

Davarpanah, Afshin; Mirshekari, Behnam

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Research paper

Sensitivity analysis of reservoir and rock properties during low salinity water injection



Afshin Davarpanah*, Behnam Mirshekari

Department of Petroleum Engineering, Science and Research Branch, Islamic Azad University, Tehran, Iran

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ABSTRACT

The ubiquitous consumption of hydrocarbon fuels in a vast majority of industrial purposes has been dramatically increased in the coming decades. Therefore, the reason why numerous studies experimental investigations are being done is to enhance the oil recovery factor. Low salinity water injection is considered as the significant proposed enhanced oil recovery techniques in which the salinity percentage of the injected water is adjusted to improve oil displacement efficiency. Hence, low salinity water injection is considerably influenced by the oil recovery factor regarding altering wettability condition. The objective of this study is to simulate the low salinity water injection under different reservoir characteristics of rock compressibility, porosity and net to gross (NTG) on the amount of total field oil production (FOPT), total field gas production (FGPT), field pressure ratio (FPR) and field gas-oil ratio (FGOR) for 7400 days. Consequently, rock compressibility has less impact on the amount of total field oil production, total field gas production, field pressure ratio, and field gas-oil ratio. By increasing the amount of porosity and NTG, the amount of FOPT, FGPT, and FGOR are raised dramatically, and it is evident that this parameter is directly influenced by this type of reservoir. On the contrary, the amount of FOPT, FGPT, and FGOR are decreased in the NTG period of 0.5 to 1.

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Abbreviations

FOPT	Total Field Oil Production
FGPT	Total Field Gas Production
FPR	Field Pressure Ratio
FGOR	Field Gas-Oil Ratio
LSW	Low Salinity Water
HSW	High Salinity Water
NTG	Net to Gross

1. Introduction

The daily increase of fossil fuels as the primary sources of energy has caused to explore a wide range of laboratory measurements to achieve the optimum and economical (Davarpanah and Mirshekari, 2019a,b; Armin Razmjoo et al., 2019; Bagheri et al., 2019). Thereby, several energy management scenarios and considerations should be taken into account by petroleum industries to serve the purpose of oil production enhancements by virtually eliminating the unnecessary expenses (Alboudwarej and

Sheffield, 2016; Clements, 2017; Dai and et al., 2013; Davarpanah and Mirshekari, 2019d; Davarpanah et al., 2019d). Enhanced oil recovery techniques and their appropriate procedures exert a considerable influence on the volume of produced oil. After the years of production, the power of natural mechanisms has drastically plummeted due to the insufficient bottom hole pressure to drive the fluids to the surface (Davarpanah and Mirshekari, 2018; Davarpanah et al., 2019b; Kothencz et al., 2017; Kozlova et al., 2016; Kumar and Mandal, 2017; Lake et al., 2014). Subsequently, it is a sense of urgency to utilize artificial recovery methodologies like secondary and tertiary processes to move the captured oil to the production wells and improved the production rate. Secondary and tertiary oil recovery techniques have not altered the physical properties of reservoir fluids and rocks (Davarpanah, 2018; Davarpanah et al., 2019a; Luo et al., 2014; Lyu et al., 2017; Mohsenzadeh et al., 2016). Fluid selection in the injection method is affected widely by geology, reservoir fluids composition, injected fluid cost and its availability (Schumacher, 1978; Seo and Sung, 2016; Song et al., 2015). Waterflooding is considered as one of the efficient and widely used techniques to oil recovery enhancement and numerous studies were reported in the literature to demonstrate the emphasis of this phenomenon due to its affordability and ubiquity (Davarpanah and Mirshekari, 2019c; Davarpanah et al., 2019c; Djuraev et al., 2017; Kondash and Vengosh, 2015; Rowan et al., 2015; Sorbie, 2013; Xuezhong et al., 2016).

* Corresponding author.

E-mail address: Afshin.Davarpanah@srbiau.ac.ir (A. Davarpanah).

