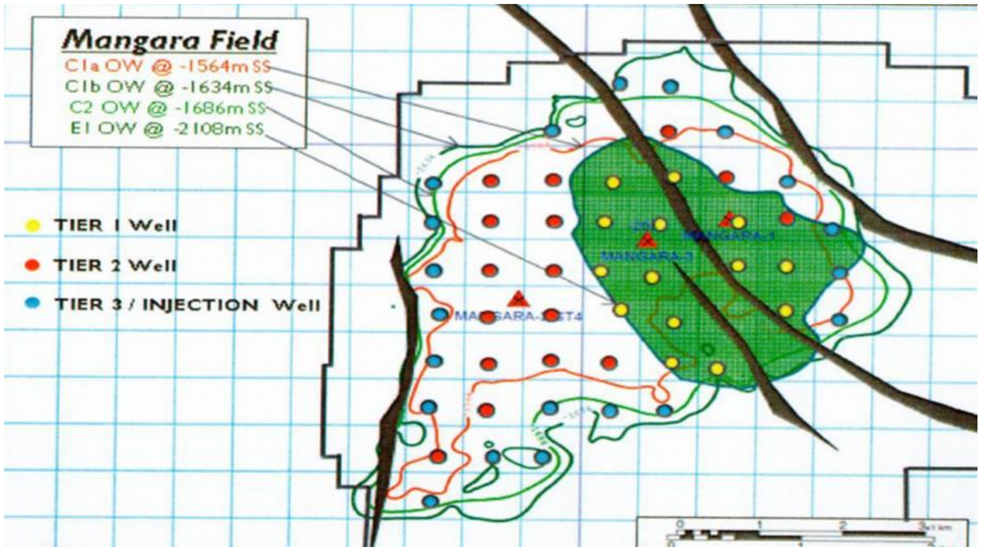
Reservoirs	Depth of Wells (m)	Production Wells	Completion of Well to Maximize Oil Production
C1a	1564	Oils	Liner crepined and cemented
C1B	1634	Oils	Liner crepined and cemented
C2	1686	Oils	Liner crepined and perforated
E1	2O18	Oils	Liner crepined and perforated

Reservoirs wells depths (m) Producing wells Completion of producing wells to maximize recovery.

In the initial forecasts for the expansion of the factory the first cumulative production is planned for 10,000 bbl/d in 2013 to expect 25,000 bbl/d in 2014 [34, 35]. But this was not the case until 2020.

3.8.3. Completion and Start of OUITS

The A-01 well will be the first well to be drilled from the Mangara A Pad. The objective of the well is to economically produce oil from the C reservoirs. Formation evaluation objectives include mud logging, collection of cuttings samples and full depth wire line logging data.



(Tier 1): 2500 to 3000 bbl/d; (Tier 2): 1500 to 2000 bbl/d; (Tier 3): 1250 to 1750 bbl/d, (Tier 3), can be both producing and injecting wells

Figure 9: Development map of the Mangara field (Glencore Limmited 2020).

