International Journal of Petroleum and Geoscience Engineering (IJPGE) 1 (1): 50-61, 2013
ISSN 2289-4713

Production Optimization Using Different Scenarios of Gas Lift and ESP Installation

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ARTICLE INFO

Article history

Received:5 March2013

Accepted:30 March2013

Keywords:
Production,
Gas Lift,
ESP,
Pump,
Scenario,
Optimization

A b s t r a c t

The production optimization is the key to increase the total production. However, proper production scenario is resulted from the complete reservoir model. The reservoir condition is the clue to find the best production method. This paper had summarized the different studies of gas lift and ESP installation for real field data and compared it with the result of water and gas injection simulation. Different cases of production planning (including new infill wells, modification in reservoir simulation and etc.) had been done for next 40 years of the field life.

1. Introduction

The goal of production optimization is to maximize oil production. It could be done by different methods. The reservoir conditions dictate the proper production method.

The best production state for oil and gas constantly changes. In order to get the best producing state to reach the maximum ultimate oil recovery the real time analyses should be done by a reservoir simulator. Different production cases could be studied in the lifetime of the reservoir as the water injection, gas injection, gas lift design, electrical submersible pumps (ESP), different EOR methods as chemical or steam flooding, thermal methods as huff and puff and etcetera.

The reservoir simulator, which is using during the lifetime of the reservoir, gets the data from field and adjusts it with the present data. After the data are updated, the reservoir simulator should be updated again, and proper production strategy could be chosen. Therefore, there are three stages of the simulator updating as:

- Data validation
- Model updating
- Model optimization

There are some studied that published recently. They usually had used the real time evaluation method to optimize the production.

In this paper, first, we discuss some production strategies; then the background of the field of study will be expressed. The results of different production cases present and finally the conclusion on the results will discuss.

2. Production strategies

As it mentioned different production cases could be studied in the lifetime of the reservoir. Some of them related to reservoir treatment. The most important processes of these kinds in order to improve the production are the water injection, gas injection. These two methods provide the pressure maintenance and proper sweep efficiency to move the oil into the production well; of course, these strategies are suitable for lots of reservoirs (not all of them) and show a good result on a certain period. The well treatment models are related to the well completion treatment, such as gas lift, ESP design and well completion.

2.1. Reservoir treatment

The reservoir characteristics dictate the state of the reservoir treatment. It is common to use commercial reservoir simulators. The state of the reservoir should be updated in the simulator, in order to find the proper enhanced oil recovery (EOR) method. There are lots of EOR methods but the water and gas injection are very popular.

2.2. Well treatment

The production planning should be combined with the geological study and reservoir research. There are some production models that utilize the flow pattern in a stable state. These models define the conditions that the well flows or the time that the well needs to be lifted by some methods as the artificial lift. There are some lifting strategies as natural flowing, plunger lift, gas lift and pumps. The best method should be chosen (Yang et al., 1999 [1]).

2.2.1. Gas lift

Gas lift might be used to improve the production of wells, mostly with low GOR. It could be done by injecting gas in gas valves or directly into the tubing. The process is as follows, the density fluid will decrease; so the pressure drop rate from gravity will reduced. The gas lift friction is important and might lead to a large pressure drop. Lots of researchers had studied the gas lift procedure as Mayhill (1974) [2] sketched gas lift curve. He had plotted the oil production versus injected gas. Some other researchers like Kami et al. (1981) [3] used performance curves. Fang and Lo (1996) [4] generates the performance curve by lots of break points.

The optimization process in gas lift method is to find the proper rate for the well to maximize the oil production. The cost is also important to design the gas lift, it should be economic.

2.2.2. ESP

Electrical submersible pumps (ESP) are one of the effective lifting methods in order to exploit large volumes of oil from deep wells in different conditions. ESP system consists of an electric motor, rotary gas separator, centrifugal pump, motor controller and cable. The ESP’s are designed to handle wide ranges oil rate. They also can provide considerable lift pressure (6000 psi). The ESP unit places inside the well to provide enough lift when the reservoir pressure is not enough to lift the oil to the surface.