However, petroleum industries must manage the procedures appropriately to achieve a balance between production and efficient expenditures; management circumstances would be brilliantly succeeded as the significant steps of each enhancement production. Proper and optimized planning are being categorized as following steps; appropriate enhanced oil recovery processes should be specified and having a good understanding of reservoir properties to estimate further processes analytically and give engineers the chance to be dominated on the occasions. Since then, to facilitate the optimization procedures, fostering the engineering parameters should be prioritized. Furthermore, experimental evaluation and field tests should be sequentially done to operate the procedures appropriately, and comprehensive and analytical model of the reservoir should be assessed ubiquitously to facilitate the estimation procedures (Davarpanah, 2016; Ebadati et al., 2018; Lyu et al., 2017; Ren et al., 2017; Valizadeh and Davarpanah, 2019).

To develop a reservoir model, the required steps are being explicitly considered to ease the enhancement processes properly. These steps are electing the proper simulator for modelling and estimating the processes analytically; a stunning range of data should be gathered to check the validity of the model; history matching and sensitivity analysis; efficient anticipation for the operation of the projects and extensive literature studies to have considerable experience of reservoir fundamentals. In other words, reservoir development planning considers as those strategies which they are begun with the exploration and appraisal well phase and end with the abandonment phase of a particular field to establish the course of action during the productive life of the asset. Fig. 1 summarizes the phases of a reservoir development plan. The main objective of the complete cycle of a development plan is to maximize the asset value (Davarpanah et al., 2018; Kakoli et al., 2016; Mazarei et al., 2019; Rabbani et al., 2018; Razmjoo et al., 2019).

Considering again the importance of time and reservoir pressure in development plans, Fig. 2 presents a simple decision tree to evaluate the potential applicability of different recovery processes in light to medium crude oil reservoirs (Alvarado and Manrique, 2010; Hafeznia et al., 2017; Kumar et al., 2017; Pérez and et al, 2017).

In the coming decades, recent researches were based on the water content modification like ionic alteration, which caused to dramatically change the reservoir wettability. The low salinity water injection method (LSWI) has become one of the relevant research topics in the oil industry because of its enormous possible advantages (Davarpanah and Nassabeh, 2017; Teklu et al., 2014; Wan et al., 2016, 2013; Wei et al., 2014; Zhang et al., 2017). Low water salinity injection which is elaborated as the smart injection of water is defined as the simultaneous injection of brine with ionic composition (that is a bit different form this composition in the formation of water) (Al-Saedi et al., 2019; Li, 2011; Mohammadkhani et al., 2018; Puntervold et al., 2018). Regarding the different composition of brine, various chemical interactions might occur in the formation, and therefore, a chemical equilibrium has been established between the brine, crude oil, and the rock (Dang et al., 2013). Jerauld et al. (2006) proposed the low salinity waterflooding by the utilization of an empirical correlation to interpolate the saturation of residual oil versus the consideration of low salinity and high salinity water injection.

Moreover, they defined capillary pressure and relative in the form of the LSW and HSW weighted-average of the curves (Jerauld et al., 2006). According to the previous studies on the salinity water injection, it is of elaborated that low salinity water injection has provided more efficient recovery factors rather than the high salinity and formation water injection. Mahani et al. (2011) conducted an experimental investigation on the wettability alteration which was induced by low salinity water injection through

Table 1
Reservoir and rock properties.

Parameter	Value	Unit
Reservoir depth	1200	Ft.
Flowing pressure	1760	Psia
Reservoir pressure	4350	Psia
Reservoir temperature	175	F
Test temperature	180	°F
Bubble point pressure	3715	Psia
Oil formation volume factor at Bubble point pressure	1.6822	Bbl./STB
Density of total gas evolved at standard condition	1.1761	Gal/Lit
Density of stock tank at standard condition	0.8575	Gr/cc
Density of reservoir fluid at Bubble point pressure	0.6636	Gr/cc
Gas oil ratio at standard condition	1230.22	SCF/STB
Average compressibility factor	15.54	psi ⁻¹ * 10 ⁻⁶
Average thermal exponent factor	7.26	F ⁻¹ 10 ⁻⁴

the change of injected salinity water above the threshold salinity (Mahani et al., 2011).