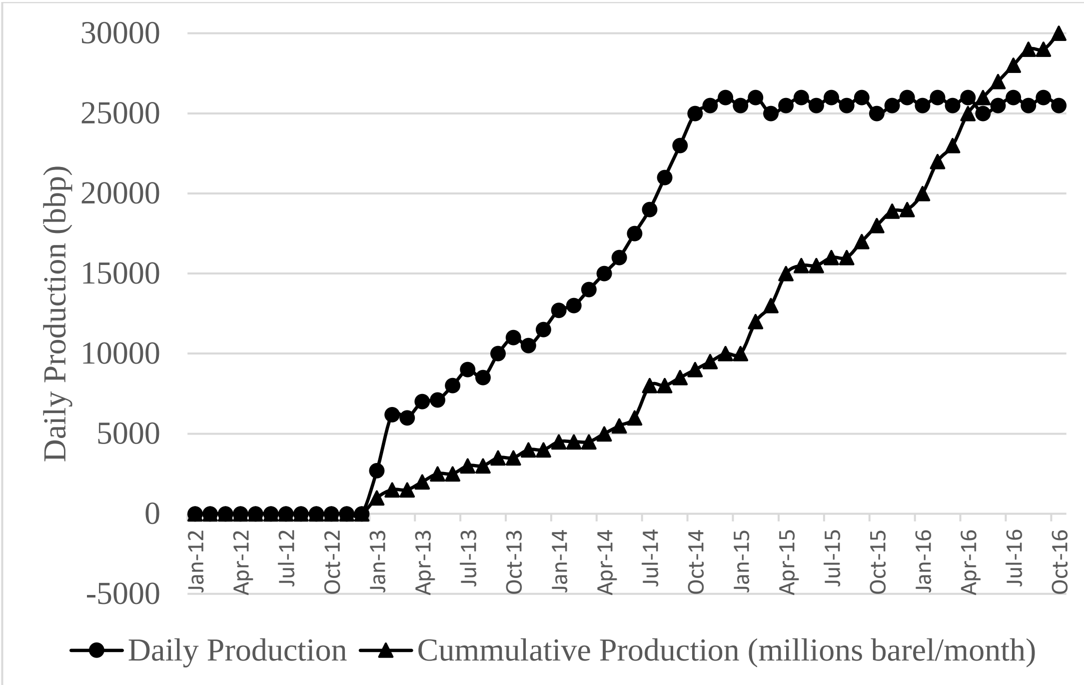
The main target of the reservoir is the C2 sand planned at TVD. Secondary target reservoirs are C1a, C1b, and C3 sands. The total predicted depth is 2483 m MD (2483 m TVD), resulting in the D3 formation.

3.9. Production of the Mangara Site

With the new configuration of water injection from the Mangara deposit, the production is shown in Fig. (**10**). The project projects cumulative production of 25,000 bbl/d with an investment of 300 million US dollars [36-38]. The daily production of oil will be between 14,000 to 18,000 bbl/d with a water production of between 5,000 to 7,000 bbl/d, or three barrels of oil for each barrel of water, which will certainly be a proportion, which should be approximately equal to that of the beginning of the life of the deposit [39-42], is lying. However, test production between January 2013 and June 2013 was lower than the value of 14,000 bbl/d of January 2014. Daily production should normally continue to grow linearly since October 2014. However, production fluctuations will continue until October 2016 with a slight increase in water production [43-45]. However, the cumulative growth in production should be remarkable from 2016 [46, 47].

4. Conclusion

The petrophysical properties of all reservoirs C, D, E of the Mangara deposit present and permeability is between 5 to 100 md, a porosity between 9 to 15%. This are qualified as relatively good. Such petrophysical properties tend to produce more oil than water. The reserves estimated at seven thousand six hundred and fourteen million barrels (7,614.Mbbl) and therefore their production will probably end around the year 2040 will actually be produced on the sole condition of producing around thirty million (30,000,000) barrel of water. The preventive scenario provided us with information on the productive state of the Mangara field. The recovery mechanisms on fields linked to increases in oil production rates; in particular, the injection (flooding) of water has an ability to maintain pressure and therefore an oil recovery rate lower than oil production water. The flow of oil and water will drop gradually and in accordance with the recovery rates until 2040. The efficiency of oil recovery will increase until 2040 and will reach 36%, this situation will cause excessive flow water and production of EPPG on the surface. While under the support of the aquifer, the recovery efficiency will reach only 28%, with an average inflow of water and therefore less production of EPP. But under the deposit's own energy the recovery efficiency will be 20%, therefore less water flow and low production of EPPs in primary recovery or under the deposit's own energy, the gas content is higher, therefore low production of oils, but by flooding the reservoir with water the gas content is low and substantially equal to the gas content produced when the reservoirs are under the support of the aquifer. Overall, the pace of production is indeed responsible for the massive quantity of oils retained in the EPPGs.



Linear growth will bring cumulative production to 30,000 bbl/d until 2032 with daily production of around 18,000 bbl.

Figure 10: Overall production from the Mangara field.

Conflict of Interest

There is not any financial or other substantive conflict of interest that might construed to influence the results or interpretation of this manuscript.

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