The cooling procedures of ESP motors are by the mean of fluid passing the ESP motor in pumping procedure. The important point in ESP design is that the pump should always process in suitable condition of load applied and electricity. After some overload or under load of the pump, some stages might be shut off and it will affect the well productivity. Installation of new ESP string requires work-over operation and could be costly. ESP's has been used in different conditions and had been applied in all over the world [5-9].

3. Approach

The approach of this study is as follows. The enough amounts of data are provided for the reservoir simulator. The reservoir simulator matches the data with the defined correlations and provides the knowledge about the reservoir. Figure 1 shows the drive mechanism obtained for the reservoir in the history of production. Figure 2 shows the pressure profile of the field (two separate platforms of field, D and H) for the history of production and compare the real data values with the simulated values.

After the data matching, the reservoir simulator can predict the oil production for next years. Different scenarios of production should be studied to obtain the maximum cumulative production. These scenarios contain thermal methods, chemical flooding, CO_2 injection, water injection, ESP/gas lift installation and drilling new production/injection wells.

Figure 3 shows the schematic of the reservoir porosity. The south and north parts of field are producing with platforms D and H.

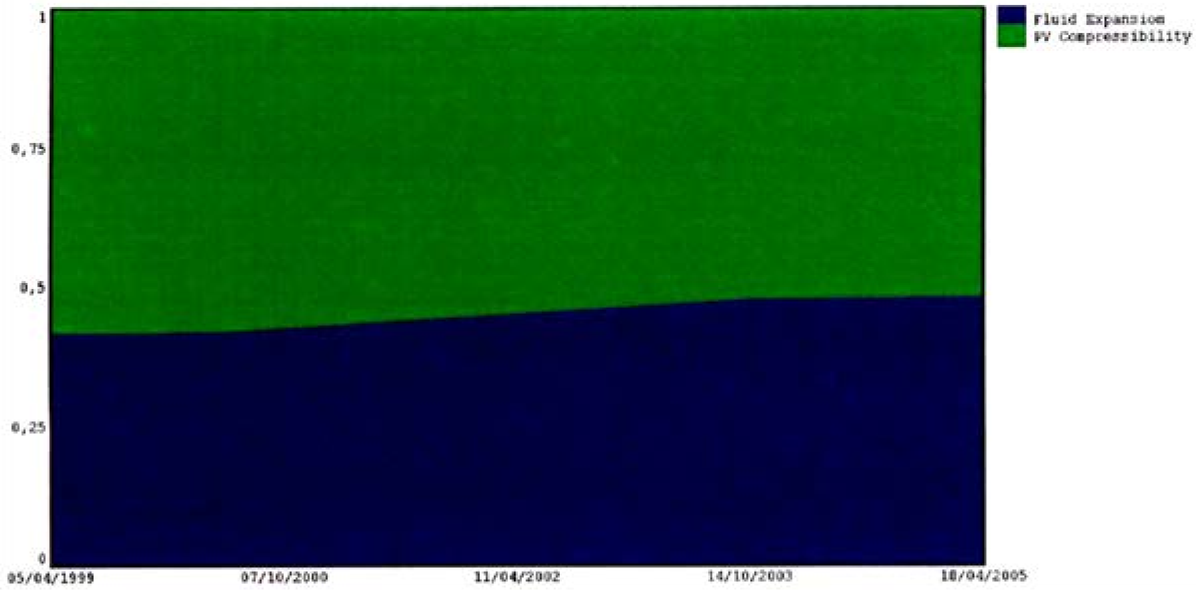

Fig. 1. History of reservoir drive mechanism.