Although, numerous publications have been dedicated to reservoir development planning and integrated reservoir management which most of them have exerted a considerable influence on the oil recovery improvement, the objective of this comprehensive study is to investigate those mechanisms behind the LSWI impact on the oil recovery enhancement through data matching and its comparison with sensitivity analysis. Because the wettability alteration process is the reason behind the low salinity effect as the decrease in salinity increases the size of the double layer between the clay and oil interface, leading to organic material release. Therefore, it is evident that rock compressibility has less impact on the amount of FOPT, FGPT, FPR and FGOR. Moreover, NTG and Porosity have significantly affected each of the mentioned factors.

2. Simulation procedure

2.1. Location and history

Based on field reports which are taken from laboratory and experimental evaluations, the reservoir is a saturated fracture reservoir which entails the three-phase of oil, water and gas in solution. In this reservoir, three wells have been drilled. Two wells were drilled vertically, and the other was drilled horizontally. The more information details about the studied well are mentioned in Table 1.

In this part of the study, different scenarios are being investigated which each parameter have played a significant role in the optimum economic production of a reservoir; in respect of the way, four divergent scenarios including Net to Gross (NTG), Permeability, Rock Compressibility and porosity were being studied in three colourful ranges that entailed max, min and default preface of eclipse software.

3. Results and discussion

3.1. Net to Gross (NTG)

In this scenario, the amount of Total Field Oil production (FOPT), Total Field Gas production (FGPT), Field Pressure Ratio (FPR) and Field Gas-Oil Ratio (FGOR) are being simulated for 7400 days. The results of this study are shown clearly in Figs. 3–6. Furthermore, the amount of preferred NTG for three cases are illustrated numerically in Table 2;

As can be seen in Fig. 3. The rate of FOPT has been increased dramatically by passing the time and rising the amount of NTG = 1.5; to have the maximum amount of FOPT = 7.1 * 10⁷.

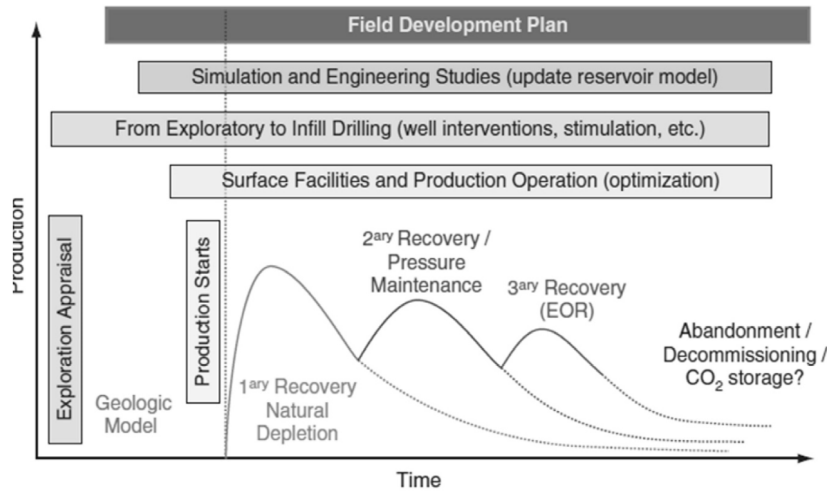


Fig. 1. The main phases of a field development plan (Alvarado and Manrique, 2010).

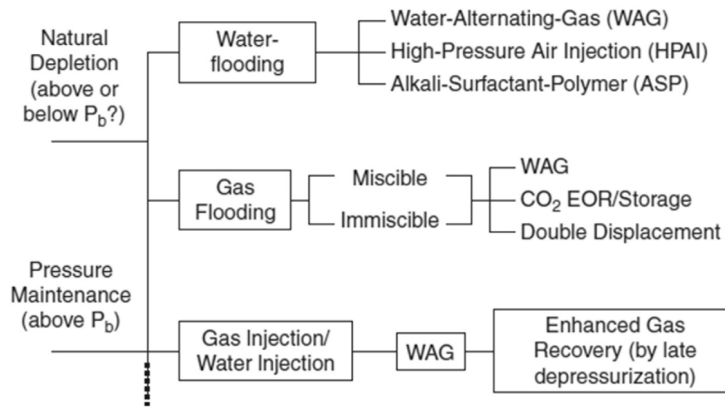


Fig. 2. A simplified example of a decision tree to evaluate the potential recovery processes as part of the RDP in light to medium crude oil reservoirs (Alvarado and Manrique, 2010).

Table 2
The amount of preferred NTG for three testing models.

NTG	Max	Min	Default
Amount	1.5	0.5	1
Model test no.	522	221	521

Table 3
The amount of preferred porosity for three testing models.

Porosity	Min	Max	Default
Amount	0.001	0.015	0.008
Model test no.	222	223	221

Furthermore, the minimum amount of $NTG = 0.5$ are simulated to approximately 6.8×10^7 Which is relatively be considered the same. FGPT has the same trend in rising the amount versus time, but it has a bit differences between the prefaced NTG number and the default value of NTG the minimum FGPT among other NTGs. It is plotted in Fig. 4. Max and min amount of NTG are reported 5.6×10^7 and 5.2×10^7 respectively.

As can be seen in Fig. 5. The pressure decline rate had the same pattern for three testing models, and by decreasing the amount of NTG, the pressure drop would be reduced more. Also, Field Gas-Oil Ratio witnessed negligible fluctuation, which is to be clarified in Fig. 6.

3.2. Porosity

In this scenario, the amount of Total Field Oil production (FOPT), Total Field Gas production (FGPT), Field Pressure Ratio

(FPR) and Field Gas-Oil Ratio (FGOR) are being simulated for 7400 days. The results of this study are shown clearly in Figs. 7–10. Furthermore, the amount of preferred Porosity for three cases are illustrated numerically in Table 3;

As can be seen in Fig. 7. The rate of FOPT has been increased dramatically by passing the time and rising the amount of porosity = 0.015; to have the maximum amount of FOPT = 7.4×10^7 . Furthermore, the minimum amount of porosity = 0.001 are simulated to approximately 6×10^7 . FGPT has the same trend in rising the amount versus time; to increase FGPT by rising of porosity. It is plotted in Fig. 8. Max and min amount of FGPT are reported 5.8×10^7 and 4.6×10^7 respectively.

As can be seen in Fig. 9. The pressure decline rate had the same pattern for three testing models, and by decreasing the amount of porosity, the pressure drop would be reduced more. Also, Field Gas-Oil Ratio witnessed negligible fluctuation, which is being clarified in Fig. 10.

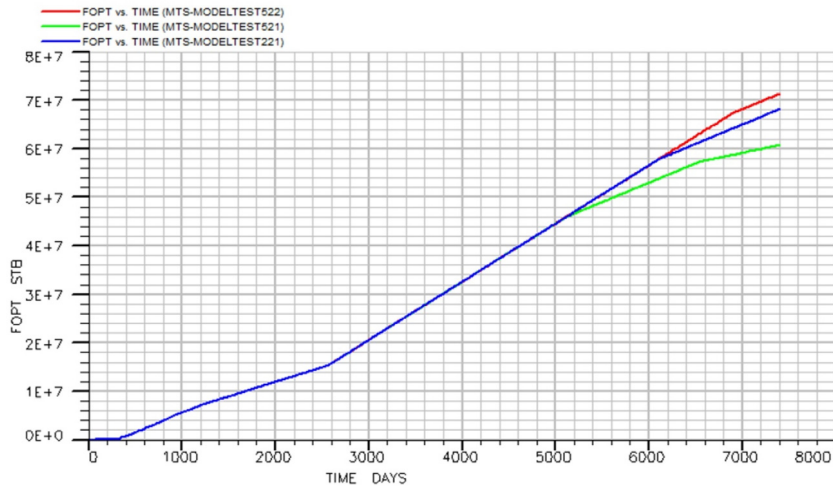


Fig. 3. The rate of FOPT versus Time for three testing models (NTG evaluation).