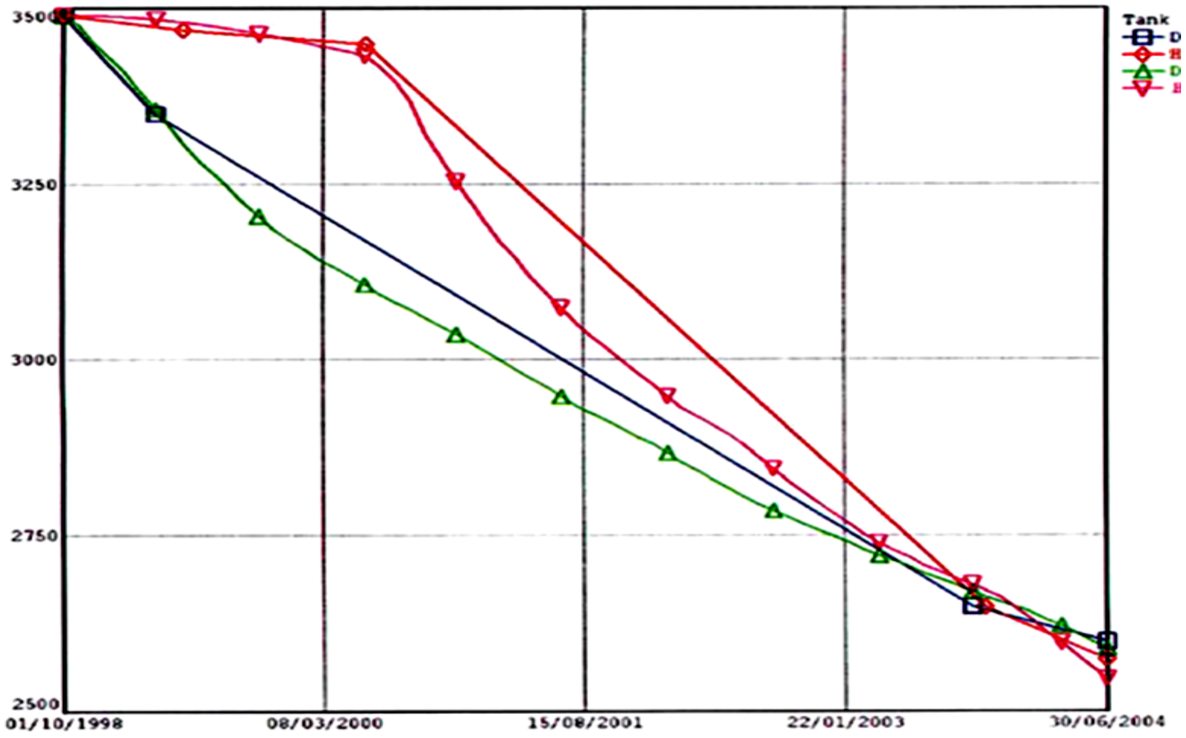

Fig. 2. History of field pressure drop.