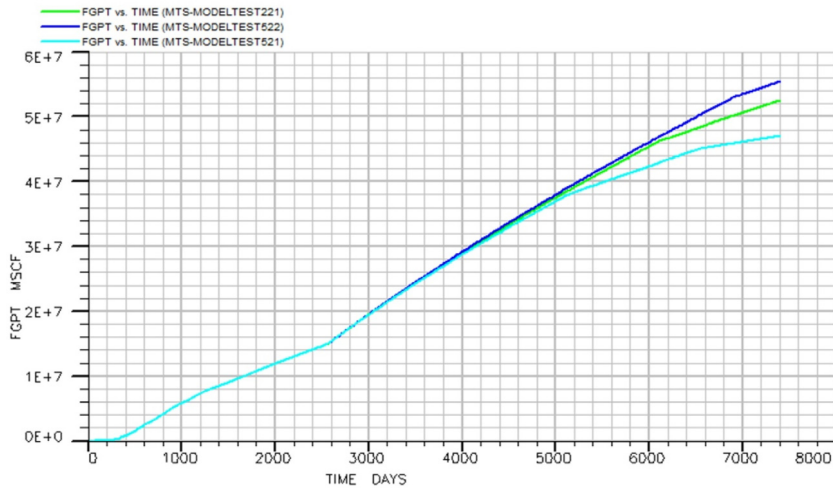


Fig. 4. The rate of FGPT versus Time for three testing models (NTG evaluation).

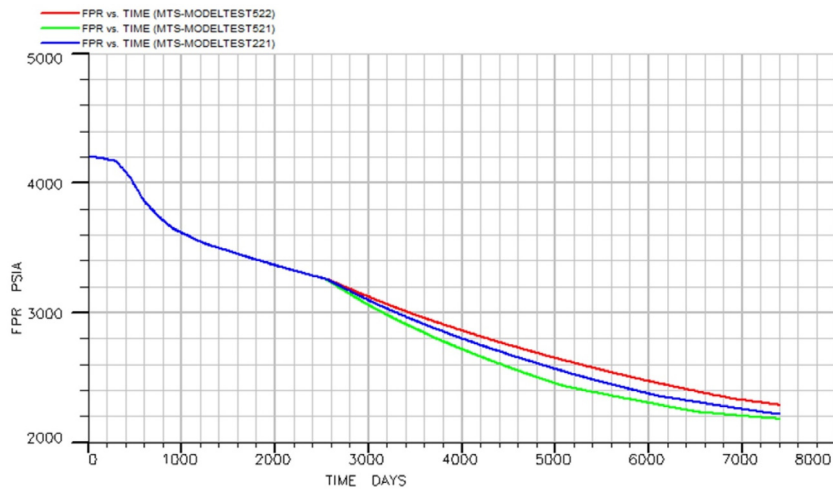


Fig. 5. The rate of FPR versus Time for three testing models (NTG evaluation).

3.3. Rock compressibility

In this scenario, the amount of Total Field Oil production (FOPT), Total Field Gas production (FGPT), Field Pressure Ratio

(FPR) and Field Gas-Oil Ratio (FGOR) are being simulated for 7400 days. The results of this study are shown clearly in Figs. 11–14. Furthermore, the amount of preferred Rock Compressibility for three cases are illustrated numerically in Table 4;

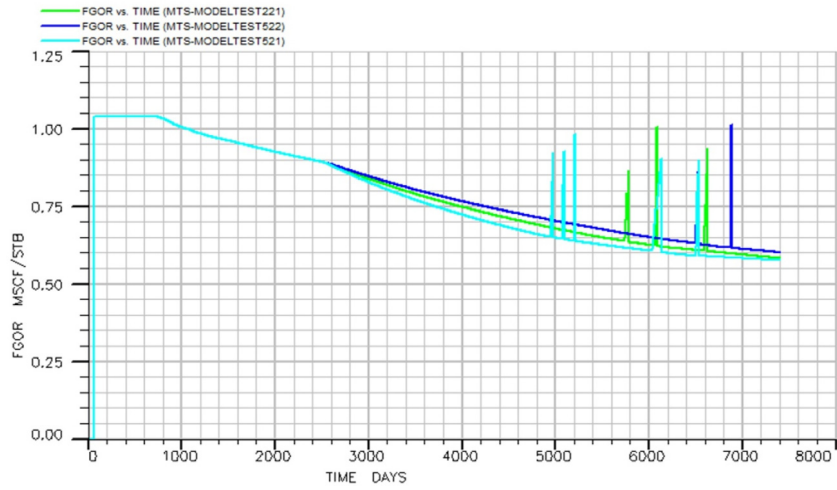


Fig. 6. The rate of FGOR versus Time for three testing models (NTG evaluation).

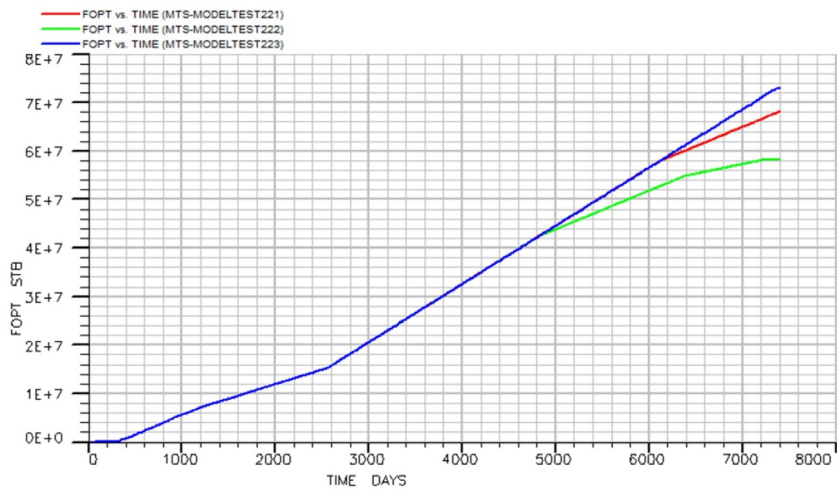


Fig. 7. The rate of FOPT versus Time for three testing models (Porosity evaluation).

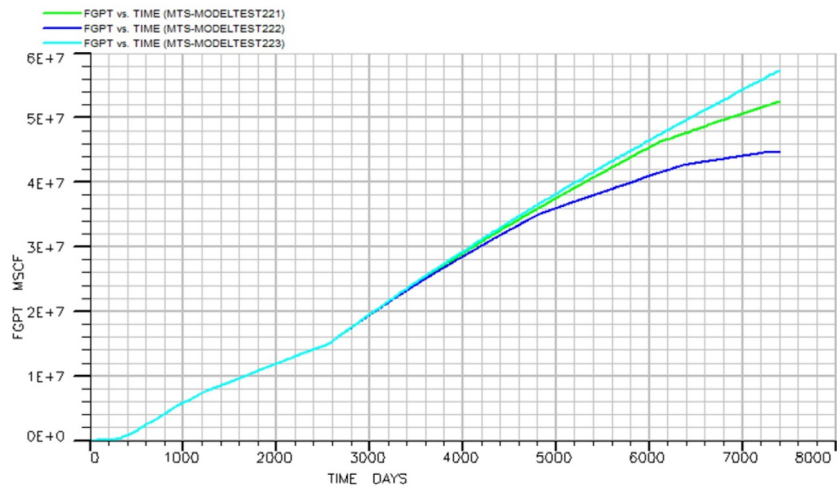


Fig. 8. The rate of FGPT versus Time for three testing models (Porosity evaluation).

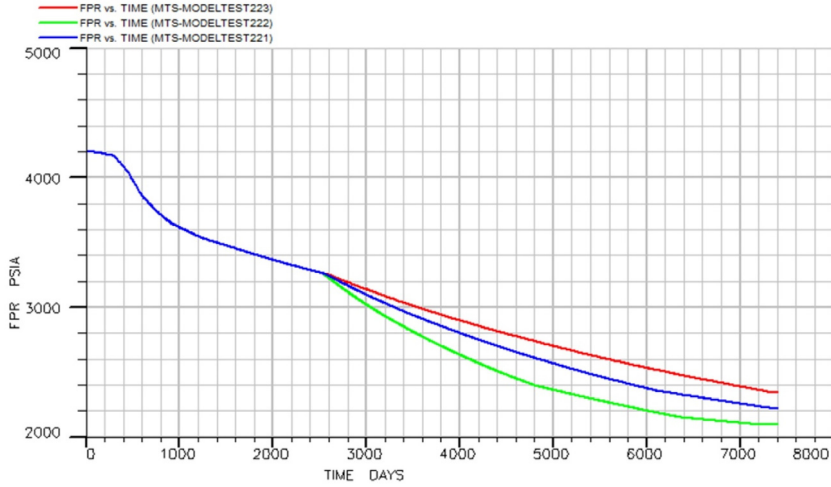


Fig. 9. The rate of FPR versus Time for three testing models (Porosity evaluation).