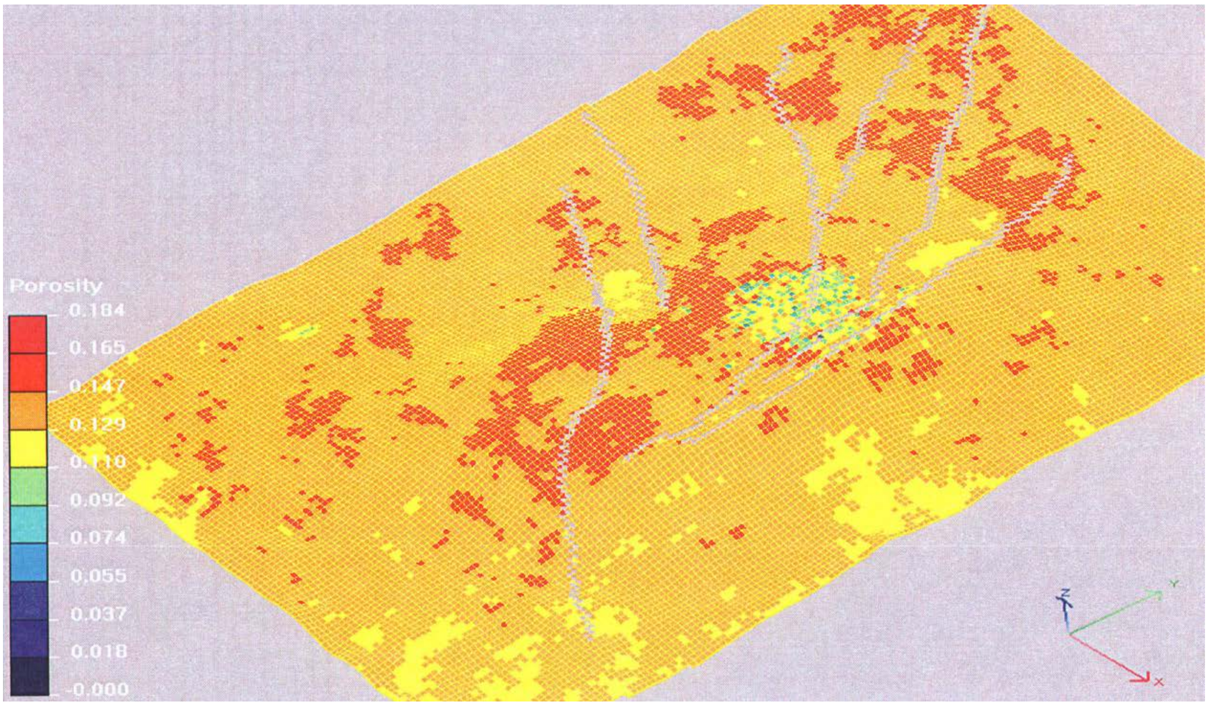

Fig. 3. The schematic of the reservoir porosity distribution.

4. Result and discussion

The main objective is to improve oil sweep efficiency by providing pressure support and optimizing wells spacing and architecture.

Field production history shows that no formation water is produced so far. The simulation study shows that there is no active aquifer. The field is generally fractured, especially in south part. It affects the result of EOR methods especially in water injection. The result of water injection is provided in table 1. These results are obtained by different water injection scenarios for the injectors in different parts of the reservoir (due to a fix capable amount of water to inject). This result looks reasonable because the production from the north part is about 3 times higher than the south part.

The thermal methods also have been applied in the simulation. This technique is not suitable in the reservoir because the oil is not heavy, reservoir is too deep and permeability is too low.

The chemical methods (surfactant and polymer flooding) are not attractive for this field as the reservoir permeability is too low.

The pump installation has been studied and the results are provided in table 2.

The CO_2 flooding method has been applied in the simulation. This method usually has some affects as reducing the interfacial tension, capillary threshold, and capillary hold up amount. At full miscibility conditions in the rock, the capillary threshold as well as capillary pressure will be zero, causing full mobilization of oil. In this reservoir fluid characteristics meet most of the required criteria of this method and the result was good. Of course, one key aspect of this method is the availability of $C0_2$ in the vicinity of the field at economic conditions.

Table.1: Water injection scenarios.

	Production 2006-2025				Status on 1/1/2025		
	Oil MMSTB	Water MMSTB		Gas BSCF	Oil rate STB/d	Water Cut%	GOR Scf/STB
		Production	Injection				
Base Case	10.8	0.1	0	3.3	792	0	306
Case 1 water injector	20.3	0	2.6	6.2	1991	0	306
Case 2 water injector	16.8	0	1.0	5.1	783	0	306
Case 3 water injector	18.8	0	3.6	5.8	1923	0	306

Table.2: ESP scenarios.

	Production 2006-2025			Status on 1/1/2025		
	Oil MMSTB	Water MMSTB	Gas BSCF	Oil rate STB/d	Water Cut%	GOR Scf/STB
Base Case	10.8	0.1	3.3	7920	0	306
E.S.P. scenario #1	37.4	0.4	11.5	3153	2.2	306
E.S.P. scenario #2	57.6	0.5	20.8	6721	1.8	452

Gas lift allows increasing wells output as shown the results in table 3. Drilling new horizontal wells in available slots would improve the ultimate recovery due to the special reservoir conditions.

This screening indicates that among the classical EOR methods, only C02 flooding may be attractive for the field after a feasibility and economic study. The overall production statistics until 2025 are summarized in the table 4. The results show that the ESP scenario enhances the oil exploitation. If the simulation continues with this scenario until 2049 (after that the production is not economic), the field can deliver the cumulative oil about 121 MMSTB as the results in table 5.

Figure 5 shows the comparison of the production of ESP, gas lift and the base case for upcoming years. If the economic issues are applied in the methods, figure 6 would be obtained. This figure expressed that the initial cost of gas lift facility installation is high and this might be unfavourable for the managers.