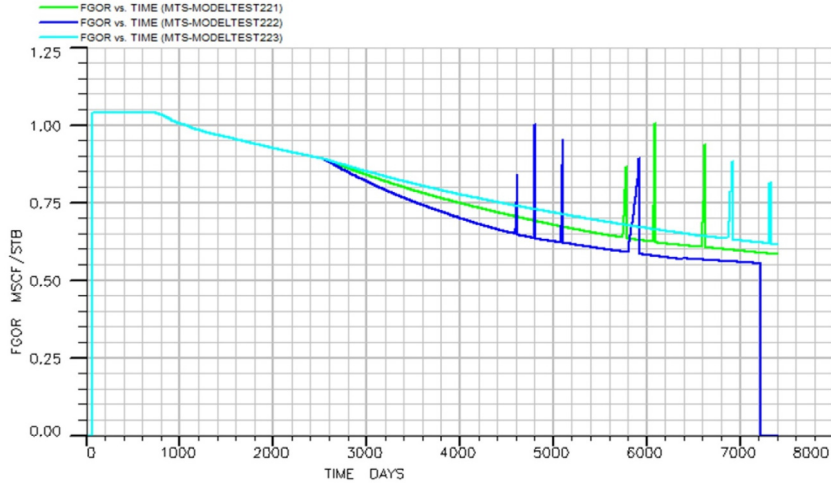


Fig. 10. The rate of FGOR versus Time for three testing models (Porosity evaluation).

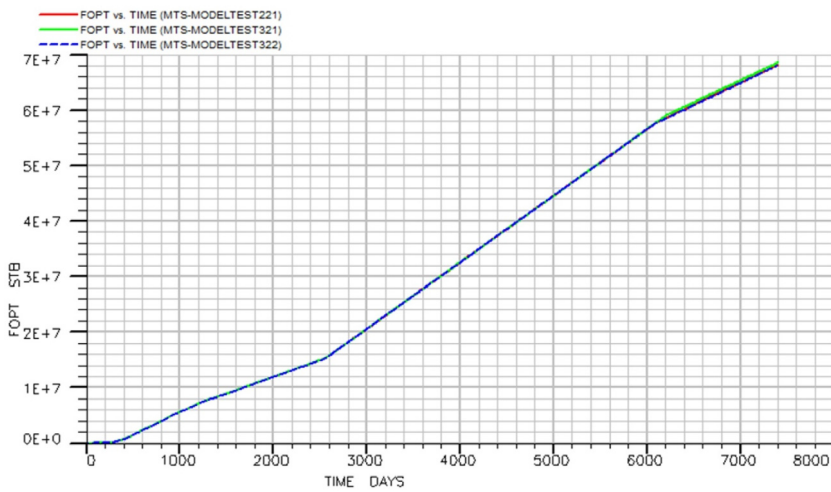


Fig. 11. The rate of FOPT versus Time for three testing models (Rock Compressibility evaluation).

4. Conclusion

In this comprehensive study, the amount of total field oil production (FOPT), total field gas production (FGPT), field pressure

ratio (FPR) and field gas-oil ratio (FGOR) are being simulated for 7400 days by the consideration of four parameters including NTG, porosity, and rock compressibility. Because Rock Compressibility would be negligible impact on the result of this simulation and

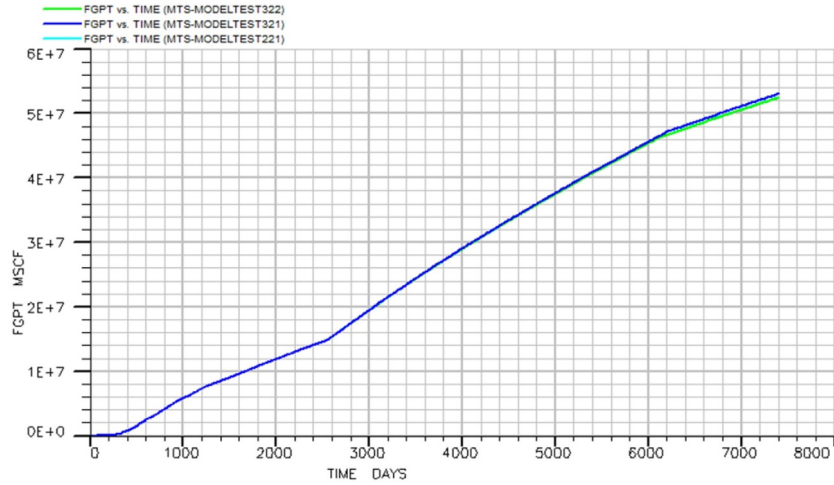


Fig. 12. The rate of FGPT versus Time for three testing models (Rock Compressibility evaluation).

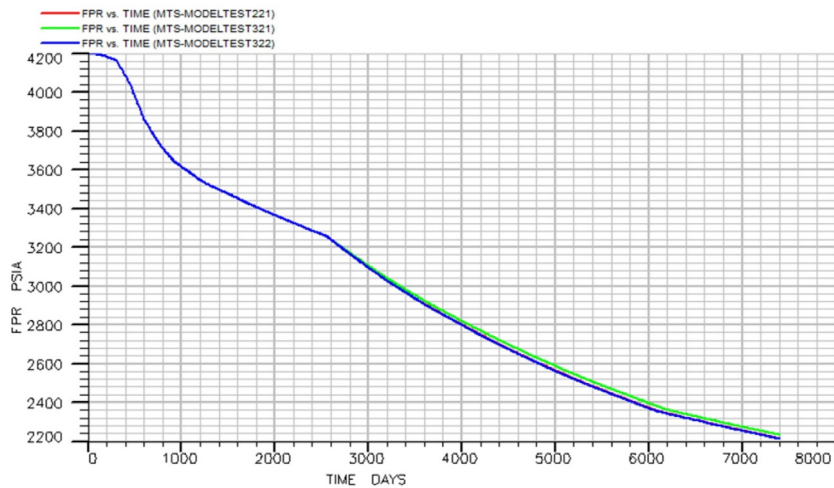


Fig. 13. The rate of FPR versus Time for three testing models (Rock Compressibility evaluation).

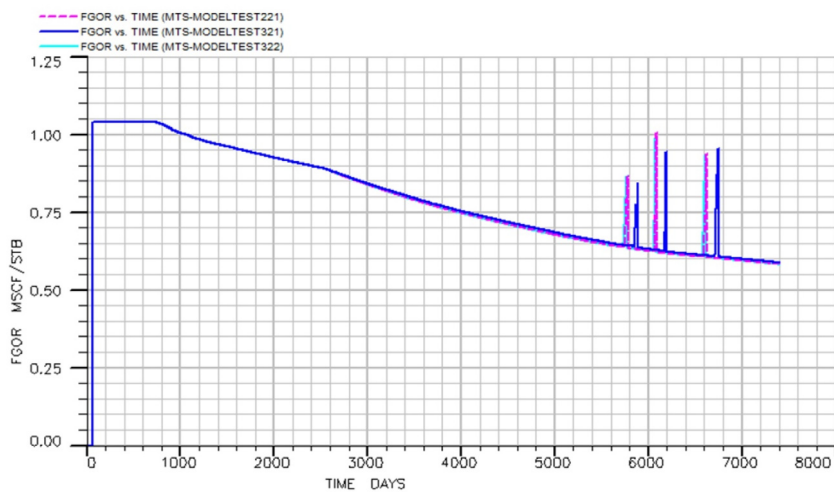


Fig. 14. The rate of FGOR versus Time for three testing models (Rock Compressibility evaluation).

lead to having less operational experimental processes to investigate the effects of these parameters. Furthermore, by increasing the amount of porosity, the amount of FOPT, FGPT, FGOR are

raised dramatically, and it is evident that this parameter is directly influenced by this type of reservoir. On the other hand, by increasing the amount of NTG, the amount of FOPT, FGPT, FGOR are raised dramatically in the NTG period of 1 to 1.5, and it is

Table 4

The amount of preferred rock compressibility for three testing models.

Rock compressibility	Min	Max	Default
Amount	754E−4	68024E−4	10244E−6
Model test no.	322	321	221

evident that this parameter is directly influenced this type of reservoir. On the contrary, the amount of FOPT, FGPT, and FGOR are decreased in the NTG period of 0.5 to 1.

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