Some other contributions also have been applied in the simulation study as some changes in geological models, and adding some production/injection wells. After defining the results, table 6 would be obtained. It is recommended to implement the optimum case (ESP on the 11 wells), to compare after a few years, actual versus predicted oil production and in the same time update the simulation model. Only after these actions it is recommended to eventually consider additional drilling. Use of ESP has a major impact on oil production (+ 50%) Water injection looks attractive (+ 80 % between cases 4 and 6) but uncertainty remains on communication between injectors and producers. Aquifer plays a minor role Fault permeability is an issue as production varies by 15% pending on sealing or non-sealing faults. Also addition of solvent in injected water has a minor effect.

Table.3: Gas lift scenarios.

	Production 2006-2025				Status on 1/1/2025		
	Oil MMSTB	Water MMSTB	Gas BSCF		Oil rate STB/d	Water Cut%	GOR Scf/STB
			Production	Gas lift			
Base Case	10.8	0.1	3.3	0	792	0	306
D& H platforms on Gas Lift	54.3	05	19.1	27.5	6242	2.1	436
D platform on Gas Lift	31.7	0.2	9.9	7.9	3220	0.9	355
H platform on Gas Lift	40.5	0.4	14.1	21.3	4322	2.4	428

Table.4: Overall production statistics.

	Cumulative production in 2025			Status in 2025		
	Oil MMSTB	Water MMSTB	Gas BSCF	Oil rate STB/d	Water Cut%	GOR Scf/STB
Base Case	31.8	0.14	9.7	792	0	306
ESP scenario	78.6	0.54	27.2	6721	1.8	452
Gas lift scenario	75.3	0.54	33.9	6242	2.1	436
Water injection	41.3	0.04	12.6	1991	0	306
Gas injection: 2 new gas injectors	56.9	0	5.1	783	0	306

Table.5: ESP scenario until 2049.

Production	Cumulative Prod (MMSTB)	Production in a year (MMSTB)
2005	21.04	1.44
2006	23.30	2.26
2007	25.31	2.01
2008	27.22	1.90
2009	28.97	1.76
2010	33.20	4.23
2011	37.70	4.50
2012	42.00	4.30
2013	46.15	4.14
2014	50,05	3.90
2015	53.71	3.66
2016	57.17	3.47
2017	60.48	3.31
2018	63.63	3.16
2019	66.62	2.99
2020	69.47	2.85
2021	72.15	2.68
2022	74.71	2.56
2023	77.17	2.46
2024	79.53	2.36
2025	81.78	2.26

2026	83.96	2.18
2027	86.07	2.11
2028	88.11	2.04
2029	90.09	1.97
2030	92.00	1.91
2031	93.85	1.85
2032	95.65	1.80
2033	97.40	1.75
2034	99.11	1.71
2035	100.77	1.66
2036	102.41	1.63
2037	104,00	1.59
2038	105.56	1.56
2039	107.09	1.53
2040	108.60	1.51
2041	110.07	1.48
2042	111.52	1.45
2043	112.94	1.42
2044	114.35	1.40
2045	115.72	1.38
2046	117.07	1.35
2047	118.40	1.33
2048	119.71	1.31
2049	121.00	1.29

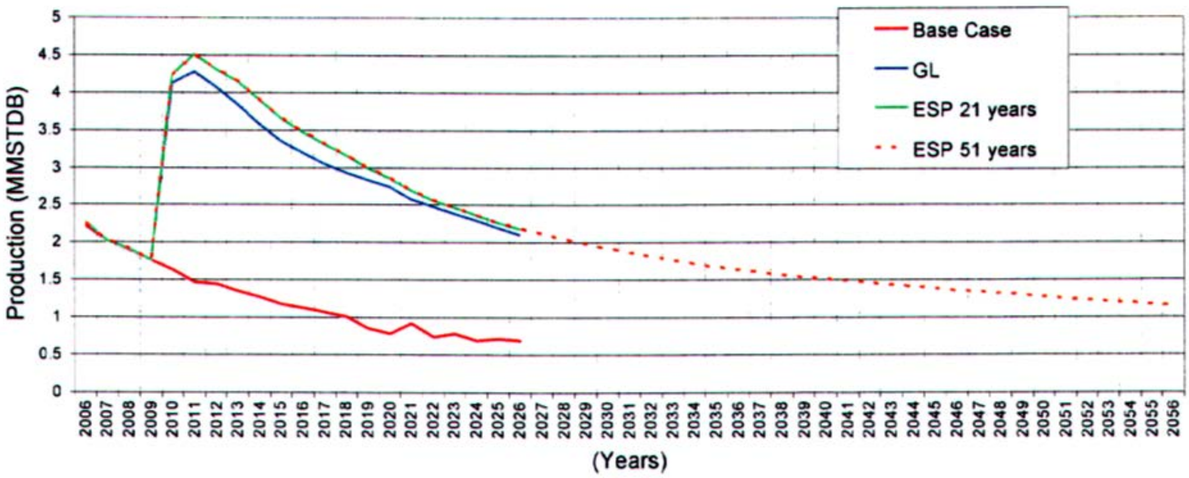

Fig. 5. Comparison of the production of ESP, gas lift and the base case.

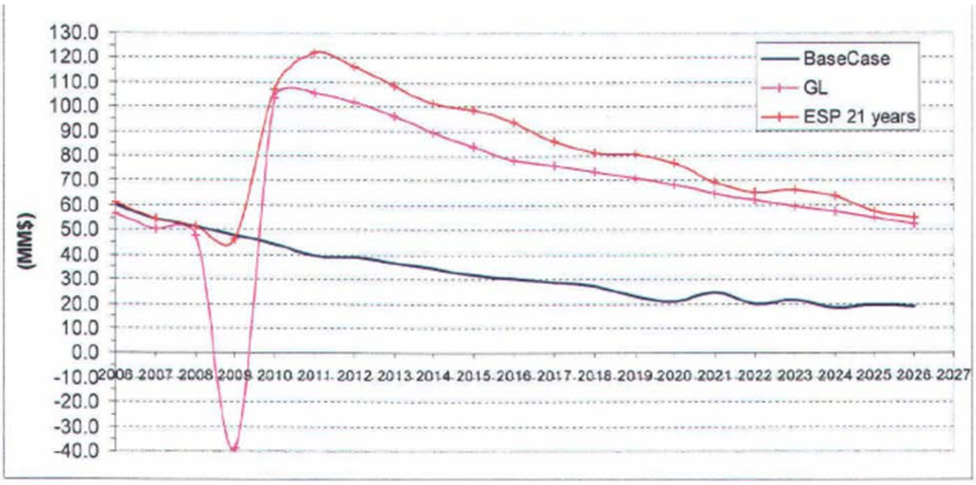

Fig. 6. Comparison of the production of ESP, gas lift and the base case with considering the economic issues.

Table.6: Results after considering other contributions in the simulation as some changes in geological models, and adding some production/injection wells.

	Producers	Injectors	Lift	Geology	Cumulative Oil in 2040 MMSTB
Case 1-Base	11		Natural		53
Case 2	11		ESP		80.3
Case 3	23		Natural		83.7
Case 4	23		ESP		95
Case 5	23		ESP	No aquifer	89.2
Case 6	14	13	ESP		175.6
Case 7	14	13 + solvent	ESP		179.6
Case 8	23		ESP	Seaiing faults	89
Case 9	14	13	ESP	Seaiing faults	152.2

5. Conclusion

The following conclusions are obtained in this study;

i. ESP (electrical submersible pumping) will increase the production by lowering the flowing bottom hole pressures.

ii. Gas lift also improves the production but the initial installation cost is high, so it is not economic.

iii. The low matrix permeability and low fracturing in some part of reservoir cause low ultimate recovery factor.

iv. The lack of pressure support and active aquifer lead to low production results for the water injection method.

v. This screening indicates that among the classical EOR methods, only C02 flooding might be attractive for this field.

vi. Different cases of well facilities and EOR models combined with the new wells and new injectors and the results shows more than three times improvement from base case.

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